# Cenovus Energy Inc.

Management's Discussion and Analysis
For the Period Ended March 31, 2011

*This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated April 26, 2011, should be read with our unaudited interim consolidated financial statements for the period ended March 31, 2011 ("interim Consolidated Financial Statements"), as well as the audited consolidated financial statements for the year ended December 31, 2010 (the "Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates and projections. For information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information, as well as definitions used in this MD&A, see the Advisory section at the end of this MD&A.*

*Management is responsible for preparing the MD&A. The Audit Committee of the Cenovus Board of Directors (the "Board") reviewed the MD&A and recommended its approval by the Board.*

*This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency is indicated, and in accordance with International Financial Reporting Standards ("IFRS"), which are also generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada. For all periods up to and including the year ended December 31, 2010, we prepared our Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). In accordance with the standard related to the first time adoption of IFRS, our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been prepared in accordance with our IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed by the standard related to the first time adoption of IFRS ("IFRS 1"), has not been re-presented on an IFRS basis. Production volumes are presented on a before royalties basis. Certain amounts in prior years have been reclassified to conform to the current year's IFRS presentation format.*

**WHERE TO FIND**:

## INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

We are a Canadian oil company headquartered in Calgary, Alberta, and had a market capitalization of approximately $29 billion on March 31, 2011. In the first quarter of 2011, we had total crude oil, natural gas and NGLs production in excess of 246,000 barrels of oil equivalent per day. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties are located in the Athabasca region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. Also located within the Athabasca region is our Pelican Lake property, where we have an enhanced oil recovery project using polymer flood technology, as well as our emerging Grand Rapids project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation. We also have established conventional crude oil and natural gas production in Alberta and Saskatchewan. In addition to our upstream assets, we have 50 percent ownership in two refineries in Illinois and Texas, U.S.A., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel, to reduce the volatility associated with commodity price movements.

Our operational focus over the next five years will be to increase production, predominantly from Foster Creek and Christina Lake, as well as Pelican Lake, and to continue assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach. Our conventional crude oil and natural gas production base is expected to generate reliable production and cash flows which will enable further development of our oil sands assets. In all of our operations, whether crude oil or natural gas, technology plays a key role in improving the way we extract the resources, increasing the amount recovered and reducing costs. Cenovus has a knowledgeable, experienced team committed to continuous innovation. One of our most significant ongoing objectives is to advance technologies that reduce the amount of water, steam, natural gas and electricity consumed in our operations and to minimize surface land disturbance.

The Company's strategy is to focus on the development of its substantial crude oil resource in Alberta and Saskatchewan. Our future opportunities are primarily in developing the land position that we hold in the Athabasca region in northeast Alberta. In addition to our Foster Creek and Christina Lake oil sands projects, the next three emerging projects in this area are as follows:

| | Ownership Interest |
|---|---|
| Narrows Lake | 50 percent (1) |
| Grand Rapids | 100 percent |
| Telephone Lake | 100 percent |

(1) Approximate ownership interest

For our Narrows Lake property, located within the Christina Lake Region, we have submitted a joint application and environmental impact assessment. This project is expected to begin producing in 2016, and is expected to have a gross production capacity of 130,000 bbls/d. At our Grand Rapids property, which is located within the Greater Pelican Region, a pilot project is underway. If this pilot is determined to be successful, we expect to file a regulatory application for a commercial operation with gross production capacity of 180,000 bbls/d. Our Telephone Lake property is located within the Borealis Region. We have submitted a regulatory application for the development of this property, including the construction of a facility with gross production capacity of 35,000 bbls/d.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands, most of which is undeveloped. Our 10 year business plan includes growing our net oil sands production from approximately 60,000 bbls/d in 2010 to 300,000 bbls/d by the end of 2019. Growth is expected to be primarily internally funded through cash flow generated from our established crude oil and natural gas production base where we also have opportunities to add production through new technologies. Our natural gas production provides a reliable stream of operating cash flow and an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our refineries, which are operated by ConocoPhillips, an unrelated U.S. public company, enable us to moderate commodity price cycles by processing heavy oil, thus economically integrating our oil sands production. A key milestone in this regard is the planned 2011 coker startup of the Coker and Refinery Expansion ("CORE") project at the Wood River refinery. We also employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we expect to continue to pay meaningful dividends as part of delivering a strong total shareholder return over the long-term.

## OUR BUSINESS STRUCTURE

Our reportable segments are as follows:

- **Oil Sands**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips.

- **Conventional**, which includes the development and production of conventional crude oil, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide sequestration project at Weyburn, and the Bakken and Shaunavon crude oil properties.

- **Refining and Marketing**, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

- **Corporate and Eliminations**, which primarily includes unrealized gains or losses recorded on derivative financial instruments, gains or losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

## OVERVIEW OF THE FIRST QUARTER OF 2011

We entered 2011 looking to build upon our strong 2010 results. Overall, the first quarter results have met or exceeded our expectations. Excellent operational performance at Foster Creek and Christina Lake resulted in record production levels at each of these projects. Conventional crude oil production volumes in the quarter were on track to meet full year expectations, while natural gas production volumes were less than expected mainly due to weather related issues.

Pricing had a significant impact on our quarterly results. While WTI prices were up substantially, the WTI-WCS differential widened to an average of nearly US$23.00 per barrel, primarily due to higher industry-wide inventory levels of WCS in January and February. The increased WTI price had a negative impact on our royalty calculations, particularly Foster Creek, and also resulted in realized losses on our crude oil financial instruments for the quarter. While prices had a negative impact on our Oil Sands and Conventional operations, operating cash flow from our Refining and Marketing operations increased significantly with improved refining margins due to higher crack spreads and the low cost of purchased product largely due to the widening WTI-WCS differential. The improvement in our refining margins offsets some of the pricing impact in our Oil Sands and Conventional segments and reflects the successful integration of our business model which reduces the volatility associated with commodity price movements.

Early in the quarter, to manage the continued impacts of pipeline apportionment arising from pipeline outages late in 2010, we were able to pursue alternate markets for our crude oil which resulted in increased costs for transportation and blending, but allowed us to move production for a competitive netback price and largely minimize production shut-ins.

Our capital program is generally on plan. Capital expenditures of $713 million for the quarter were significantly higher than 2010. The increased spending was primarily due to work continuing on the next phases of Foster Creek and Christina Lake and successfully completing our largest ever stratigraphic well program in the quarter drilling 440 gross stratigraphic wells.

First quarter operational and development highlights compared to 2010 include:
- Foster Creek production averaging 57,744 bbls/d, an increase of 13 percent;
- Christina Lake production averaging 9,084 bbls/d, an increase of 22 percent;
- A four percent increase in our Conventional crude oil and NGLs production volumes, excluding the impact of 2010 divestitures, primarily due to higher production at Bakken and Lower Shaunavon;
- A 16 percent decrease in our natural gas production volumes consistent with our strategy of divesting of non-core properties and natural declines not being offset by our decision to reduce the related capital investment in response to weak natural gas prices;
- Expansion phases C and D at Christina Lake continuing to progress on target with expected first production at phase C in the third quarter of 2011 and at phase D in early 2013; and
- Additional progress on the CORE project at Wood River with coker start up expected in the fourth quarter of 2011.

The financial highlights for the first quarter of 2011 compared to 2010 include:

- Revenues increasing $278 million, or nine percent, primarily due to improved refined product prices as well as five percent higher crude oil and NGLs production volumes partially offset by lower average commodity sales prices;
- Higher benchmark WTI crude oil prices were offset by wider heavy oil differentials and a strengthening of the Canadian dollar resulting in a lower netback price, excluding realized risk management gains or losses. In addition, lower natural gas volumes and sales prices contributed to lower Oil Sands and Conventional operating cash flow;
- Operating cash flow from Refining and Marketing increasing $183 million due to an improvement in refining operating cash flow of $186 million attributable to higher crack spreads;
- Our Conventional segment generating more than $200 million in operating cash flow in excess of the related capital, which partially funded the further development of our oil sands projects;
- Cash flow of $693 million, decreasing four percent from the first quarter of 2010, primarily due to lower natural gas prices and volumes;
- Operating earnings decreasing $144 million to $209 million, primarily due to lower cash flow and higher deferred income tax expense (excluding deferred tax on unrealized risk management gains and losses); and
- Continuing our quarterly dividend of $0.20 per share.

Overall, we achieved solid results in the quarter.

## OUR BUSINESS ENVIRONMENT

Key performance drivers for our financial results include commodity prices, price differentials, refining crack spreads as well as the U.S./Canadian dollar exchange rate. The following table shows select market benchmark prices and foreign exchange rates to assist in understanding our financial results.

### Selected Benchmark Prices [1]

| | **2011** | 2010 | | | | 2009 | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **Q1** | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 |
| **Crude Oil Prices** *(US$/bbl)* | | | | | | | | | |
| West Texas Intermediate | | | | | | | | | |
| Average | **94.60** | 85.24 | 76.21 | 78.05 | 78.88 | 76.13 | 68.24 | 59.79 | 43.31 |
| End of period spot price | **106.72** | 91.38 | 79.97 | 75.63 | 83.45 | 79.36 | 70.46 | 69.82 | 49.64 |
| Western Canada Select (WCS) | | | | | | | | | |
| Average | **71.74** | 67.12 | 60.56 | 63.96 | 69.84 | 64.01 | 58.06 | 52.37 | 34.38 |
| End of period spot price | **91.37** | 72.87 | 64.97 | 61.38 | 70.25 | 71.84 | 59.76 | 59.12 | 42.69 |
| Average Price – Differential WTI-WCS | **22.86** | 18.12 | 15.65 | 14.09 | 9.04 | 12.12 | 10.18 | 7.42 | 8.93 |
| Condensate (C5 @ Edmonton) | **98.90** | 85.24 | 74.53 | 82.87 | 84.98 | 74.42 | 65.76 | 58.07 | 46.26 |
| Average Price - Differential | | | | | | | | | |
| WTI-Condensate (premium)/discount | **(4.30)** | - | 1.68 | (4.82) | (6.10) | 1.71 | 2.48 | 1.72 | (2.95) |
| **Refining Margin 3-2-1 Crack Spread** [2] *(US$/bbl)* | | | | | | | | | |
| Chicago | **16.62** | 9.25 | 10.34 | 11.60 | 6.11 | 5.00 | 8.48 | 10.95 | 9.75 |
| Midwest Combined (Group 3) | **19.04** | 9.12 | 10.60 | 11.38 | 6.82 | 5.52 | 8.06 | 9.16 | 9.62 |
| **Natural Gas Prices** | | | | | | | | | |
| AECO *($/GJ)* | **3.58** | 3.39 | 3.52 | 3.66 | 5.08 | 4.01 | 2.87 | 3.47 | 5.34 |
| NYMEX *(US$/MMBtu)* | **4.11** | 3.80 | 4.38 | 4.09 | 5.30 | 4.17 | 3.39 | 3.50 | 4.89 |
| Basis Differential NYMEX-AECO | | | | | | | | | |
| *(US$/MMBtu)* | **0.29** | 0.28 | 0.78 | 0.32 | 0.19 | 0.19 | 0.67 | 0.39 | 0.35 |
| **Foreign Exchange** | | | | | | | | | |
| Average U.S./Canadian dollar | | | | | | | | | |
| exchange rate | **1.015** | 0.987 | 0.962 | 0.973 | 0.961 | 0.947 | 0.911 | 0.857 | 0.803 |

(1) These benchmark prices do not include the impacts of our hedging program or reflect our sales prices. For our average sales prices and realized risk management results, refer to the Operating Netbacks in the Results of Operations section of this MD&A.
(2) 3-2-1 Crack Spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of gasoline and one barrel of ultra low sulphur diesel.

The benchmark WTI price in the first quarter of 2011 increased as it was impacted by the geopolitical conflict in Libya which resulted in a reduced supply of crude oil from the region. While the majority of this production is sold to European markets, it does have an impact on North American crude oil prices. As a result, the benchmark WTI price increased to above US$106.00 per barrel in the first quarter. Despite rising prices, the WTI discount to global crudes increased during the first quarter as growing onshore supply, pipeline limitations and higher Cushing-area refinery maintenance created congestion due to limited pipeline capacity to U.S. Gulf Coast markets, which resulted in further discounting of inland crudes. The natural disaster in Japan did not have a material effect on crude oil prices in the first quarter despite the reduced demand for crude oil due to Japan's economic activities being interrupted. WTI is an important benchmark for Canadian crude since it reflects onshore North American prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties.

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. The effect of pipeline transportation disruptions and the apportionment of crude oil from western Canada to mid-west U.S. refineries that began in the second half of 2010 continued to affect WCS pricing into the first quarter of 2011. In addition to heavy crude supply growth, inland synthetic and tight oil crudes also showed strong growth which strained available pipeline capacity and resulted in all grades of inland crudes being discounted to tidewater crudes, including WTI at Cushing, Oklahoma. These pipeline restrictions resulted in a continued buildup of WCS inventory early in the year and, along with the increased WTI price, resulted in the WTI-WCS differential widening to as much as US$33.00 per barrel before recovering to US$15.35 per barrel at the end of the first quarter as Canadian inventory levels moderated.

Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. The WTI-Condensate differential is the benchmark price of condensate relative to the price of WTI. As purchased condensate is sold as part of the crude oil blend, the cost of condensate purchases impacts our revenues as well as our transportation and blending costs. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem. As WTI discounts to offshore light crudes increased, condensate premiums to WTI grew since the marginal barrel of condensate in Alberta markets was sourced from markets tied to global, rather than inland prices.

Benchmark global refining margin crack spreads remained weak for most of the first quarter until earthquake damage to the Japanese refining capacity moderately improved benchmark crack spreads. However, crack spreads in the U.S. inland Chicago and Group 3 markets improved significantly from the same period in 2010, benefiting from both the previously discussed inland crude oil discounts and refined product prices that continued to be tied to global market prices.

In the first quarter of 2011, benchmark NYMEX natural gas prices were lower than the same period in 2010. The lower natural gas prices continue to reflect the impact of strong natural gas supply growth. Despite a very cold winter and significant switching from coal fired to natural gas fired electric generation, natural gas in storage remained just above the five year averages at the end of the quarter.

During the first quarter of 2011, the Canadian dollar strengthened relative to the U.S. dollar, primarily driven by the increase in crude oil prices. However, since the start of the Libyan conflict, the Canadian dollar has not appreciated as it had previously with increases in crude oil prices. An increase in the value of the Canadian dollar compared to the U.S. dollar has a negative impact on our revenues as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a strengthened Canadian dollar reduces our reported results.

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. Realized gains on risk management activities, after-tax, in the first quarter of 2011 were $11 million (2010 – gains of $17 million). Further information regarding our risk management program can be found in the notes to the interim Consolidated Financial Statements.

## FINANCIAL INFORMATION

This is our first reporting period using our IFRS accounting policies. In accordance with IFRS 1, our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been prepared in accordance with our IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed under IFRS 1, has not been re-presented. Further information regarding our IFRS accounting policies can be found in the Accounting Policies and Estimates section of this MD&A as well as in the notes to the interim Consolidated Financial Statements.

## SELECTED CONSOLIDATED FINANCIAL RESULTS

| ($ millions, except per share amounts) | **Q1 2011** | Q4 2010 | Q3 2010 | Q2 2010 | Q1 2010 | Q4 2009 | Q3 2009 | Q2 2009 | Q1 2009 |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | ***(Prepared following previous GAAP)*** | | | |
| Revenues [1] | **3,500** | 3,363 | 2,962 | 3,094 | 3,222 | 3,005 | 3,001 | 2,818 | 2,693 |
| Operating Cash Flow [2] | **834** | 815 | 661 | 665 | 840 | 954 | 1,134 | 1,173 | 928 |
| Cash Flow [2] | **693** | 645 | 509 | 537 | 721 | 235 | 924 | 945 | 741 |
| - per share – diluted [3] | **0.91** | 0.85 | 0.68 | 0.71 | 0.96 | 0.31 | 1.23 | 1.26 | 0.99 |
| Operating Earnings [2] | **209** | 147 | 156 | 143 | 353 | 169 | 427 | 512 | 414 |
| - per share – diluted [3] | **0.28** | 0.19 | 0.21 | 0.19 | 0.47 | 0.23 | 0.57 | 0.68 | 0.55 |
| Net Earnings | **47** | 78 | 295 | 183 | 525 | 42 | 101 | 160 | 515 |
| - per share – basic [3] | **0.06** | 0.10 | 0.39 | 0.24 | 0.70 | 0.06 | 0.13 | 0.21 | 0.69 |
| - per share – diluted [3] | **0.06** | 0.10 | 0.39 | 0.24 | 0.70 | 0.06 | 0.13 | 0.21 | 0.69 |
| Capital Investment [4] | **713** | 701 | 479 | 444 | 491 | 507 | 515 | 488 | 652 |
| Free Cash Flow [2] | **(20)** | (56) | 30 | 93 | 230 | (272) | 409 | 457 | 89 |
| Cash Dividends [5] | **151** | 151 | 150 | 150 | 150 | 159 | n/a | n/a | n/a |
| - per share [5] | **0.20** | 0.20 | 0.20 | 0.20 | 0.20 | US$0.20 | n/a | n/a | n/a |

(1) Under previous GAAP, the amounts for 2009 represent Net revenues, which include the gains and losses on the revenue components of our risk management activities which are now reported in a separate line item.
(2) Non-GAAP measures defined within this MD&A.
(3) Any per share amounts prior to December 1, 2009 have been calculated using Encana Corporation's ("Encana") common share balances based on the terms of the plan of arrangement ("Arrangement"), wherein Encana shareholders received one common share of Cenovus and one common share of the new Encana.
(4) Includes expenditures on property, plant and equipment and exploration and evaluation assets.
(5) The fourth quarter 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

## REVENUES VARIANCE

| ($ millions) | | |
|---|---|---|
| Revenues for the Three Months Ended March 31, 2010 | $ | 3,222 |
| Increase (decrease) due to: | | |
| Oil Sands | | 53 |
| Conventional | | (126) |
| Refining and Marketing | | 353 |
| Corporate and Eliminations | | (2) |
| **Revenues for the Three Months Ended March 31, 2011** | **$** | **3,500** |

Our Oil Sands revenues increased in the first quarter of 2011 primarily due to seven percent higher crude oil production partially offset by lower average crude oil sales prices as a result of the widening WTI-WCS differential. Also contributing to the increase in revenues was the increase in price and volumes of condensate used to blend with heavy oil, consistent with increases in our production. Partially offsetting these revenue increases was higher royalties as a result of higher WTI prices and a full quarter of project post payout royalties at Foster Creek.

Our Conventional revenues decreased in the first quarter of 2011 primarily due to lower natural gas sales prices and expected declines in natural gas production as well as decreases in the average crude oil sales prices. Partially offsetting these decreases were increases in crude oil production and lower natural gas royalties.

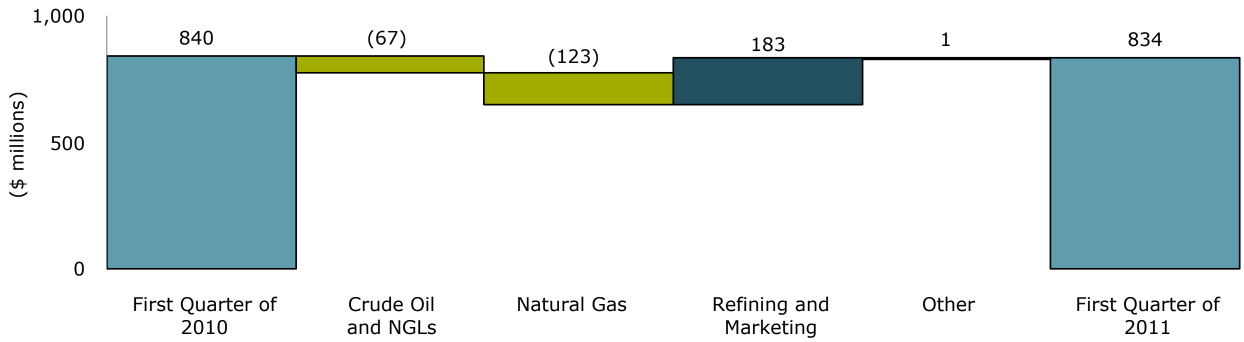
Our Refining and Marketing revenues in the first quarter of 2011 increased primarily because of higher refined product prices as well as higher volumes related to operational third party sales undertaken by the marketing group.

Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

## OPERATING CASH FLOW

| ($ millions) | Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| Oil Sands | | |
| Crude Oil and NGLs | **$ 250** | $ 299 |
| Natural Gas | **7** | 16 |
| Other | **2** | - |
| Conventional | | |
| Crude Oil and NGLs | **208** | 226 |
| Natural Gas | **185** | 299 |
| Other | **2** | 3 |
| Refining and Marketing | **180** | (3) |
| Operating Cash Flow | **$ 834** | $ 840 |

Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between years. Operating cash flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains or losses on risk management activities. Operating cash flow excludes unrealized gains and losses on risk management activities, which are included in the Corporate and Eliminations segment.



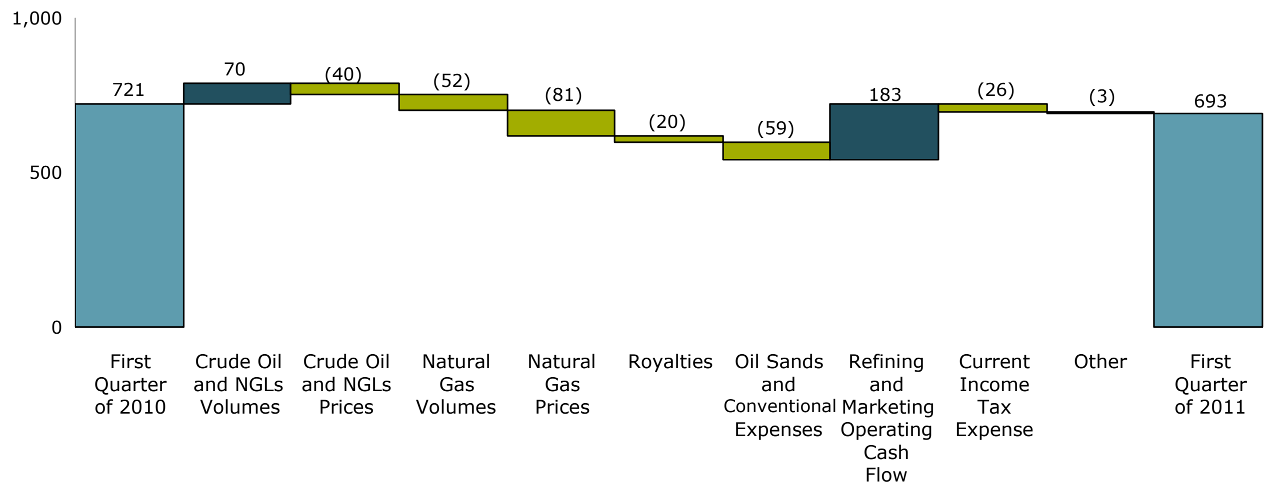

Operating cash flow decreased $6 million in the first quarter of 2011 primarily because of a $123 million reduction related to natural gas as a result of lower sales prices and volumes. Operating cash flow generated by crude oil and NGLs decreased $67 million in the first quarter of 2011 primarily due to lower average sales prices, as well as higher royalties and higher operating expenses partially offset by increased production. These decreases were partially offset by higher operating cash flow from Refining and Marketing, which increased $183 million due primarily to improved refinery margins. This improvement was attributable to both higher refined product prices as well as favourable purchased product costs resulting from the widened WTI-WCS differential and U.S. inland crude oil discounts.

Details of the components that explain the decrease in operating cash flow can be found in the Reportable Segments section of this MD&A.

## CASH FLOW

Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Cash flow is commonly used in the oil and gas industry to assist in measuring the ability to finance capital programs and meet financial obligations.

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Cash From Operating Activities | **$ 631** | $ 820 |
| (Add back) deduct: | | |
| Net change in other assets and liabilities | **(29)** | (15) |
| Net change in non-cash working capital | **(33)** | 114 |
| Cash Flow | **$ 693** | $ 721 |




In the first quarter of 2011 our cash flow decreased $28 million compared to the same period in 2010 primarily due to:

- A 28 percent decrease in the average natural gas sales price to $3.82 per Mcf compared to $5.27 per Mcf;
- Natural gas production declining 16 percent, as a result of the divestiture of 41 MMcf/d in non-core properties in 2010 and expected natural declines;
- Higher crude oil and NGLs operating expenses mainly due to increased repairs and maintenance activities, weather related issues and increased long-term incentive expense as a result of the increase in our share price;
- A five percent decrease in the average sales price of crude oil and NGLs to $65.37 per barrel compared to $68.85 per barrel;
- A $26 million increase in current income tax expense as a result of higher operating cash flow in Refining and Marketing. Current income tax expense was also higher because we utilized certain Canadian tax pools from our inception in the first quarter of 2010, which lowered current income tax expense; and
- An increase in royalties of $20 million primarily as a result of higher WTI prices in 2011, as well as 2010 only including two months of Foster Creek project post payout royalties.

The decreases in our 2011 first quarter cash flow were partially offset by:

- A significant increase in operating cash flow from Refining and Marketing of $183 million, mainly due to improved refinery margins; and
- A five percent increase in our crude oil and NGLs production volumes.

## OPERATING EARNINGS

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Net Earnings | **$ 47** | $ 525 |
| (Add back) deduct: | | |
| Unrealized risk management gains (losses), after-tax [(1)] | **(201)** | 170 |
| Non-operating foreign exchange gains (losses), after-tax [(2)] | **39** | 2 |
| Operating Earnings | **$ 209** | $ 353 |

(1) The unrealized risk management gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods.
(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions and deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

Operating earnings is a non-GAAP measure defined as net earnings excluding the after-tax gain (loss) on discontinuance; after-tax gain on bargain purchase; after-tax effect of unrealized risk management gains (losses) on derivative instruments; after-tax gains (losses) on non-operating foreign exchange; after-tax effect of gains (losses) on divestiture of assets; and the effect of changes in statutory income tax rates.

We believe that these non-operating items reduce the comparability of our underlying financial performance between periods. The above reconciliation of operating earnings has been prepared to provide information that is more comparable between periods. The items identified above that affected our cash flow and identified below that affected our net earnings also impacted our operating earnings.

The decline in operating earnings in the first quarter of 2011 is consistent with lower cash flow and higher deferred income tax expense (excluding deferred tax on unrealized risk management gains and losses and non-operated foreign exchange gains and losses) partially offset by lower DD&A.

## NET EARNINGS VARIANCE

| ($ millions) | |
|---|---|
| Net Earnings for the Three Months Ended March 31, 2010 | $ 525 |
| Increase (decrease) due to: | |
| Operating Cash Flow | (6) |
| Corporate and Eliminations | |
| Unrealized risk management gains (losses), net of tax | (371) |
| Unrealized foreign exchange gains (losses) | 4 |
| Expenses [(1)] | (69) |
| Depreciation, depletion and amortization | 23 |
| Income taxes, excluding income taxes on unrealized risk management gains (losses) | (59) |
| **Net Earnings for the Three Months Ended March 31, 2011** | **$ 47** |

(1) Includes general and administrative, interest income, finance costs, realized foreign exchange (gains) losses, gain (loss) on divestitures, other (income) loss, net and Corporate operating expenses.

In the first quarter of 2011, our net earnings decreased $478 million compared to the same period in 2010. The items identified above that reduced our operating cash flow in the first quarter of 2011 also reduced our net earnings. Other significant factors that impacted 2011 first quarter net earnings include:

- Unrealized risk management losses, after-tax, of $201 million, compared to gains of $170 million, after-tax, in the first quarter of 2010;
- Unrealized foreign exchange gains of $36 million in the first quarter of 2011 compared to gains of $32 million in 2010;
- A decrease of $23 million in DD&A;
- Increased general and administrative expenses primarily from higher long-term incentive expense with the increase in our share price; and
- Income tax expense, excluding the impact of the unrealized risk management gains and losses, in the first quarter of 2011 of $107 million, compared to $48 million for the same period in 2010.

## Risk Management Impact on Net Earnings

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. Changes in mark-to-market gains or losses on these financial instruments affect our net earnings until these contracts are settled and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts.

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Unrealized Risk Management Gains (Losses), after-tax [1] | **$ (201)** | $ 170 |
| Realized Risk Management Gains (Losses), after-tax [2] | **11** | 17 |
| Hedging Impacts in Net Earnings | **$ (190)** | $ 187 |

(1) A non-cash item included in the Corporate and Eliminations financial results. Further detail on unrealized risk management gains (losses) can be found in the Corporate and Eliminations section of this MD&A.
(2) Included in the Oil Sands, Conventional and Refining and Marketing segments financial results and included in operating cash flow and cash flow.

## NET CAPITAL INVESTMENT

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Oil Sands | **$ 404** | $ 184 |
| Conventional | **176** | 102 |
| Refining and Marketing | **102** | 204 |
| Corporate | **31** | 1 |
| Capital Investment | **713** | 491 |
| Acquisitions | **19** | - |
| Divestitures | **(4)** | (72) |
| Net Capital Investment [1] | **$ 728** | $ 419 |

(1) Includes expenditures on property, plant and equipment and exploration and evaluation assets.

Exploration and Evaluation ("E&E") assets relate to properties on which technical feasibility and commercial viability has not been determined. Under IFRS, we disclose E&E assets separately from Property, Plant and Equipment ("PP&E") in our financial statements. However, for purposes of managing our capital program, we do not differentiate between E&E and PP&E expenditures, and therefore we have not split our capital investment between E&E and PP&E within this MD&A.

Oil Sands capital investment in the first quarter of 2011 was primarily focused on facility spending at both Foster Creek and Christina Lake related to the next phases of expansion. We also drilled 440 gross stratigraphic wells during the quarter, our largest program to date. The results of these stratigraphic wells will be used to support the development of our Oil Sands projects. Conventional capital investment in the first quarter of 2011 was primarily focused on the continued development of our conventional oil properties. Refining and Marketing capital investment was primarily focused on the CORE project at the Wood River refinery.

Overall, our capital investment in the first quarter of 2011 was $222 million more than the same period in 2010 and reflects our commitment to our 10 year business plan of growing net oil sands production to 300,000 bbls/d. Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

## FREE CASH FLOW

In order to determine the funds available for financing and investing activities, including dividend payments, we use a non-GAAP measure of free cash flow, defined as cash flow less capital investment, which excludes acquisitions and divestitures. Cash flow is a non-GAAP measure and is defined under the cash flow section of this MD&A.

| | **Three Months Ended March 31,** | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Cash Flow | **$ 693** | $ 721 |
| Capital Investment | **713** | 491 |
| Free Cash Flow | **$ (20)** | $ 230 |

## RESULTS OF OPERATIONS

### Crude Oil and NGLs Production Volumes

| | **2011** | 2010 | | | | 2009 | | | |
|---|---|---|---|---|---|---|---|---|---|
| (bbls/d) | **Q1** | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 |
| Oil Sands | | | | | | | | | |
| Foster Creek | **57,744** | 52,183 | 50,269 | 51,010 | 51,126 | 47,017 | 40,367 | 34,729 | 28,554 |
| Christina Lake | **9,084** | 8,606 | 7,838 | 7,716 | 7,420 | 7,319 | 6,305 | 6,530 | 6,635 |
| Pelican Lake | **21,360** | 21,738 | 23,259 | 23,319 | 23,565 | 23,804 | 25,671 | 23,989 | 26,029 |
| Senlac | **-** | - | - | - | - | 2,221 | 5,080 | 2,574 | 2,334 |
| Conventional | | | | | | | | | |
| Heavy Oil | **16,447** | 16,553 | 16,921 | 16,205 | 16,962 | 17,127 | 18,073 | 18,074 | 18,290 |
| Light & Medium Oil | **31,539** | 29,323 | 28,608 | 29,150 | 30,320 | 30,644 | 29,749 | 30,189 | 31,004 |
| NGLs [1] | **1,181** | 1,190 | 1,172 | 1,166 | 1,156 | 1,183 | 1,242 | 1,184 | 1,213 |
| | **137,355** | 129,593 | 128,067 | 128,566 | 130,549 | 129,315 | 126,487 | 117,269 | 114,059 |

(1) NGLs include condensate volumes.

Overall, our crude oil and NGLs production increased five percent in the first quarter of 2011 from the first quarter of 2010. Increases in production volumes at Foster Creek, Christina Lake and our Conventional light and medium crude oil properties were partially offset by expected natural declines and the divestiture of non-core assets in 2010. Further information on the changes in our production can be found in the Reportable Segments section of this MD&A.

### Natural Gas Production Volumes

| | **2011** | 2010 | | | | 2009 | | | |
|---|---|---|---|---|---|---|---|---|---|
| (MMcf/d) | **Q1** | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 |
| Conventional | **620** | 649 | 694 | 705 | 730 | 750 | 775 | 799 | 814 |
| Oil Sands | **32** | 39 | 44 | 46 | 45 | 47 | 55 | 57 | 52 |
| | **652** | 688 | 738 | 751 | 775 | 797 | 830 | 856 | 866 |

In the first quarter of 2011, our natural gas production volumes declined as expected. We expected lower volumes due to our strategic decision to restrict capital spending over the last two years in favour of increasing investment in crude oil projects. The decline is also consistent with our strategy to divest of non-core natural gas properties which had produced approximately 41 MMcf/d in the first quarter of 2010, which was approximately five percent of our production. Another factor that partly reduced our natural gas production was poor winter weather.

## Operating Netbacks

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| | **2011** | | 2010 | |
| | **Crude Oil & NGLs** | **Natural Gas** | Crude Oil & NGLs | Natural Gas |
| | ($/bbl) | ($/Mcf) | ($/bbl) | ($/Mcf) |
| Price [1] | **$ 65.37** | **$ 3.82** | $ 68.85 | $ 5.27 |
| Royalties | **9.98** | **0.08** | 8.78 | 0.14 |
| Transportation and blending [1] | **2.60** | **0.17** | 1.83 | 0.21 |
| Operating expenses | **13.43** | **1.19** | 11.34 | 0.93 |
| Production and mineral taxes | **0.36** | **0.06** | 0.59 | 0.07 |
| Netback excluding Realized Risk Management | **39.00** | **2.32** | 46.31 | 3.92 |
| Realized Risk Management Gains (Losses) | **(2.67)** | **0.89** | (0.78) | 0.53 |
| Netback including Realized Risk Management | **$ 36.33** | **$ 3.21** | $ 45.53 | $ 4.45 |

(1) Operating netbacks for crude oil and NGLs exclude the value of condensate sold as bitumen blend and condensate costs recorded in transportation and blending expense.

In the first quarter of 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, decreased by $7.31 per barrel primarily due to decreased sales prices which reflected the widening of the WTI-WCS differential and a stronger Canadian dollar as well as higher royalties as a result of the increased WTI benchmark price and higher operating expenses. Our average netback for natural gas, excluding realized risk management gains and losses, decreased by $1.60 per Mcf primarily as a result of lower sales prices and increased operating expenses. The increase in operating expenses for both crude oil and NGLs and natural gas was primarily due to higher long-term incentive costs due to the increase in our share price in the first quarter of 2011. Further discussions on the items included in our operating netbacks are contained in the Reportable Segments section of this MD&A.

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. In the first quarter of 2011, this strategy resulted in realized gains on our natural gas financial instruments and realized losses on our crude oil financial instruments. This result is consistent with our contract prices compared to the current business environment of declining benchmark natural gas prices and increasing WTI benchmark crude oil prices. Further information regarding this program can be found in the notes to the interim Consolidated Financial Statements.

# REPORTABLE SEGMENTS

## OIL SANDS

In northeast Alberta, we are a 50 percent partner in the Foster Creek and Christina Lake oil sands projects and also produce heavy oil from our wholly owned Pelican Lake operations. We have several new resource plays in the early stages of assessment, including Narrows Lake, Grand Rapids and Telephone Lake. The Oil Sands assets also include the Athabasca natural gas property from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Oil Sands highlights for the first quarter of 2011 include:

- Foster Creek and Christina Lake both achieving record production levels and increasing production 14 percent compared to the same period in 2010;
- Successfully completing a large winter stratigraphic well program with 440 gross wells drilled to further progress our Oil Sands projects and to address potential Pelican Lake lease expiries; and
- Progression of expansion phases at both Foster Creek and Christina Lake.

## OIL SANDS - CRUDE OIL

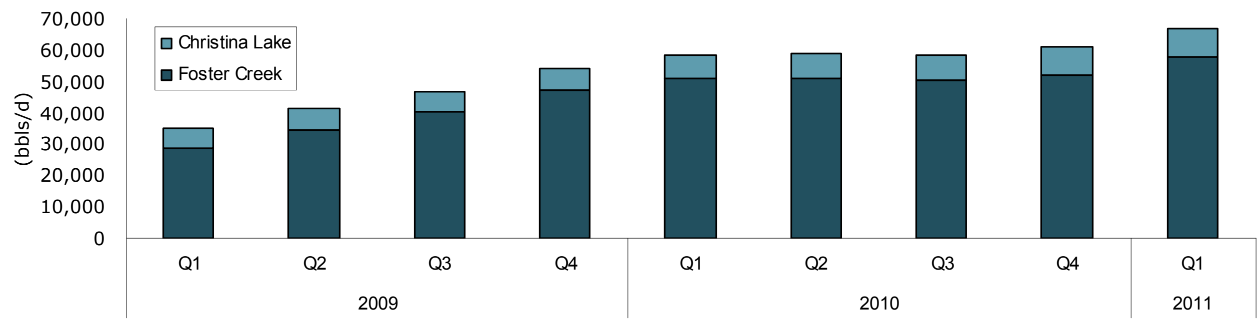
### Financial Results

| ($ millions) | Three Months Ended March 31, 2011 | 2010 |
|---|---|---|
| Gross sales | **$ 784** | $ 699 |
| Less: Royalties | **82** | 57 |
| Revenues | **702** | 642 |
| Expenses | | |
| Transportation and blending | **321** | 251 |
| Operating | **107** | 83 |
| (Gains) losses on risk management | **24** | 9 |
| Operating Cash Flow | **250** | 299 |
| Capital Investment | **390** | 182 |
| Operating Cash Flow in Excess (Deficient) of Related Capital Investment | **$ (140)** | $ 117 |

### Production Volumes

| | **Three Months Ended March 31,** | | |
|---|---|---|---|
| Crude oil *(bbls/d)* | **2011** | **2011 vs 2010** | 2010 |
| Foster Creek | **57,744** | **13%** | 51,126 |
| Christina Lake | **9,084** | **22%** | 7,420 |
| Subtotal | **66,828** | **14%** | 58,546 |
| Pelican Lake | **21,360** | **-9%** | 23,565 |
| | **88,188** | **7%** | 82,111 |

### Foster Creek and Christina Lake Production Volumes by Quarter




### Revenues Variance

| ($ millions) | First Quarter of 2010 | Revenues Variances in: Price | Volume | Royalties | Condensate[1] | **First Quarter of 2011** |
|---|---|---|---|---|---|---|
| Crude Oil | $ 642 | (34) | 58 | (25) | 61 | **$ 702** |

(1) Revenues include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

In the first quarter of 2011, our average crude oil sales price decreased seven percent to $60.35 per barrel compared to the same period in 2010 which is consistent with the increases to the U.S. dollar WCS benchmark crude oil prices being more than offset by the strengthening of the Canadian dollar. Further reducing our average sales price in the quarter was the impact of pipeline apportionments restricting access to U.S. markets.

Foster Creek production increased 13 percent primarily as a result of improved plant efficiency with decreased downtimes and improvement in the steam to oil ratio in the first quarter of 2011. At Foster Creek, a turnaround is scheduled for the second quarter of 2011 which is expected to take approximately three weeks and reduce production by approximately 8,000 bbls/d for the quarter. The 22 percent increase in production at Christina Lake was a result of increased production from the phase B expansion, well optimizations and production from the first wedge well at Christina Lake. At Pelican Lake, the decrease in production was the result of expected natural production declines and one month of pipeline apportionment partially offset by the results of polymer injection activities.

Royalties increased $25 million in the first quarter of 2011 due to higher WTI prices partially offset by a strengthened Canadian dollar used for calculating royalty rates as well as 2010 only including two months of project post payout royalties for Foster Creek. In the first quarter of 2011 the effective royalty rate for Foster Creek was 21.2 percent (2010 – 9.7 percent) and for Christina Lake was 4.8 percent (2010 – 4.0 percent). Pelican Lake royalties decreased mainly as a result of higher capital and operating expenditures, which resulted in an effective royalty rate of 13.9 percent (2010 – 21.4 percent).

Transportation and blending costs increased $70 million in the first quarter of 2011. The condensate portion of the increase ($61 million) primarily resulted from the increased volume of condensate required due to higher production at Foster Creek and Christina Lake as well as an increase in the average cost of condensate. Blending costs at Pelican Lake were consistent with 2010. Transportation costs increased $9 million primarily as a result of transportation charges to access available markets to avoid shut-in of volumes resulting from pipeline restrictions combined with higher production volumes.

Operating costs increased $24 million due to increased field personnel, higher repairs and maintenance as well as higher long-term incentive expense. In addition, operating costs at Foster Creek and Christina Lake increased due to the increase in production volumes, while Pelican Lake incurred higher polymer chemical costs.

Realized gains or losses on risk management in the first quarter of 2011 resulted in losses of $24 million ($3.01 per barrel) compared to losses of $9 million ($1.04 per barrel) in the first quarter of 2010.

## OIL SANDS – NATURAL GAS

Oil Sands includes our 100 percent owned natural gas operations in Athabasca and other minor properties. Primarily as a result of natural declines, in the first quarter of 2011 our natural gas production decreased to 32 MMcf/d (2010 – 45 MMcf/d). As a result of the decreased production and lower natural gas prices, operating cash flow declined $9 million in the first quarter of 2011.

## OIL SANDS - CAPITAL INVESTMENT

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Foster Creek | **$ 103** | $ 56 |
| Christina Lake | **108** | 63 |
| Subtotal | **211** | 119 |
| Pelican Lake | **84** | 22 |
| New Resource Plays | **94** | 39 |
| Other [1] | **15** | 4 |
| Capital Investment [2] | **$ 404** | $ 184 |

(1) Includes Athabasca natural gas.
(2) Includes expenditures on property, plant and equipment and exploration and evaluation assets.

Oil Sands capital investment in the first quarter of 2011 was primarily focused on the continued development of our expansion phases at Foster Creek and Christina Lake, the drilling of stratigraphic test wells to support the development of our Oil Sands projects, as well as activities related to our Pelican Lake polymer flood. We are on schedule to increase gross production capacity at Foster Creek and Christina Lake to approximately 218,000 bbls/d of bitumen with the expected completion of Christina Lake phases C and D.

Foster Creek capital investment in the first quarter of 2011 increased compared to the same period in 2010 as a result of increased spending on phases F, G and H, which received regulatory approval in the third quarter of 2010. The majority of Foster Creek spending was related to drilling stratigraphic test wells, engineering and design, site preparation, plant expansion and well pad construction for the F, G and H expansion as well as capital maintenance on our producing phases.

At Christina Lake, capital investment was higher in the first quarter of 2011 compared to the same period in 2010 due primarily to the drilling of stratigraphic test wells and the phase C and D expansions, including engineering and design, module fabrication, plant expansion and well pad drilling. Our plan is to increase gross production capacity to approximately 98,000 bbls/d with the expected completions of phases C and D. We plan to begin injecting steam late in the second quarter of 2011 at phase C with first production expected in the third quarter of this year. Steam injection and production at phase D is expected to begin in early 2013.

Capital investment for Pelican Lake was primarily related to infill drilling to progress the polymer flood, drilling of stratigraphic test wells and capital maintenance.

Capital investment in new resource plays in the first quarter of 2011 was mainly related to the drilling of stratigraphic test wells and completion of seismic programs to support future oil sands projects. The Grand Rapids pilot project commenced steaming in late 2010 and we expect production to begin in the second quarter of 2011. Results from this pilot are expected to give us a better understanding of the performance of SAGD in the formation.

### Gross Stratigraphic Wells

Consistent with our strategy to unlock the value of our resource base, we completed our largest ever stratigraphic test well program in the quarter. The stratigraphic test wells drilled at Foster Creek and Christina Lake are to support the next phases of expansion, while the other stratigraphic test wells have been drilled to continue to gather data on the quality of our projects and to support regulatory applications for project approval. We also drilled a number of wells at Pelican Lake to address potential lease expiries.

| | **Three Months Ended March 31,** | |
|---|---|---|
| | **2011** | 2010 |
| Foster Creek | **110** | 67 |
| Christina Lake | **59** | 24 |
| Subtotal | **169** | 91 |
| Pelican Lake | **57** | - |
| Narrows Lake | **41** | 35 |
| Grand Rapids | **38** | 31 |
| Borealis | **84** | 26 |
| Other | **51** | 15 |
| | **440** | 198 |

## CONVENTIONAL

Our Conventional operations include the development and production of crude oil, natural gas and NGLs in Alberta and Saskatchewan. The assets in this segment are strategically important for their long life reserves, stable operations and diversity of products produced. The reliability of these properties to deliver consistent production and operating cash flow is important to the funding of our future oil sands growth.

Conventional highlights in the first quarter of 2011 include:

- Generating operating cash flow in excess of capital investment of more than $200 million; and
- Further development of the Bakken and Lower Shaunavon plays increasing average production to approximately 3,300 bbls/d from less than 1,800 bbls/d in 2010.

## CONVENTIONAL - CRUDE OIL and NGLs

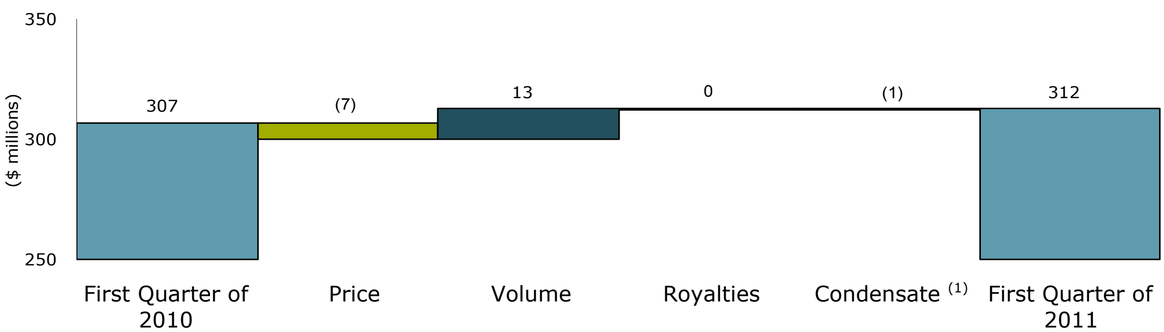
### Financial Results

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Gross sales | **$ 356** | $ 351 |
| Less: Royalties | **44** | 44 |
| Revenues | **312** | 307 |
| Expenses | | |
| Transportation and blending | **27** | 26 |
| Operating | **63** | 46 |
| Production and mineral taxes | **5** | 7 |
| (Gains) losses on risk management | **9** | 2 |
| Operating Cash Flow | **208** | 226 |
| Capital Investment | **153** | 66 |
| Operating Cash Flow in Excess of Related Capital Investment | **$ 55** | $ 160 |

### Production Volumes

| | Three Months Ended March 31, | | |
|---|---|---|---|
| *(bbls/d)* | **2011** | **2011 vs 2010** | 2010 |
| Heavy Oil | | | |
| Alberta | **16,447** | **-3%** | 16,962 |
| Light and Medium Oil | | | |
| Alberta | **11,326** | **-4%** | 11,852 |
| Saskatchewan | **20,213** | **9%** | 18,468 |
| NGLs | **1,181** | **2%** | 1,156 |
| | **49,167** | **2%** | 48,438 |

### Revenues Variance




(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense.

In the first quarter of 2011 our average crude oil and NGLs sales price decreased two percent from $75.84 per barrel to $74.35 per barrel, as increases in the price of WTI were more than offset with a widening of the WTI-WCS differential and the strengthened Canadian dollar.

Production in the first quarter of 2011 was slightly higher than the same period in 2010 primarily due to increased production from the Bakken, Lower Shaunavon and Weyburn areas partially offset by the divestiture of non-core properties in the second quarter of 2010 that had produced approximately 1,300 bbls/d in the first quarter of 2010.

Production was also lower because of expected natural declines and weather challenges as well as one month of apportionment.

Royalties in the first quarter of 2011 were consistent with the same period in 2010 as a result of lower royalty rates being offset by increased production and adjustments related to prior period royalties, which resulted in an effective royalty rate of 13.4 percent (2010 – 14.1 percent).

Transportation and blending costs were consistent in the first quarter of 2011 as decreases in volumes of condensate required for blending were offset by increases in the average cost of condensate and higher pipeline costs.

Operating costs increased $17 million in the first quarter of 2011 primarily due to higher long-term incentive expense, increased workover activity mainly at Weyburn, Lower Shaunavon and Bakken, increased electricity costs, higher repair and maintenance activity and higher trucking costs.

In the first three months of 2011, realized risk management losses were $9 million ($2.06 per barrel) compared to losses of $2 million ($0.34 per barrel) in the first quarter of 2010.

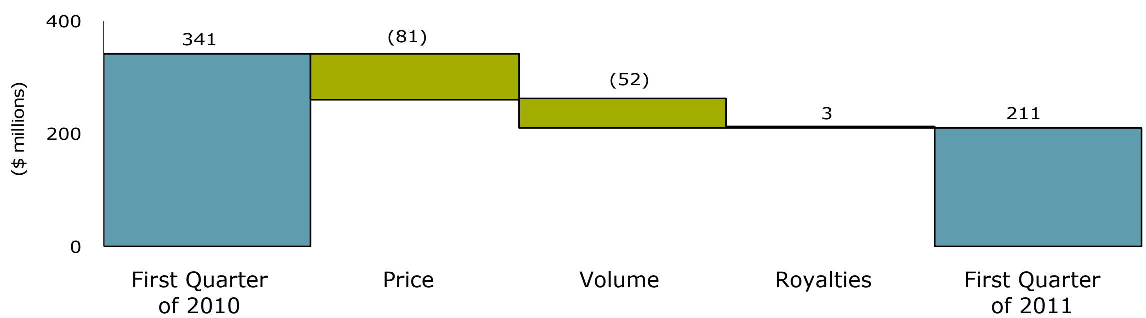
Our Conventional crude oil and NGLs operating cash flow in excess of capital investment decreased $105 million in the first quarter of 2011 compared to the same period in 2010 mainly due to increased capital investment in 2011 and higher operating costs.

## CONVENTIONAL - NATURAL GAS

### Financial Results

| | **Three Months Ended March 31,** | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Gross sales | **$ 214** | $ 347 |
| Less: Royalties | **3** | 6 |
| Revenues | **211** | 341 |
| Expenses | | |
| Transportation and blending | **10** | 14 |
| Operating | **61** | 56 |
| Production and mineral taxes | **3** | 5 |
| (Gains) losses on risk management | **(48)** | (33) |
| Operating Cash Flow | **185** | 299 |
| Capital Investment | **23** | 36 |
| Operating Cash Flow in Excess of Related Capital Investment | **$ 162** | $ 263 |

### Revenues Variance




Our natural gas revenues and operating cash flow are down significantly due to lower average sales prices, consistent with the change in the benchmark AECO price. The cumulative impact of restricted natural gas capital spending over the last two years, divestitures of 41 MMcf/d of production from non-core properties in 2010 and winter weather issues resulted in an expected decline in natural gas production volumes by 15 percent to 620 MMcf/d in the first quarter of 2011 (2010 – 730 MMcf/d).

Royalties decreased by $3 million in the first three months of 2011 as a result of lower commodity prices and production volumes. The average royalty rate for the first quarter of 2011 was 1.4 percent (2010 – 1.8 percent).

Costs related to transportation decreased by $4 million in the first three months of 2011 due to lower production volumes.

Operating expenses for the first quarter of 2011 increased by $5 million as a result of higher long-term incentive expense as well as higher electricity costs partially offset by reduced operations due to divestitures in 2010 and lower production volumes. The reduced operations were specifically related to reductions in property tax, repairs and maintenance, and workovers.

Our realized risk management gains in the first quarter of 2011 increased to $48 million ($0.86 per Mcf), compared to gains of $33 million ($0.52 per Mcf) for the same period in 2010.

Our Conventional natural gas operating cash flow in excess of capital investment decreased $101 million in the first quarter of 2011 compared to the same period in 2010 mainly due to lower average sales prices and production volumes in 2011.

## CONVENTIONAL - CAPITAL INVESTMENT

| | **Three Months Ended March 31,** | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Alberta | **$ 110** | $ 67 |
| Saskatchewan | **66** | 35 |
| Capital Investment (1) | **$ 176** | $ 102 |

(1) Includes expenditures on property, plant and equipment and exploration and evaluation assets.

For the first three months of 2011, approximately 87 percent or $153 million of our capital investment was on our crude oil properties (2010 – 65 percent or $66 million). Capital investment in Alberta was primarily focused on our oil program, while we reduced capital investment at our shallow and liquids rich deep natural gas projects. Our capital investment in Saskatchewan continued to focus on drilling and facility work at Weyburn as well as appraisal projects and additional drilling in the Lower Shaunavon and Bakken areas.

The following table details our Conventional drilling activity. The increase in crude oil wells reflects the development of our Alberta properties and the Lower Shaunavon and Bakken areas in Saskatchewan. In the first quarter of 2011, we drilled 11 wells in the Lower Shaunavon and Bakken areas, two of which were on production at the end of the first quarter 2011 and six which are ready to begin production in the second quarter of 2011. Well recompletions are mostly related to Alberta CBM development.

| | **Three Months Ended March 31,** | |
|---|---|---|
| (net wells) | **2011** | 2010 |
| Crude oil | **103** | 41 |
| Natural gas | **15** | 76 |
| Recompletions | **456** | 391 |
| Stratigraphic test wells | **3** | 3 |

## REFINING AND MARKETING

This segment includes the results of our refining operations in the U.S. that are jointly owned with and operated by ConocoPhillips. Accordingly, reported amounts for refining are affected by the U.S./Canadian dollar exchange rate. This segment's results also include the marketing of third party purchases and sales of product, undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

Refining and Marketing highlights in the first quarter of 2011 include:

- Operating cash flow increasing $183 million from the first quarter of 2010 primarily due to improved refinery margins; and
- The progression of the CORE project to approximately 94 percent complete from 91 percent at the beginning of the year.

### Financial Results

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Revenues | **$ 2,282** | $ 1,929 |
| Purchased product | **1,969** | 1,789 |
| Gross margin | **313** | 140 |
| Operating expenses | **128** | 143 |
| (Gain) loss on risk management | **5** | - |
| Operating Cash Flow | **180** | (3) |
| Capital Investment | **102** | 204 |
| Operating Cash Flow in Excess (Deficient) of Capital Investment | **$ 78** | $ (207) |

Refining and Marketing revenues in the first three months of 2011 increased 18 percent primarily due to increased revenues from our refineries, which were attributable to higher prices for refined products.

Purchased product costs, which are determined on a first-in, first-out inventory valuation basis, increased 10 percent in the first three months of 2011 due mainly to higher crude oil prices at our refineries as well as increased third-party marketing volumes. Our refining operations continued to benefit in the first quarter of 2011 from the wider light-heavy crude oil price differentials that began in the third quarter of 2010 as a result of pipeline disruptions, as well as more recent discounts to U.S. inland crude oil.

Operating costs, consisting mainly of labour, utilities and supplies, decreased 10 percent in the first quarter of 2011 mainly due to lower refinery maintenance and turnaround costs.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $183 million primarily due to higher refining margins as a result of increased refined product prices. This contrasts the first quarter of 2010 which was affected by refinery optimization activities due primarily to weaker diesel and gasoline prices. Partially offsetting these increases to our operating cash flow in 2011 was a strengthening of the Canadian dollar.

## REFINERY OPERATIONS (1)

| | Three Months Ended March 31, | |
|---|---|---|
| | **2011** | 2010 |
| Crude oil capacity *(Mbbls/d)* | **452** | 452 |
| Crude oil runs *(Mbbls/d)* | **362** | 355 |
| Crude utilization *(%)* | **80** | 79 |
| Refined products *(Mbbls/d)* | **383** | 377 |

(1) Represents 100% of the Wood River and Borger refinery operations.

On a 100 percent basis, our refineries have a current capacity of approximately 452,000 bbls/d of crude oil and 45,000 bbls/d of NGLs, including processing capability to refine up to 145,000 bbls/d of blended heavy crude oil. Upon completion of the Wood River CORE project we expect to be able to refine approximately 275,000 bbls/d (on a 100 percent basis) of heavy crude oil (approximately 150,000 bbls/d of bitumen equivalent) primarily into motor fuels.

Despite significantly improved market conditions, crude utilization in the first quarter of 2011 was substantially unchanged when compared with the prior year due to various operational and weather-related disruptions. Utilization in the first quarter of 2010 was mainly impacted by refinery optimization activities undertaken in conjunction with market conditions at that time.

## REFINING AND MARKETING - CAPITAL INVESTMENT

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Wood River Refinery | **$ 96** | $ 180 |
| Borger Refinery | **6** | 22 |
| Marketing | **-** | 2 |
| Capital Investment | **$ 102** | $ 204 |

Our refining capital investment in the first quarter of 2011 continued to focus on the CORE project at the Wood River refinery. In the first quarter of 2011, of the $96 million capital expenditures at the Wood River refinery, $78 million were related to the CORE project. At March 31, 2011, the CORE project was approximately 94 percent complete with an expected coker start up in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach approximately US$3.7 billion (US$1.85 billion net to Cenovus). The total estimated cost of the CORE project is expected to be approximately US$3.9 billion (US$1.95 billion net to Cenovus), or about 10 percent higher than originally forecast.

The balance of the 2011 first quarter capital investment at the Wood River and Borger refineries was related to refining reliability and maintenance projects, clean fuels and other emission reduction environmental initiatives.

## CORPORATE AND ELIMINATIONS

### Financial Results

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Revenues | **$ (26)** | $ (24) |
| Expenses ((add)/deduct) | | |
| Purchased product | **(26)** | (24) |
| Operating | **(1)** | - |
| (Gains) losses on risk management | **268** | (237) |
| | **$ (267)** | $ 237 |

The Corporate and Eliminations segment includes intersegment eliminations that relate to transactions that have been recorded at transfer prices based on current market prices as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and unrealized mark-to-market gains and losses on long-term power purchase contracts.

The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities made up of the following:

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| General and administrative | **$ 113** | $ 49 |
| Interest income | **(32)** | (38) |
| Finance costs | **117** | 125 |
| Foreign exchange (gain) loss, net | **(23)** | (27) |
| Other (income) loss, net | **(1)** | (1) |
| | **$ 174** | $ 108 |

General and administrative expenses were $64 million higher in the first quarter of 2011 primarily due to higher long-term incentive expense due to an increase in our share price as well as increases in salaries and benefits.

Interest income primarily includes interest earned on our U.S. dollar denominated partnership contribution receivable. Interest income for the first quarter of 2011 decreased by $6 million from the same period in 2010 mainly as a result of decreasing interest being earned on the partnership contribution receivable as it continues to be collected combined with the strengthening Canadian dollar.

Finance costs primarily include interest expense on our long-term debt and U.S. dollar denominated partnership contribution payable, as well as the unwinding of discount on decommissioning liabilities. In the first quarter of 2011, our finance costs were $8 million lower than the same period in 2010 primarily as a result of the strengthening Canadian dollar reducing our interest expense on our U.S. dollar denominated long-term debt as well as decreasing interest being incurred on the partnership contribution payable as it continues to be repaid. The weighted average interest rate on outstanding debt for the period ended March 31, 2011 was 5.6 percent (March 31, 2010 – 5.8 percent).

In the first quarter of 2011 we reported net foreign exchange gains of $23 million (2010 - gains of $27 million), of which $36 million were unrealized (2010 - $32 million). The strengthening of the Canadian dollar in the first quarter of 2011 led to unrealized gains on our U.S. dollar denominated long-term debt, which were partially offset by unrealized losses on our U.S. dollar denominated partnership contribution receivable.

## Summary of Unrealized Gains (Losses) on Risk Management

Our strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the gains or losses on risk management reflected in the Corporate and Eliminations segment are the result of volatility between periods in the forward commodity prices and changes in the balance of unsettled contracts. The table below provides a summary of the unrealized mark-to-market gains and losses recognized for each period. Additional information regarding financial instruments can be found in the notes to the interim Consolidated Financial Statements.

| | **Three Months Ended March 31,** | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Crude Oil | **$ (260)** | $ (2) |
| Natural Gas | **(33)** | 243 |
| Refining | **3** | - |
| Power | **22** | (4) |
| Gains (losses) on risk management | **(268)** | 237 |
| Income Tax Expense (Recovery) | **(67)** | 67 |
| Unrealized Gains (Losses) on Risk Management, after-tax | **$ (201)** | $ 170 |

## DEPRECIATION, DEPLETION and AMORTIZATION

| | **Three Months Ended March 31,** | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Oil Sands | **$ 86** | $ 92 |
| Conventional | **195** | 207 |
| Refining and Marketing | **16** | 24 |
| Corporate and Eliminations | **9** | 6 |
| | **$ 306** | $ 329 |

Oil Sands DD&A decreased by $6 million in the first quarter of 2011 as increases in production volumes were offset by a lower DD&A rate at Foster Creek due to the significant addition of proved reserves at the end of 2010. The decrease in production volumes in our Conventional segment resulted in a $12 million reduction in DD&A. Refining and Marketing DD&A in the first quarter of 2011 was lower primarily due to a strengthening of the average U.S./Canadian dollar exchange rate. Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

## INCOME TAXES

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Current tax | **$ 41** | $ 15 |
| Deferred tax | **(1)** | 100 |
| Total | **$ 40** | $ 115 |

When comparing the first quarter of 2011 to 2010, our current tax expense increased and our deferred tax expense decreased. The current tax expense increase is attributable to the substantial utilization in 2010 of certain Canadian tax pools acquired at inception and an increase in income from our Refining and Marketing segment. Our deferred tax expense decreased in the first quarter of 2011 as a result of unrealized mark to market losses in 2011 compared to gains in 2010.

Our effective tax rate in the first quarter of 2011 was 46.0 percent (2010 – 18.0 percent). The increase is due to a significant change in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction, and lower permanent differences.

Our effective tax rate in any year is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration permanent differences, adjustments for changes in tax rates and other tax legislation, variation in the estimate of reserves and the differences between the provision and the actual amounts subsequently reported on the tax returns. Permanent differences include:

- The non-taxable portion of Canadian capital gains and losses;
- Multi-jurisdictional financing;
- Non-deductible stock-based compensation;
- Recognition of net capital losses; and
- Taxable foreign exchange gains not included in net earnings.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. We believe that our provision for taxes is adequate.

## LIQUIDITY AND CAPITAL RESOURCES

| | Three Months Ended March 31, | |
|---|---|---|
| ($ millions) | **2011** | 2010 |
| Net cash from (used in) | | |
| Operating activities | **$ 631** | $ 820 |
| Investing activities | **(684)** | (372) |
| Net cash provided (used) before Financing activities | **(53)** | 448 |
| Financing activities | **130** | (203) |
| Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency | **2** | (3) |
| Increase (decrease) in cash and cash equivalents | **$ 79** | $ 242 |

## OPERATING ACTIVITIES

Net cash from operating activities decreased $189 million in the first quarter of 2011 compared to the same period in 2010 mainly because of a $28 million decrease in cash flow, which is discussed in the Financial Information section of this MD&A, as well as a reduction of $147 million related to the net change in non-cash working capital.

Excluding the impact of risk management assets and liabilities and assets held for sale, we had working capital of $30 million at March 31, 2011 compared to $276 million at December 31, 2010. We anticipate that we will continue to meet the payment terms of our suppliers.

## INVESTING ACTIVITIES

Net cash used for investing activities in the first quarter of 2011 increased to $684 million from $372 million in 2010. Total capital expenditures for the first three months of 2011 increased to $729 million compared to $491 million in 2010. We had proceeds from divestitures of $2 million in the first three months of 2011 (2010 – proceeds of $72 million). The changes to our capital expenditures are discussed under the Net Capital Investment and Reportable Segments sections of this MD&A. Also decreasing the cash used in investing was the total net change in non-cash working capital, which increased cash and cash equivalents by $53 million in the first quarter of 2011 (2010 – increase of $45 million).

## FINANCING ACTIVITIES

We have a $2.5 billion committed credit facility with a maturity date of November 30, 2014, and a commercial paper program, both of which are used to manage our short-term cash requirements. At March 31, 2011, we had short-term borrowings in the form of commercial paper in the amount of $250 million. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding.

In addition, we have in place a Canadian debt shelf prospectus for $1.5 billion and a U.S. debt shelf prospectus for US$1.5 billion, the availability of which are dependent on market conditions. No notes have been issued under either prospectus.

In the first quarter of 2011, we declared and paid a dividend of $0.20 per share (2010 – $0.20 per share) for total dividend payments of $151 million (2010 - $150 million). The declaration of dividends is at the sole discretion of the Board and considered quarterly.

Net cash from financing activities in the first quarter of 2011 was $130 million (2010 – cash used of $203 million). The increase in net cash from financing was primarily the result of the issuance of $250 million of commercial paper and proceeds of $31 million from the issuance of common shares. Our long-term debt was $3,355 million as at March 31, 2011 and does not require any payments of principal until 2014.

As at March 31, 2011, we are in compliance with all of the terms of our debt agreements.

## FINANCIAL METRICS

| | **March 31, 2011** | December 31, 2010 |
|---|---|---|
| Debt to Capitalization | **30%** | 29% |
| Debt to Adjusted EBITDA (times) | **1.4x** | 1.3x |

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the partnership contribution payable or receivable. We define our non-GAAP measure of Capitalization as Debt plus shareholders' equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as earnings before interest income, finance costs, income taxes, DD&A, unrealized gain (loss) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss). These metrics are used to steward our overall debt position as measures of our overall financial strength.

In order to increase comparability of Debt to Adjusted EBITDA between periods and remove the non-cash component of risk management, we have changed our definition of Adjusted EBITDA to exclude unrealized gains and losses on risk management activities. Adjusted EBITDA and the ratio of Debt to Adjusted EBITDA for prior periods have been re-presented in a consistent manner. Our capital structure objectives and targets remain unchanged from previous periods.

We continue to target a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. Additional information regarding the impact of the adoption of IFRS on our metrics can be found in the Accounting Policies and Estimates section below, and in the notes to the interim Consolidated Financial Statements. Additional information regarding our capital structure can be found in the notes to the interim Consolidated Financial Statements.

## OUTSTANDING SHARE DATA

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. As at March 31, 2011 there were approximately 753.9 million common shares outstanding and no preferred shares outstanding.

## CONTRACTUAL OBLIGATIONS AND COMMITMENTS

Cenovus has entered into various commitments in the normal course of operations primarily related to debt, future demand charges on firm transportation agreements (which include amounts for projects awaiting regulatory approval), building leases, capital commitments and marketing agreements. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans.

## LEGAL PROCEEDINGS

We are involved in various legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims.

## RISK MANAGEMENT

Our business, prospects, financial condition, results of operations and cash flows, and in some cases our reputation, are impacted by risks that are categorized as follows:

- Financial risks including market risk (fluctuations in commodity prices, foreign exchange rates and interest rates), credit and liquidity risk;
- Operational risks including capital, operating and reserves replacement risks; and
- Safety, environmental and regulatory risks including regulatory process and approval risks, stakeholder and partner support for activities and growth plans and changes to royalty and income tax legislation.

We are committed to identifying and managing these risks in the near-term, as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board-approved Market Risk Mitigation Policy, Enterprise Risk Management Policy, Credit Policy and risk management programs. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. We take a proactive approach to the identification and management of issues that can affect our assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for issue identification and management.

Further information regarding the risk factors affecting Cenovus can be found in the Advisory section of this MD&A and in the Risk Factors section of our Annual Information Form ("AIF") for the year ended December 31, 2010, available at www.cenovus.com.

## ENVIRONMENTAL REGULATION AND RISK

Environmental regulation impacts many aspects of our business. Regulatory regimes apply to all companies active in the energy industry. We are required to obtain regulatory approvals, licenses and permits in order to operate and we must comply with standards and requirements for the exploration, development and production of crude oil and natural gas and the refining, distribution and marketing of petroleum products. Regulatory assessment, review and approval are generally required before initiating, advancing or changing operations projects. Further information regarding the status of each project can be found in the Reportable Segments section of this MD&A.

### Climate Change

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants and a number of legislative and regulatory measures to address GHG emissions are in various phases of review, discussion or implementation in the U.S. and Canada. Adverse impacts to our business if comprehensive GHG regulation is enacted in any jurisdiction in which we operate may include, among other things, increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances which may add costs to the products we produce and reduce demand for crude oil and certain refined products.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

We intend to continue our activity to use scenario planning to anticipate future impacts, reduce our emissions intensity and improve our energy efficiency. We will also continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

Further information regarding Climate Change affecting Cenovus can be found in the Risk Management section of the December 31, 2010 MD&A and in the Risk Factors section of our AIF for the year ended December 31, 2010.

### ALBERTA'S REGULATORY FRAMEWORK

Alberta's Land-use Framework, which is to be implemented under the Alberta Land Stewardship Act ("ALSA"), sets out the Government of Alberta's approach to managing Alberta's land and natural resources to achieve long-term economic, environmental and social goals. ALSA contemplates the amendment or extinguishment of previously issued consents such as regulatory permits, licenses, approvals and authorizations in order to achieve or maintain an objective or policy resulting from the implementation of a regional plan.

The Government of Alberta is expected to develop a regional plan for each of seven regions in the province and has identified the Lower Athabasca Regional Plan ("LARP") as a priority. The LARP is intended to identify and set resource and environmental management outcomes for air, land, water and biodiversity, and guide future resource decisions while considering social and economic impacts. As a stakeholder with significant activities in the region, we are actively participating in the feedback process and will monitor developments going forward.

On April 5, 2011, the Government of Alberta released the draft LARP, which identifies management frameworks for air, land and water, as well as areas related to conservation, tourism and recreation. Some of our lands are impacted by the designation of conservation, tourism and recreation areas; however, the areas identified have no direct impact on our current operations at Foster Creek or Christina Lake or any of our filed applications. It is possible that if the draft land use designations for conservation, tourism and recreation areas are adopted in their current form, that some of our oil sands tenures could be cancelled and access to some parts of our current resource properties restricted. This matter will continue to be monitored through the consultation phase on the current draft of the LARP.

### TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and to integrating our corporate responsibility principles into the way we conduct our business. We recognize the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks.

Our Corporate Responsibility ("CR") policy continues to drive our commitments, strategy and reporting, and enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators. This policy is available on our website at www.cenovus.com.

As our CR reporting process matures, indicators will be developed and integrated in our CR reporting that better reflect Cenovus's operations and challenges. Our online presence will be expanded through the corporate responsibility section of our website. We expect to release our first comprehensive corporate responsibility report by the end of the second quarter of 2011.

## ACCOUNTING POLICIES AND ESTIMATES

### ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

This is our first reporting period using our IFRS accounting policies. In accordance with IFRS 1, our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been prepared in accordance with our IFRS accounting policies. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and has not been re-presented.

In each of our MD&As throughout 2010, as well as in our MD&A for the year ended December 31, 2010, we included updates on the status of our IFRS conversion project, as well as detailed information on our IFRS accounting policies and elections, including the estimated impact of adopting the accounting policies. The information below summarizes the significant accounting policies that we have adopted under IFRS as well as the actual impact of adopting the policies.

Under previous GAAP, our Debt to Capitalization ratio was 26 percent at December 31, 2010, which increased to 29 percent under IFRS, still below our target range. The increase in the ratio was largely due to the revaluation of the refineries in our IFRS opening balance sheet, which reduced our shareholders' equity by approximately $1.6 billion after-tax on January 1, 2010.

We concluded that the adoption of IFRS did not have a significant impact on any of our internal control processes. In terms of financial literacy, we held additional internal IFRS education sessions in the first quarter of 2011, and we plan to continue these sessions throughout 2011 to ensure that there is a strong level of knowledge of IFRS throughout our organization.

## ACCOUNTING POLICIES

Our IFRS consolidated financial statements for the year ending December 31, 2011 must use the standards that are in effect on December 31, 2011, and therefore we have prepared our interim Consolidated Financial Statements using the standards that are expected to be effective at the end of 2011. However, our IFRS accounting policies will only be finalized when our first annual IFRS financial statements are prepared for the year ending December 31, 2011. Therefore, certain accounting policies that we currently expect to follow under IFRS may not be adopted and the application of such policies to certain transactions or circumstances may be modified. As a result, our interim Consolidated Financial Statements for the three months ended March 31, 2011 are subject to change.

Our interim Consolidated Financial Statements for the three months ended March 31, 2011 provide the following reconciliations from previous GAAP to IFRS:

- Equity as at January 1, 2010;
- Equity as at March 31, 2010;
- Equity as at December 31, 2010;
- Net earnings for the three months ended March 31, 2010, and net earnings for the year ended December 31, 2010; and
- Comprehensive income for the three months ended March 31, 2010, and comprehensive income for the year ended December 31, 2010.

Below we have summarized the significant accounting policies that we have adopted in the transition from previous GAAP to IFRS, including the significant elections and exemptions that are allowed upon first time adoption of IFRS, as well as the significant impacts on our net earnings for the three months ended March 31, 2010 and the year ended December 31, 2010.

### Opening Balance Sheet – Carrying Value of Refineries

On transition to IFRS, we elected to measure the carrying value of our refineries at their fair value, which permanently reduced their carrying value by approximately $2.6 billion. As a result, our Refining and Marketing DD&A was reduced by $26 million for the three months ended March 31, 2010 ($103 million for the year ended December 31, 2010).

It was also determined that the refining deferred asset, which had a carrying value of $121 million at January 1, 2010, was fully impaired under IFRS. As a result, other assets at January 1, 2010, were reduced by $121 million and DD&A in the Refining and Marketing segment was reduced by $4 million for the three months ended March 31, 2010 ($17 million for the year ended December 31, 2010).

### Pre-exploration expense

Under IFRS, costs incurred prior to obtaining the legal right to explore must be expensed whereas under previous GAAP these costs were capitalized in the full cost pool. The adoption of this policy did not impact our net earnings for the three months ended March 31, 2010, however, for the year ended December 31, 2010, we expensed $3 million of pre-exploration costs under IFRS.

### E&E Assets

E&E costs are incurred when the legal right to explore has been obtained but before technical feasibility and commercial viability have been determined. These costs are capitalized under IFRS as they were under previous GAAP, however, they are separately disclosed on the balance sheet as E&E assets. E&E assets are not depreciated and are carried forward until technical feasibility and commercial viability of the field, area or project is determined. If it is determined that the field, area or project is not technically feasible, commercially viable or if we decide not to continue the E&E activity, then the accumulated costs are expensed to exploration expense in the period in which the determination is made. Once technical feasibility and commercial viability is established, E&E assets are tested for impairment and transferred to PP&E, net of any impairment loss. There was no impact to net earnings for the three month period ended March 31, 2010 or the year ended December 31, 2010 due to the adoption of this policy.

## Opening Balance Sheet – Full Cost Pool

Under previous GAAP, we accounted for our oil and gas properties in one cost centre using full cost accounting. IFRS has no equivalent treatment. IFRS 1 - First-time Adoption of IFRS, permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) to the unit of account level upon transition to IFRS using reserve information. Applying this exemption, the cost of our E&E assets were reclassified from PP&E to the new E&E asset category, and the remainder of our full cost pool was allocated to our IFRS areas using the estimated proved reserve values discounted at 10 percent at the transition date. This approach was also consistent with the allocation method which was required to be used in the formation of Cenovus. The IFRS allocation process did not affect the net book value of our PP&E at the date of transition as no IFRS impairments were recognized.

Under both IFRS and previous GAAP, the DD&A on our development and production PP&E is calculated using the unit-of-production method based on estimated proved reserves. However, under previous GAAP, we calculated our DD&A rate at the country cost centre level whereas under IFRS, our DD&A rates are calculated at the area level. The adoption of this policy resulted in a $35 million increase in our DD&A for the three months ended March 31, 2010 and a $135 million increase in our DD&A for the year ended December 31, 2010.

## Asset Impairments

Under previous GAAP, upstream property, plant and equipment and goodwill were tested for impairment at the country cost centre level, and refining assets were tested for impairment at the entire complex level. Under IFRS, upstream assets are tested for impairment at a much more granular level referred to as a cash-generating unit ("CGU"). A CGU is the smallest identifiable group of assets capable of generating cash inflows that are largely independent of cash inflows from other assets. Our policy for testing E&E assets for impairment is to allocate these assets to the CGU to which they relate. We continue to test the refining assets for impairment at the entire complex level for each refinery, which is consistent with the CGU level under IFRS.

Under IFRS, our assets and CGUs are tested for impairment when facts and circumstances suggest that the carrying amount of an asset or CGU may exceed its recoverable amount. An annual test is performed for a CGU or group of CGUs if the CGU has been allocated goodwill. E&E assets are also tested for impairment immediately before they are transferred to PP&E.

Under previous GAAP, long-lived assets were subject to a two part impairment test. Firstly, a loss was recognized if the carrying value exceeded the undiscounted future cash flows. If a loss was recognized, it was measured as the amount by which the carrying value exceeded its fair value. Under IFRS, an impairment loss is recognized if an asset's or CGU's net book value exceeds its recoverable amount. Recoverable amount is determined as the greater of an asset's or CGU's value-in-use ("VIU") and fair value less costs to sell ("FVLCTS"). VIU is estimated as the discounted present value of the future cash flows expected to arise from the continuing use of an asset or CGU. FVLCTS is estimated as the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable, willing parties, which generally reflects current market prices for similar assets or CGUs.

Previous GAAP did not allow for the reversal of impairment losses. Under IFRS, impairment losses recognized in prior periods are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased, except for goodwill impairments, which are never reversed. In the event that an impairment loss reverses, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset or CGU in prior periods.

The adoption of these IFRS impairment testing policies had no impact on our opening balance sheet or net earnings for the three months ended March 31, 2010. At December 31, 2010, under previous GAAP and IFRS, an impairment loss was recognized on a refining processing unit. However, the amount of the impairment under IFRS was $14 million, which was a reduction of $23 million due to the January 1, 2010 fair value election on the refining assets, as discussed above. We will monitor this impairment loss under IFRS in future periods to determine whether a reversal of all or a portion of the impairment is appropriate.

## Divestitures of Assets

Under previous GAAP, gains or losses on divestitures of oil and gas assets were not recognized unless the divestiture would affect our DD&A rate by 20 percent or more, and if not, proceeds were credited to the full cost pool. Under IFRS, all gains and losses on divestiture of assets are recognized. The adoption of this policy had no impact on our net earnings for the three month period ended March 31, 2010, however for the year ended December 31, 2010 we recognized gains of $125 million.

## Exchanges of Assets

Under previous GAAP, exchanges of oil and gas assets were typically measured at the book value of the asset given up. Under IFRS, these exchanges are measured at fair value and any resulting gains or losses are recognized in net earnings. However, if the transaction lacks commercial substance or the fair value of the asset received or the asset given up is not reliably measurable, the carrying amount of the asset given up is used as the cost of the asset acquired. The adoption of this policy did not impact our net earnings for the three month period ended March 31, 2010 or the year ended December 31, 2010.

## Decommissioning Liabilities

Under IFRS, we have renamed asset retirement obligation to decommissioning liabilities. Under previous GAAP, the historical credit-adjusted risk-free discount rates used to estimate our liability were not updated to current market discount rates, while under IFRS, the credit-adjusted risk-free discount rate is updated each reporting period. The adoption of this policy did not have a significant impact on our net earnings for the three month period ended March 31, 2010 or the year ended December 31, 2010.

## Compensation Plans

We have certain obligations for payments to our employees related to stock option and incentive plans of Cenovus. Under previous GAAP, we had accrued the liability for these payments using the intrinsic valuation method, while under IFRS this liability is measured at fair value. While the carrying value in each reporting period will be different under IFRS compared to previous GAAP, the cumulative expense recognized over the life of the instrument under both methods will be the same. The adoption of this policy resulted in a recovery of stock-based compensation expense of $4 million for the three month period ended March 31, 2010 (recovery of $9 million for the year ended December 31, 2010).

## Income Taxes

Under IFRS, the term future income taxes has been changed to deferred income taxes. The carrying amounts of our tax balances have been directly impacted by the tax effects resulting from the adoption of our IFRS accounting policies. The deferred income tax liability on our IFRS opening balance sheet was reduced by $986 million, primarily due to the fair value election on our refineries. For the three months ended March 31, 2010, our income tax expense did not change, and for the year ended December 31, 2010, our income tax expense increased by $53 million, primarily related to the tax effects on the recognition of gains on our PP&E divestitures.

## Diluted Earnings per Share

Under previous GAAP, stock options with attached stock appreciation rights were accounted for as liabilities and were not included in the calculation of diluted earnings per share ("EPS"), while under IFRS, all stock options are included in the calculation. The adoption of this policy did not have a significant impact on the calculation of diluted EPS for either the three month period ended March 31, 2010 or the year ended December 31, 2010.

## Cash Flow

Cash flow as defined in this MD&A was not impacted by the adoption of IFRS for the three months ended March 31, 2010. However, for the year ended December 31, 2010, our cash flow was reduced by $3 million, as a result of expensing pre-exploration costs under IFRS that had been capitalized under previous GAAP.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

We are required to make judgments, assumptions and estimates in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates, and those differences may be material. The basis of presentation and our significant accounting policies can be found in the notes to the interim Consolidated Financial Statements. The following discussion highlights significant changes to our critical accounting policies and estimates from those disclosed in our MD&A for the year ended December 31, 2010, as a result of the adoption of IFRS.

### E&E Assets

The decision regarding technical feasibility and commercial viability of our E&E assets involves a number of assumptions, such as estimated reserves, commodity price forecasts, expected production volumes and discount rates, all of which are subject to material changes in the future.

### Opening Balance Sheet – Full Cost Pool

On transition to IFRS, our full cost pool under previous GAAP was allocated to our IFRS areas based on estimated proved reserve values. The estimate of proved reserve values required a number of assumptions and estimates, including quantities of reserves, expected production volumes, future commodity prices, discount rates as well as future development and operating costs. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction, nor do they represent costs historically spent.

### Property, Plant and Equipment – DD&A

Under IFRS, estimates of reserves at the area level, rather than the country cost centre level, can have a significant impact on net earnings, as they are a key component in the calculation of DD&A. A downward revision in our estimate of reserve quantities could result in a higher DD&A charge to earnings.

### Asset Impairments

For impairment testing, the assessment of facts and circumstances is a subjective process that often involves a number of estimates and is subject to interpretation. Also, the testing of assets or CGUs for impairment, as well as the assessment of potential impairment reversals, requires that we estimate an asset's or CGU's recoverable amount. The estimate of a recoverable amount requires a number of assumptions and estimates, including quantities of reserves, expected production volumes, future commodity prices, discount rates as well as future development and operating costs. These assumptions and estimates are subject to change as new information becomes available and changes in any of the assumptions, such as a downward revision in reserves, a decrease in commodity prices or an increase in costs, could result in an impairment of an asset's or CGU's carrying value.

### Exchanges of Assets

The estimate of fair value, which is used to recognize gains or losses on asset exchanges, requires a number of assumptions and estimates, including quantities of reserves, future commodity prices, discount rates as well as future development and operating costs. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

### Decommissioning Liabilities

Since the discount rate used to estimate our decommissioning liabilities is updated each reporting period under IFRS, changes in the credit-adjusted risk-free rate can change the amount of the liability, and these changes could potentially be material in the future.

### Compensation Plans

As a result of measuring our obligations for payments under the Cenovus compensation plans at fair value under IFRS, fluctuations in the estimated fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation fluctuates, as it is based on assumptions for the risk-free interest rate, dividend yield, as well as the volatility of our share price.

## FUTURE CHANGES IN ACCOUNTING POLICIES

### IFRS Accounting Policies

As described in this MD&A, our IFRS financial statements for the year ending December 31, 2011 must use the standards that are in effect on December 31, 2011, and therefore our financial statements under IFRS for the three month period ended March 31, 2011 are subject to change. Changes to the accounting policies used may result in material changes to our reported financial position, results of operations and cash flows.

### Financial Instruments

The IASB intends to replace IAS 39, "Financial Instruments: Recognition and Measurement" ("IAS 39") with IFRS 9, "Financial instruments" ("IFRS 9"). IFRS 9 will be published in three phases, of which the first phase has been published.

The first phase addresses the accounting for financial assets and financial liabilities. The second phase will address the impairment of financial instruments, and the third phase will address hedge accounting.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is effective for annual periods beginning on or after January 1, 2013 with different transitional arrangements depending on the date of initial application. We are currently evaluating the impact of adopting IFRS 9 on our consolidated financial statements.

## OUTLOOK

Our long-term objective is to focus on building net asset value and generating an attractive total shareholder return through the following strategies:

- Material growth in oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties, and heavy oil production at Pelican Lake. We also have an extensive inventory of new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and have a 100 percent working interest in many of these assets;
- Continue the development of our resources in multiple phases using a low cost manufacturing-like approach;
- Leadership in low cost oil sands development enabled by technology, innovation and continued respect for the health and safety of our employees, emphasis on industry leading environmental performance and meaningful dialogue with our stakeholders;
- Primarily fund growth internally through free cash flow generation mainly from our established conventional crude oil and natural gas assets along with sufficient capacity on our debt facilities for additional cash requirements, as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core oil and gas assets;
- Maintain a lower risk profile through natural gas and refining integration as well as a consistent hedging strategy; and
- Maintain a meaningful dividend.

The key challenges that need to be effectively managed to enable our growth are commodity price volatility, timely regulatory and partner approvals, environmental regulations and competitive pressures within our industry. Additional detail regarding the impact of these factors on our financial results is discussed in the Risk Management section of this MD&A and in the Risk Factors section of our AIF for the year ended December 31, 2010.

The balance between robust demand growth and significant OPEC spare production capacity that kept WTI prices between US$70.00 and US$90.00 per barrel for most of the past 18 months was broken by the loss of over one million bbls/d of supply as hostilities escalated in Libya. The duration of these losses is uncertain but WTI prices should adjust lower as this lost supply returns to the market or is offset by increased output from other OPEC countries. Demand growth should partially ease in response to current high prices but should still remain near historic averages as prices have yet to materially weaken global Gross Domestic Product growth. The natural disaster in Japan could disrupt global supply chains, but once Japanese refining capacity returns to the market, rebuilding efforts commence as well as reduced nuclear energy output, the demand for crude oil is expected to increase.

Growth in Canadian heavy crude oil production and strong growth in inland light oil production have tested the capabilities of North America's pipeline grid. This has depressed inland prices for all crude grades relative to offshore crudes due to constraints in pipeline infrastructure. With inland product prices continuing to be set by U.S. Gulf Coast prices, this widening spread between discounted inland crude and elevated product prices have substantially improved refinery economics. With strong growth in inland crude supply expected to continue, pipeline capacity is expected to struggle to keep pace resulting in continued inland crude discounts.

We expect our 2011 capital investment program to be internally funded through cash flow with sufficient capacity on our debt facilities for additional cash requirements. We also plan to divest of certain non-core assets in 2011 for proceeds of $300 to $500 million. Our conventional crude oil and natural gas assets in Alberta and Saskatchewan are key to providing free cash flow to enable oil sands growth. Our 10 year business plan outlines how Cenovus expects to reach net oil sands production of 300,000 bbls/d by the end of 2019. Continued expansions are planned at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve this objective.

As part of ongoing efforts to maintain financial resilience and flexibility, Cenovus has taken steps to reduce pricing risk through a commodity hedging program. While we have historically benefitted from this strategy, there is no certainty that we will continue to derive such benefits in the future.

We will continue to develop our strategy with respect to capital investment and returns to shareholders. Future dividends will be at the sole discretion of the Board and considered quarterly.

## ADVISORY

## FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this MD&A is identified by words such as "anticipate", "believe", "expect", "plan", "forecast", "target", "project", "could", "focus", "vision", "goal", "proposed", "scheduled", "outlook", "potential", "may" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, anticipated finding and development costs, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, forecasted commodity prices, future use and development of technology and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally.

The factors or assumptions on which the forward-looking information is based include: assumptions inherent in our current guidance, available at www.cenovus.com; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and our access to various sources of capital; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of Debt to Adjusted EBITDA as well as Debt to Capitalization; our ability to access external sources of debt and equity capital; success of hedging strategies; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets;

potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining of crude oil into petroleum and chemical products at two refineries; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in Alberta's regulatory framework, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our Annual Information Form/Form 40-F for the year ended December 31, 2010, available at www.sedar.com, www.sec.gov and www.cenovus.com.

## CRUDE OIL, NGLs AND NATURAL GAS CONVERSIONS

In this document, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

## ABBREVIATIONS

The following is a summary of the abbreviations that have been used in this document:

| Oil and Natural Gas Liquids | | Natural Gas | |
|---|---|---|---|
| bbl | Barrel | Mcf | thousand cubic feet |
| bbls/d | barrels per day | MMcf | million cubic feet |
| Mbbls/d | thousand barrels per day | MMcf/d | million cubic feet per day |
| MMbbls | million barrels | Bcf | billion cubic feet |
| NGLs | Natural gas liquids | MMBtu | million British thermal units |
| BOE | barrel of oil equivalent | GJ | Gigajoule |
| BOE/d | barrel of oil equivalent per day | CBM | Coal Bed Methane |
| WTI | West Texas Intermediate | | |
| WCS | Western Canada Select | | |

The Arrangement refers to the commencement of independent operations on December 1, 2009 following a plan of arrangement with Encana under the Canada Business Corporations Act to create two independent publicly traded energy companies.

## NON-GAAP MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by GAAP such as cash flow, operating cash flow, free cash flow, operating earnings, Adjusted EBITDA, Debt and Capitalization and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with GAAP. The definition and reconciliation of each non-GAAP measure, is presented in this MD&A.

## ADDITIONAL INFORMATION

For convenience, references in this document to the "Company", "Cenovus", "we", "us", "our" and "its" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("subsidiaries") of Cenovus, and the assets, activities and initiatives of such subsidiaries.

Additional information relating to Cenovus, including our AIF for the year ended December 31, 2010, is available on SEDAR at www.sedar.com and on our website at www.cenovus.com.