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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 40-F

[Check one]

o **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**
OR

R **ANNUAL REPORT PURSUANT TO SECTION 13(a) or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: December 31, 2009 **Commission File Number: 1-34513**

CENOVUS ENERGY INC.

(Exact name of Registrant as specified in its charter)

Not applicable
(Translation of Registrant's name into English (if applicable)

Canada
(Province or other jurisdiction of incorporation or organization)

1311
(Primary Standard Industrial
Classification Code Number (if applicable))

Not applicable
(I.R.S. Employer
Identification Number (if applicable))

4000, 421-7th Avenue S.W.
Calgary, Alberta, Canada T2P 4K9
(403) 766-2000
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
111 8th Avenue
New York, New York 10011
(212) 894-8641
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Common shares, no par value (together with associated common share purchase rights)	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act.

None
(Title of Class)

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Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

None
(Title of Class)

For Annual Reports indicate by check mark the information filed with this Form:

R Annual information form R Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

751,308,563

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, please indicate the filing number assigned to the Registrant in connection with such Rule.

Yes o 82-_____ No R

Indicate by check mark whether the Registrant (1) has filed all reports to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to filing requirements for the past 90 days.

Yes o No R

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes o No o

The Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, each of the Registrant's Registration Statements under the Securities Act of 1933: Form S-8 (File No. 333-163397).

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Principal Documents

The following documents have been filed as part of this Annual Report on Form 40-F, beginning on the following page:

(a) Annual Information Form of Cenovus Energy Inc. for the fiscal year ended December 31, 2009.

(b) Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2009.

(c) Consolidated Financial Statements of Cenovus Energy Inc. as at December 31, 2009 *(Note 21 to the Consolidated Financial Statements relates to United States Accounting Principles and Reporting (U.S. GAAP)).*

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CENOVUS ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2009

February 18, 2010

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NOTICE TO READER

This is the annual information form of Cenovus Energy Inc. for the year ended December 31, 2009. In this annual information form, unless otherwise specified or the context otherwise requires, reference to "we", "us", "our" or "Cenovus" includes reference to subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries subsequent to the Effective Date and the Cenovus Assets, as held by EnCana prior to the Effective Date. We acquired the Cenovus Assets from EnCana on the Effective Date in connection with the Arrangement.

Unless otherwise specified, all dollar amounts are expressed in U.S. dollars and all references to "dollars", "US$" or to "$" are to U.S. dollars and all references to "C$" are to Canadian dollars.

Unless otherwise indicated, all financial information included in this annual information form is determined using Canadian GAAP, which differs from U.S. GAAP in certain material respects, and thus may not be comparable to financial statements and financial information of U.S. companies. The notes to our audited consolidated financial statements for the year ended December 31, 2009 contain a discussion of the principal differences between the financial results calculated under Canadian GAAP and under U.S. GAAP.

Certain historical information contained in this annual information form has been provided by, or derived from information provided by, certain third parties, including EnCana. Although we have no knowledge that would indicate that any such information is untrue or incomplete, we assume no responsibility for the completeness or accuracy of such information or the failure by such third parties to disclose events which may have occurred or may affect the completeness or accuracy of such information, but which are unknown to us.

We commenced independent operations on December 1, 2009 following the completion of the Arrangement. The description of our business, recent significant developments, the presentation of financial statements and other information throughout this annual information form in respect of periods prior to December 1, 2009 is based on information with respect to the Cenovus Assets as operated by EnCana prior to December 1, 2009. See "General Development of our Business - The Arrangement" for further information on the Arrangement. Such financial information has been derived from the historical consolidated financial statements of EnCana for each of the relevant periods on a carve-out basis from such historical consolidated financial statements of EnCana for the relevant period and should be read in conjunction with our audited consolidated financial statements for the year ended December 31, 2009 and the carve-out consolidated financial statements in relation to Cenovus Energy for the year ended December 31, 2008 and the Management's Discussion and Analysis thereon, each as set out in the Information Circular of EnCana dated October 20, 2009 relating to an arrangement involving Cenovus Energy Inc., and the unaudited interim carve-out consolidated financial statements in relation to Cenovus Energy for the nine months ended September 30, 2009 and the Management's Discussion and Analysis thereon which are accessible on the SEDAR profile of EnCana at ***www.sedar.com*** and have been filed with the SEC and are available via EDGAR at ***www.sec.gov***.

"Cenovus Energy" represents the historical operations, assets, liabilities and cash flows of the Integrated Oil and Canadian Plains Divisions of EnCana (prior to the completion of the Arrangement), as well as a portion of the Market Optimization and Corporate functions of EnCana (prior to the completion of the Arrangement). As a result, comparative historical financial results may not be indicative of those that would have resulted had we existed as a stand-alone entity during those periods. See "Risk Factors".

This annual information form contains certain forward-looking statements or information within the meaning of applicable securities legislation. Forward-looking statements or

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information are typically identified by words such as "projected", "anticipate", "believe", "expect", "plan", "intend" or similar words suggesting future outcomes or statements regarding an outlook. All statements other than statements of historical fact contained in this annual information form are

forward-looking statements or information. See “Note Regarding Forward-Looking Statements”.

NI 51-101 imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. We have obtained an exemption from the Canadian securities regulatory authorities to permit us to provide disclosure in accordance with the relevant legal requirements of the SEC. This facilitates comparability of our oil and gas disclosure with that provided by U.S. and other international issuers, given that we are active in the U.S. capital markets. Accordingly, the proved and probable reserves data and much of the other oil and gas information included in this annual information form is disclosed in accordance with U.S. disclosure requirements. Such information, as well as the information that we anticipate disclosing in the future in reliance on such exemption, may differ from the corresponding information prepared in accordance with NI 51-101 standards. Pursuant to U.S. reporting protocols, production and reserves information is required to be presented on an after royalties basis. In addition, to provide more complete information on our business, we are voluntarily providing production and reserves information on a before royalties basis. The probable reserves data contained in this annual information form is also being provided on a voluntary basis. See “Reserves and Other Oil and Gas Information” and “Note Regarding Reserves Data and Other Oil and Gas Information”.

Unless otherwise noted, capitalized terms used in this annual information form have the meaning ascribed thereto under the heading “Glossary”.

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CORPORATE STRUCTURE

Cenovus Energy Inc. was incorporated on September 24, 2008 under the CBCA as 7050372 Canada Inc. Pursuant to the Arrangement, 7050372 and Subco amalgamated under the CBCA on the Effective Date with the amalgamated company’s name being “Cenovus Energy Inc.”. Our executive and registered office is located at #4000, 421 - 7 Avenue S.W., Calgary, Alberta, Canada T2P 4K9. Prior to completion of the Arrangement, 7050372 did not carry on any active business and did not issue any shares.

For a further description of the Arrangement, see “General Development of Our Business – The Arrangement”.

Intercorporate Relationships

We have the following principal subsidiaries and partnerships which have total assets that exceed ten percent of our total consolidated assets or sales and revenues which exceed ten percent of our total consolidated sales and revenues as at and for the year ended December 31, 2009:

Subsidiaries & Partnerships	Percentage Owned[1]	Jurisdiction of Incorporation, Continuance, Formation or Organization
Cenovus FCCL Ltd.	100	Alberta
FCCL Partnership	50	Alberta
Cenovus Downstream Holdings ULC	100	Alberta
Cenovus US Refineries, LLC	100	Delaware
Cenovus US Refinery Holdings	100	Delaware
WRB Refining LLC	50	Delaware

Note:
(1) Includes indirect ownership.

The above table does not include all of our subsidiaries and partnerships. The assets and revenues of our unnamed subsidiaries and partnerships did not exceed 20 percent of our total consolidated assets or total consolidated sales and revenues as at and for the year ended December 31, 2009.

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GENERAL DEVELOPMENT OF OUR BUSINESS

Cenovus is an integrated oil company headquartered in Calgary, Alberta. Our operations include enhanced oil recovery (“EOR”) properties and established crude oil and natural gas production in Alberta and Saskatchewan. We also have ownership interests in two refineries in Illinois and Texas, USA.

We began independent operations on December 1, 2009 following the split of EnCana into two independent publicly traded energy companies – Cenovus and EnCana. Although we are a new company, we have operated a number of our assets for decades.

The Arrangement

The division of EnCana into two highly focused and independent publicly traded energy companies was completed on November 30, 2009. It resulted in, among other things, the establishment of our company as an independent integrated oil company anchored by stable production and cash flow from well-established crude oil and natural gas plays, integrated from crude oil production through to refined products.

Pursuant to the Arrangement and a number of preliminary transactions completed on or prior to the Effective Date, we indirectly acquired:

(a) those assets associated with EnCana’s Integrated Oil Division, which included EnCana’s interests in the Foster Creek, Christina Lake, Narrows Lake and Borealis areas and the U.S. refinery interests in addition to certain of EnCana’s other bitumen interests and natural

gas assets located in the Athabasca area;

(b) those assets associated with EnCana's Canadian Plains Division, which included the majority of EnCana's legacy oil and natural gas assets in southern Alberta and Saskatchewan. This Division included the EOR properties located at Weyburn and Pelican Lake, as well as the Southern Alberta oil and gas properties; and

(c) those assets associated with the foregoing businesses, including marketing, corporate and office space (including a proportionate share of The Bow office project).

Pursuant to the Pre-Arrangement Reorganization in connection with the Arrangement, EnCana transferred the Cenovus Assets to Subco in exchange for, among other things, an interest bearing demand intercompany note in the amount of $3.5 billion (the "Demand Note").

The Assumed Liabilities assumed, directly or indirectly, in connection with the Arrangement included, among others, those liabilities relating to EnCana's Integrated Oil and Canadian Plains Divisions described above.

As a result of the Arrangement, each shareholder of EnCana (other than a Dissenting Shareholder) received one new EnCana common share (such shares being represented by existing EnCana common share certificates) and one Common Share for each EnCana common share held. On the Effective Date, 751,273,307 Common Shares were issued to such former holders of EnCana common shares.

In connection with the Arrangement and in order to provide ongoing liquidity, including working capital requirements, prior to the completion of the Arrangement, we obtained commitments from a syndicate of banks to make available an unsecured credit facility in the amount of C$2.5 billion. The revolving syndicated credit facility consists of two tranches, a C$2.0 billion three-year tranche and a C$500 million 364-day tranche. The terms of each of these facilities commenced on the Effective Date.

On September 18, 2009, a predecessor entity of Cenovus completed, in three tranches, a $3.5 billion private offering of debt securities (comprised of the 2014 Notes, 2019 Notes and 2039 Notes) which are exempt from the registration requirements of the U.S. Securities Act

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under Rule 144A and Regulation S (the "Cenovus Note Offering"). See "Prior Sales". The net proceeds of the Cenovus Note Offering were placed into an escrow account pending the completion of the Arrangement. Upon completion of the Arrangement, the net proceeds, together with other pre-funded amounts, were released from escrow and were applied to repay all of the amounts outstanding under the Demand Note.

We have filed a business acquisition report in Form 51-102F4 in respect of the Arrangement. The business acquisition report is accessible under our profile on SEDAR at ***www.sedar.com*** and in our Form 6-K filed with the SEC on December 16, 2009, available via EDGAR at ***www.sec.gov***.

Our Business

Our operations are organized into two operating divisions:

- **Integrated Oil** Division, which includes all of the assets within the upstream and downstream integrated oil business with our joint venture partner, as well as other bitumen interests and the Athabasca natural gas assets. The Integrated Oil Division has assets in both Canada and the U.S. including two major EOR properties: (i) Foster Creek; and (ii) Christina Lake; as well as two refineries: (i) Wood River; and (ii) Borger.
- **Canadian Plains** Division, which contains established crude oil and natural gas development assets in Alberta and Saskatchewan and includes two major EOR properties: (i) Weyburn; and (ii) Pelican Lake; as well as the Southern Alberta oil and gas properties. The Division 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.

For financial statement reporting purposes, our operating and reportable segments are:

- **Upstream Canada**, which includes Cenovus's development and production of bitumen, crude oil, natural gas and natural gas liquids ("NGLs") and other related activities in Canada. This includes the Foster Creek and Christina Lake operations which are jointly owned with ConocoPhillips, an unrelated U.S. public company, and operated by Cenovus.
- **Downstream Refining**, which is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips and operated by ConocoPhillips.
- **Corporate and Eliminations**, which primarily includes unrealized gains or losses recorded on derivative financial instruments as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, 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.

In addition to the Arrangement, the following describes the significant events of the last three years in respect of our business:

2009

- In the first quarter of 2009, two new expansion phases at Foster Creek were commissioned. Phases D and E added a total of 60,000 barrels per day of bitumen production capacity, increasing the total production capacity of Foster Creek to approximately 120,000 barrels per day.

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- In the second quarter of 2009, a joint regulatory application for Foster Creek phases F, G and H was submitted to the Energy Resources Conservation Board ("ERCB") and Alberta Environment. Each phase is expected to increase production capacity by 30,000 barrels per day of bitumen.
- In the fourth quarter of 2009, FCCL sanctioned the next phase, phase D, of expansion at Christina Lake, which is expected to increase production capacity by 40,000 barrels per day of bitumen in 2013.
- In the fourth quarter of 2009, a joint regulatory application for Christina Lake phases E, F and G was submitted to the ERCB and Alberta Environment. Each phase is expected to increase production capacity by 40,000 barrels per day of bitumen.

2008

- In the second quarter of 2008, Christina Lake phase B expansion was commissioned. This phase added 8,000 barrels per day of production capacity, increasing the total production capacity at Christina Lake to approximately 18,000 barrels per day of bitumen.
- In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction on the CORE project. Our 50 percent share of the CORE project is expected to cost approximately $1.8 billion and is anticipated to be completed and in operation in 2011. The expansion is expected to more than double heavy crude oil refining capacity to approximately 240,000 barrels per day and increase crude oil refining capacity by 50,000 barrels per day to approximately 356,000 barrels per day.

2007

- The creation of the integrated oil business venture, consisting of upstream and downstream assets, with ConocoPhillips was completed on January 3, 2007. It is comprised of two 50-50 operating entities, a Canadian upstream enterprise operated by Cenovus and a U.S. downstream enterprise operated by ConocoPhillips, with both ConocoPhillips and Cenovus having contributed equally valued assets and equity. The integrated oil business provides greater certainty of execution for our Foster Creek and Christina Lake EOR projects and allows us to participate in the full value chain from crude oil production through to refined products.
- In the first quarter of 2007, Foster Creek phase C expansion was commissioned. This phase added 30,000 barrels per day of production capacity, increasing the total production capacity at Foster Creek to approximately 60,000 barrels per day of bitumen.
- In the second quarter of 2007, a 25,000 barrel per day coker addition at the Borger refinery was completed. The refinery was shut down for approximately one month to complete a major planned turnaround timed to coincide with bringing the new coker online. The refinery started up again in June 2007 and ran its first barrel of Canadian heavy oil on July 10, 2007, marking a major milestone for the refinery.
- In the third quarter of 2007, regulatory approval and sanctioning was received for the Christina Lake phase C expansion, which is expected to increase production capacity by 40,000 barrels per day of bitumen in 2011.
- In the fourth quarter of 2007, a joint regulatory application for development of the Borealis property was submitted to the ERCB and Alberta Environment that would allow for the construction of a SAGD facility with production capacity of approximately 35,000 barrels per day of bitumen.

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NARRATIVE DESCRIPTION OF OUR BUSINESS

The following maps outline the location of our assets, including our major properties and refining assets as at December 31, 2009.

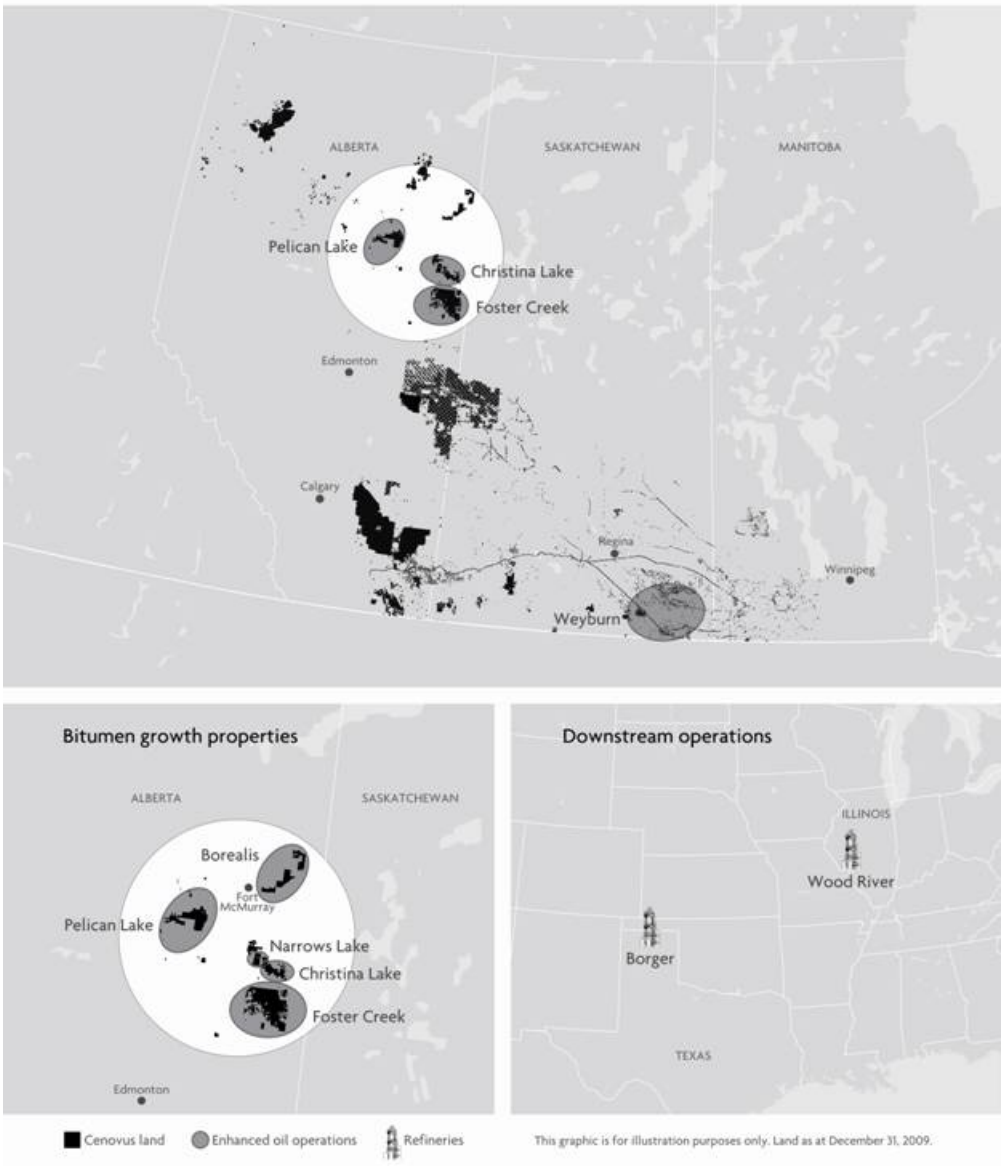


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One hundred percent of our reserves and production are located in Canada. At December 31, 2009, we had a land base of approximately 7.8 million net acres and a proved reserves base (our share after royalties) of approximately 719 million barrels of bitumen reserves, 232 million barrels of crude oil and NGLs reserves and 1,474 billion cubic feet of natural gas reserves. The estimated proved reserves life index as at December 31, 2009 was approximately 14.7 years. We also had probable reserves (our share after royalties) of approximately 403 million barrels of bitumen, 127 million barrels of crude oil and NGLs and 405 billion cubic feet of natural gas as at December 31, 2009.

The following narrative describes each of our operating divisions in greater detail.

Integrated Oil Division

The Integrated Oil Division includes all of the assets within the integrated oil business with ConocoPhillips described below, as well as other bitumen interests and the Athabasca natural gas assets. The Integrated Oil Division has assets in both Canada and the U.S. and contains two EOR properties: (i) Foster Creek; and (ii) Christina Lake; as well as two refineries at Wood River and Borger. In 2009, the Integrated Oil Division had capital investment of approximately $1,383 million, which included continued development of the CORE project, as well as the drilling of approximately 80 net wells (including 40 stratigraphic test wells).

As at December 31, 2009, we held bitumen rights of approximately 1,055,000 gross acres (760,000 net acres) within the Athabasca and Cold Lake areas, as well as the exclusive rights to lease an additional 652,000 net acres on our behalf and/or our assignee's behalf on the Cold Lake Air Weapons Range.

The following table summarizes landholdings for the Integrated Oil Division as at December 31, 2009.

Landholdings (thousands of acres)	Developed Acreage Gross	Developed Acreage Net	Undeveloped Acreage Gross	Undeveloped Acreage Net	Total Acreage Gross	Total Acreage Net	Average Working Interest
Foster Creek	7	4	65	32	72	36	50%
Christina Lake	1	-	24	12	25	12	50%
Narrows Lake(1)	-	-	25	15	25	15	60%
Borealis	-	-	36	36	36	36	100%
Athabasca	520	443	355	283	875	726	83%
Other	23	10	923	675	946	685	72%
Integrated Oil Total	551	457	1,428	1,053	1,979	1,510	76%

Note:

(1) Under an area of mutual interest arrangement, ConocoPhillips made an election to participate in a certain Cenovus lease acquisition through ConocoPhillips's interest in FCCL, reducing Cenovus's working interest share to 50 percent on January 1, 2010.

The following table sets forth our share of daily average production figures for the periods indicated.

Production (annual average)	Crude Oil and NGLs (bbls/d) 2009	Crude Oil and NGLs (bbls/d) 2008	Natural Gas (MMcf/d) 2009	Natural Gas (MMcf/d) 2008	Total Production (BOE/d) 2009	Total Production (BOE/d) 2008
Foster Creek	36,654	25,947	-	-	36,654	25,947
Christina Lake	6,527	4,236	-	-	6,527	4,236
Athabasca	-	-	49	63	8,167	10,500
Other	2,553	2,729	-	-	2,553	2,729
Integrated Oil Total	45,734	32,912	49	63	53,901	43,412

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The following table summarizes the Integrated Oil Division's interests in producing wells as at December 31, 2009. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2009.

Producing Wells (number of wells)	Producing Oil Wells Gross	Producing Oil Wells Net	Producing Gas Wells Gross	Producing Gas Wells Net	Total Producing Wells Gross	Total Producing Wells Net
Foster Creek	171	86	-	-	171	86
Christina Lake	16	8	8	4	24	12
Athabasca	-	-	683	647	683	647
Integrated Oil Total	187	94	691	651	878	745

The following describes major producing areas or activities in the Integrated Oil Division.

Integrated Oil Business

On January 3, 2007, the creation of the integrated oil business with ConocoPhillips was completed. The integrated oil business includes Canadian upstream assets contributed by Cenovus and U.S. downstream assets contributed by ConocoPhillips. The business is comprised of two 50-50 operating entities, a Canadian upstream entity, FCCL, operated by Cenovus and a U.S. downstream enterprise, WRB, operated by ConocoPhillips.

FCCL owns the Foster Creek and Christina Lake EOR projects. Cenovus FCCL Ltd., our wholly-owned subsidiary, is the operating and managing partner of FCCL. WRB owns the Wood River and Borger refineries. ConocoPhillips held a disproportionate economic interest in the Borger refinery of 85 percent in 2007 and 65 percent in 2008, before reverting to 50 percent in 2009. ConocoPhillips is the operator and manager of WRB. FCCL has a management committee, while WRB has a board of directors; both are composed of three of our representatives and three of ConocoPhillips's representatives, with each company holding equal voting rights.

At December 31, 2009, the combined production capacity of the Foster Creek and Christina Lake properties was approximately 138,000 barrels per day. FCCL plans to increase production capacity to approximately 218,000 barrels of bitumen per day from the combined facilities at Foster Creek and Christina Lake with the completion of the Christina Lake phase C expansion in 2011 and phase D expansion in 2013.

At December 31, 2009, WRB had processing capability to refine up to approximately 70,000 barrels per day of bitumen equivalent. WRB plans to refine approximately 150,000 barrels per day of bitumen equivalent to primarily motor fuels with the completion of the CORE project in 2011.

Foster Creek

We have a 50 percent interest in Foster Creek, an EOR property which uses SAGD technology and produces from the McMurray formation. We hold surface access rights from the Governments of Canada and Alberta and bitumen rights for exploration, development and transportation from areas within the Cold Lake Air Weapons Range which were granted by the Government of Alberta. In addition, we hold exclusive rights to lease several hundred thousand acres of bitumen rights in other areas on the Cold Lake Air Weapons Range on our behalf and/or our assignee's behalf. In the first quarter of 2009, two new expansion phases were completed at Foster Creek adding production capacity of approximately 60,000 barrels of bitumen per day and increasing total production capacity to approximately 120,000 barrels of bitumen per day.

We continually research and develop technologies to increase bitumen recovery, decrease costs of extracting bitumen and reduce our

environmental footprint. One focus area is alternate methods of artificial lift where we utilize new pump designs that are expected to enable us to optimize SAGD performance by operating at lower pressures, thereby realizing lower steam-oil ratios and decreasing facility capital and operating costs. As at

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December 31, 2009, electrical submersible pumps were in use on 133 wells at Foster Creek and we expect to continue to utilize this technology on new SAGD wells.

In addition, we have successfully piloted another technology at Foster Creek whereby an additional well, a wedge well, is drilled between two producing well pairs to produce bitumen that is heated by proximity to a steam chamber, but is not recoverable by the adjacent production wells. We have received a U.S. patent for this technology, with the Canadian patent pending and expected to be received in the first half of 2010. This technology requires no additional steam, thus it helps reduce the overall steam-oil ratio. In 2009, we drilled 18 wedge wells (2008 - four wells). As at December 31, 2009, there were 27 wedge wells producing. This process will be piloted at our Christina Lake property in the first quarter of 2010.

We also focus on reducing our reliance on natural gas for the generation of steam used in SAGD production operations. The Solvent Aided Process (“SAP”) is discussed under “Christina Lake” below.

We operate an 80-megawatt natural gas-fired cogeneration facility in conjunction with the SAGD operation at Foster Creek. The steam and power generated by the facility is presently being used within the SAGD operation and the excess power generated is being sold into the Alberta Power Pool.

Christina Lake

We have a 50 percent interest in a SAGD EOR project at Christina Lake which produces from the McMurray formation. During 2008, the phase B expansion was completed which increased production capacity to approximately 18,000 barrels of bitumen per day.

The phase C expansion, which is expected to add an additional 40,000 barrels per day of bitumen production capacity, is currently under construction and is expected to be completed in 2011, increasing total bitumen production capacity to 58,000 barrels per day.

During the fourth quarter of 2009, the phase D expansion was sanctioned by FCCL. This expansion is expected to add an additional 40,000 barrels per day of bitumen production capacity at Christina Lake. We have accelerated the completion of phase D by six months and it is expected to be completed in mid-2013. Regulatory approval for this additional phase was received in 2008.

There have been several innovations to SAGD technology that have been undertaken at Christina Lake over the past several years. One major project that started in 2009 is a new SAP pilot. This SAP pilot utilizes a mixture of steam and solvent to enhance recovery of the bitumen by reducing the steam-oil ratio and increasing the overall recovery of the oil in place. Business cases are currently being evaluated for the potential use of this technology in the Christina Lake and Narrows Lake development plans.

Another innovation was undertaken in 2007, whereby a remote water disposal system was utilized to successfully manage bottom water pressures and further reduce the steam-oil ratio.

Narrows Lake

We hold a 50 percent interest in the Narrows Lake area which is located within the greater Christina Lake regional area. We are preparing development plans and regulatory applications for a project at Narrows Lake that would include two to three phases with each phase expected to add approximately 40,000 barrels per day of bitumen production capacity.

Wood River Refinery

We have a 50 percent interest in the Wood River refinery, located in Roxana, Illinois. As at December 31, 2009, the Wood River refinery had a processing capacity of approximately 306,000 barrels per day of crude oil. It processes light, low-sulphur and heavy, high-sulphur

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crude oil that it receives from North American crude oil pipelines to produce gasoline, diesel and jet fuel, petrochemical feedstocks and asphalt. The gasoline and diesel are transported via pipelines to markets in the upper Midwest. Other products are transported via pipeline, truck, barge and railcar to markets in the Midwest. In 2007, the refinery completed the construction of a proprietary sulphur removal unit that produces low-sulphur gasoline. In September 2008, regulatory approval was received to proceed with the CORE project at Wood River which is expected to increase crude oil refining capacity by approximately 50,000 barrels per day, increase coking capacity by approximately 65,000 barrels per day, more than double heavy crude oil refining capacity to approximately 240,000 barrels per day and increase the clean transportation fuels yield by approximately ten percent to approximately 89 percent. Capital expenditures for the CORE project are estimated at $3.6 billion ($1.8 billion net to Cenovus) and the project is scheduled to be completed in 2011. At December 31, 2009, the CORE project was 71 percent complete, on

schedule and on budget.

Borger Refinery

We have a 50 percent interest in the Borger refinery, located in Borger, Texas. As at December 31, 2009, the Borger refinery had a processing capacity of approximately 146,000 barrels per day of crude oil and approximately 45,000 barrels per day of NGLs. It processes mainly medium, high-sulphur and heavy, high-sulphur crude oil and NGLs that it receives from North American pipeline systems to produce gasoline, diesel and jet fuel along with NGLs and solvents. The refined products are transported via pipelines to markets in Texas, New Mexico, Colorado and the U.S. Mid-Continent. In July 2007, a new coker with a capacity of approximately 25,000 barrels per day was brought into service along with a new vacuum unit and revamped gas, oil and distillate hydrotreaters. This project has enabled the refinery to process heavy oil blends, particularly Canadian heavy oil, and comply with clean fuel regulations for ultra-low sulphur diesel and low-sulphur gasoline. The project has also enabled compliance with required reductions of sulphur dioxide and other air emissions.

The following table summarizes the combined refineries' key operational results for the periods indicated.

Refinery Operations[(1)]	**2009**	**2008**
Crude Oil Capacity (Mbbls/d)	452	452
Crude Oil Runs (Mbbls/d)	394	423
Crude Utilization (%)	87	93
Refined Products (Mbbls/d)		
Gasoline	223	230
Distillates	120	139
Other	74	79
Total	417	448

Note:
(1) Represents 100 percent of the Wood River and Borger refinery operations.

Other Integrated Oil Division Properties

Borealis

We hold a 100 percent working interest in the Borealis area, which is located approximately 90 kilometres northeast of Fort McMurray. Borealis is not included in the integrated oil business with ConocoPhillips. Approximately 200 delineation wells have been drilled in the greater Borealis area as at December 31, 2009. A joint application for development has been submitted to the ERCB and Alberta Environment that would allow for the construction of a SAGD facility with production capacity of approximately 35,000 barrels of bitumen per day. We continue to evaluate the greater Borealis area in support of the development application.

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Athabasca Gas

We produce natural gas from the Cold Lake Air Weapons Range and several surrounding landholdings located in northeast Alberta and hold surface access and natural gas rights for exploration, development and transportation from areas within the Cold Lake Air Weapons Range that were granted by the Governments of Canada and Alberta. The majority of our natural gas production in the area is processed through wholly-owned and operated compression facilities.

Natural gas production continues to be impacted by the September 2003, July 2004, September 2004, July 2007 and October 2009 ERCB decisions to shut-in natural gas production from the McMurray, Wabiskaw and Clearwater formations that may put at risk the recovery of bitumen resources in the area. The decisions resulted in a decrease in annualized natural gas production of approximately 25 million cubic feet per day in 2009 (26 million cubic feet per day in 2008). The Alberta Government's Department of Energy is providing financial assistance in the form of a royalty credit, which is equal to approximately 50 percent of the cash flow lost as a result of the shut-in wells.

Canadian Plains Division

The Canadian Plains Division encompasses crude oil development and production activities in Alberta and Saskatchewan, as well as established natural gas development and production activities in both southern and northern Alberta and southern Saskatchewan. Three major properties are located in the Canadian Plains Division: EOR projects at Pelican Lake and Weyburn, as well as conventional oil and natural gas in Southern Alberta. The Division also markets crude oil and natural gas, including third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

As at December 31, 2009, the Canadian Plains Division had an established land position of approximately 6.7 million gross acres (6.3 million net acres), of which approximately 4.3 million gross acres (4.1 million net acres) are developed. The mineral rights on approximately 50 percent of the total net acreage are owned in fee title by Cenovus, which means that production is subject to a mineral tax that is generally less than the Crown royalty imposed on production from land where the government owns the mineral rights. In 2009, the Canadian Plains Division had capital investment of approximately $478 million and drilled approximately 614 net wells. Of our capital expenditures, 56 percent was oil focused, while 43 percent of the capital expenditure was natural gas focused.

Plans for 2010 include further EOR initiatives, continued drilling, well optimizations, well recompletions (including coalbed methane ("CBM")) and investment in facility infrastructure necessary for continued development.

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The following table summarizes the landholdings for the Canadian Plains Division as at December 31, 2009.

	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working
Landholdings (thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Interest**
Weyburn	99	87	383	377	482	464	96%
Pelican Lake	133	133	279	264	412	397	96%
Southern Alberta							
Suffield	928	917	63	60	991	977	99%
Brooks North	569	567	8	8	577	575	100%
Langevin	1,132	1,022	371	345	1,503	1,367	91%
Drumheller	356	345	19	16	375	361	96%
Total Southern Alberta	2,985	2,851	461	429	3,446	3,280	95%
Other	1,058	986	1,303	1,193	2,361	2,179	92%
Canadian Plains Total	4,275	4,057	2,426	2,263	6,701	6,320	94%

The following table sets forth our share of daily average production figures for the periods indicated.

	Crude Oil and NGLs (bbls/d)		Natural Gas (MMcf/d)		Total Production (BOE/d)	
Production (annual average)	**2009**	**2008**	**2009**	**2008**	**2009**	**2008**
Weyburn	14,960	14,056	-	-	14,960	14,056
Pelican Lake	20,105	21,975	-	1	20,105	22,102
Southern Alberta						
Suffield	12,038	13,054	213	231	47,567	51,621
Brooks North	1,104	839	260	273	44,373	46,339
Langevin	8,293	9,111	185	203	39,044	43,029
Drumheller	2,122	2,276	81	93	15,679	17,776
Total Southern Alberta	23,557	25,280	739	800	146,663	158,765
Other	5,428	6,027	36	41	11,489	12,748
Canadian Plains Total	64,050	67,338	775	842	193,217	207,671

The following table summarizes the Canadian Plains Division's interests in producing wells as at December 31, 2009. These figures exclude wells which were capable of producing, but that were not producing, as of December 31, 2009.

	Producing Oil Wells		Producing Gas Wells		Total Producing Wells	
Producing Wells (number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Weyburn	764	482	-	-	764	482
Pelican Lake	445	445	9	9	454	454
Southern Alberta						
Suffield	745	745	10,348	10,330	11,093	11,075
Brooks North	57	57	7,338	7,230	7,395	7,287
Langevin	251	246	7,028	6,388	7,279	6,634
Drumheller	121	118	1,612	1,552	1,733	1,669
Total Southern Alberta	1,174	1,166	26,326	25,550	27,500	26,665
Other	665	626	1,173	1,154	1,838	1,780
Canadian Plains Total	3,048	2,719	27,508	26,663	30,556	29,381

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The following describes major producing areas or activities in the Canadian Plains Division.

Weyburn

We have a 62 percent working interest (50 percent economic interest) in the unitized portion of the Weyburn crude oil field in southeast Saskatchewan. The Weyburn unit produces light and medium sour crude from the Mississippian Midale formation and covers 78 sections of land. Cenovus is the operator and we are increasing ultimate recovery in the EOR area of the field with a carbon dioxide ("CO_2") miscible flood project. As at December 31, 2009, approximately 70 percent of the approved and planned CO_2 flood pattern development at the Weyburn unit was complete. Since the inception of the project, approximately 15 million tonnes of CO_2 have been injected as part of the EOR program. We estimate that another 15 million tonnes will be injected as part of the EOR project. The CO_2 is delivered by pipeline directly to the Weyburn facility from a coal gasification project in North Dakota.

Pelican Lake

Pelican Lake produces heavy crude oil from the Cretaceous Wabiskaw formation in northeast Alberta through horizontally drilled waterflood and polymer EOR methods. Facility infrastructure expansion in this area continued in 2009 to accommodate higher total fluid production volumes associated with its waterflood and polymer projects. The polymer flood program was expanded by 50 injection wells during 2009.

In addition to the heavy crude oil in the Wabiskaw formation, large deposits of bitumen have been identified in the Cretaceous Grand Rapids and the Devonian Grosmont formations in the Pelican Lake area which we continue to evaluate. In 2009, 17 stratigraphic test wells were drilled to acquire technical data on these formations.

We hold a 38 percent non-operated interest in a 110-kilometre, 20-inch diameter crude oil pipeline which connects the Pelican Lake area to a major pipeline that transports crude oil from northern Alberta to crude oil markets.

In August 2008, we entered into an agreement with Pembina Pipeline Corporation ("Pembina") to transport blended heavy oil from Utikuma, Alberta to Edmonton, Alberta via Pembina's 100,000 barrels per day capacity pipeline. This pipeline will be used to transport heavy oil from our Pelican Lake property to crude oil markets. The parties also agreed to transport condensate, used as diluent for transporting heavy oil, from Whitecourt, Alberta to Utikuma, Alberta via a 22,000 barrel per day capacity pipeline. The initial term of the agreement is ten years from the in-service date, which is estimated to be in mid-2011.

Southern Alberta

We own all the mineral rights across the majority of our fee title lands in southern Alberta and we lease the majority of the Cretaceous rights in Suffield and parts of southeastern Alberta. Approximately 59 percent of the land we hold in this area is fee simple or freehold and approximately 41 percent is Crown land. Our Southern Alberta properties are comprised of both oil and gas fields.

Southern Alberta - Oil Properties

We hold interests in multiple zones, primarily in the Early Cretaceous, in the Suffield, Langevin, Brooks North and Drumheller areas in southern Alberta with a mix of medium and heavy oil production. Development in this area focuses on infill drilling, optimization of existing wells and EOR schemes. We operate water handling facilities to effectively manage primary and enhanced oil production.

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The following table sets forth net oil wells drilled and daily average oil production figures for the periods indicated.

Net Wells Drilled and Production (annual average)	Net Wells Drilled		Light/Medium (bbls/d)		Heavy Oil (bbls/d)	
	2009	2008	2009	2008	2009	2008
Suffield	40	47	-	-	12,038	13,054
Brooks North	18	3	894	642	-	-
Langevin	14	16	8,053	8,862	-	-
Drumheller	28	1	1,421	1,595	-	-
Southern Alberta - Oil Properties - Total	100	67	10,368	11,099	12,038	13,054

Southern Alberta - Natural Gas Properties

We hold interests in multiple zones, primarily in the Late Cretaceous, in the Suffield, Brooks North, Langevin and Drumheller areas in southern Alberta.

Development in this area focuses on infill drilling up to 16 wells per section, recompletions and optimization of existing wells.

The following table sets forth net gas wells drilled and daily average gas production figures for the periods indicated.

Net Wells Drilled and Production (annual average)	Net Wells Drilled		Gas Production (MMcf/d)	
	2009	2008	2009	2008
Suffield	170	468	213	231
Brooks North	163	478	260	273
Langevin	109	248	185	203
Drumheller	56	172	81	93
Southern Alberta - Natural Gas Properties - Total	498	1,366	739	800

Included in the Brooks North and Langevin area lands is the Belly River Cretaceous formation where Cenovus is producing CBM. In 2009, approximately 500 wells were recompleted which added approximately 14 million cubic feet per day of natural gas production by the end of the year. The CBM assets are long-life and low decline and are expected to generate production for future growth in a capital efficient manner.

Suffield is one of the core areas of our Southern Alberta major property. The Suffield area is largely made up of the Suffield Block, where operations are carried out pursuant to an agreement among Cenovus, the Government of Canada and the Province of Alberta governing surface access to CFB Suffield. In 1999, the parties agreed to permit access to the Suffield military training area to additional operators. Our predecessor companies, Alberta Energy Company Ltd. and EnCana Corporation, have operated at CFB Suffield for over 30 years. On October 6, 2008, pursuant to the Canadian *Environmental Assessment Act*, a joint review panel ("JRP"), made up of provincial and federal regulators, heard our application for a shallow gas infill development in the National Wildlife Area ("NWA") at CFB Suffield. The hearing was completed in late October 2008. On January 27, 2009, the JRP released its recommendations, concluding that the proposed project could proceed provided two

key pre-conditions were met: first, critical habitat assessments for certain specific species of plants and animals must be finalized by Environment Canada within the NWA; and second, the role of the Suffield Environmental Advisory Committee ("SEAC") must be clarified by the parties to the surface access agreement, and SEAC must be resourced adequately to provide proper environmental oversight of the project. The JRP also concluded that other mitigations and recommendations should be followed once the two key pre-conditions were met. We are working with necessary interested parties to proceed with this project.

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Other Properties

We have started evaluating medium and light oil prospects in the Bakken and Shaunavon areas in Saskatchewan.

We also hold interests in other conventional oil and natural gas producing properties, primarily located in east central and northern Alberta.

Crude Oil and Natural Gas Marketing

Our Marketing group is focused on enhancing the netback price of our proprietary production. Canadian Plains divisional results include third-party purchases and sales of product to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification. The Marketing and Power group is also focused on ensuring reliable sourcing and lowest delivered cost of power at the field level.

We also seek to mitigate the market risk associated with future cash flows by entering into various risk management contracts relating to produced products. Details of those transactions related to our various risk management positions for crude oil, natural gas and power are found in the notes to our consolidated financial statements for the year ended December 31, 2009.

Crude Oil Marketing

We manage the transportation and marketing of crude oil for our upstream operating divisions. Our objective is to sell production to achieve the best price within the constraints of a diverse sales portfolio, as well as to obtain and manage condensate supply, inventory and storage to meet diluent requirements. During 2009, our blend volumes on behalf of FCCL were 120,894 barrels per day (2008 - 80,866 barrels per day), while our non-partnership blend volumes were 78,303 barrels per day (2008 - 86,560 barrels per day).

Natural Gas Marketing

Our natural gas is primarily marketed to industrials, other producers and energy marketing companies. In 2009, approximately 25 percent of our sales of natural gas were directly marketed by us to industrials. The remaining 75 percent of sales of natural gas were marketed to other producers and energy marketing companies. Prices received by us are based primarily upon prevailing index prices for natural gas. Prices are impacted by competing fuels in such markets and by North American regional supply and demand for natural gas.

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RESERVES AND OTHER OIL AND GAS INFORMATION

We retain independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of our bitumen, crude oil, NGLs and natural gas reserves annually. These evaluators are McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. The following reserves information is derived from the reserves reports prepared for us by each of these companies.

We have a Reserves Committee (as defined herein) of independent Board members which reviews the qualifications and appointment of the IQREs. The Reserves Committee also reviews the procedures for providing information to the evaluators.

Cenovus's Vice-President, Strategic Planning and Reserves Governance and two other staff under this individual's direction oversee the preparation of the reserves estimates by the IQREs. Currently, this internal staff of two professional engineers have combined relevant experience of over 65 years. The Vice-President and other engineering staff are all members of the appropriate provincial professional associations and are members of various industry associations such as the Society of Petroleum Engineers.

The evaluations by the IQREs are conducted from the fundamental petrophysical, geological, engineering, financial and accounting data. Processes and procedures are in place to ensure that the IQREs are in receipt of all relevant information. Reserves are estimated based on material balance analysis, decline analysis, volumetric calculations or a combination of these methods, in all cases having regard to economic considerations. In the case of producing reserves, the emphasis is on decline analysis where volumetric analysis is considered to limit forecasts to reasonable levels. Non-producing reserves are estimated by analogy to producing offsets, with consideration of volumetric estimates of in place quantities.

There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves. See "Risk Factors - Risks relating to our Business - Our crude oil and natural gas reserves data and future net revenue estimates are uncertain". Classifications of reserves as proved or

probable are only attempts to define the degree of uncertainty associated with the estimates. In addition, whereas proved reserves are those reserves that can be estimated with reasonable certainty to be economically producible, probable reserves are those additional reserves that are less certain to be recovered than proved reserves, but which, together with proved reserves, are as likely as not to be recovered. Therefore, probable reserves estimates, by definition, have a higher degree of uncertainty than proved reserves.

Reserves Quantities Information

Revised reserves disclosure requirements issued by the SEC at the end of 2008 require separate disclosure of our bitumen reserves from our crude oil and NGLs reserves. The following information in this annual information form reflects this separation for each of the years presented.

The majority of our bitumen reserves will be recovered and produced using SAGD technology. SAGD involves injecting steam into horizontal wells drilled into the bitumen formation and recovering heated bitumen from producing wells located below the injection wells. This technique has a surface footprint comparable to conventional oil production. We have no bitumen reserves that require mining techniques to recover the bitumen.

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Total Proved Reserves After Royalties

In 2009, bitumen reserves increased by approximately eight percent, largely as a result of Christina Lake phase D receiving approval to proceed. The increase was partially offset by reductions attributed to higher royalty bitumen rates resulting from a higher WTI price. In addition, as a result of the new Alberta Royalty Framework, where royalties are determined on a sliding scale depending on the price of bitumen, when prices are between C$55 per barrel and C$120 per barrel, pre-payout royalty rates range from one to nine percent of gross revenue. Once a project reaches payout, the royalty is based on the greater of one to nine percent of a project's gross revenue or 25 to 40 percent of net revenue. The actual royalty rate that is payable within these ranges is determined based on the WTI U.S. dollar price of crude oil, translated into Canadian dollars. In 2008, bitumen reserves increased by approximately 12 percent, largely due to lower royalties resulting from a lower WTI price. In 2007, bitumen reserves decreased by approximately 26 percent, as a consequence of 50 percent of the Foster Creek and Christina Lake reserves being contributed into the integrated oil business with ConocoPhillips. The subsequent approval of Christina Lake phase C and other minor additions and revisions in the year restored 52 percent of the contributed reserves.

In 2009, crude oil and NGLs reserves decreased by approximately four percent as aggregate additions and revisions were insufficient to replace production. During 2008, crude oil and NGLs reserves increased by approximately four percent as reserve additions exceeded production and negative revisions. During 2007, crude oil and NGLs reserves decreased approximately four percent as reserves additions were more than offset by production.

In 2009, natural gas reserves decreased by approximately 21 percent as production and negative revisions to undeveloped reserves due to low gas prices, exceeded additions and positive revisions. Natural gas reserves during 2008 decreased by approximately eight percent, with positive revisions and additions insufficient to offset production. In 2007, natural gas reserves decreased by approximately nine percent, as positive revisions and additions only replaced approximately 46 percent of production.

Impact of SEC Modernization of Oil and Gas Reporting Requirements

SEC reporting requirements have changed with respect to prices used to estimate reserves and in the definition of proved oil and gas reserves. Our IQREs have determined that no changes to reserves have occurred as a result of the definition changes. However, the changes related to prices did impact our reserves at December 31, 2009. The following is a summary of the impact of using the new pricing rules (average 2009 prices) as compared to the old pricing rules (price on December 31, 2009): bitumen reserves are higher by 28 million barrels and oil and NGLs reserves are higher by seven million barrels, both as a result of lower royalty rates, and natural gas reserves are lower by 156 billion cubic feet as a result of low gas prices.

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Net Proved Reserves (Share After Royalties)[1][2]
Constant Pricing

	Bitumen (millions of barrels)	Crude Oil and Natural Gas Liquids (millions of barrels)	Natural Gas (billions of cubic feet)
2007			
Beginning of year	800	240	2,209
Revisions and improved recovery	63	12	47
Extensions and discoveries	142	5	116
Purchase of reserves in place	-	-	-
Sale of reserves in place	(398)	-	-
Production	(11)	(26)	(353)
End of year	596	231	2,019

Developed	72	184	1,818
Undeveloped	524	47	201
Total	596	231	2,019
2008			
Beginning of year	596	231	2,019
Revisions and improved recovery	84	27	93
Extensions and discoveries	-	8	75
Purchase of reserves in place	-	-	-
Sale of reserves in place	-	-	(1)
Production	(12)	(25)	(331)
End of year	668	241	1,855
Developed	126	175	1,715
Undeveloped	542	66	140
Total	668	241	1,855
2009			
Beginning of year	668	241	1,855
Revisions and improved recovery	(88)	8	(128)
Extensions and discoveries	160	6	50
Purchase of reserves in place	-	-	-
Sale of reserves in place	(4)	-	(2)
Production	(17)	(23)	(301)
End of year	719	232	1,474
Developed	108	170	1,450
Undeveloped	611	62	24
Total	719	232	1,474

Notes:

(1) Definitions:
- (a) "Net" reserves are the remaining reserves attributable to the Cenovus Assets, after deduction of estimated royalties and including royalty interests.
- (b) "Proved" oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations.
- (c) "Proved Developed" reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
- (d) "Proved Undeveloped" reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) Estimates of total net proved bitumen, crude oil or natural gas reserves are not filed with any U.S. federal authority or agency other than the SEC.

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Supplemental Reserves Disclosure

The volatility of our net bitumen reserves and the net oil reserves at Pelican Lake due to the linkage of royalty rates to the WTI oil reference price has led Cenovus to conclude that it would facilitate comprehension of our assets to disclose our reserves on a before royalty basis, in addition to the above disclosure on a net, or after royalty, basis. This will provide a clearer understanding of the outcome of our reserves development activities.

Total Proved Reserves Before Royalties

In 2009, bitumen reserves increased by approximately 24 percent, as a result of the approval of Christina Lake phase D. In 2008, bitumen reserves were unchanged, as minor revisions offset production in the year. In 2007, bitumen reserves decreased by approximately 22 percent, as a consequence of 50 percent of the Foster Creek and Christina Lake reserves being contributed into the integrated oil business effective January 2, 2007. The subsequent approval of Christina Lake phase C and other minor additions and revisions in the year restored approximately 57 percent of the contributed reserves.

In 2009, crude oil and NGLs reserves remained relatively constant as additions and revisions very slightly exceeded production. During 2008, crude oil and NGLs reserves decreased by approximately four percent as reserves additions and positive revisions were exceeded by production and negative revisions. During 2007, crude oil and NGLs reserves decreased approximately one percent as reserves additions nearly offset production.

In 2009, natural gas reserves decreased by approximately 21 percent as production and negative revisions to undeveloped reserves due to low gas prices exceeded additions and positive revisions. Natural gas reserves during 2008 decreased by approximately nine percent, with positive revisions and additions insufficient to offset production. In 2007, natural gas reserves decreased by approximately nine percent, as positive revisions and additions only replaced approximately 43 percent of production.

Impact of SEC Modernization of Oil and Gas Reporting Requirements

SEC reporting requirements have changed with respect to prices used to estimate reserves and in the definition of proved oil and gas reserves. Our IQREs have determined that no changes to reserves have occurred as a result of the definition changes. However, the changes related to prices did impact our reserves at December 31, 2009. The following is a summary of the impact of using the new pricing rules (average 2009 prices) as compared to the old pricing rules (price on December 31, 2009): bitumen reserves are unchanged, oil and NGLs reserves are slightly down by one million barrels and natural gas reserves are lower by 164 billion cubic feet as a result of low gas prices.

Company Share Proved Reserves Before Royalties [1][2]
Constant Pricing

	Bitumen (millions of barrels)	Crude Oil and Natural Gas Liquids (millions of barrels)	Natural Gas (billions of cubic feet)
2007			
Beginning of year	901	292	2,342
Revisions and improved recovery	93	23	37
Extensions and discoveries	165	5	122
Purchase of reserves in place	-	-	-
Sale of reserves in place	(449)	-	-
Production	(11)	(31)	(374)
End of year	699	289	2,127
Developed	82	228	1,917
Undeveloped	617	61	210
Total	699	289	2,127
2008			
Beginning of year	699	289	2,127
Revisions and improved recovery	12	7	76
Extensions and discoveries	-	8	79
Purchase of reserves in place	-	-	-
Sale of reserves in place	-	-	-
Production	(12)	(28)	(345)
End of year	699	276	1,937
Developed	135	202	1,790
Undeveloped	564	74	147
Total	699	276	1,937
2009			
Beginning of year	699	276	1,937
Revisions and improved recovery	28	22	(151)
Extensions and discoveries	161	6	51
Purchase of reserves in place	-	-	-
Sale of reserves in place	(5)	-	(3)
Production	(17)	(27)	(305)
End of year	866	277	1,529
Developed	132	203	1,504
Undeveloped	734	74	25
Total	866	277	1,529

Notes:

(1) Definitions:
- (a) "Company Share" reserves are the remaining reserves attributable to the Cenovus Assets, before deduction of estimated royalties, but including royalty interests.
- (b) "Proved" oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods, and government regulations.
- (c) "Proved Developed" reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
- (d) "Proved Undeveloped" reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) Estimates of total Company Share proved bitumen, crude oil or natural gas reserves are not filed with any U.S. federal authority or agency other than the SEC.

Optional Disclosure of Probable Reserves

In addition to providing total proved reserves results, both before and after royalties, we are also providing information on our probable reserves. Probable reserves are those additional reserves quantities of bitumen, crude oil, natural gas and NGLs that are less certain to be recovered than proved reserves, but which, together with proved reserves, are as likely as not to be recovered.

Probable reserves were estimated at the same time as the IQREs estimated the proved reserves, and incorporate the same technical and economic data in their estimation.

Total Probable Reserves After Royalties

At the end of 2009, probable bitumen reserves were 403 million barrels, or approximately 35 percent less than the previous year, due to the reclassification of Christina Lake phase D to proved reserves from probable reserves. In 2008, bitumen reserves were 624 million barrels, an increase of approximately 16 percent. In 2007, bitumen reserves were 537 million barrels.

At the end of 2009, probable crude oil and NGLs reserves were 127 million barrels, a decrease of approximately seven percent. In 2008, crude

oil and NGLs reserves were 136 million barrels, an increase of approximately 14 percent. In 2007, crude oil and NGLs reserves were 119 million barrels.

At the end of 2009, probable natural gas reserves were 405 billion cubic feet, a decrease of approximately 22 percent. Natural gas reserves in 2008 were 522 billion cubic feet, a decrease of approximately eight percent. In 2007, natural gas reserves were 569 billion cubic feet.

Net Probable Reserves (Share After Royalties) [(1)(2)]
Constant Pricing

	Bitumen (millions of barrels)	Crude Oil and Natural Gas Liquids (millions of barrels)	Natural Gas (billions of cubic feet)
2007			
End of year	537	119	569
2008			
End of year	624	136	522
2009			
End of year	403	127	405
Developed	10	69	362
Undeveloped	393	58	43
Total	403	127	405

Notes:
(1) Definitions:
(a) "Net" reserves are the remaining reserves attributable to the Cenovus Assets, after deduction of estimated royalties, but including royalty interests.
(b) "Probable" reserves are those additional reserves quantities of bitumen, crude oil, natural gas and NGLs that are less certain to be recovered than proved reserves, but which, together with proved reserves, are as likely as not to be recovered.
(c) "Probable Developed" reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
(d) "Probable Undeveloped" reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
(2) Estimates of total net probable bitumen, crude oil or natural gas reserves are not filed with any U.S. federal authority or agency other than the SEC.

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Supplemental Reserves Disclosure

As with proved reserves, the impact of oil price variations on royalty rates on probable reserves from year to year can create an unclear view of the development of our bitumen business. We are providing probable reserves on a before royalty basis below to assist understanding of our business.

Probable Reserves Before Royalties

At the end of 2009, probable bitumen reserves were 479 million barrels, or approximately 25 percent less than the previous year, due to the reclassification of Christina Lake phase D to proved reserves from probable reserves. In 2008, bitumen reserves were 637 million barrels, an increase of approximately two percent. In 2007, bitumen reserves were 622 million barrels.

At the end of 2009, probable crude oil and NGLs reserves were 156 million barrels, a decrease of approximately one percent. In 2008, crude oil and NGLs reserves were 158 million barrels, an increase of approximately five percent. In 2007, crude oil and NGLs reserves were 150 million barrels.

At the end of 2009, probable natural gas reserves were 436 billion cubic feet, a decrease of approximately 23 percent. Natural gas reserves in 2008 were 566 billion cubic feet, a decrease of approximately eight percent. In 2007, natural gas reserves were 618 billion cubic feet.

Company Share Probable Reserves Before Royalties [(1)(2)]
Constant Pricing

	Bitumen (millions of barrels)	Crude Oil and Natural Gas Liquids (millions of barrels)	Natural Gas (billions of cubic feet)
2007			
End of year	622	150	618
2008			
End of year	637	158	566
2009			
End of year	479	156	436
Developed	12	84	393
Undeveloped	467	72	43
Total	479	156	436

Notes:
(1) Definitions:
(a) "Company Share" reserves are the remaining reserves attributable to the Cenovus Assets, before deduction of estimated royalties, but including royalty interests.
(b) "Probable" reserves are those additional reserves quantities of bitumen, crude oil, natural gas and NGLs that are less certain to be recovered than proved reserves, but which, together with proved reserves, are as likely as not to be recovered.
(c) "Probable Developed" reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
(d) "Probable Undeveloped" reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively

major expenditure is required for recompletion.

(2) Estimates of total Company Share probable bitumen, crude oil or natural gas reserves are not filed with any U.S. federal authority or agency other than the SEC.

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Development of Proved Undeveloped Reserves

Bitumen

At the end of 2009, we had proved undeveloped bitumen reserves of 611 million barrels after royalties, or approximately 85 percent of our total proved bitumen reserves. Our existing reserves will be recovered using SAGD. Typical SAGD project development involves installing a steam generation facility, at a cost much greater than drilling a production/injection well pair, and drilling sufficient SAGD wells to fully utilize the available steam.

Proved bitumen reserves have been determined in compliance with Canadian Oil and Gas Evaluation Handbook standards. Proved developed bitumen reserves are differentiated from proved undeveloped bitumen reserves by the presence of drilled production/injection well pairs at the reserves estimation effective date. Because a steam plant has a long life relative to well pairs, in the early stages of a SAGD project, only a small portion of proved reserves will be developed as the number of well pairs drilled will be limited by the available steam capacity.

The forecast production of Cenovus's proved bitumen reserves extends over 40 years, based on existing facilities. Production of the current proved developed portion is estimated to last ten years.

Oil

We have a significant CO_2 EOR project at Weyburn and a significant waterflood/polymer flood EOR project at Pelican Lake. These projects occur in large, well-developed reservoirs, where undeveloped reserves are not necessarily defined by the absence of drilling, but by improved recovery associated with development of the EOR schemes. Extending both EOR schemes requires intensive capital investment in infrastructure development and will occur over many years.

At Weyburn, investment in proved undeveloped reserves is projected to continue for well over 30 years, with drilling of supplementary wells taking place over the next six years and CO_2 flood advancement continuing many years beyond that. At Pelican Lake, investment in proved undeveloped reserves is projected to continue for over 20 years, with a combination of infill drilling and polymer flood advancement.

Material Changes to Proved Undeveloped Reserves

The approval of Christina Lake phase D added approximately 160 million barrels of proved undeveloped bitumen reserves in 2009. Natural gas reserves were reduced by approximately 108 billion cubic feet due to low gas prices.

Development Progress

In 2009, approximately $240 million was spent to convert 17 million barrels of bitumen, eight million barrels of oil and 41 billion cubic feet of natural gas from proved undeveloped to proved developed reserve status.

Aging of Proved Undeveloped Reserves

The only current proved undeveloped reserves that have remained undeveloped for five years or more are located in the Pelican Lake EOR project. Limited polymer flooding to date has provided positive indications for broader application throughout the reservoir.

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Commodity Prices for Reserves Evaluation

To estimate Cenovus's reserves, the IQREs used the following 2009 reference prices:

	2009	2008	% Change
Crude Oil ($/bbl)			
WTI	61.18	44.60	37
WCS (C$)	58.65	41.98	40
Natural Gas ($/MMbtu)			
Henry Hub	3.87	5.71	(32)
AECO (C$)	3.77	6.22	(39)

The 2009 prices reflect the new SEC requirements that prices be determined by using the average of the first day of the month price for each of the 12 months preceding the effective date of the evaluation. The 2008 reference prices were based on prices at December 31, 2008.

Other Disclosures About Oil and Gas Activities

The tables in this section set forth oil and gas information prepared by us in accordance with the U.S. Financial Accounting Standards Board's ASC 932-10, "Extractive Activities - Oil and Gas".

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

In calculating the standardized measure of discounted future net cash flows for 2009, 12-month average price and cost assumptions were applied to our annual future production from proved reserves to determine cash inflows. For the 2008 and 2007 calculations of standardized measure of discounted future net cash flows, the prices were based on the year-end price for each of the respective years. Future production and development costs are based on average price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a ten percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by the IQREs in relation to the reserves they respectively evaluated, and adjusted to the extent provided by contractual arrangements such as price risk management activities, in existence at year-end and to account for asset retirement obligations and future income taxes.

We caution that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of our oil and gas properties, nor the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of ten percent may not appropriately reflect future interest rates. The computation also excludes values attributable to the marketing of our proprietary production and third-party purchases and sales of product.

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	2009	2008	2007
		($ millions)	
Future cash inflows	48,006	31,626	57,706
Less future:			
Production costs	16,757	15,001	17,345
Development costs	5,313	4,334	4,635
Asset retirement obligation payments	2,954	1,669	1,769
Income taxes	5,553	2,142	7,641
Future net cash flows	17,429	8,480	26,316
Less 10 percent annual discount for estimated timing of cash flows	9,816	3,366	13,472
Discounted future net cash flows	7,613(1)	5,114	12,844

Note:

(1) 2009 discounted future net cash flows have been calculated using 12-month average prices of: crude oil - WTI of $61.18/bbl and WCS of C$58.65/bbl; natural gas - Henry Hub of $3.87/MMbtu and AECO of C$3.77/MMbtu. Future net cash flows would have been $12,524 million using the following single day December 31, 2009 prices: WTI of $79.36/bbl and WCS of C$75.21/bbl; natural gas - Henry Hub of $5.78/MMbtu and AECO of C$5.63/MMbtu. In 2008 and 2007, future net cash flows were calculated using the December 31 period end price for the respective years.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

	2009	2008	2007
		($ millions)	
Balance, beginning of year	5,114	12,844	8,963
Changes resulting from:			
Sales of oil and gas produced during the period	(3,330)	(3,896)	(3,151)
Discoveries and extensions, net of related costs	817	165	1,330
Purchases of proved reserves in place	–	–	3
Sales of proved reserves in place	(11)	(2)	(1,244)
Net change in prices and production costs	5,561	(10,401)	6,206
Revisions to quantity estimates	(270)	1,589	524
Accretion of discount	632	1,647	1,127
Previously estimated development costs incurred net of changes in future development costs	(92)	670	468
Other	180	89	(73)
Net change in income taxes	(988)	2,409	(1,309)
Balance, end of year	7,613	5,114	12,844

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Results of Operations, Capitalized Costs and Costs Incurred

Results of Operations[1]

	2009	2008	2007
		($ millions)	
Oil and gas revenues, net of royalties, transportation and selling costs	4,058	4,732	3,883
Less:			
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	728	836	732
Depreciation, depletion and amortization	1,090	1,103	1,217
Operating income	2,240	2,793	1,934
Income taxes	634	815	574
Results of operations	1,606	1,978	1,360

Note:
(1) All of our proved oil and gas reserves are located within Canada.

Capitalized Costs

	2009	2008	2007
		($ millions)	
Proved oil and gas properties	19,975	16,423	19,105
Unproved oil and gas properties	615	177	160
Total capital cost	20,590	16,600	19,265
Accumulated depreciation, depletion and amortization	10,945	8,476	9,707
Net capitalized costs	9,645	8,124	9,558

Costs Incurred

	2009	2008	2007
		($ millions)	
Acquisitions			
– Unproved	3	–	–
– Proved	–	–	14
Total acquisitions	3	–	14
Exploration costs	60	195	101
Development costs	894	1,305	1,140
Total costs incurred	957	1,500	1,255

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Production Volumes and Per-Unit Results

Production Volumes

The following tables summarize our net daily production volumes, after royalties, on a quarterly basis for the periods indicated.

	Production Volumes - 2009				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Oil and Natural Gas Liquids (bbls/d)					
Heavy Oil					
Foster Creek	36,654	45,035	38,954	34,249	28,170
Christina Lake	6,527	7,022	6,097	6,428	6,559
Integrated Oil – Other[1]	2,553	1,921	4,401	1,800	2,069
Canadian Plains	32,143	30,338	31,684	31,508	35,097
Light and Medium Oil – Canadian Plains	30,721	29,110	30,676	31,183	31,946
Natural Gas Liquids[2] – Canadian Plains	1,186	1,164	1,216	1,162	1,201
Total Oil and Natural Gas Liquids	109,784	114,590	113,028	106,330	105,042
Natural Gas (MMcf/d)					
Integrated Oil – Other	49	31	51	72	42
Canadian Plains	775	734	775	792	800
Total Natural Gas	824	765	826	864	842
Total (BOE/d)	247,117	242,090	250,695	250,330	245,375

Notes:
(1) Senlac property sold November 2009.
(2) Natural gas liquids include condensate volumes.

	Production Volumes - 2008				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Oil and Natural Gas Liquids (bbls/d)					
Heavy Oil					
Foster Creek	25,947	28,955	26,979	21,038	26,770
Christina Lake	4,236	6,113	4,568	3,633	2,606

Integrated Oil – Other	2,729	2,133	2,273	3,009	3,514
Canadian Plains	35,029	32,843	34,655	34,618	38,029
Light and Medium Oil – Canadian Plains	31,128	32,147	30,134	30,479	31,752
Natural Gas Liquids(1) – Canadian Plains	1,181	1,126	1,147	1,189	1,262
Total Oil and Natural Gas Liquids	100,250	103,317	99,756	93,966	103,933
Natural Gas (MMcf/d)					
Integrated Oil – Other	63	59	61	67	65
Canadian Plains	842	820	831	856	860
Total Natural Gas	905	879	892	923	925
Total (BOE/d)	251,083	249,817	248,423	247,799	258,100

Note:
(1) Natural gas liquids include condensate volumes.

	Production Volumes - 2007				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION VOLUMES					
Oil and Natural Gas Liquids (bbls/d)					
Heavy Oil					
Foster Creek	24,262	24,869	26,243	25,132	20,739
Christina Lake	2,552	2,321	2,497	2,862	2,530
Integrated Oil – Other	2,688	3,040	2,235	2,489	2,990
Canadian Plains	38,784	38,581	38,647	38,408	39,510
Light and Medium Oil – Canadian Plains	32,156	31,706	32,064	31,740	33,129
Natural Gas Liquids(1) – Canadian Plains	1,260	1,422	1,209	1,206	1,203
Total Oil and Natural Gas Liquids	101,702	101,939	102,895	101,837	100,101
Natural Gas (MMcf/d)					
Integrated Oil – Other	91	69	105	98	91
Canadian Plains	875	876	858	874	891
Total Natural Gas	966	945	963	972	982
Total (BOE/d)	262,702	259,439	263,395	263,837	263,768

Note:
(1) Natural gas liquids include condensate volumes.

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Per-Unit Results

The following tables summarize our net per-unit results on a quarterly basis, after royalties, for the periods indicated. The results exclude the impact of realized financial hedging.

	Per-Unit Results–2009				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Crude Oil – Heavy – Foster Creek ($/bbl)					
Price	50.07	60.41	56.76	46.98	27.08
Production and mineral taxes	–	–	–	–	–
Transportation and selling	2.27	1.69	2.33	3.02	2.19
Operating	10.75	10.28	10.19	10.25	12.96
Netback	37.05	48.44	44.24	33.71	11.93
Crude Oil – Heavy – Christina Lake ($/bbl)					
Price	47.66	54.06	59.28	49.25	26.08
Production and mineral taxes	–	–	–	–	–
Transportation and selling	2.78	0.95	5.06	2.46	2.74
Operating	14.76	17.75	14.41	11.92	14.78
Netback	30.12	35.36	39.81	34.87	8.56
Crude Oil – Heavy – Canadian Plains ($/bbl)					
Price	48.49	57.48	57.30	48.22	31.34
Production and mineral taxes	(0.01)	0.02	(0.01)	0.02	(0.07)
Transportation and selling	1.12	0.81	1.10	1.37	1.17
Operating	9.80	13.24	8.74	9.61	7.82
Netback	37.58	43.41	47.47	37.22	22.42
Crude Oil – Heavy – Total ($/bbl)					
Price	49.24	58.81	57.14	47.90	29.08
Production and mineral taxes	0.03	0.03	0.05	0.05	(0.03)
Transportation and selling	1.84	1.32	2.07	2.26	1.74
Operating	10.72	11.94	9.76	10.42	10.71
Netback	36.65	45.52	45.26	35.17	16.66
Crude Oil – Light and Medium – Canadian Plains ($/bbl)					
Price	55.29	67.84	61.76	55.00	37.51
Production and mineral taxes	2.14	1.74	2.26	1.86	2.69
Transportation and selling	0.87	0.71	0.76	1.02	0.96
Operating	10.04	11.16	10.22	9.35	9.50
Netback	42.24	54.23	48.52	42.77	24.36
Crude Oil – Total ($/bbl)					
Price	50.96	61.13	58.39	50.00	31.75
Production and mineral taxes	0.63	0.47	0.65	0.59	0.83
Transportation and selling	1.56	1.17	1.72	1.89	1.50
Operating	10.53	11.74	9.89	10.10	10.33
Netback	38.24	47.75	46.13	37.42	19.09
Natural Gas Liquids - Canadian Plains ($/bbl)					
Netback	43.51	55.89	44.88	38.36	34.86

Total Liquids ($/bbl)					
Price	50.87	61.08	58.25	49.88	31.78
Production and mineral taxes	0.62	0.47	0.64	0.58	0.82
Transportation and selling	1.55	1.15	1.70	1.87	1.48
Operating	10.41	11.62	9.78	9.99	10.21
Netback	38.29	47.84	46.13	37.44	19.27
Natural Gas – Total ($/Mcf)					
Price	3.60	3.95	2.86	3.22	4.41
Production and mineral taxes	0.04	0.03	0.04	0.06	0.04
Transportation and selling	0.14	0.12	0.14	0.13	0.15
Operating	0.76	0.80	0.77	0.70	0.78
Netback	2.66	3.00	1.91	2.33	3.44
Total ($/BOE)					
Price	34.58	41.36	35.80	32.36	28.69
Production and mineral taxes	0.42	0.31	0.42	0.46	0.49
Transportation and selling	1.14	0.93	1.24	1.25	1.14
Operating[1]	7.17	8.02	6.97	6.69	7.00
Netback	25.85	32.10	27.17	23.96	20.06

Note:
(1) Operating costs for the year include costs related to long-term incentives of $0.09/BOE.

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	Per-Unit Results–2008				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Crude Oil – Heavy – Foster Creek ($/bbl)					
Price[1]	62.88	17.97	92.07	95.64	59.95
Production and mineral taxes	–	–	–	–	–
Transportation and selling	2.21	1.90	1.98	2.63	2.46
Operating	14.38	10.08	14.42	19.90	14.90
Netback	46.29	5.99	75.67	73.11	42.59
Crude Oil – Heavy – Christina Lake ($/bbl)					
Price[2]	59.63	29.61	86.06	81.02	56.94
Production and mineral taxes	–	–	–	–	–
Transportation and selling	3.34	2.78	2.81	3.62	5.25
Operating	22.79	14.07	22.24	30.92	33.66
Netback	33.50	12.76	61.01	46.48	18.03
Crude Oil – Heavy – Canadian Plains ($/bbl)					
Price	74.08	31.30	95.86	98.65	70.44
Production and mineral taxes	0.03	0.06	0.07	(0.10)	0.07
Transportation and selling	1.60	1.13	2.42	1.60	1.29
Operating	9.04	7.17	7.62	11.30	9.93
Netback	63.41	22.94	85.75	85.85	59.15
Crude Oil – Heavy – Total ($/bbl)					
Price	68.98	25.39	94.05	96.35	66.12
Production and mineral taxes	0.07	0.05	0.10	0.02	0.12
Transportation and selling	1.97	1.62	2.29	2.10	1.91
Operating	12.26	9.13	11.62	15.92	12.89
Netback	54.68	14.59	80.04	78.31	51.20
Crude Oil – Light and Medium – Canadian Plains ($/bbl)					
Price	84.84	41.60	107.59	107.08	85.90
Production and mineral taxes	3.33	2.05	4.70	3.97	2.72
Transportation and selling	1.20	0.96	1.41	1.27	1.16
Operating	10.56	8.28	9.40	13.05	11.60
Netback	69.75	30.31	92.08	88.79	70.42
Crude Oil – Total ($/bbl)					
Price	73.95	30.31	98.26	99.82	72.36
Production and mineral taxes	1.09	0.66	1.53	1.29	0.94
Transportation and selling	1.73	1.42	2.02	1.83	1.68
Operating	11.73	8.87	10.93	14.99	12.48
Netback	59.40	19.36	83.78	81.71	57.26
Natural Gas Liquids - Canadian Plains ($/bbl)					
Netback	78.91	45.13	98.34	96.34	75.09
Total Liquids ($/bbl)					
Price	74.00	30.47	98.26	99.77	72.39
Production and mineral taxes	1.08	0.65	1.51	1.28	0.93
Transportation and selling	1.71	1.40	2.00	1.81	1.66
Operating	11.59	8.78	10.80	14.81	12.33
Netback	59.62	19.64	83.95	81.87	57.47
Natural Gas – Total ($/Mcf)					
Price	7.76	5.63	8.66	9.50	7.19
Production and mineral taxes	0.11	0.06	0.16	0.16	0.06
Transportation and selling	0.24	0.21	0.25	0.24	0.25
Operating	0.84	0.72	0.62	1.00	1.03
Netback	6.57	4.64	7.63	8.10	5.85
Total ($/BOE)					
Price	57.55	32.39	70.37	73.39	54.82
Production and mineral taxes	0.83	0.47	1.19	1.07	0.58
Transportation and selling	1.54	1.34	1.69	1.57	1.57
Operating[3]	7.68	6.19	6.54	9.38	8.62
Netback	47.50	24.39	60.95	61.37	44.05

Notes:
(1) The Foster Creek price for 2008 includes the impact of the write-down of condensate inventories to net realizable value (2008 - $4.68/bbl; Q4 2008 - $12.53/bbl; Q3 2008 - $3.59/bbl).
(2) The Christina Lake price for 2008 includes the impact of the write-down of condensate inventories to net realizable value (2008 - $0.25/bbl; Q4 2008 - $0.84/bbl).

(3) Operating costs for the year include a recovery of costs related to long-term incentives of $0.06/BOE.

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	Per-Unit Results–2007				
	Year	Q4	Q3	Q2	Q1
Crude Oil – Heavy – Foster Creek ($/bbl)					
Price	40.48	45.76	43.87	39.44	33.33
Production and mineral taxes	–	–	–	–	–
Transportation and selling	2.74	2.55	2.24	3.11	3.03
Operating(1)	13.44	12.75	10.98	13.37	16.49
Netback	24.30	30.46	30.65	22.96	13.81
Crude Oil – Heavy – Christina Lake ($/bbl)					
Price	36.72	42.64	34.50	39.08	32.69
Production and mineral taxes	–	–	–	–	–
Transportation and selling	4.31	5.21	0.90	8.75	3.36
Operating(1)	24.57	29.98	25.50	20.65	23.19
Netback	7.84	7.45	8.10	9.68	6.14
Crude Oil – Heavy – Canadian Plains ($/bbl)					
Price	43.91	49.52	48.22	40.70	37.22
Production and mineral taxes	0.05	0.07	0.06	0.06	(0.01)
Transportation and selling	1.18	1.13	1.36	1.19	1.03
Operating	7.59	9.06	7.27	7.56	6.48
Netback	35.09	39.26	39.53	31.89	29.72
Crude Oil – Heavy – Total ($/bbl)					
Price	42.23	47.38	45.98	40.12	35.74
Production and mineral taxes	0.04	0.04	0.06	0.06	0.01
Transportation and selling	1.93	1.81	1.71	1.72	2.48
Operating	10.93	11.64	9.85	10.84	11.39
Netback	29.33	33.89	34.36	27.50	21.86
Crude Oil – Light and Medium – Canadian Plains ($/bbl)					
Price	56.41	68.78	59.68	52.43	44.81
Production and mineral taxes	2.37	2.36	2.16	2.37	2.59
Transportation and selling	1.33	1.22	1.39	1.27	1.43
Operating	9.20	10.34	8.84	9.10	8.55
Netback	43.51	54.86	47.29	39.69	32.24
Crude Oil – Total ($/bbl)					
Price	46.52	54.07	50.23	43.94	38.12
Production and mineral taxes	0.77	0.76	0.73	0.78	0.80
Transportation and selling	1.74	1.62	1.61	1.96	1.78
Operating	10.39	11.23	9.53	10.29	10.52
Netback	33.62	40.46	38.36	30.91	25.02
Natural Gas Liquids - Canadian Plains ($/bbl)					
Netback	59.98	73.12	61.29	56.08	46.69
Total Liquids ($/bbl)					
Price	46.69	54.33	50.36	44.08	38.22
Production and mineral taxes	0.76	0.75	0.72	0.77	0.79
Transportation and selling	1.72	1.60	1.59	1.94	1.76
Operating	10.27	11.08	9.42	10.17	10.41
Netback	33.94	40.90	38.63	31.20	25.26
Natural Gas – Total ($/Mcf)					
Price	6.08	6.22	5.23	6.64	6.24
Production and mineral taxes	0.10	0.03	0.11	0.12	0.11
Transportation and selling	0.27	0.26	0.26	0.27	0.28
Operating	0.74	0.89	0.66	0.74	0.69
Netback	4.97	5.04	4.20	5.51	5.16
Total ($/BOE)					
Price	40.51	44.04	38.85	41.48	37.74
Production and mineral taxes	0.65	0.42	0.70	0.75	0.71
Transportation and selling	1.65	1.58	1.56	1.74	1.70
Operating(2)	6.75	7.59	6.12	6.66	6.64
Netback	31.46	34.45	30.47	32.33	28.69

Notes:
(1) First quarter operating costs include a prior year under accrual of operating costs of approximately $1.75/bbl for Foster Creek and $2.53/bbl for Christina Lake.
(2) Operating costs for the year include a recovery of costs related to long-term incentives of $0.21/BOE.

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The following tables show the impact of our realized financial hedging on per-unit results.

	2009				
	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	0.98	(0.05)	(0.01)	1.39	2.86
Natural Gas ($/Mcf)	3.22	2.24	4.04	3.68	2.82
Total ($/BOE)	11.18	7.07	13.25	13.24	11.02

	2008				
	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	(6.07)	2.71	(8.85)	(12.50)	(6.63)
Natural Gas ($/Mcf)	(0.30)	1.07	(1.15)	(1.41)	0.34
Total ($/BOE)	(3.50)	4.85	(7.69)	(10.01)	(1.43)

	2007				
	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	(3.40)	(9.98)	(4.94)	(1.47)	2.60
Natural Gas ($/Mcf)	0.75	0.85	1.04	0.42	0.71
Total ($/BOE)	1.40	(0.87)	1.84	0.98	3.58

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Drilling Activity

The following tables summarize our gross participation and net interest in wells drilled for the periods indicated.

	Exploration Wells Drilled										
	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2009:											
Canadian Plains	4	4	-	-	-	-	4	4	8	12	4
Total Canada	4	4	-	-	-	-	4	4	8	12	4
2008:											
Canadian Plains	1	1	5	3	2	1	8	5	34	42	5
Total Canada	1	1	5	3	2	1	8	5	34	42	5
2007:											
Canadian Plains	3	3	4	4	-	-	7	7	89	96	7
Total Canada	3	3	4	4	-	-	7	7	89	96	7

	Development Wells Drilled(1)(2)(3)										
	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2009:											
Integrated Oil	45	24	8	8	8	8	61	40	10	71	40
Canadian Plains	107	106	555	502	2	2	664	610	261	925	610
Total Canada	152	130	563	510	10	10	725	650	271	996	650
2008:											
Integrated Oil	41	21	13	13	4	4	58	38	41	99	38
Canadian Plains	105	92	1,489	1,372	7	7	1,601	1,471	503	2,104	1,471
Total Canada	146	113	1,502	1,385	11	11	1,659	1,509	544	2,203	1,509
2007:											
Integrated Oil	55	29	6	2	6	4	67	35	43	110	35
Canadian Plains	161	138	2,215	2,115	4	3	2,380	2,256	466	2,846	2,256
Total Canada	216	167	2,221	2,117	10	7	2,447	2,291	509	2,956	2,291

Notes:
(1) "Gross" wells are the total number of wells in which we will have an interest.
(2) "Net" wells are the number of wells obtained by aggregating our working interests in each of the gross wells.
(3) At December 31, 2009, 11 gross wells (seven net wells), all in Canada, were being drilled.

In addition to the above tables, we drilled stratigraphic test wells during the year ended December 31, 2009, with the Integrated Oil Division having drilled 79 gross wells (40 net wells) and the Canadian Plains Division having drilled 22 gross wells (22 net wells).

Location of Wells(1)(2)

The following table summarizes our interests in producing wells, including wells mechanically capable of producing, as at December 31, 2009.

	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta:						
Integrated Oil	187	94	767	716	954	810
Canadian Plains	3,151	3,066	28,342	27,469	31,493	30,535
Total Alberta	3,338	3,160	29,109	28,185	32,447	31,345
Saskatchewan:						
Canadian Plains	864	557	452	418	1,316	975
Total Saskatchewan	864	557	452	418	1,316	975
Total	4,202	3,717	29,561	28,603	33,763	32,320

Notes:
(1) Cenovus also has varying royalty interests in 9,450 natural gas wells and 4,229 crude oil wells which are producing or capable of producing.
(2) Includes wells containing multiple completions as follows: 24,868 gross natural gas wells (24,037 net wells) and 1,504 gross crude oil wells (1,292 net wells).

Interest in Material Properties(1)

The following table summarizes our developed, undeveloped and total landholdings as at December 31, 2009.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
			(thousands of acres)			
Alberta:						
Integrated Oil						
– Crown(2)	551	457	1,428	1,053	1,979	1,510
Canadian Plains						
– Fee(3)	1,910	1,910	450	450	2,360	2,360
– Crown(2)	2,088	1,907	844	743	2,932	2,650
– Freehold(4)	68	55	21	18	89	73
Total Alberta	4,617	4,329	2,743	2,264	7,360	6,593
Saskatchewan:						
Canadian Plains						
– Fee(3)	68	68	438	438	506	506
– Crown(2)	124	103	369	313	493	416
– Freehold(4)	14	10	42	40	56	50
Total Saskatchewan	206	181	849	791	1,055	972
Manitoba:						
Canadian Plains – Fee(3)	3	3	261	261	264	264
Total Manitoba	3	3	261	261	264	264
Total	4,826	4,513	3,853	3,316	8,679	7,829

Notes:
(1) This table excludes approximately 2.4 million gross acres under lease or sublease, reserving to us, royalties or other interests.
(2) Crown/Federal lands are those lands owned by the federal or provincial government or the First Nations, in which we have purchased a working interest lease.
(3) Fee lands are those lands in which we have a fee simple interest in the mineral rights and have either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. The current fee lands acreage summary now includes all fee titles owned by us, that have one or more zones that remain unleased or available for development.
(4) Freehold lands are those lands owned by individuals (other than a government or Cenovus) in which Cenovus holds a working interest lease.

Capital Expenditures, Acquisitions and Divestitures

Our growth in recent years has been achieved primarily through internal growth. We have a large inventory of internal growth opportunities and continue to examine select acquisition opportunities to develop and expand our major properties. Acquisition opportunities may include corporate or asset acquisitions. We may finance any such acquisitions with debt, equity, cash generated from operations, proceeds from asset divestitures or a combination of these sources.

The following table summarizes our net capital investment for 2009 and 2008.

	2009	2008
	($ millions)	
Capital Investment		
Upstream Canada		
Foster Creek	231	336
Christina Lake	198	218
Canadian Plains	478	872
Other	47	90
	954	1,516
Downstream Refining	907	478
Corporate	31	52
Capital Investment	1,892	2,046
Acquisitions	3	-
Divestitures	(209)	(47)
Net Acquisition and Divestiture Activity	(206)	(47)
Net Capital Investment	1,686	1,999

Delivery Commitments

As part of the Arrangement, we assumed, under existing contracts and agreements, and we have, as part of our ordinary business operations, a number of delivery commitments to provide crude oil and natural gas. We have sufficient reserves of natural gas and crude oil to meet these commitments. More detailed information relating to such commitments can be found in the notes to our audited consolidated financial statements for the year ended December 31, 2009.

GENERAL

Competitive Conditions

All aspects of the oil and gas industry are highly competitive and we actively compete with other companies, particularly in the following areas: (i) exploration for and development of new sources of bitumen, crude oil and natural gas reserves; (ii) reserves and property acquisitions; (iii) transportation and marketing of oil, natural gas, NGLs, diluents and electricity; (iv) supply of refinery feedstock and the market for refined products; (v) access to services and equipment to carry out exploration, development or operating activities; and (vi) attracting and retaining experienced industry personnel. The oil and gas industry also competes with other industries that provide alternative forms of energy to consumers. Competitive forces can lead to cost increases or result in an oversupply of oil and natural gas, both of which could have a negative impact on our financial results.

Environmental Protection

Our operations are subject to laws and regulations concerning protection of the environment, pollution and the handling and transport of hazardous materials. These laws and regulations generally require us to remove or remedy the effect of our activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the use or release of specified substances. The Safety, Environment and Responsibility Committee of our Board (the "SER Committee") reviews and recommends to our Board for approval environmental policies and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety ("EH&S") performance in day-to-day operations, as well as inspections and assessments, have been designed to provide assurance that environmental and regulatory standards are met. Contingency plans have been put in place for a timely response to an environmental event and remediation/reclamation programs have been put in place and utilized to restore the environment.

We recognize that there is a cost associated with carbon emissions and we believe that greenhouse gas regulations and the cost of carbon at various price levels can be adequately accounted for as part of business planning. As part of our future planning, management and the Board review the impact of a variety of carbon constrained scenarios on our strategy, with a current price range from $15 to $65 per tonne of emissions applied across a range of regulatory policy options. A major benefit of applying a range of carbon prices at the strategic level is that it provides direct guidance to the capital allocation process. Although uncertainty remains regarding potential future emissions regulation, we will continue to assess and evaluate the cost of carbon relative to our investments across a range of scenarios.

We also examine the impact of carbon regulation on our major projects, including both our SAGD operations and refining assets. We continue to closely monitor potential greenhouse gas legislation developments in the U.S. Some of the climate change legislation being contemplated in the U.S. would require refiners to obtain emission allowances for emissions of greenhouse gases, including CO_2 based on the carbon content of their fuels. If this type of legislation is enacted into law, this could have a material impact on the cost structure of refined petroleum products that would be passed onto the consumer.

We expect to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2009, expenditures beyond normal compliance with environmental regulations were not material. We do not anticipate making material expenditures beyond amounts paid in respect of normal compliance with environmental regulations in 2010. Based on estimates at December 31, 2009, the total anticipated undiscounted future cost of abandonment and reclamation costs to be incurred over the life of our proved reserves is estimated at approximately $5.4 billion.

Social and Environmental Policies

We have a Corporate Responsibility Policy (the ''Policy'') that applies to any activity undertaken by or on behalf of Cenovus. The Policy has specific requirements in the areas of: (i) leadership commitment; (ii) sustainable value creation; (iii) governance and business practices; (iv) human rights; (v) labour practices; (vi) EH&S; (vii) stakeholder engagement; and (viii) socio-economic and community development.

The Policy and any revisions are approved by our executive team and our Board. Accountability for implementation of the Policy is at the operational level within Cenovus's business units. Business units have established processes to evaluate risks and programs are implemented to minimize that risk. Results related to the commitments are tied to the individual performance assessment process.

The Policy states the following with respect to the environment: (i) Cenovus will safeguard the environment and will operate in a manner consistent with recognized global industry standards in EH&S; (ii) we will strive to make efficient use of resources, to minimize our environmental footprint and to conserve habitat diversity and the plant and animal populations that may be affected by our operations; and (iii) we will strive to reduce our emissions intensity and increase our energy efficiency.

With respect to Cenovus's relationship with the communities in which we do business, the Policy states that: (i) we engage in collaborative, consultative and partnership approaches in our community investment and programs, recognizing that no corporation is solely responsible for changing the fundamental economic, environmental and social situation in a community or country; and (ii) through our activities, Cenovus will assist in local capacity-building and develop mutually beneficial relationships, to make a positive difference in the communities and regions where we operate.

With respect to human rights, the Policy states that Cenovus will not take part in human rights abuse and will not engage or be complicit in any activity that solicits or encourages human rights abuse.

Through the Policy, Cenovus is committed to protecting the health and safety of all individuals affected by our activities, including our workforce and the public. We will not compromise the health and safety of any individual in the conduct of our activities. Cenovus will strive to provide a safe and healthy working environment and we expect our workers to comply with the health and safety practices established for their protection.

Some of the steps that Cenovus has taken to embed the corporate responsibility approach throughout the organization include: (i) an EH&S management system; (ii) a security program to regularly assess security threats to business operations and to manage the associated risks; (iii) corporate responsibility performance metrics to track our progress; (iv) an energy efficiency program that focuses on reducing energy use at Cenovus's operations and supports initiatives at the community level while also incentivizing employees to reduce energy use in their homes; (v) an Investigations Practice and an Investigations Committee to review and resolve potential violations of Cenovus policies or practices and other regulations; (vi) an Integrity Helpline that provides an additional avenue for Cenovus's stakeholders to raise their concerns as well as the corporate responsibility website which allows people to write to Cenovus about non-financial issues of concern; (vii) an internal corporate EH&S audit program that evaluates Cenovus's compliance with the expectations and requirements of the EH&S management system; (viii) related policies and practices such as an Alcohol and Drug Policy, a Code of Business Conduct & Ethics and guidelines for correct behaviours with respect to the acceptance of gifts, conflicts of interest and the appropriate use of Cenovus equipment and technology in a manner that is consistent with leading ethical business practices; and (ix) a requirement for acknowledgement and sign-off on key policies from our Board and employees. In addition, our Board approves such policies and is advised of significant contraventions thereof, and

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receives updates on trends, issues or events which could have a significant impact on Cenovus.

Employees

At December 31, 2009, we employed 2,221 full-time equivalent ("FTE") employees as set forth in the following table.

	FTE Employees
Integrated Oil Division	804
Canadian Plains Division	859
Cenovus-wide	558
Total	2,221

We also engage a number of contractors and service providers.

Foreign Operations

One hundred percent of our reserves, production and assets are located in North America, which limits our exposure to risks and uncertainties in countries considered politically and economically unstable. Any of our future operations and related assets outside North America may be adversely affected by changes in governmental policy, social instability or other political or economic developments which are not within our control, including the expropriation of property, the cancellation or modification of contract rights and restrictions on repatriation of cash.

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DIRECTORS AND EXECUTIVE OFFICERS

Directors

The names, province or state and country of residence, position(s) of, and the number of Common Shares, as at December 31, 2009, beneficially owned, or controlled or directed, directly or indirectly by, the persons who serve as our directors are set out below.

Name and Residence[1]	Office Held	Principal Occupation	Common Shares Held
Ralph S. Cunningham[2,4,5,7] Houston, Texas, United States	Director	President & Chief Executive Officer EPE Holdings, LLC (Midstream energy services)	0
Patrick D. Daniel[2,3,4,5] Calgary, Alberta, Canada	Director	President & Chief Executive Officer Enbridge Inc. (Energy delivery)	39,348
Ian W. Delaney[2,4,5,7] Toronto, Ontario, Canada	Director	Chairman and Chief Executive Officer Sherritt International Corporation (Nickel/cobalt mining, oil and natural gas production, electricity generation and coal mining)	58,600
Brian C. Ferguson[8] Calgary, Alberta, Canada	Director, President & Chief Executive Officer	President & Chief Executive Officer Cenovus Energy Inc.	97,887

Michael A. Grandin[2,5,9] Calgary, Alberta, Canada	Chair	Corporate Director	123,120
Valerie A.A. Nielsen[2,3,5,6] Calgary, Alberta, Canada	Director	Corporate Director	44,217
Charles M. Rampacek[5,6,7] Dallas, Texas, United States	Director	Corporate Director	0
Colin Taylor[3,4,5] Toronto, Ontario, Canada	Director	Corporate Director	2,300
Wayne G. Thomson[2,5,6,7] Calgary, Alberta, Canada	Director	President Enviro Valve Inc. (Private technology company)	0

Notes:
(1) Each of the directors became members of our Board pursuant to the Arrangement.
(2) Former director of EnCana.
(3) Member of the Audit Committee.
(4) Member of the Human Resources and Compensation Committee.
(5) Member of the Nominating and Corporate Governance Committee.
(6) Member of the Reserves Committee.
(7) Member of the Safety, Environment and Responsibility Committee.
(8) As an officer and a non-independent director, Mr. Ferguson is not a member of any of the Committees of our Board.
(9) Ex-officio non-voting member of all other Committees of our Board. As an ex-officio non-voting member, Mr. Grandin attends as his schedule permits and may vote when necessary to achieve a quorum.

Each of the directors was appointed as a member of our Board effective November 30, 2009 pursuant to the Arrangement and will hold office until the first annual meeting of the holders of Common Shares or until his or her successor is duly elected or appointed, unless his or her office is earlier vacated. Additional directors may be appointed by our Board prior or subsequent to the first annual meeting of holders of Common Shares in accordance with our articles. We have been granted an exemption by the TSX from being required to hold our first annual meeting of holders of Common Shares within six months of December 31, 2009. As a result, the first annual meeting of holders of Common Shares is expected to

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occur in the second quarter of 2011 and, in any event, not later than May 31, 2011, at which time holders of Common Shares will vote on the election of our directors and appointment of our auditors.

Five Year Occupational History of Directors

Ralph S. Cunningham

Mr. Cunningham has been a director and President and Chief Executive Officer of EPE Holdings, LLC, the sole general partner of Enterprise GP Holdings L.P. (a publicly traded midstream energy holding company) since August 2007. From February 2006 until July 2007, he served as Group Executive Vice President and Chief Operating Officer and, from June 2007 to July 2007, also served as Interim President and Chief Executive Officer of Enterprise Products GP, LLC, the sole general partner of Enterprise Products Partners L.P. (a publicly traded midstream energy company). In addition, he has served as a director of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners, L.P., since February 2006. He is also a director of Agrium Inc. (agricultural chemicals company), a director of LE GP, LLC, the general partner of Energy Transfer Equity, L.P. (a publicly traded energy partnership) and a director and Chairman of TETRA Technologies, Inc. (energy services and chemicals company). He was President and Chief Executive Officer of CITGO Petroleum Corporation (energy company) from May 1995 until his retirement in May 1997. In the not-for-profit sector, he is a member of the Auburn University Chemical Engineering Advisory Council and the Auburn University Engineering Advisory Council.

Patrick D. Daniel

Mr. Daniel has been President & Chief Executive Officer of Enbridge Inc. (energy delivery) since January 2001 and a director since May 2000. He has been a senior executive officer of Enbridge or its predecessor since 1994 and is a director of a number of Enbridge subsidiaries. He is a director of Canadian Imperial Bank of Commerce and a member of the North American Review Board of American Air Liquide Holdings, Inc. (industrial and medical gases and related services). In the not-for-profit sector, he is a member of the National Petroleum Council (an Oil and Natural Gas Advisory Committee to the U.S. Secretary of Energy) and a director of the American Petroleum Institute.

He holds a Bachelor of Science (University of Alberta) and Master of Science (University of British Columbia), both in chemical engineering.

Ian W. Delaney

Mr. Delaney has been Chairman of Sherritt International Corporation (nickel/cobalt mining, oil and natural gas production, electricity generation and coal mining) since 1995 and assumed the additional responsibilities of Chief Executive Officer of Sherritt International Corporation in January 2009. He is also Chairman of The Westaim Corporation (technology investment company) and a director of OPTI Canada Inc. (oilsands development and upgrading company).

Brian C. Ferguson

Mr. Ferguson became President & Chief Executive Officer of Cenovus on November 30, 2009. Prior to his executive leadership role at Cenovus, he was appointed Executive Vice-President & Chief Financial Officer of EnCana on March 1, 2006. At the time of the merger between Alberta Energy Company Ltd. and PanCanadian Energy Corporation in 2002, Mr. Ferguson was appointed Executive Vice-President, Corporate

Development with responsibility for three primary functions: investor relations; business development, which included corporate strategic planning, acquisitions and divestitures, and corporate reserve evaluations; and a combined legal and corporate secretarial team.

Mr. Ferguson is a member of the Canadian Institute of Chartered Accountants (CICA) and is currently serving as Chairman of CICA's Risk Oversight and Governance Board.

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He earned a Bachelor of Commerce degree, with distinction, from the University of Alberta in 1980 and received his Chartered Accountant designation in 1983.

Michael A. Grandin

Mr. Grandin is a Corporate Director. He is a director of BNS Split Corp. II (investment company) and HSBC Bank Canada. He was Chairman and Chief Executive Officer of Fording Canadian Coal Trust (publicly traded mining trust) from February 2003 to October 2008 when it was acquired by Teck Cominco Limited. He was President of PanCanadian Energy Corporation from October 2001 to April 2002 when it merged with Alberta Energy Company Ltd. to form EnCana. He was also Executive Vice-President and Chief Financial Officer of Canadian Pacific Limited from December 1997 to October 2001. Mr. Grandin served as Dean of the Haskayne School of Business, University of Calgary from April 2004 to January 2006.

Valerie A.A. Nielsen

Ms. Nielsen is a Corporate Director. She is a director of Wajax Income Fund (diversified company engaged in the sale and after-sales parts and service support of mobile equipment, diesel engines and industrial components). In the not-for-profit sector, she is a director of the Canada Olympic Committee. She was a member and past chair of an advisory group on the General Agreement on Tariffs and Trade (GATT), the North America Free Trade Agreement (NAFTA) and international trade matters pertaining to energy, chemicals and plastics from 1986 to 2002.

She holds a Bachelor of Science (Hon.) (Dalhousie University).

Charles M. Rampacek

Mr. Rampacek is a Corporate Director. Since June 2003, Mr. Rampacek has provided business and management consulting services to the energy industry. Since 2006, Mr. Rampacek has served as a director of Enterprise Products GP, LLC, the sole general partner of Enterprise Products Partners, L.P. (a publicly traded midstream energy company), and since 1998 he has been a director of Flowserve Corporation (a publicly traded manufacturer of industrial pumps, valves and seals). From August 2000 until May 2003, he served as Chairman and President and Chief Executive Officer of Probex Corporation (a publicly held energy technology company) and, from January 1996 through August 2000, Mr. Rampacek was President and Chief Executive Officer of Lyondell-Citgo Refining, L.P. (a crude oil refiner and manufacturer of petroleum products). From 1982 to 1995, he held various executive positions with energy-related subsidiaries of Tenneco Inc. (a publicly traded energy company) including President of Tenneco Gas Transportation Company, Executive Vice President of Tenneco Gas Operations and Senior Vice President of Refining and Natural Gas Liquids. In the not-for-profit sector, Mr. Rampacek serves on the Engineering Advisory Council for the University of Texas and the College of Engineering Leadership Board for the University of Alabama.

Colin Taylor

Mr. Taylor is a Corporate Director. From June 1996 until May 2004, Mr. Taylor served two consecutive four-year terms as Chief Executive and Managing Partner of Deloitte & Touche LLP. Subsequently, he was Senior Counsel at Deloitte & Touche LLP until his retirement in May 2008. He has held a number of international management and governance responsibilities throughout his professional career. Mr. Taylor also served as Advisory Partner to a number of public and private company clients of Deloitte & Touche LLP.

Wayne G. Thomson

Mr. Thomson has been President and a director of Enviro Valve Inc. (private company manufacturing proprietary pressure relief valves) since July 2009. He has also been President and a director of Virgin Resources Limited (private junior international oil and gas exploration company focused in Yemen) since February 2005. He is also a director of TG World Energy Corp. (TSX Venture listed international oil and gas exploration company). He

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has served as President and a director of private and public companies in the oil and gas sector, namely, EcoMax Energy Services Ltd., Airborne Pollution Control, Hadrian Energy Corp., Gardiner Oil and Gas Limited and Petrocorp Exploration Limited (New Zealand oil and gas company).

Other Reporting Issuer Experience of Directors

The following table sets out our directors that are directors of other reporting issuers (or the equivalent) in Canada or a foreign jurisdiction:

Name	Name of Reporting Issuer
Ralph S. Cunningham	Agrium Inc. DEP Holdings, LLC(1) Enterprise Products GP, LLC(2) EPE Holdings, LLC(3) LE GP, LLC(4) TETRA Technologies, Inc.
Patrick D. Daniel	Canadian Imperial Bank of Commerce Enbridge Inc.
Ian W. Delaney	OPTI Canada Inc. Sherritt International Corporation The Westaim Corporation
Michael A. Grandin	BNS Split Corp. II HSBC Bank Canada
Valerie A.A. Nielsen	Wajax Income Fund
Charles M. Rampacek	Enterprise Products GP, LLC(2) Flowserve Corporation
Wayne G. Thomson	TG World Energy Corp.

Notes:
(1) The sole general partner of Duncan Energy Partners L.P.
(2) The general partner of Enterprise Products Partners L.P.
(3) The sole general partner of Enterprise GP Holdings L.P.
(4) The general partner of Energy Transfer Equity L.P.

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Executive Officers

The names, province and country of residence and positions of the persons who serve as our executive officers are set out below.

Name and Residence	Office Held and Principal Occupation
Brian C. Ferguson Calgary, Alberta, Canada	Director, President & Chief Executive Officer
Ivor M. Ruste Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer
John K. Brannan Calgary, Alberta, Canada	Executive Vice-President *(President, Integrated Oil Division)*
Harbir S. Chhina Calgary, Alberta, Canada	Executive Vice-President, Enhanced Oil Development & New Resource Plays
Kerry D. Dyte Calgary, Alberta, Canada	Executive Vice-President, General Counsel & Corporate Secretary
Judy A. Fairburn Calgary, Alberta, Canada	Executive Vice-President, Environment & Strategic Planning
Sheila M. McIntosh Calgary, Alberta, Canada	Executive Vice-President, Communications & Stakeholder Relations
Donald T. Swystun Calgary, Alberta, Canada	Executive Vice-President *(President, Canadian Plains Division)*
Hayward J. Walls Calgary, Alberta, Canada	Executive Vice-President, Organization & Workplace Development

Five Year Occupational History of Executive Officers

John K. Brannan

Mr. Brannan is our Executive Vice-President (*President, Integrated Oil Division*). From November 2004 to November 2009, Mr. Brannan held the following positions with EnCana: Executive Vice-President (*President, Integrated Oil Division*) effective January 1, 2007; Managing Director, Frontier and International New Ventures effective July 1, 2005; and from November 19, 2003 to June 30, 2005, Managing Director, International & New Ventures.

Harbir S. Chhina

Mr. Chhina is our Executive Vice-President, Enhanced Oil Development & New Resource Plays. From November 2004 to November 2009, Mr. Chhina held the following positions with EnCana: Vice-President, Upstream Operations, Integrated Oil Division effective January 1, 2007; and from April 16, 2003 to December 31, 2006, Vice-President, Oil Recovery Business Unit.

Kerry D. Dyte

Mr. Dyte is our Executive Vice-President, General Counsel & Corporate Secretary. Mr. Dyte held the following positions with EnCana: from January 1, 2007 to November 2009, Vice-President, General Counsel & Corporate Secretary; and from December 1, 2002 to December 31, 2006, General Counsel & Corporate Secretary.

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Judy A. Fairburn

Ms. Fairburn is our Executive Vice-President, Environment & Strategic Planning. From April 2002 to November 2009, Ms. Fairburn held the following positions with EnCana: Vice-President, Environment & Corporate Responsibility effective May 1, 2009; Vice-President, Environment & Strategic Planning effective December 2008; Vice-President, Downstream Operations effective January 2007; Vice-President, Weyburn Business Unit effective July 2004; Vice-President, Portfolio Management, Upstream Operations effective April 2003; and Vice-President, Strategic Planning, Onshore North America effective April 2002.

Sheila A. McIntosh

Ms. McIntosh is our Executive Vice-President, Communications & Stakeholder Relations. From November 2004 to November 2009, Ms. McIntosh held the following positions with EnCana: Executive Vice-President, Corporate Communications effective January 1, 2007; and from November 19, 2003 to December 31, 2006, Vice-President, Investor Relations.

Ivor M. Ruste

Mr. Ruste is our Executive Vice-President & Chief Financial Officer. From May 2006 to November 2009, Mr. Ruste held the following positions with EnCana: Executive Vice-President, Corporate Responsibility & Chief Risk Officer effective May 1, 2009; Executive Vice-President & Chief Risk Officer effective January 1, 2008; Vice-President, Finance for the Integrated Oil Division effective January 1, 2007; and Vice-President, Finance of the Corporate Finance Group effective May 1, 2006. From February 2003 to April 2006, he was a partner and the Office Managing Partner for the Edmonton, Alberta office of KPMG LLP, as well as the Alberta Region Managing Partner for KPMG LLP. During this period, he was also a member of the Board of Directors of KPMG Canada and, from December 2003 to March 2006, he was Vice Chair of the Board of Directors for KPMG Canada.

Donald T. Swystun

Mr. Swystun is our Executive Vice-President (*President, Canadian Plains Division*). From November 2004 to November 2009, Mr. Swystun held the following positions with EnCana: Executive Vice-President, (*President, Canadian Plains Division*) effective January 1, 2007; Executive Vice-President, Corporate Development effective March 1, 2006; and from September 1, 2001 to February 28, 2006, President, Ecuador Region.

Hayward J. Walls

Mr. Walls is our Executive Vice-President, Organization & Workplace Development. From November 2004 to November 2009, Mr. Walls held the following positions with EnCana: Executive Vice-President, Corporate Services effective January 1, 2006; and effective November 19, 2003, Vice-President, Information Services & Chief Information Officer.

As of December 31, 2009, all of our directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 1,020,399 Common Shares or approximately 0.14 percent of the number of Common Shares that were outstanding as of such date.

Corporate Cease Trade Orders or Bankruptcies

To our knowledge, other than as described below, none of our current directors or executive officers is, as at the date of this annual information form, or has been, within ten years before the date of this annual information form, a director, chief executive officer or chief financial officer of any company that:

(a) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days

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(collectively, an "Order") and that was issued while that person was acting in the capacity as director, chief executive officer or chief financial officer; or

(b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of the company being the subject of such an Order and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

To our knowledge, other than as described below, none of our directors or executive officers:

(a) is, at the date of this annual information form, or has been within ten years before the date of this annual information form, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to its own bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) has, within ten years before the date of this annual information form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or executive officer.

Mr. Rampacek was the Chairman and President and Chief Executive Officer of Probex Corporation ("Probex") in 2003 when Probex filed a petition seeking relief under Chapter 7 of the Bankruptcy Code (United States). In 2005, two complaints seeking recovery of certain alleged losses were filed against former officers and directors of Probex, including Mr. Rampacek, as a result of the bankruptcy. These complaints were defended under Probex's director and officer insurance by AIG and settlement was reached and paid by AIG with bankruptcy court approval in the first half of 2006. An additional complaint was filed in 2005 against noteholders of certain Probex debt, of which Mr. Rampacek was a party. A settlement of $2,000 was reached and similarly approved in the first half of 2006.

Conflicts of Interest

There are potential conflicts of interest to which our directors and officers may be subject in connection with our operations. In particular, certain of our directors and officers are, or may be, involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with ours or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of ours. Conflicts, if any, will be subject to the procedures and remedies available under the CBCA. The CBCA provides that, in the event a director or officer has an interest in a material contract or transaction, whether made or proposed, with the corporation, the director or officer shall disclose his interest in such contract or transaction and shall refrain from voting on any matter in respect of such contract or unless otherwise provided by the CBCA. As at the date of this annual information form, we are not aware of any existing or potential material conflicts of interest between us and any of our directors or officers.

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STATEMENT OF EXECUTIVE COMPENSATION

The amounts reported in this Statement of Executive Compensation are reported in U.S. dollars. As the amounts are paid in Canadian dollars, we have converted the amounts to U.S. dollars using the exchange rate of C$1.00 = US$0.9555, which is the exchange rate for Canadian dollars to U.S. dollars on December 31, 2009 based on the daily noon buying rate published by the Bank of Canada.

Compensation Discussion and Analysis

Introduction

To ensure we meet our commitments to our shareholders, our employees and the communities in which we conduct our business, we depend on our highly-skilled, committed and experienced team of executive officers to execute on our strategy.

Our executive compensation program will focus on attracting, motivating, rewarding and retaining a strong team of executive officers and will encourage short and long-term performance, to ensure that the interests of our executive officers are aligned with the interests of our shareholders.

Compensation Philosophy

Our compensation philosophy will demonstrate how we value our employees and our executive officers and how we align their interests with the interests of our shareholders. Our compensation philosophy is being developed to include the following elements:

- In our business, against the companies we compete with, we strive to be an employer of choice.
- Our compensation is results-oriented and includes competitive salaries and benefits, plus annual and long-term incentives.
- We provide a total compensation package, where all elements of the compensation program play a role in attracting, motivating, rewarding and retaining our employees and our executive officers and which incorporates clear differentiation of pay based on individual and company performance.
- Our total compensation is designed to be competitive and to position the total compensation of our executive officers to be in the top quartile of our peer group for outstanding performance. Similarly, for lesser performance, we will provide lower total compensation through our annual and long-term incentive programs.

- We recognize that total compensation may be impacted by increases and decreases in commodity prices that may occur as a result of the cyclical nature of our business. Therefore, we will test the total compensation of our executive officers for various performance outcomes to understand how these changes will impact compensation.

Committee Oversight

Our compensation program is overseen and governed by our Human Resources and Compensation Committee ("HRC Committee"). As outlined in its mandate, the HRC Committee's responsibilities include:

- Review and monitor our compensation philosophy and compensation program design on at least an annual basis.
- Review competitive analysis and performance data to make recommendations regarding the compensation of our President & Chief Executive Officer to our Board and to approve the compensation of our other executive officers and report it to our Board.
- Review and recommend succession planning for our executive officers to our Board.
- Review and monitor our short and long-term incentive programs, including making recommendations regarding the related incentive plans for approval by our Board and, in the case of our Employee Stock Option Plan, for approval by our shareholders (where required), and approve grants of long-term incentives.
- Review and monitor our pension and investment plans and programs and recommend pension and investment matters to the Board where necessary.

Market Data Comparisons and Our Peer Group

We will participate in annual compensation surveys that are conducted by various compensation consultants to monitor how we are doing. These surveys are useful for determining compensation trends and will give us guidance to help us determine how well we are meeting our compensation program principles.

We target to have the total direct compensation of our executive officers provided at a level that is consistent with the total direct compensation provided by our peer group to their executive officers. Specifically, we target the total direct compensation for our executive officers at the 50th percentile of our peer group and allow for the ability to provide higher compensation for superior performance. For the initial compensation review conducted for our executive officers, we identified the following companies as our peer group:

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- Canadian Natural Resources Limited
- Devon Energy Corporation
- Enbridge Inc.
- EnCana Corporation
- Husky Energy Inc.
- Imperial Oil Limited
- Marathon Oil Corporation
- Murphy Oil Corporation
- Nexen Inc.
- Suncor Energy Inc.
- Talisman Energy Inc.
- TransCanada Corporation

This peer group is comprised of North American oil and gas companies of similar size and complexity to Cenovus, taking into consideration market capital and revenue.

We engage the services of Towers Watson, a respected compensation consultant, to advise us on the competitiveness of the compensation of our executive officers and on the competitiveness of our compensation program as a whole. Specifically, we obtain advice from Towers Watson on the following items:

- Regular competitive analysis of the elements of our compensation program, including base salary, annual bonus program, long-term incentive program, retirement and pension benefits and other compensation, which are provided to our executive officers.
- The objectives and principles that we use to design our compensation philosophy and program, including advice regarding the peer group.
- Trends and best practices in compensation philosophy and program design, using various research methods including compensation and workforce surveys.
- Provision of comprehensive retirement programs and pension plan advice, including acting as our actuary for pension plan matters and as asset management consultant for our pension and investment plans.

Our HRC Committee has directly retained Towers Watson to advise it specifically regarding matters relating to the compensation of our executive officers, including commenting and advising on the information provided to the HRC Committee by management concerning our executive officers and particularly regarding the compensation of our President & Chief Executive Officer. The retainer of Towers Watson by our Board is

independent from the advice provided to management. The terms of the retainer will be stated in a formal mandate that outlines the role of Towers Watson and the terms of reference as an independent advisor to the HRC Committee. To ensure independence, there is a clear reporting relationship between Towers Watson and the HRC Committee, regular meetings are held between Towers Watson and the HRC Committee without management present, and executive compensation consulting work is retained and managed directly by the Chair of the HRC Committee.

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The Elements of our Compensation Program

Base Salary

Base salary provides a level of fixed cash compensation which is consistent with market practice. We determine the base salary of our executive officers annually based upon comparisons to the most recently available market data, and considering experience, scope of responsibilities, individual performance and strategic leadership over the course of the year.

Annual Bonus Program

We are developing the details of our annual bonus program with the objective of rewarding short-term performance and results in a manner consistent with market practice.

Our executive officers will identify performance objectives for each calendar year. In determining annual bonus awards, our program will involve evaluation of the following on an annual basis:

- Individual performance as compared to stated objectives; and
- Company performance on the basis of objective financial and operational measures as well as certain more subjective measures such as corporate and environmental responsibility, corporate governance and employment practices, all of which will be identified more particularly over the course of the year.

Bonus awards will be payable in the first quarter of each year, based upon the prior year's achievement of stated corporate and individual objectives.

Long-Term Incentive Program

We are developing our long-term incentive program to align the interests of our executive officers with our shareholders through holdings of significant equity interests and to provide for long-term retention. In addition to the intrinsic performance risk contained within equity-based incentives, we also believe it is important to include achievement of additional performance measures that will determine vesting of a portion of long-term incentives that may be granted.

We currently expect to grant long-term incentives on an annual basis, in conjunction with our annual compensation cycle, using guidelines based on a review of competitive market data and on individual performance. Our long-term incentive programs provide for the granting of stock options and performance share units.

We plan to use recycle ratio as the key performance measure for vesting of performance-based long-term incentives. We believe that recycle ratio is the key measure of total value added as it measures our ability to generate operating cash flow in excess of the all-in costs of adding reserves. Recycle ratio is calculated as follows:

$$\text{Recycle Ratio} = \frac{\text{Netback}}{\text{Finding \& Development Costs}}$$

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Netback is calculated based upon:

- operating & administrative costs;
- commodity price;
- royalties; and
- transportation.

Finding & Development Costs are calculated based upon:

- capital spending (capital efficiency); and
- reported proved reserves additions.

The balance of the long-term incentives will vest based upon prescribed time vesting criteria over a period of three years.

Cenovus Options have associated tandem stock appreciation rights ("TSARs"). A TSAR entitles the optionholder to surrender the right to exercise the Cenovus Option to purchase a specified number of Common Shares and to receive cash (or, at our election, Common Shares) instead. The optionholder will be paid the closing price of a Common Share on the TSX on the last trading day preceding the date the TSAR is exercised less the grant price of the Cenovus Option, multiplied by the number of Cenovus Options surrendered. When a TSAR is exercised, the Cenovus Option it is associated with is surrendered and the underlying right to purchase a Common Share is forfeited.

The grant price of Cenovus Options will be the closing price of the Common Shares on the TSX on the day immediately prior to the day the Cenovus Options are granted.

Replacement Stock Options

Pursuant to the Arrangement, replacement stock options (with associated TSARs) were granted to our employees and executive officers. For each EnCana stock option held as of November 30, 2009, our employees and executive officers received one EnCana Replacement Option and one Cenovus Replacement Option. The grant price of the previously held EnCana stock options was adjusted as required by the EnCana Key Employee Stock Option Plan using a stated formula based upon the one day volume weighted average trading price of a common share of each of EnCana (as traded on the TSX on a pre-Arrangement basis), new EnCana (as traded on the TSX on an if, as and when issued basis) and Cenovus (as traded on the TSX on an if, as and when issued basis) on December 2, 2009. All of the replacement stock options have associated TSARs.

The Cenovus Replacement Options have a five year term from their original grant date and vest according to their original grant date based upon the following schedule: 30 percent on the first anniversary date of the original grant, 30 percent on the second anniversary date of the original grant and the remaining 40 percent on the third anniversary date of the original grant. For two-thirds of the Cenovus Replacement Options which replaced grants from 2007 to 2009, there is an additional vesting requirement related to achievement of a stated recycle ratio. Specifically:

- 0 percent of the performance-based Cenovus Replacement Options vest where the recycle ratio is equal to or less than 1.0.
- 50 percent of the performance-based Cenovus Replacement Options vest where the recycle ratio is 2.0 or greater.
- 100 percent of the performance-based Cenovus Replacement Options vest where the recycle ratio is 3.0 or greater.
- Recycle ratios of between 1.0 and 3.0 will result in vesting of performance-based Cenovus Replacement Options on a linear basis such that portions of the grant may vest.

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- Performance-based Cenovus Replacement Options that do not vest in a particular year are forfeited and cancelled.

Deferred Share Units

We have a Deferred Share Unit Plan for Employees ("DSU Plan") under which our employees (including our executive officers) may elect, irrevocably and in the prior calendar year, to convert either 25 percent or 50 percent of their annual bonus (which would otherwise be paid in cash) to deferred share units ("DSUs"). In addition, the DSU Plan allows the HRC Committee to award a grant of DSUs on terms and conditions it determines at the time of the grant. Dividend equivalents are paid in the form of additional DSUs, consistent with dividends declared on Common Shares.

DSUs generally vest when they are credited to the individual's account, unless the HRC Committee determines otherwise. DSUs may only be redeemed upon the departure of the individual from Cenovus, either by resignation, termination or retirement. When an individual departs, he or she must redeem the DSUs in his or her account by December 15 of the first calendar year following the year of his or her departure from Cenovus. The value of DSUs that may be redeemed is equal to the number of DSUs in the individual's account on the date of redemption multiplied by the trading price of a Common Share on the day prior to the date of redemption. This amount is paid to the individual in cash on an after-tax basis.

Pursuant to the Arrangement, DSUs of EnCana held by employees of Cenovus were exchanged for Cenovus DSUs. The fair value of the Cenovus DSUs credited to each employee was based on the fair market value of Cenovus Common Shares relative to EnCana common shares prior to the Effective Date of the Arrangement.

Retirement and Pension Benefits

We believe it is important to provide for the future retirement of our executive officers through retirement and pension benefits. Our program provides competitive retirement and pension benefits, gives long-term financial security and aids with retention.

Certain of our executive officers, including our President & Chief Executive Officer, participate in the Defined Benefit Option of Cenovus's Canadian Pension Plan (our "DB Plan"). Under our DB Plan, normal retirement is at age 65, although employees may retire as early as age 55 with a reduced pension for early commencement. We pay pensions from our DB Plan up to the permitted levels for registered pension plans.

Certain of our other executive officers, including our Executive Vice-President & Chief Financial Officer, participate in the Defined Contribution Option of Cenovus's Canadian Pension Plan (our "DC Plan"). Under the terms of the DC Plan, contributions are made to an account for each employee or executive officer in the amount of eight percent of base salary. Each executive officer individually manages the investments made

within their accounts. A specified number of investment options are made available by Cenovus within the DC Plan and the accounts held by executive officers.

Our Canadian Pension Plan, which includes both our Defined Benefit Option and Defined Contribution Option, is a registered pension plan. Additional pension benefits may be payable from the Cenovus Energy Inc. Canadian Supplemental Pension Plan for pension benefits beyond the limits permitted from a registered pension plan. Pension benefits are based on years of credited service and final average pensionable earnings for DB Plan participants.

Other Compensation

To achieve a competitive total compensation package, we provide additional elements of compensation such as an annual allowance, company-paid parking, financial and retirement planning services, company matching of personal contributions to an investment plan of up

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to five percent of base salary and, in some cases, membership fees associated with the personal use of clubs.

2009 Compensation for our Named Executive Officers

Our Board considered available market data, taking into account the size and nature of our business, peer comparisons, experience, leadership and individual performance to determine the compensation to be provided to our executive officers in their capacity as executive officers of Cenovus in December 2009.

Effective December 1, 2009, the annual base salary of Brian C. Ferguson, our President & Chief Executive Officer, is $859,950 and of Ivor M. Ruste, our Executive Vice-President & Chief Financial Officer, is $429,975.

For the annual bonus award for the 2009 performance year, our Board considered the performance of our executive officers in their capacities as executive officers of Cenovus in December 2009 and also took into consideration their role, leadership and guidance through the Arrangement and through the transition period following the successful completion of the Arrangement.

Our President & Chief Executive Officer, Mr. Ferguson, was the strategic leader for Cenovus through the course of the Arrangement and in the transition period that followed. Our Board identified that Mr. Ferguson's performance was outstanding for his role leading up to the completion of the Arrangement and in transition activities that resulted in Cenovus becoming a fully independent company in December 2009. In addition, our Board recognized the successful operating and financial performance measures for the year for the Integrated Oil and Canadian Plains Divisions, which are our key operations. In recognition of the strong operating and financial performance of EnCana and Cenovus in 2009, and Mr. Ferguson's role in the Arrangement and in the transition in December 2009, our Board awarded a maximum bonus award. The amount of Mr. Ferguson's bonus earned in December 2009 was $119,438 (representing 1/12th of the amount of the total award). In addition, our Board used its discretion to include in this bonus amount $47,775 representing a special award relating to the significant contributions of Mr. Ferguson to the successful completion of the Arrangement that was made in the form of a grant of DSUs that vest one-half on the date of grant and one-half one year from the date of grant.

Mr. Ruste, Executive Vice-President & Chief Financial Officer, also achieved outstanding results in his role relating to the Arrangement and in the transition in December 2009. Of particular note, Mr. Ruste provided leadership in structuring and obtaining financing that allowed the Arrangement to proceed and that provides a strong foundation for Cenovus. In recognition of the strong operating and financial performance of EnCana and Cenovus, and Mr. Ruste's role in the Arrangement and in the transition in December 2009, Mr. Ruste was awarded a maximum bonus award, attributable to December 2009, of $62,440 (representing 1/12th of the total bonus award). This bonus award includes an amount of $35,831 representing a special award relating to the significant contributions of Mr. Ruste to the successful completion of the Arrangement that was made in the form of a grant of DSUs that vest one-half on the date of grant and one-half one year from the date of grant.

For 2009, the bonus target for all our employees, including our executive officers, was increased by ten percent to reinforce the achievement of significant capital budget savings in 2009. The successful achievement of this program was reflected in the December 2009 annual bonus payment of our executive officers.

Our executive officers were not granted any long-term incentives in December 2009 by Cenovus. Cenovus Replacement Options that were granted on November 30, 2009 as a result of the Arrangement are reported in the Outstanding Option-Based Awards Table that follows this Compensation Discussion and Analysis.

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Share Ownership Guidelines

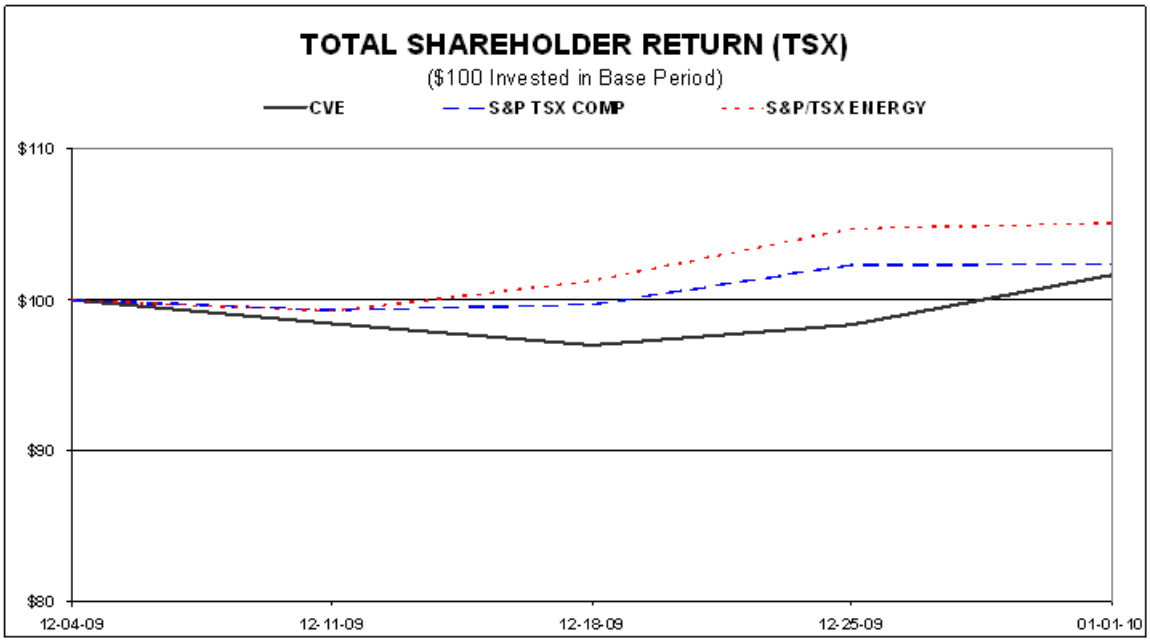
We believe it is important to closely align the interests of our executive officers with our shareholders and one key way to accomplish this is to require that they maintain certain minimum holdings of Common Shares. As a result, our HRC Committee approved the following Common Share ownership guidelines in December 2009:

President & Chief Executive Officer	4 times annual base salary
Other Executive Officers	2 times annual base salary

The executive officers who held executive officer positions with EnCana are required to achieve these Common Share ownership guidelines by December 1, 2012. For those new executive officers appointed at the time of successful completion of the Arrangement or in future years, achievement of the Common Share ownership guidelines will be required within five years of their appointment as an executive officer. The executive officers newly appointed at the time of successful completion of the Arrangement have until December 1, 2014 to achieve these guidelines.

Performance Graph

The following chart compares the cumulative total shareholder return for Cenovus on the TSX of $100 invested in Common Shares (assuming reinvestment of dividends) over the period of time that Cenovus Common Shares traded on the TSX in December 2009.



Cenovus began trading on a regular basis on the TSX on December 3, 2009. Therefore, we are unable to determine any trends at this very early stage in respect of the compensation of our executive officers as compared to total shareholder return for the month of December 2009 as shown in the Performance Graph.

Tables

The amounts reported in the following tables are reported in U.S. dollars. As the amounts are paid in Canadian dollars, we have converted the amounts to U.S. dollars using the exchange rate of C$1.00 = US$0.9555, which is the exchange rate for Canadian dollars to U.S. dollars on December 31, 2009 based on the daily noon buying rate published by the Bank of Canada.

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Summary Compensation Table

Cenovus commenced independent operations on December 1, 2009. The compensation earned in December 2009 by the President & Chief Executive Officer and the Executive Vice-President & Chief Financial Officer, in their capacities as executive officers of Cenovus, as discussed in the Compensation Discussion and Analysis, is summarized in the following table.

Name and Principal Position[1]	Year	Salary ($)	Non-Equity Incentive Plan Compensation: Annual Incentive Plans ($)	Pension Value[2] ($)	All Other Compensation[3] ($)	Total Compensation ($)
Brian C. Ferguson President & Chief Executive Officer	**2009**	71,662	119,438[4]	33,421	7,195	231,716

Ivor M. Ruste Executive Vice-President & Chief Financial Officer	**2009**	35,831	62,440(4)	2,867	5,117	106,255

Notes:
(1) No other executive officer of Cenovus was paid Total Compensation (excluding Pension Value) for December 2009 in his or her capacity as an executive officer of Cenovus of more than $150,000.
(2) Pension Value represents the compensatory change from November 30, 2009 to December 31, 2009 set out in the Compensatory Change column of the Defined Benefit Pension Table or the Defined Contribution Pension Table, as applicable.
(3) All Other Compensation represents Mr. Ferguson's and Mr. Ruste's annual allowance and company matching of contributions to the investment plan for December 2009. There was no other compensation paid by Cenovus in 2009 to Mr. Ferguson and Mr. Ruste.
(4) The Annual Incentive Plans amounts include the amount of the annual bonuses paid to Mr. Ferguson and Mr. Ruste that were earned in their capacities as executive officers of Cenovus for the month of December 2009. These amounts were paid partially in cash and partially in the form of DSUs under the DSU Plan.

Outstanding Option-Based Awards

The following table outlines the option-based awards outstanding as at December 31, 2009. There are no outstanding share-based awards.

Name	Number of securities underlying unexercised options(1) (#)	Grant Date of Cenovus Replacement Options	Original Grant Date	Option Exercise price(2) (C$)	Option expiration date	Value of unexercised in-the-money options(3) (US$)
Brian C. Ferguson	80,000	30-Nov-2009	13-Feb-2006	22.91	13-Feb-2011	274,420
	134,250	30-Nov-2009	13-Feb-2007	26.64	13-Feb-2012	0
	138,750	30-Nov-2009	13-Feb-2008	32.96	13-Feb-2013	0
	150,000	30-Nov-2009	11-Feb-2009	26.27	11-Feb-2014	32,965
Ivor M. Ruste	50,000	30-Nov-2009	01-May-2006	26.54	01-May-2011	0
	67,125	30-Nov-2009	13-Feb-2007	26.64	13-Feb-2012	0
	69,375	30-Nov-2009	13-Feb-2008	32.96	13-Feb-2013	0
	90,000	30-Nov-2009	11-Feb-2009	26.27	11-Feb-2014	19,779

Notes:
(1) The number of securities underlying unexercised options includes stock options that have vested and options that have not yet vested. For the 2007, 2008 and 2009 stock option grants, performance-based Cenovus Replacement Options that do not vest in a given year will be cancelled and deducted from the amounts stated in this table.
(2) The exercise price of the previously held EnCana stock options was adjusted, as required by the EnCana Key Employee Stock Option Plan, using a formula based upon the one day volume weighted average trading price of a common share of each of EnCana (as traded on the TSX on a pre-Arrangement basis), new EnCana (as traded on the TSX on an if, as and when issued basis) and Cenovus (as traded on the TSX on an if, as and when issued basis) on December 2, 2009.
(3) The value of unexercised in-the-money options is based on the December 31, 2009 closing price of the Common Shares of C$26.50 on the TSX.

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Incentive Plan Awards – Value Vested or Earned During the Year

This table provides the value of non-equity incentive plan compensation that was earned in December 2009. No option-based or share-based awards vested during December 2009.

Name	Non-Equity Incentive Plan Compensation – Value Earned During the Year(1) ($)
Brian C. Ferguson	119,438
Ivor M. Ruste	62,440

Note:
(1) Non-Equity Incentive Plan Compensation includes the amount of the annual bonuses paid to Mr. Ferguson and Mr. Ruste that were earned in their capacities as executive officers of Cenovus for the month of December 2009. These amounts were paid partially in cash and partially in the form of a grant of DSUs under the DSU Plan.

Defined Benefit Pension Table

The following table outlines the estimated annual benefits, accrued pension obligations and compensatory and non-compensatory changes under the DB Plan.

Name	Number of Years of Credited Service (#)	Annual Benefits Payable ($)		Accrued Obligation at Start of Year(1) ($)	Compensatory Change(2) ($)	Non-Compensatory Change(3) ($)	Accrued Obligation at Year End ($)
		At Year End	At Age 65				
Brian C. Ferguson	27.25(4)	379,967	548,509	9,649,835(5)	33,421	(337,671)	9,345,585(6)

Notes:
(1) The accrued obligation at the start of year is as of November 30, 2009 and is determined using the same methodology and assumptions described in the pension accounting information letter reflecting the company split from EnCana.
(2) Includes service cost net of employee contributions plus the difference between actual and estimated earnings.
(3) Includes interest on the accrued obligation as of November 30, 2009, employee contributions plus changes in the discount rate and exchange rates and other net experience as at December 31, 2009.
(4) Includes three additional years of service granted under an individual agreement.
(5) Includes incremental obligation of $4,452,253 arising as a result of Mr. Ferguson's appointment as President & Chief Executive Officer (and the change in his base salary and bonus entitlement for pension inclusion purposes). Also includes optional contributions account balance of $51,833, as of November 30, 2009, which represents the accumulated value of employee paid optional contributions to purchase optional DB pension benefits.
(6) Includes optional contributions account balance of $53,815, as of December 31, 2009, which represents the accumulated value of employee paid optional contributions to purchase optional DB pension benefits.

Defined Contribution Pension Table

The following table outlines the change in value of DC Plan holdings over the course of 2009.

Name	Accumulated Value at Start of Year ($)	Compensatory Change ($)	Non-Compensatory Change ($)(1)	Accumulated Value at Year End ($)
Ivor M. Ruste	119,340	2,867	2,909	125,116

Note:
(1) Includes investment earnings during 2009.

Employment, Severance and Change in Control Arrangements

Cenovus has entered into change in control agreements with our executive officers. In addition, our executive officers receive the same treatment as other employees on a change in control in respect of vesting of a portion of their replacement stock options as specifically stated in the replacement stock option grant agreements. Cenovus has not entered into any other employment or severance arrangements with our executive officers.

The change in control agreements that have been entered into with our executive officers provide for a "double trigger" for payment of severance benefits. First, a change in control

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as defined in the agreement must occur. Secondly, the employment of the executive officer must terminate (other than for cause, disability, retirement or death), which would include termination by the executive officer for certain specified reasons such as a change in responsibilities or a reduction in salary and benefits.

The terms of the change in control agreements provide for the following severance benefits should both aspects of the double trigger be activated (change in control and termination of employment):

- A lump sum severance payment representing the amount of salary and bonus, for a period of 36 months for our President & Chief Executive Officer and for a period of 24 months for our other executive officers. The bonus is determined based upon the average of the bonus payments paid to the executive officer over the preceding five-year period, which for our executive officers will include consideration of high performance reward program awards paid while at EnCana.
- Medical, dental and insurance benefits continue, for a period of 36 months for our President & Chief Executive Officer and for a period of 24 months for our other executive officers.
- All time-based replacement stock options and 50 percent of the performance-based replacement stock options would immediately vest and be available for exercise, for a period of 36 months for our President & Chief Executive Officer and for a period of 24 months for our other executive officers. The remaining 50 percent of the performance-based replacement stock options vest upon the achievement of the stated performance criteria as outlined in the grant agreements for the replacement stock options.
- Pension benefits continue to accrue, for a period of 36 months for our President & Chief Executive Officer and for a period of 24 months for our other executive officers.

Under the terms of the Cenovus Replacement Option grant agreements, on a change in control, immediate vesting of time-based and 50 percent of the performance-based Cenovus Replacement Options would occur for all optionholders.

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Change in Control Table

The following table outlines the amounts that would be payable to our President & Chief Executive Officer and our Executive Vice-President & Chief Financial Officer if a change in control occurred on December 31, 2009 and, in the case of the change in control agreements, employment terminated as a result of the change in control on December 31, 2009.

	Long-Term Incentive Grant Agreements	*Change in Control Agreements*					
Name	Value of Exercisable Vested LTIs(1)	Cash Severance	Annual Incentive Plan(2)	Value of Exercisable Vested LTIs(1)	Pension Benefits	Other Compensation and Benefits(3)	Total
Brian C. Ferguson	21,977	2,579,850	2,256,980	21,977	5,087,764(4)	259,020	10,205,591
Ivor M. Ruste	13,186	859,950	799,621	13,186	96,314(5)	122,808	1,891,879

Notes:
(1) The value of exercisable vested LTIs is calculated by multiplying the number of options that would vest on a change in control by the difference between the grant price and C$26.50, the closing price of a Common Share on December 31, 2009.
(2) The Annual Incentive Plan amount is calculated based upon the average of the bonus payments paid to Mr. Ferguson over the preceding five-year period and Mr. Ruste over the preceding four-year period (Mr. Ruste has four years of prior service), which for our executive officers will include consideration of high performance reward program awards paid while at EnCana. The average is then applied to a period of 36 months for Mr. Ferguson and over a period of 24 months for Mr. Ruste.
(3) The value of Other Compensation and Benefits is the amount in the column titled "Other Compensation" in the Summary Compensation table multiplied by 36 for Mr. Ferguson and by 24 for Mr. Ruste.

(4) The calculation of Mr. Ferguson's five-year annual average pensionable earnings is based on his annual base salary plus bonus (67 percent of salary). The early retirement reduction factor applicable under the Cenovus Energy Inc. Canadian Supplemental Pension Plan is calculated at the age he would have attained at December 31, 2012. This incremental lump sum pension value is equal to the difference between the actuarial present values of Mr. Ferguson's accrued pension, as modified, less the accrued pension, unmodified, using the commuted value basis for the DB Plan as of December 31, 2009. The discount rates used are 3.9 percent for ten years and 5.4 percent thereafter.
(5) This incremental lump sum pension value is equal to eight percent of two times his annual base salary plus bonus (40 percent of salary).

Director Compensation

In December 2009, the compensation to be paid to our non-employee directors was determined following a review of the elements and level of compensation for directors of a company of comparable size and scope to Cenovus. Our President & Chief Executive Officer does not receive compensation for serving as a director of Cenovus.

Fees

Each non-employee director of our Board is paid an annual retainer of $28,665 per year. This annual retainer is paid in quarterly installments and is pro-rated for periods of partial service. For each meeting of the Board (excluding our annual organization meeting for which no attendance fee is payable), a fee of $1,433 is paid to each non-employee director who attends in person or by telephone. For each meeting of a Committee of the Board, a fee of $1,433 is paid to each Committee member who attends in person or by telephone.

Each non-employee director is reimbursed for travel and other expenses for attending Board or Committee meetings. In addition, for each meeting of the Board where the director is

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normally resident outside of western Canada, or when the location of a meeting of the Board or a Committee of the Board is outside of western Canada and away from the director's place of residence, an additional fee equal to the normal meeting fee is paid to the director.

The Chair of each Committee of the Board is paid an additional fee of $7,166 per annum for each Committee which the director chairs. The Audit Committee Chair is paid a supplemental fee of $7,166 per year. Our non-executive Chair of the Board receives an additional annual retainer of $238,875.

Deferred Share Units

Each non-employee director is provided with an annual grant of 7,500 DSUs under the Deferred Share Unit Plan for Directors of Cenovus Energy Inc. This annual grant of DSUs is made on January 1 of each year, the first grant occurring on January 1, 2010. Dividend equivalents are paid in the form of additional DSUs consistent with dividends declared on Common Shares. Newly appointed or elected directors receive their initial grant of DSUs upon joining the Board. We also provide the option to our non-employee directors to take all or a portion of their annual retainer and meeting fees in the form of DSUs.

DSUs vest when they are credited to the director's account. DSUs may only be redeemed upon the departure of the director from Cenovus, either by resignation, termination or retirement. When a director departs, he or she must redeem the DSUs in his or her account by December 15 of the first calendar year following the year of his or her departure as a director. The value of DSUs that may be redeemed is equal to the number of DSUs in the director's account on the date of redemption multiplied by the trading price of a Common Share on the day prior to the date of redemption. This amount is paid to the director in cash on an after-tax basis.

Pursuant to the Arrangement, DSUs of EnCana held by the directors of Cenovus were exchanged for Cenovus DSUs. The fair value of the Cenovus DSUs credited to each director was based on the fair market value of Cenovus Common Shares relative to EnCana common shares prior to the Effective Date of the Arrangement.

Share Ownership Guidelines

In December 2009, we implemented share ownership guidelines for our non-employee directors. Each director (excluding our non-executive Chair of our Board) is required to beneficially own voting shares of Cenovus, which may include holdings of DSUs, at least equal in value, based on the market price of Common Shares, to $477,750. Our non-executive Chair of our Board is required to beneficially own voting shares of Cenovus, including DSUs, at least equal in value, based on the market price of Common Shares, to $955,500. Each director is required to achieve the share ownership guidelines by the later of December 1, 2014 or within five years after the director joins the Board.

The following table summarizes the annual compensation of our directors paid by Cenovus from November 30, 2009 to December 31, 2009.

Director Compensation Table

Name	Fees Earned ($)	All Other Compensation[1] ($)	Total ($)
Ralph S. Cunningham	7,416	1,433	8,849
Patrick D. Daniel	9,472	0	9,472
Ian W. Delaney	7,416	1,433	8,849
Michael A. Grandin	30,188	0	30,188
Valerie A.A. Nielsen	8,226	0	8,226
Charles M. Rampacek	6,792	1,433	8,226
Colin Taylor	8,226	1,433	9,659
Wayne G. Thomson	7,416	0	7,416

Note:
(1) Represents travel fees paid to directors as applicable.

AUDIT COMMITTEE

The full text of the Audit Committee mandate is included in Appendix C of this annual information form.

Composition of the Audit Committee

The Audit Committee consists of three members, all of whom are independent and financially literate in accordance with the definitions in National Instrument 52-110 *Audit Committees* ("NI 52-110"). The relevant education and experience of each of the members of the Audit Committee is outlined below.

Patrick D. Daniel (Audit Committee Chair)

Mr. Daniel holds a Bachelor of Science (University of Alberta) and a Master of Science (University of British Columbia), both in chemical engineering. He also completed Harvard University's Advanced Management Program. He is President and Chief Executive Officer and a director of Enbridge Inc. (energy delivery company), as well as a director of a number of Enbridge subsidiaries. He is a past director and member of the Audit Committee of Enerflex Systems Income Fund (compression systems manufacturer). He is also a past director and Chair of the Finance Committee of Synenco Energy Inc. (oilsands mining) which was acquired by Total E&P Canada Ltd. in August 2008.

Valerie A.A. Nielsen

Ms. Nielsen holds a holds a Bachelor of Science (Hon.) (Dalhousie University). She is a professional geophysicist who has held management positions in the oil and gas industry and/or provided consulting services to industry for over 30 years. She has also completed a variety of finance and accounting courses at the university level. Ms. Nielsen was a member and past chair of an advisory group on the General Agreement on Tariffs and Trade (GATT), the North America Free Trade Agreement (NAFTA) and international trade matters pertaining to energy, chemicals and plastics from 1986 to 2002. She was also a director of the Bank of Canada. She is a director and serves on the Audit Committee of Wajax Income Fund (diversified company engaged in the sale and after-sales parts and service support of mobile equipment, diesel engines and industrial components).

Colin Taylor (Financial Expert)

Mr. Taylor is a chartered accountant, as well as a member and Fellow of the Institute of Chartered Accountants of Ontario. He also completed Harvard University's Advanced Management Program. Mr. Taylor served two consecutive four-year terms (June 1996 to May 2004) as Chief Executive and Managing Partner and was Senior Counsel of Deloitte & Touche LLP until his retirement in May 2008. He has held a number of international management and governance responsibilities throughout his professional career. Mr. Taylor also served as Advisory Partner to a number of public and private company clients of Deloitte & Touche LLP.

The above list does not include Michael A. Grandin who is an ex-officio member of the Audit Committee.

Pre-Approval Policies and Procedures

We have adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP. The Audit Committee has established a budget for the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by PricewaterhouseCoopers LLP. The budget generally covers the period between the adoption of the budget and the next meeting of the Audit Committee, but, at the option of the Audit Committee, it may cover a longer or shorter period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that: (i) the Audit Committee knows precisely what services it is being asked to pre-approve; and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

Subject to the following paragraph, the Audit Committee has delegated authority to the Chair of the Audit Committee (or if the Chair is unavailable, any other member of the Audit Committee) to pre-approve the provision of permitted services by PricewaterhouseCoopers LLP which are not otherwise pre-approved by the Audit Committee, including the fees and terms of the proposed services ("Delegated Authority"). Any required determination about the Chair's unavailability will be required to be made by the good faith judgment of the applicable other member(s) of the Audit Committee after considering all facts and circumstances deemed by such member(s) to be relevant. All pre-approvals granted pursuant to Delegated Authority must be presented by the member(s) who granted the pre-approvals to the full Audit Committee at its next meeting.

The fees payable in connection with any particular service to be provided by PricewaterhouseCoopers LLP that has been pre-approved pursuant to Delegated Authority: (i) may not exceed C$200,000, in the case of pre-approvals granted by the Chair of the Audit Committee, and (ii) may not exceed C$50,000, in the case of pre-approvals granted by any other member of the Audit Committee.

All proposed services or the fees payable in connection with such services that have not already been pre-approved must be pre-approved by either the Audit Committee or pursuant to Delegated Authority. Prohibited services may not be pre-approved by the Audit Committee or pursuant to Delegated Authority.

External Auditor Service Fees

During fiscal 2009, no fees were billed to Cenovus for professional services rendered by PricewaterhouseCoopers LLP. Prior to the Arrangement, all fees had been billed to EnCana.

We did not rely on the *de minimus* exemption provided by Section (c)(7)(i)(C) of Rule 2-01 of SEC Regulation S-X in 2009.

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STATEMENT OF CORPORATE GOVERNANCE PRACTICES

Cenovus and the Board are committed to attaining the highest standards of corporate governance. We maintain appropriate governance practices as fundamental to generating long-term shareholder value. We continually assess and update our practices and believe we employ a leading system of corporate governance to ensure the interests of our shareholders are well protected.

The securities regulatory authorities in all of the provinces and territories of Canada (collectively, the "CSA") adopted National Policy 58-201 *Corporate Governance Guidelines* ("NP 58-201") effective June 30, 2005 and National Instrument 58-101 *Disclosure of Corporate Governance Practices* ("NI 58-101") effective June 30, 2005, as amended effective December 31, 2007 and March 17, 2008. Disclosure of governance practices is required in accordance with NI 58-101.

With respect to the U.S., we are required to comply with the provisions of the *Sarbanes-Oxley Act of 2002* and the rules adopted by the SEC pursuant to that Act, as well as the governance rules of the NYSE, in each case as applicable to foreign issuers. Most of the NYSE corporate governance standards are not mandatory for Cenovus as a non-U.S. company, but we are required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. companies listed on the NYSE under NYSE corporate governance standards. Except as summarized on our website ***www.cenovus.com***, we are in compliance with the NYSE corporate governance standards in all significant respects.

Our Board and its Committees continually evaluate and enhance our corporate governance practices by monitoring Canadian and U.S. regulatory developments affecting corporate governance, accountability and transparency of public company disclosure.

The following statement of our corporate governance practices is made in accordance with Form 58-101F1 of NI 58-101. Statements are also included with respect to certain applicable provisions of the *Sarbanes-Oxley Act of 2002*, related SEC rules, NYSE rules and Canadian rules relating to audit committees pursuant to NI 52-110. Our approach to corporate governance meets or exceeds the best practices enunciated under NP 58-201.

Board of Directors

Independence

Our Board is currently composed of nine directors, eight of whom are independent directors. Mr. Ferguson, our President & Chief Executive Officer, is the only member of our Board who is a member of our management. The remainder of the directors are independent directors on the basis that such directors have no direct or indirect material relationship with us which could be reasonably expected to interfere with the exercise of a member's independent judgment.

Our Board is responsible for determining whether or not each director is independent within the meaning of such term set forth in NI 58-101. In applying this definition, our Board considers all relationships of our directors with us, including business, family and other relationships.

Pursuant to our By-Laws, our Chair and the Chief Executive Officer shall not be the same person, except in very limited circumstances. The Chair of our Board is required to ensure that our Board is properly organized, functions effectively and meets its obligations and responsibilities including those relating to corporate governance matters.

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Majority Voting for Directors

Our Board has a policy requiring that a director tender his or her resignation if the director receives more "withheld" votes than "for" votes at any meeting where shareholders vote on the uncontested election of directors. Our Board will consider the resignation and, in the absence of special circumstances, will accept the resignation consistent with an orderly transition. The director will not participate in any Committee or our Board deliberations on the resignation offer. Our Board will make its decision to accept or reject the resignation within 90 days. Our Board may fill a vacancy in accordance with our articles, By-Laws and applicable corporate laws.

Other Directorships

Our Board has not adopted a formal policy limiting the number of outside directorships of our directors. Other public company board memberships held by our directors are described in "Directors and Executive Officers - Other Reporting Issuer Experience of Directors" in this annual information form. Directors who serve together on other boards are Mr. Cunningham and Mr. Rampacek who are directors of Enterprise Products GP, LLC, the sole general partner of Enterprise Products Partners, L.P. We do not believe this interlocking board relationship will impact on the ability of these directors to act in our best interests.

Board of Directors' Mandate

The fundamental responsibility of our Board pursuant to our Board of Directors' Mandate (the "Board Mandate") is to appoint a competent executive team and to oversee the management of the business, with a view to maximizing shareholder value and ensuring corporate conduct in an ethical and legal manner via an appropriate system of corporate governance and internal control. The Board Mandate sets out the key responsibilities of our Board in its stewardship and includes the following primary responsibilities. The Board Mandate is set out as Appendix D to

this annual information form.

Supervision of Management

Our Board is responsible for appointing the Chief Executive Officer and monitoring the Chief Executive Officer's performance against a set of mutually agreed upon corporate objectives directed at maximizing shareholder value. The HRC Committee provides recommendations to our Board on succession planning, on senior management development and on the performance of management in relation to the accomplishment of their annual objectives. The HRC Committee is comprised exclusively of independent directors. Annually, the HRC Committee measures management's performance and total compensation against the combined set of objectives comprised in our annual budget and our strategic plan. Our Board supports management's commitment to training and developing all employees.

Our Strategic Plan

Our Board is responsible for the annual review and approval of our strategic plan. Key objectives of the strategic plan, as well as quantifiable operating and financial targets, and systems for the identification, monitoring and mitigation of principal business risks, are incorporated into the annual strategy review. Our Board discusses and reviews all materials relating to the strategic plan with management and receives updates from management on the strategic plan throughout the year. Management is required to seek our Board's approval for any transaction that would have a significant impact on our strategic plan.

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Risk Management

Our Board is responsible for ensuring that a system is in place to identify our principal risks, including operational risks, and to monitor the process to manage such risks. The Audit Committee reviews management's identification of significant financial risks or exposures and meets regularly to review reports and discuss significant risk areas with the internal and external auditors. In addition, our Board ensures that an adequate system of internal control exists.

Communications

Our Board is responsible for approving a communications policy or policies to ensure that a system for corporate communications to all stakeholders exists, including processes for consistent, transparent, regular and timely public disclosure, and to facilitate feedback from stakeholders.

We provide detailed information on our business, operating and financial results in accordance with our continuous disclosure requirements under applicable securities laws. Our news releases and other prescribed documents are required to be filed on the electronic database maintained by the CSA known as "SEDAR" at ***www.sedar.com*** and that maintained by the SEC known as "EDGAR" at ***www.sec.gov***.

Our Board receives regular reports on any key communications issues. Procedures to facilitate feedback from shareholders include the following:

(a) shareholders may send comments via email to ***investor.relations@cenovus.com***;

(b) a confidential and, where desired, anonymous Integrity Helpline to report concerns by telephone to 1-877-445-3222, or by written correspondence to our corporate offices at P.O. Box 766, 421 – 7 Avenue S.W., Calgary, Alberta, Canada T2P 0M5; and

(c) our transfer agent, CIBC Mellon Trust Company, has a website (***www.cibcmellon.com***) and a toll-free number (1-800-387-0825) to assist shareholders.

Expectations of Directors

The Board Mandate also sets out the expectations and business duties of the directors, including the expectation for directors to attend all meetings and the responsibility to ensure that Board materials are distributed to all directors in advance of regularly scheduled meetings to allow for sufficient review. Our Board has a code of business conduct and ethics for directors, officers, employees, contractors and consultants, and monitors compliance with the practice, and approves any waivers of the practice, for officers and directors.

Corporate Governance

Our Board is responsible for establishing an appropriate system of corporate governance, including policies and practices to ensure our Board functions independently of management and to ensure that processes are in place to address applicable regulatory, corporate, securities and other compliance matters.

Position Descriptions

We have established written guidelines for each of the President & Chief Executive Officer, the Chair of our Board and each Committee Chair which are available on our website at ***www.cenovus.com***. Our Board is responsible for monitoring the Chief Executive Officer's performance against mutually agreed corporate objectives directed at maximizing shareholder value. As part of this process, the HRC Committee reviews and approves corporate goals and objectives relevant to the President & Chief Executive Officer's compensation and evaluates the President & Chief Executive Officer's performance in light of

these corporate goals and objectives. Our Board has established clearly defined limits with respect to management's authority.

Orientation and Continuing Education of Directors

The Nominating and Corporate Governance Committee of our Board (the "NCG Committee") is responsible for implementing procedures for the orientation and education of new Board members concerning their role and responsibilities and for the continued development of existing members of our Board. We have established a formal program for new directors which includes a series of interviews and orientation sessions with senior management and field tours of major producing properties and areas of operations hosted by the respective division executive and senior operating staff. As part of the formal orientation, new directors will receive an information package containing our strategic planning materials, directors' information handbook, recently issued disclosure materials and independent third-party peer comparison information. In addition to the formal program, new members to our Board are encouraged to conduct their own due diligence through independent meetings with the Chair of our Board, President & Chief Executive Officer or any other director.

We provide continuing education opportunities for all directors so that individual directors can enhance their skills and have a current understanding of our business environment.

In addition to ongoing internal continuing education programs, directors have the opportunity to attend external educational programs to assist in their development as a director. All such external programs will be approved through the Chair of our Board.

Ethical Business Conduct

We have a set of guiding principles and values outlining the basis on which we operate as a high performance, principled corporation. These principles and values, in conjunction with our Corporate Responsibility Policy, establish our commitment to conducting business ethically and legally. To provide further guidelines in this regard, we have established a written code of business conduct and ethics (the "Code of Business Conduct & Ethics").

The Code of Business Conduct & Ethics applies to all officers, employees, contractors, consultants and directors. The Code of Business Conduct & Ethics makes specific reference to the protection and proper use of our assets, fair dealings with our stakeholders, detection and prevention of fraud and compliance with laws and regulations. All of our officers, employees, contractors, consultants and directors are asked to review the Code of Business Conduct & Ethics and confirm on a regular basis that they understand their individual responsibilities and agree to its requirements.

Any waiver of the Code of Business Conduct & Ethics for officers or directors may only be made by our Board and will be promptly disclosed to shareholders as required by law.

We have established the Investigations Practice to provide an effective, consistent and appropriate procedure by which all incidents that potentially violate our policies or practices, or are potential violations under statutes, regulations, rules and policies applicable to us, are properly received, reviewed, investigated, documented and brought to appropriate resolution. For this purpose, the Investigations Committee conducts, reviews and oversees investigations. The Investigations Committee also refers violations related to any accounting, internal accounting controls or auditing matters to the Audit Committee. The applicable Committees of our Board, including specifically the Audit Committee, receive quarterly summaries on the nature and status of ongoing investigations and the resolutions of any investigations since the previous report. These Committees will report any significant or material investigations to our Board.

We have an Integrity Helpline which provides an additional avenue for stakeholders to communicate concerns about how we conduct our business. Concerns can be reported to the Integrity Helpline orally or in writing and may be made confidentially or anonymously. All concerns reported through the Integrity Helpline relating to violations of policies or practices are handled in accordance with the Investigations Practice. A report of

investigations and Integrity Helpline complaints, which preserves confidentiality and anonymity, is prepared on a quarterly basis and provided to the applicable Committees of our Board at regularly scheduled Committee meetings.

In addition to the statutory obligations of directors to address conflict of interest matters, we have established a protocol to assist our executive team in managing in advance any potential conflicts of interest that may impact individual directors. The protocol requires an executive team member to: confirm an individual director's potential conflict with the Chief Executive Officer; provide advice to the Chair for advance notice to the affected director; ensure the portion of written reference material which gives rise to a conflict is excluded from the pre-meeting distribution to the affected director; and, with respect to the particular item in question, recommend directly to the affected director that he or she abstain from participating in the meeting or excuse himself or herself from the meeting.

We have established a policy on Disclosure, Confidentiality and Employee Trading that governs the conduct of all staff, contractors, consultants and directors and restricted trading and insider guidelines for directors and senior officers.

President & Chief Executive Officer general guidelines have been established which require the President & Chief Executive Officer to foster a corporate culture that promotes ethical practices and encourages individual integrity and social responsibility.

The Corporate Responsibility Policy, Code of Business Conduct & Ethics and the President & Chief Executive Officer General Guidelines are available at ***www.cenovus.com***.

Nomination of Directors

The NCG Committee is comprised of all of the independent directors of our Board. The NCG Committee has a written mandate establishing the NCG Committee's purpose which includes assessing and recommending new nominees to our Board. In assessing new nominees, the NCG Committee seeks to ensure that there is a sufficient range of skills, expertise and experience to ensure that our Board can carry out its

mandate and function effectively. The NCG Committee receives and evaluates suggestions for candidates from individual directors, the President & Chief Executive Officer and from professional search organizations.

The NCG Committee also considers the appropriate size of our Board for the ensuing year and, on a periodic basis, oversees the evaluation and assessment of the effectiveness of our Board as a whole, the Committees of our Board and the contribution of individual members.

The NCG Committee is responsible for reviewing, reporting and providing recommendations for improvement to our Board with respect to all aspects of corporate governance. The NCG Committee is responsible for this Statement of Corporate Governance Practices. The NCG Committee monitors best practices among major Canadian and U.S. companies to help ensure we adhere to high standards of corporate governance.

The NCG Committee has the authority to retain and terminate any search firm to be used by the NCG Committee or our Board to identify candidates. The NCG Committee, upon approval by a majority of the members, may engage any outside resources deemed advisable.

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Compensation

The HRC Committee is comprised exclusively of independent directors. The HRC Committee has a written mandate establishing the responsibilities of the HRC Committee. The HRC Committee is authorized to engage outside resources if deemed advisable and has the authority to retain and terminate any consultant used in the evaluation of executive officer compensation.

The HRC Committee has two primary functions:

- to assist our Board in carrying out its responsibilities by reviewing compensation and human resources issues in support of the achievement of our business strategy and making recommendations to our Board as appropriate. The HRC Committee is responsible for reviewing and approving corporate goals and objectives relevant to the President & Chief Executive Officer compensation, evaluating the President & Chief Executive Officer's performance against those goals and objectives and making recommendations to our Board with respect to the President & Chief Executive Officer's compensation; and
- to assist our Board in carrying out its fiduciary responsibilities in reviewing pension issues and overseeing the investment management of our savings and investment plans.

Our Board reviews the adequacy and form of the directors' compensation to ensure that it realistically reflects the responsibilities and risks involved in being a director. The HRC Committee recommends to our Board, for approval, the directors' compensation and the remuneration for the non-executive Chair of our Board.

Audit Committee

For further information about our Audit Committee and a copy of the Audit Committee Mandate, please see "Audit Committee" in this annual information form and Appendix C to this annual information form, respectively.

Reserves Committee

One hundred percent of our reserves are evaluated by independent qualified reserves evaluators. We have a reserves committee of our Board (the "Reserves Committee"), which is comprised solely of independent directors. The Reserves Committee reviews the qualifications and appointment of the independent qualified reserves evaluators, the procedures for providing information to the evaluators and the annual reserves estimates prior to public disclosure.

Safety, Environment and Responsibility Committee

The SER Committee's primary function is to assist our Board in fulfilling its role in oversight and governance by reviewing, reporting and making recommendations to our Board on our policies, standards and practices with respect to corporate responsibility, including the environment, occupational health, safety and overall business conduct and ethics.

Board Assessments

We have established appropriate practices for the regular evaluation of the effectiveness of our Board, its Committees and its members.

The NCG Committee is responsible for assessing the effectiveness of our Board and Committees of our Board. As part of its process, the Chair of the NCG Committee meets periodically with each director to discuss the effectiveness of our Board, Committees of our Board and each director. To assist the Chair in the review, each director is required to complete an anonymous effectiveness questionnaire annually as well as periodic self and peer evaluation forms. Formal long-form effectiveness questionnaires are expected to be

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used every two years and more abbreviated forms are expected to be used in alternating years. The assessments will include a review of an individual director's knowledge, skills, experience and meaningful contributions.

The Vice-Chair of the NCG Committee also meets periodically with the Chair of the NCG Committee to discuss his effectiveness as the Chair of the Board, Chair of the NCG Committee and as a member of our Board. The NCG Committee assesses the adequacy of information given to

directors, communication between our Board and management and the processes of our Board and its Committees.

The NCG Committee recommends to our Board any changes that would enhance the performance of our Board based on all of the NCG Committee's assessments.

Key Governance Documents

Many policies and practices support our corporate framework. The following documents constitute key components of our corporate governance system and are available at ***www.cenovus.com***:

- Code of Business Conduct & Ethics
- Corporate Responsibility Policy
- Board of Directors' Mandate
- Chair of the Board of Directors and Committee Chair General Guidelines
- President & Chief Executive Officer General Guidelines
- Audit Committee Mandate
- Human Resources and Compensation Committee Mandate
- Nominating and Corporate Governance Committee Mandate
- Reserves Committee Mandate
- Safety, Environment and Responsibility Committee Mandate

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DESCRIPTION OF CAPITAL STRUCTURE

The following is a summary of the rights, privileges, restrictions and conditions which are attached to the Common Shares and the Preferred Shares. We are 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 of December 31, 2009, there were approximately 751 million Common Shares outstanding and no Preferred Shares have been issued.

Common Shares

The holders of Common Shares are entitled to receive dividends if, as and when declared by our Board. The holders of Common Shares are entitled to receive notice of and to attend all meetings of shareholders and are entitled to one vote per Common Share held at all such meetings. In the event of the liquidation, dissolution or winding up or other distribution of our assets among our shareholders for the purpose of winding up our affairs, the holders of Common Shares will be entitled to participate rateably in any distribution of our assets.

We have a Shareholder Rights Plan that was adopted to ensure, to the extent possible, that all our shareholders are treated fairly in connection with any take-over bid for us. The Shareholder Rights Plan creates a right that attaches to each issued Common Share. Until the separation time, which typically occurs at the time of an unsolicited take-over bid, whereby a person acquires or attempts to acquire 20 percent or more of our Common Shares, the rights are not separable from the Common Shares, are not exercisable and no separate rights certificates are issued. Each right entitles the holder, other than the 20 percent acquiror, from and after the separation time (unless delayed by our Board) and before certain expiration times, to acquire Common Shares at 50 percent of the market price at the time of exercise. The Shareholder Rights Plan must be reconfirmed by our shareholders at our annual shareholder meeting to be held in 2012 and every third annual shareholder meeting thereafter until its expiry.

Preferred Shares

Preferred Shares may be issued in one or more series. Our Board may determine the designation, rights, privileges, restrictions and conditions attached to each series of Preferred Shares before the issue of such series. Holders of Preferred Shares are not entitled to vote at any meeting of our shareholders, but may be entitled to vote if we fail to pay dividends on that series of Preferred Shares. The First Preferred Shares are entitled to priority over the Second Preferred Shares and the Common Shares with respect to the payment of dividends and the distribution of our assets in the event of any liquidation, dissolution or winding up of our affairs. Our Board is restricted from issuing First Preferred Shares or Second Preferred Shares if by doing so the aggregate amount payable to holders of each such class of shares as a return of capital in the event of liquidation, dissolution or winding up or any other distribution of our assets among our shareholders for the purpose of winding up our affairs would exceed C$500 million.

Employee Stock Option Plan

Our employee stock option plan ("ESOP") was approved by shareholders in connection with the Arrangement. The purpose of the ESOP is to provide eligible employees with an incentive to achieve the longer-term objectives of Cenovus; to give suitable recognition to the ability and industry of such persons who contribute materially to the success of Cenovus; and to attract and retain in the employ of Cenovus or any of our subsidiaries, persons of experience and ability by providing them with the opportunity to acquire an increased proprietary interest in Cenovus. Non-employee directors of Cenovus are not entitled to receive Cenovus Options under the ESOP.

The ESOP is administered by the HRC Committee. The HRC Committee has the authority to interpret the ESOP and any option granted thereunder and the discretion to attach TSARs to

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the options. The following is a summary of the principal terms of the ESOP. Further information relating to the Cenovus Replacement Options is also set out under the heading “Statement of Executive Compensation – Compensation Discussion and Analysis – The Elements of our Compensation Program – Long-Term Incentive Program – Replacement Stock Options”.

Common Shares Reserved

A maximum of 64 million Common Shares have been reserved for issuance under the ESOP, representing approximately 8.52 percent of the total number of outstanding Common Shares as at December 31, 2009. There were 39,603,522 Cenovus Options outstanding under the ESOP and 24,361,222 Cenovus Options available for grant, representing approximately 5.27 percent and 3.24 percent, respectively, of the total number of outstanding Common Shares as at December 31, 2009. Any Common Share subject to a Cenovus Option that expires or terminates without having been fully exercised may be made the subject of a further option.

Grant of Options, Exercise Price, Vesting and Expiry

Cenovus Options may be granted from time to time to eligible employees of Cenovus and our subsidiaries. Subject to regulatory requirements, the terms, conditions and limitations of Cenovus Options granted under the ESOP will be determined by the HRC Committee and set out in an option agreement to be entered into effective as at the time of the grant.

The number of Common Shares reserved for issuance at any time pursuant to Cenovus Options granted to insiders (as such term is defined in the TSX Company Manual) under the ESOP, and all other security-based compensation arrangements of Cenovus, shall not exceed ten percent of the number of Common Shares then outstanding, calculated on a non-diluted basis, and the aggregate number of Common Shares issued to insiders pursuant to Cenovus Options, and all other security-based compensation arrangements of Cenovus, within any one year period, shall not exceed ten percent of the number of the Common Shares outstanding, calculated on a non-diluted basis.

Except in respect of the Cenovus Replacement Options, the exercise price of a Cenovus Option will not be less than the market price of the Common Shares at the grant date, calculated as the closing price of the Common Shares on the TSX on the last trading day preceding the date on which the option agreement granting the option is made, or, if the Common Shares shall not have traded that day, on the next preceding day on which Common Shares were traded. See “Statement of Executive Compensation – Compensation Discussion and Analysis – The Elements of our Compensation Program – Long-Term Incentive Program – Replacement Stock Options”.

The HRC Committee has the right to determine at the time of grant that a particular option will be exercisable in whole or in part on different dates or for reasons other than the passage of time. Each Cenovus Option (unless sooner terminated in accordance with the terms, conditions and limitations of the option) shall be exercisable during such period, not exceeding seven years from the date the option was granted as the HRC Committee may determine. Prior to Board approval on February 9, 2010 of an amendment to the ESOP, options could be granted for a period not exceeding five years from the date of grant. Shareholder approval will not be sought for this amendment because it was approved in accordance with the specific amendment provision in the ESOP and does not require shareholder approval. Cenovus Replacement Options have a term of five years. Cenovus Options generally vest 30 percent on the first anniversary, 30 percent on the second anniversary and an additional 40 percent on the third anniversary of the grant, and, in certain cases, subject to the satisfaction of certain performance conditions.

Performance Vesting Criteria

A portion of the Cenovus Options that will be granted may be performance-based and may vest not only upon the passage of time, but also upon the achievement of a prescribed

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performance measure, which Cenovus has currently determined to be a recycle ratio. For more detailed information concerning the performance vesting criteria, see “Statement of Executive Compensation – Compensation Discussion and Analysis – The Elements of our Compensation Program – Long-Term Incentive Program”.

Two-thirds of the Cenovus Replacement Options granted in connection with the Arrangement are also subject to additional vesting requirements dependent upon a recycle ratio. See “Statement of Executive Compensation – Compensation Discussion and Analysis – The Elements of our Compensation Program – Long-Term Incentive Program – Replacement Stock Options”.

TSARs

All Cenovus Replacement Options have associated TSARs which entitle the optionholder to surrender the right to exercise his or her option to purchase a specified number of Common Shares and to receive cash or Common Shares (at Cenovus’s discretion) in an amount equal to the excess of the closing price of the Common Shares on the TSX on the last trading day preceding the date of exercise of the TSAR, over the exercise price for the Cenovus Option, multiplied by the number of optioned Common Shares surrendered. Where a TSAR is exercised, the right to the underlying Common Share is forfeited and such number of Common Shares are returned to the Common Shares reserved and available for new option grants. Cenovus Options that may be granted in the future will also have associated TSARs.

Non-Assignable and No Rights as a Shareholder

A Cenovus Option may be exercised only by the optionholder and will not be assignable, except on death. An optionholder only has rights as a shareholder of Cenovus with respect to Common Shares that the optionholder has acquired through exercise of a Cenovus Option or through the holding of Common Shares otherwise acquired. Nothing in the ESOP or in any option grant agreement confers or will confer on any

optionholder any right to remain as an employee of Cenovus or any of our subsidiaries.

Adjustments

Adjustments will be made to the exercise price of a Cenovus Option, the number of Common Shares delivered to an optionholder upon exercise of an option and the maximum number of Common Shares that may at any time be reserved for issuance pursuant to options granted under the ESOP in certain circumstances, such as a stock dividend, split, recapitalization, merger, consolidation, combination or exchange of Common Shares or other similar corporate change.

Blackout Period

If the exercise period of a Cenovus Option expires during, or within ten business days following, a period when option exercising is prohibited by Cenovus (the "Blackout Period"), then the exercise period of such option will be extended to the date which is ten business days after the last day of the Blackout Period (the "Blackout Extension Period"), after which time such option shall expire and terminate.

Amendments

The Board may, at any time and from time to time, amend, suspend, discontinue or terminate the ESOP in whole or in part; provided, however, no such amendment, suspension, discontinuance or termination may, without the consent of any optionholder, adversely alter or impair the rights under any Cenovus Option previously granted. Any amendment to be made to the ESOP or a Cenovus Option under the ESOP is subject to the prior approval of the TSX. The Board has the power and authority to approve amendments relating to the ESOP or a specific option without further approval of the shareholders of Cenovus, examples of which include, but are not limited to:

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(i) extending or, in the event of a change in control, retirement, death or disability, accelerating the terms of vesting applicable to any Cenovus Option or group of Cenovus Options;

(ii) altering the terms and conditions of vesting applicable to any Cenovus Option or group of Cenovus Options;

(iii) changing the termination provisions of the ESOP or any Cenovus Option, provided that the change does not provide for an extension beyond the original expiry date of such option;

(iv) accelerating the expiry date in respect of a Cenovus Option;

(v) determining the adjustment provisions pursuant to the ESOP. See "Adjustments" above;

(vi) amending the definitions contained within the ESOP and other amendments of a "housekeeping" nature; and

(vii) amending or modifying the mechanics of exercise of a Cenovus Option or TSAR.

Approval by shareholders of Cenovus will be required for amendments that relate to:

(i) accelerating the terms of vesting applicable to any Cenovus Option or group of Cenovus Options other than in the event of a change in control, retirement, death or disability;

(ii) any increase in the number of shares reserved for issuance under the ESOP;

(iii) any reduction in the grant price or cancellation and reissue of Cenovus Options;

(iv) any extension of the term of a Cenovus Option beyond the original expiry date, except as permitted under the Blackout Extension Period;

(v) any increase to the length of the Blackout Extension Period;

(vi) the inclusion of non-employee directors, on a discretionary basis, as eligible participants;

(vii) any allowance for the transferability or assignability of Cenovus Options other than for estate settlement purposes;

(viii) amendments to the specific amendment provision of the ESOP; and

(ix) amendments required to be approved by shareholders of Cenovus under applicable law (including, without limitation, the rules, regulations and policies of the TSX).

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SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

Our ESOP is the only compensation plan under which our equity securities have been authorized for issuance. As of December 31, 2009, there were an aggregate of 39,603,522 options outstanding under the ESOP, the details of which are as follows:

Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by securityholders — ESOP	39,603,522	$27.19	24,361,222
Equity compensation plans not approved by securityholders	-	-	-
Total	39,603,522	$27.19	24,361,222

DIVIDENDS

The declaration of dividends is at the sole discretion of our Board and is considered quarterly.

In the fourth quarter of 2009, we paid a dividend of $0.20 per Common Share. Our Board has established a quarterly dividend of C$0.20 per Common Share. A first quarter dividend of C$0.20 was declared payable on March 31, 2010 to holders of Common Shares of record on March 15, 2010.

MARKET FOR SECURITIES

All of the outstanding Common Shares are listed and posted for trading on the TSX and the NYSE under the symbol CVE. The following table outlines the share price trading range and volume of shares traded by month in 2009.

	TSX				NYSE			
	Share Price Trading Range				Share Price Trading Range			
	High	Low	Close	Share Volume	High	Low	Close	Share Volume
	(C$ per share)			(millions)	($ per share)			(millions)
2009								
December[1]	27.18	24.68	26.50	59.0	25.70	23.37	25.20	24.5

Note:
(1) The Common Shares began trading on the TSX on December 3, 2009 and on the NYSE on December 9, 2009.

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CREDIT RATINGS

The following table outlines the ratings and outlooks of Cenovus's debt as of December 31, 2009:

	Standard & Poor's Ratings Services ("S&P")	Moody's Investors Service ("Moody's")	DBRS Limited ("DBRS")
Senior unsecured Long-Term Rating	BBB+/Stable	Baa2/Stable	A (low)/Stable
Commercial Paper Short-Term Rating	A-1(Low)/Stable	P-2/Stable	R-1 (low)/Stable

Credit ratings are intended to provide an independent measure of the credit quality of an issue of securities. The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the securities nor do the ratings comment on market price or suitability for a particular investor. A rating may not remain in effect for any given period of time and may be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

S&P's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB+ by S&P is within the fourth highest of ten categories and indicates that the obligation exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within the major rating categories. S&P's Canadian commercial paper ratings scale ranges from A-1(High) to D, which represents the range from highest to lowest quality. A rating of A-1(Low) is the third highest of eight categories and indicates that the obligor has satisfactory capacity to meet its financial commitments. A ratings outlook gives the potential direction of a short- or long-term rating and the "stable" designation indicates that a rating is not likely to change.

Moody's long-term credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa2 by Moody's is within the fourth highest of nine categories and is assigned to debt securities which are

considered medium-grade (i.e., they are subject to moderate credit risk). Such debt securities may possess certain speculative characteristics. The addition of a 1, 2 or 3 modifier after a rating indicates the relative standing within a particular rating category. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of that generic rating category. Moody's short-term credit ratings are on a scale that ranges from P-1 (highest quality) to NP (lowest quality). A rating of P-2 is the second highest of four categories and indicates that the issuer has a strong ability to repay short-term debt obligations.

DBRS' long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of A(low) by DBRS is within the third highest of ten categories and is assigned to debt securities considered to be of satisfactory credit quality. Protection of interest and principal is substantial, but the degree of strength is less than that of higher rated securities. Entities in the A category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher-rated securities. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. DBRS' short-term credit ratings are on a scale ranging from R-1 (high) to D, which represents the range from highest to lowest quality. A rating of R-1(low) is the third highest of ten categories and indicates that the short-term debt is of satisfactory credit

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quality. The overall strength and outlook for key liquidity, debt, and profitability ratios is not normally as favorable as with higher rating categories, but these considerations are still respectable. Any qualifying negative factors that exist are considered manageable, and the entity is normally of sufficient size to have some influence in the industry.

PRIOR SALES

Debt Securities

On September 18, 2009, a predecessor entity of Cenovus completed, in three tranches, a $3.5 billion private offering of debt securities (comprised of the 2014 Notes, 2019 Notes and 2039 Notes) which are exempt from the registration requirements of the U.S. Securities Act under Rule 144A and Regulation S. The net proceeds of the Cenovus Note Offering were placed into an escrow account pending the completion of the Arrangement. Upon completion of the Arrangement, the net proceeds, together with other pre-funded amounts, were released from escrow and were applied to repay all of the amounts outstanding under the Demand Note.

The Notes are our direct, unsecured and unsubordinated obligations and rank equally and rateably with all of our other existing and future unsecured and unsubordinated indebtedness. The Notes are structurally subordinate to all existing and future indebtedness and liabilities of any of our corporate and partnership subsidiaries.

We have agreed to use our commercially reasonable efforts to cause a registration statement with respect to an offer to exchange the Cenovus Notes for a new issue of notes registered under the U.S. Securities Act to be declared effective no later than September 18, 2010.

RISK FACTORS

If any event arises from the risk factors set forth below, our business, prospects, financial condition, results of operation or cash flows and, in some cases, our reputation could be materially adversely affected.

Risks relating to the Arrangement

As a result of the Arrangement, any financing that we may require will be obtained on a stand alone basis.

As a result of the Arrangement, we are independent of EnCana and any financing that we may require in the future will be obtained by us on a stand alone basis. In addition, our credit ratings are determined independently of, and without reference to, the historical or current ratings of EnCana. Differences in credit ratings affect the interest rate charged on financings, as well as the amounts of indebtedness, types of financing structures and debt markets that may be available to us.

As a result, we may not be able to secure adequate debt or equity financing or otherwise raise the capital we require on the same terms as EnCana (as it existed historically or exists currently), desirable terms or at all.

We may be unable to make the changes necessary to operate as an independent entity and may incur greater costs.

As a result of the Arrangement, we separated from the other businesses of EnCana and such separation may materially adversely affect us. We may not be able to implement successfully the changes necessary to operate independently. We may incur additional costs relating to operating independently that could materially affect our cash flow and results of operations. We require EnCana to provide us with certain services (including, but not limited to, information technology services) on a transitional basis. We may, as a result, be dependent on such services until we are able to provide our own.

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The historical financial information of our assets may not be representative of our results as an independent entity, and, therefore, may not be reliable as an indicator of our historical or future results.

Our assets were integrated within the business units of EnCana for 11 of the 12 months of 2009; consequently, our financial information has been derived, in substantial part, from the consolidated financial statements and accounting records of EnCana and reflect certain assumptions and allocations. Our financial position, results of operations and cash flows could differ from those that would have resulted had we operated autonomously or as an entity independent of EnCana for all of fiscal 2009.

Our separate operating history as a stand alone entity.

We became an independent public company on November 30, 2009. The operating history of EnCana in respect of our assets cannot be regarded as our operating history. Our ability to raise capital, satisfy our obligations and provide a return to our shareholders will be dependent upon our future performance. We will not be able to rely on the capital resources and cash flows of EnCana. Our future operating results and performance may be materially different than those we would have achieved had we been operating as part of EnCana.

Risks relating to our Business

A substantial or extended decline in crude oil, natural gas and refined products prices could have a material adverse effect on us.

Our financial performance and condition are substantially dependent on the prevailing prices of crude oil, natural gas and refined products. Fluctuations in crude oil, natural gas and refined products prices could have an adverse effect on our operations and financial condition, the value and amount of our proved reserves and the value of our refining assets. Prices for crude oil, natural gas and refined products fluctuate in response to changes in the supply of and demand for crude oil, natural gas and refined products, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are determined by international supply and demand. Factors which affect crude oil prices include the actions of the Organization of Petroleum Exporting Countries, world economic conditions, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by us are affected primarily by North American supply and demand, weather conditions and by prices of alternate sources of energy (including refined product and imported liquefied natural gas). Our refined products margins are impacted by, among other things: market competitiveness, the cost of inputs and fluctuations in the supply and demand for refined products. Any substantial or extended decline in the prices of crude oil, natural gas or refined products could result in a delay or cancellation of existing or future drilling, development or construction programs or curtailment in production at some properties or could result in unutilized long-term transportation commitments and low utilization levels at the refineries, all of which could have an adverse effect on our revenues, profitability and cash flows.

The market prices for heavy oil are lower than the established market indices for light and medium grades of oil, due principally to the higher transportation and refining costs associated with heavy oil. As well, bitumen prices are lower still than heavy oil prices due to the cost of diluent blending. Also, the market for heavy oil is more limited than for light and medium grades, making it more susceptible to supply and demand changes. Future price differentials are uncertain and any increase in the heavy oil differentials could have an adverse effect on our business.

We will conduct an annual assessment of the carrying value of our assets in accordance with Canadian GAAP. If crude oil and natural gas prices decline, the carrying value of our assets could be subject to financial downward revisions and our earnings could be adversely affected.

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Our ability to operate and complete projects is dependent on certain factors outside of our control.

Our ability to operate, generate sufficient cash flows and complete projects will depend upon numerous factors beyond our control. In addition to commodity prices and continued market demand for our products, these non-controllable factors include, but are not limited to: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for our commitments; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour; and reservoir quality.

Current market conditions are challenging with the global recession negatively impacting commodity prices as well as access to credit and capital markets. These conditions impact our customers and suppliers and may alter our spending and operating plans. There may be unexpected business impacts from this market uncertainty.

Our downstream operations will be sensitive to refined products margins. Margin volatility is impacted by numerous conditions including: fluctuations in the supply and demand for refined products; market competitiveness; the costs of crude oil; labour; maintenance; electricity; chemicals and other inputs; unplanned production disruptions due to equipment failure; power disruptions and other factors including weather. It is expected that all of these and other factors will continue to impact downstream margins for the foreseeable future. As a result, it can be reasonably expected that downstream results will fluctuate over time and from period to period.

We will undertake a variety of projects including exploration and development projects and the construction or expansion of facilities, refineries and pipelines. Project delays may delay expected revenues and project cost overruns could make projects uneconomic.

All of our operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion and tie-in of wells, production, the construction or expansion of facilities and refineries and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact our existing and planned projects.

Certain of our operations require us to obtain certain approvals from various regulatory authorities and there can be no assurance that we will be able to obtain all necessary licenses, permits and other approvals that may be required to carry out certain exploration and development activities on our properties. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder consultation, environmental impact assessments and public hearings. Regulatory approvals that are obtained may also be subject to the satisfaction of certain conditions, including, but not limited to, security deposit obligations, regulatory oversight of projects by third parties, habitat assessments and other commitments or obligations. Failure to obtain applicable regulatory approvals or satisfy any of the conditions thereto on a timely basis on satisfactory terms could result in delays, abandonment or restructuring of projects and increased costs, all of which could have a material adverse effect on our business, financial conditions, results of operations and cash flow.

Our crude oil and natural gas reserves data and future net revenue estimates are uncertain.

There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves, including many factors beyond our control. The reserves data in this annual information form represent estimates only. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as product prices, future

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operating and capital costs, historical production from the properties and the assumed effects of regulation by governmental agencies, including with respect to royalty payments, all of which may vary considerably from actual results. All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable bitumen, crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves may vary from such estimates and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Our hedging activities could result in realized and unrealized losses.

The nature of our operations results in exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. We will monitor our exposure to such fluctuations and, where we deem it appropriate, utilize derivative financial instruments and physical delivery contracts to help mitigate the potential impact of declines in crude oil, natural gas and refined product prices, changes in interest rates and foreign exchange rates. Under Canadian GAAP, derivative instruments that do not qualify as hedges, or are not designated as hedges, are marked-to-market with changes in fair value recognized in current period net earnings. The utilization of derivative financial instruments may therefore introduce significant volatility into our reported net earnings.

The terms of our various hedging agreements, if any, may limit the benefit to us of commodity price increases or changes in interest rates and foreign exchange rates. We may also suffer financial loss because of hedging arrangements if:

- we are unable to produce oil, natural gas or refined products to fulfill delivery obligations; or
- counterparties to our hedging agreements are unable to fulfill their obligations under the hedging agreements.

Our ability to secure and maintain cost effective financing for our capital and other commitments.

The nature of our operations will require significant capital commitments; consequently, failure to achieve timely and cost effective financing could have a negative impact on our future plans. Unpredictable financial markets and associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital markets.

Our business is subject to environmental legislation in all jurisdictions in which we operate and any changes in such legislation could negatively affect our results of operations.

All phases of the crude oil, natural gas and refining businesses are subject to environmental regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, territorial, state and municipal laws and regulations (collectively, “environmental legislation”).

Environmental legislation requires that wells, facility sites, refineries and other properties associated with our operations be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types

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of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. Compliance with environmental legislation can require significant expenditures, including expenditures for clean up costs and damages arising out of contaminated properties and failure to comply with environmental legislation may result in the imposition of fines and penalties. Although it is not expected that the costs of complying with environmental legislation will have a material adverse effect on our financial condition or results of operations, no assurance can be made that the costs of complying with environmental legislation in the future will not have such an effect.

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas emissions and other air pollutants and a number of legislative and regulatory measures to address greenhouse gas emissions are in various phases of review, discussion or implementation in the United States and Canada. These include proposed federal legislation and state actions in the United States to develop statewide or regional programs, each of which could impose reductions in greenhouse gas emissions.

Adverse impacts to our business if comprehensive greenhouse gas legislation 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 adding costs to the products we produce, and reduced demand for crude oil and certain refined products. In particular, some of the climate change legislation being contemplated in the U.S. would require refiners to obtain emission allowances for emissions of greenhouse gases, including CO_2 based on the carbon content of their fuels. If this approach was enacted into law, this could have a material impact on the cost structure of refined petroleum 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.

If we fail to acquire or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels.

Our future crude oil and natural gas reserves and production, and therefore our cash flows, are highly dependent upon our success in exploiting our current resource base and acquiring, discovering or developing additional reserves. Without reserves additions through exploration, acquisition or development activities, our reserves and production will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash from operating activities is insufficient and external sources of capital become limited, our ability to make the necessary capital investments to maintain and expand our crude oil and natural gas reserves will be impaired. In addition, there can be no certainty that we will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

Our operations are subject to the risk of business interruption and casualty losses.

Our business is subject to all of the operating risks normally associated with the exploration for, development of and production of crude oil and natural gas and the operation of refining facilities. These risks include, but are not limited to, blowouts, explosions, fire, gaseous leaks, migration of harmful substances and crude oil and refined products spills, acts of

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vandalism and terrorism, any of which could cause personal injury, result in damage to, or destruction of, crude oil and natural gas wells or formations or production facilities or refineries and other property, equipment and the environment, as well as interrupt operations. In addition, all of our operations are subject to all of the risks normally incident to the transportation, processing, storing, refining and marketing of crude oil, natural gas and other related products, drilling and completion of crude oil and natural gas wells, and the operation and development of crude oil and natural gas properties, including, among others, encountering unexpected formations or pressures, premature declines of reservoir pressure or productivity, blowouts, equipment failures and other accidents, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks.

The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our financial position.

We do not operate all of our properties and assets.

Other companies operate a portion of the assets in which we have interests. We will have limited ability to exercise influence over operations of these assets or their associated costs. Our dependence on the operator and other working interest owners for these properties and assets and our limited ability to influence operations and associated costs could materially adversely affect our financial performance. The success and timing of our activities on assets operated by others therefore will depend upon a number of factors that are outside of our control, including: timing and amount of capital expenditures; timing and amount of operating and maintenance expenditures; the operator's expertise and financial resources; approval of other participants; selection of technology; and risk management practices.

All of our downstream operations are operated by ConocoPhillips. The success of our downstream operations is dependant on the ability of ConocoPhillips to successfully operate this business and maintain the operations of the refineries.

We are exposed to risks associated with the use of current technology, and the pursuit of new technology, which could negatively affect our results of operations.

Current SAGD technologies for enhanced recovery of heavy oil are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process can also vary and affect costs. The performance of the reservoir can also affect the timing and levels of production using this technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on our results of operations.

There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

There are a number of risks particular to oil recovery operations that could have a material adverse impact on us.

Producing oil through enhanced recovery methods and upgrading and refining heavy oil requires high levels of investment and involves particular risks and uncertainties. Our oil operations are susceptible to loss of production, slowdowns, shutdowns, or restrictions on our ability to produce higher value products due to the interdependence of our component systems. While there are virtually no finding costs associated with bitumen resources, delineation of the resources, the costs associated with production, including drilling wells for SAGD operations, and the costs associated with upgrading heavy oil can entail significant capital outlays. The costs associated with oil production are largely fixed in the short-term and, as a result, operating costs per unit are largely dependent on levels of production.

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Fluctuations in exchange rates could affect expenses or result in realized and unrealized losses.

Worldwide prices for crude oil, natural gas and refined products are set in U.S. dollars. However, many of our expenses outside of the U.S. will be denominated in Canadian dollars. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar could impact our expenses and have an adverse effect on our financial performance and condition.

We may become subject to claims by third parties.

From time to time, we may be the subject of litigation arising out of our operations. Claims under such litigation may be material or may be indeterminate and the outcome of such litigation may materially impact our financial condition or results of operations. We may be required to incur significant expenses or devote significant resources to defend ourself against any such litigation.

We may be adversely affected by certain terms of the Separation Agreement.

Pursuant to the Separation Agreement, EnCana and Cenovus have each agreed to cooperate fully with each other and our respective counsels in the investigation, prosecution, defense and resolution of the Joint Litigation (as defined herein), which includes, without limitation, certain judicial actions to which EnCana is a party relating to the entitlement to CBM. The possible impacts and effects of such agreement are uncertain. Our obligation to cooperate fully with EnCana and its counsel in respect of the Joint Litigation and the limitation this may place on the position that Cenovus may otherwise wish to take with respect to these matters may have an adverse affect on Cenovus. The outcome of any of the Joint Litigation matters cannot be predicted and may materially impact our financial condition or results of operations. In addition, the existence of such agreement and our obligations thereunder may have an affect on the manner in which we determine to conduct our business or operations until such time that all of the Joint Litigation is resolved.

We have certain post-Arrangement indemnification and other obligations under each of the Arrangement Agreement and Separation Agreement

EnCana and Cenovus have agreed to indemnify each other for certain liabilities and obligations associated with, among other things, in the case of EnCana's indemnity, the business and assets retained by EnCana, and in the case of our indemnity, the Cenovus Businesses and the Cenovus Assets. At the present time, we cannot determine whether we will have to indemnify EnCana for any substantial obligations under the terms of the Arrangement. We also cannot assure that if EnCana has to indemnify Cenovus and our affiliates for any substantial obligations, EnCana will be able to satisfy such obligations.

In connection with the Arrangement, EnCana and Cenovus entered into the Arrangement Agreement which contains a number of representations, warranties and covenants, including agreement by each of the parties to indemnify and hold harmless each other against any loss suffered or incurred resulting from a breach of certain tax-related covenants. One of these covenants was that each party would not take any action, omit to take any action or enter into any transaction that could adversely impact the Canadian Tax Ruling or the U.S. Tax Ruling. With respect to Canadian income taxation, there are a variety of transactions that the parties were or are prohibited from undertaking prior to and after the implementation of the Arrangement. One of these is that no party is permitted to dispose of or exchange property having a fair market value greater than ten percent of the fair market value of its property, net of liabilities, or undergo an acquisition of control where such disposition or control acquisition is for Canadian tax purposes part of the "series of transactions or events" that includes the Arrangement, except in limited circumstances.

Under the Separation Agreement, (i) we have agreed to indemnify EnCana and its affiliates from and against any liabilities associated with, among other things, the Cenovus Assets

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and Cenovus Businesses, whether relating to the period, or arising, prior to or after the Reorganization Time, and (ii) EnCana has agreed to indemnify us and our affiliates from and against any liabilities associated with, among other things, the assets owned by EnCana or any affiliate of EnCana and the businesses carried on by EnCana or any affiliate of EnCana after the Reorganization Time, whether relating to the period, or arising, prior to or after the Reorganization Time.

Any indemnification claim against us pursuant to the provisions of the Arrangement Agreement or Separation Agreement could have a material adverse effect.

Our success is dependent on successful recruitment, retention and succession.

Our success is dependent upon our management and the quality of our personnel. Failure to retain current employees or to attract and retain new employees with the necessary skills could have a material adverse effect on our growth and profitability. Although the demand for personnel has recently reduced, competition for key oil and gas professionals remains high.

Our ability to operate is dependent upon a variety of information systems.

We depend on a variety of information systems to operate effectively. A failure of any one of the information systems or a failure among the systems could result in operational difficulties, damage or loss of data, productivity losses or result in unauthorized knowledge and use of information.

Other Risk Factors

A discussion of additional risks which may impact our business, prospects, financial condition, results of operation and cash flows, and in some cases our reputation, can be found in our Management's Discussion and Analysis for the year ended December 31, 2009 which is accessible on our SEDAR profile at ***www.sedar.com*** and on EDGAR at ***www.sec.gov***.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings to which we are or were a party, or that any of our property is or was the subject of, which is or was, or can be reasonably considered to be, material to us or any of our properties and we are not aware of any such legal proceedings that are contemplated.

Since incorporation, there have not been any penalties or sanctions imposed against us by a court relating to provincial and territorial securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against us, and we have not entered into any settlement agreements before a court relating to provincial and territorial securities legislation or with a securities regulatory authority.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of our directors or executive officers or any person or company that beneficially owns, or controls or directs, directly or indirectly, more than ten percent of any class or series of our outstanding voting securities, of which there are none that we are aware, or any associate or affiliate of any of the foregoing persons, in each case, as at the date of this annual information form, has or has had any material interest, direct or indirect, in any past transaction or any proposed transaction that has materially affected or is reasonably expected to materially affect us.

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INTERESTS OF EXPERTS

Our independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditors' report dated February 17, 2010 in respect of our consolidated financial statements as at December 31, 2009 and December 31, 2008 and for each of the years in the three year period ended December 31, 2009 and Cenovus's internal control over financial reporting as at December 31, 2009. PricewaterhouseCoopers LLP has advised that they are independent with respect to Cenovus within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the SEC. Prior to November 30, 2009, PricewaterhouseCoopers LLP was the auditor of EnCana and, on November 30, 2009, was appointed auditor of Cenovus.

Information relating to reserves in this annual information form has been calculated by GLJ Petroleum Consultants Ltd. and McDaniel & Associates Consultants Ltd. as independent qualified reserves evaluators. The principals of each of GLJ Petroleum Consultants Ltd. and McDaniel & Associates Consultants Ltd., in each case, as a group own beneficially, directly or indirectly, less than one percent of any class of our securities.

TRANSFER AGENTS AND REGISTRARS

In Canada: In the United States:

CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
Canada

BNY Mellon Shareowner Services
480 Washington Blvd.
Jersey City, New Jersey 07310
U.S.A.

Tel: 1-866-332-8898
Website:
www.cibcmellon.com/investorinquiry

MATERIAL CONTRACTS

The only contracts that can reasonably be regarded as material to us, other than contracts entered into in the ordinary course of business, are as follows:

(a) Arrangement Agreement. The Arrangement Agreement provided for the implementation of the Plan of Arrangement pursuant to Section 192 of the CBCA and, among other things, certain representations, warranties and covenants of the parties and certain indemnities among Cenovus and EnCana.

(b) Separation Agreement. In connection with the Arrangement, we entered into the Separation Agreement and several ancillary agreements to complete the transfer of the Cenovus Businesses to us. The Separation Agreement sets forth the agreement of the parties with respect to the indirect transfer of assets from EnCana to us and the indirect assumption of the Assumed Liabilities by us and certain transitional arrangements governing the relationship between EnCana and us following the Reorganization Time.

The Separation Agreement allocates between EnCana and Cenovus responsibility and liability for outstanding legal actions based on whether such legal actions relate primarily to the Cenovus Businesses or the Cenovus Assets (on the one hand) or the retained businesses and assets of EnCana (on the other hand). With respect to outstanding legal actions that affect both EnCana and us or unknown or future legal actions brought after the Reorganization Time, the Separation Agreement provides that each party will be liable for its proportionate share of all costs and liabilities arising out of or relating to such legal actions based on the extent to which such

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legal actions relate to the Cenovus Businesses or the Cenovus Assets (in our case) or the retained businesses and assets (in the case of EnCana).

Pursuant to the Separation Agreement, Cenovus and EnCana have agreed, in respect of certain litigation matters, including, without limitation, certain judicial actions relating to CBM involving EnCana (collectively, the “Joint Litigation”), to cooperate fully with the other and its counsel in the investigation, prosecution, defense and resolution of such Joint Litigation. Subject to certain exceptions contained within the Separation Agreement, EnCana has exclusive authority and control over the investigation, prosecution, defense and appeal of all Joint Litigation. See “Risk Factors” in this annual information form.

Under the terms of the Separation Agreement, we have generally agreed to indemnify EnCana and its affiliates from and against any liabilities associated with, among other things, the Cenovus Businesses or the Cenovus Assets, whether relating to the period, or arising, prior to or after the Reorganization Time. The Separation Agreement contains a reciprocal indemnity under which EnCana generally agrees to indemnify us and our affiliates from and against any liabilities relating to, among other things, the businesses and assets retained by EnCana. Cenovus and EnCana will indemnify each other with respect to non-performance of our respective obligations under the Separation Agreement including the obligation not to do anything after the Arrangement which could interfere with any transactions outlined in the Canadian Tax Ruling and the U.S. Tax Ruling. See “Risk Factors”.

Other matters governed by the Separation Agreement include responsibility for taxes, access to books and records, confidentiality, insurance and dispute resolution.

(c) Note Indenture. On September 18, 2009, we issued the Notes, which were issued and are governed under the terms of the Note Indenture.

Pursuant to the Note Indenture, the Notes:

(i) are our direct unsecured and unsubordinated obligations ranking equally and ratably in right of payment with all of our other unsecured and unsubordinated indebtedness;

(ii) the 2014 Notes bear interest to be paid semi-annually in arrears on March 15 and September 15 of each year, commencing March 15, 2010; the 2019 Notes bear interest to be paid semi-annually in arrears on April 15 and October 15 of each year, commencing April 15, 2010; and the 2039 Notes bear interest to be paid semi-annually in arrears on May 15 and November 15 of each year, commencing May 15, 2010; and

(iii) bear interest on overdue principal, and overdue interest, at the rate otherwise applicable to the Notes.

Interest is computed on the basis of a 360-day year of twelve 30-day months. The interest period relating to an interest payment date

shall be the period from but not including the preceding interest payment date to and including the relevant interest payment date.

Payment of the principal, premium, if any, and interest on the Notes will be made in United States dollars.

We have agreed to use our commercially reasonable efforts to cause a registration statement with respect to an offer to exchange the Notes for a new issue of notes registered under the U.S. Securities Act to be declared effective no later than September 18, 2010.

Copies of these agreements may be inspected at our registered office located at #4000, 421 – 7 Avenue S.W., Calgary, Alberta, Canada T2P 4K9 during normal business hours and are available on our SEDAR profile at ***www.sedar.com*** and on EDGAR at ***www.sec.gov***.

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PROMOTER

Under applicable Canadian securities laws, EnCana was considered a promoter of Cenovus in that it took the initiative in our founding for the purpose of implementing the Arrangement. We acquired our assets from EnCana pursuant to the Arrangement, as described in this annual information form. As consideration for the acquisition of our assets pursuant to the Arrangement, we issued the Demand Note payable to EnCana in the aggregate amount of $3.5 billion. The value of the Demand Note was determined through the equitable allocation of the pre-Arrangement value of EnCana's debt as determined by, among other things, an assessment of assets and liabilities to be transferred to Cenovus pursuant to the Arrangement, an allocation of then current income tax payable, an allocation of transaction costs related to the Arrangement and appropriate capital structures. The Demand Note was repaid in full on the Effective Date.

Subsequent to the completion of the Arrangement, Cenovus made a payment to EnCana in the amount of $250 million to adjust the cash balances of both companies as at the Effective Date to the agreed upon amounts pursuant to the Separation Agreement.

As of the date hereof, EnCana does not beneficially own or control or direct, directly or indirectly, any Common Shares.

We are independent of EnCana to the greatest extent practicable. Certain ongoing contractual arrangements between EnCana and Cenovus are generally limited to our mutual obligations under, among others, the Arrangement Agreement, the Separation Agreement and the ancillary agreements contemplated in the Separation Agreement (including the Employee Matters Agreement), including indemnification in certain circumstances, and confidentiality and access to records necessary to comply with, among other things, continuous disclosure requirements. In addition, we may require EnCana to provide us with certain services (including, but not limited to, information technology services) on a transitional basis.

Pursuant to the Employee Matters Agreement, we are required to make certain reimbursement payments to EnCana in respect of any cash payments made by EnCana on the surrender of EnCana Replacement Options by our employees.

ADDITIONAL INFORMATION

Additional information relating to us is available via SEDAR at ***www.sedar.com*** and also via EDGAR at ***www.sec.gov***.

Additional financial information is contained in our audited consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2009.

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NOTE REGARDING FORWARD-LOOKING STATEMENTS

This annual information form contains certain forward-looking statements or information (collectively referred to in this note as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "projected", "anticipate", "believe", "expect", "plan", "intend" or similar words suggesting future outcomes or statements regarding an outlook. All statements other than statements of historical fact contained in this annual information form are forward-looking statements, including, but not limited to, statements relating to the anticipated benefits of the Arrangement, operational information, future exploration and development plans, future acquisition or disposition opportunities, potential dividends, estimates of proved and probable reserves, production growth rates over the long-term, cash flow, financial metrics (including debt to capitalization and debt to adjusted EBITDA), future net capital investment, anticipated future production, estimates of reserves decline rates and capital efficiency, production capacity and annual production growth rate, our corporate structure, division of our assets, successful use of new technology and innovations to increase recovery and decrease costs, the ability to receive patents for our technology and the expected timing thereof, possible internal and external growth opportunities for our assets and the possible form of financing for the same, capital requirements, estimated cost of carbon and abandonment and site reclamation costs, our development plans, the timing of completion and anticipated capacities of the Foster Creek and Christina Lake expansions, the anticipated capacities of and the timing of capacity expansions for the Wood River refinery, including the timing of completion of the CORE project and the capital expenditures for such expansions, the ability of ConocoPhillips and Cenovus to successfully manage and operate the integrated oil business and the ability of the parties to obtain regulatory approvals, expectations that we will continue to carry out certain market optimization and risk mitigation activities in the marketing of crude oil and natural gas, expectations of future cash flows, our ability to meet delivery commitments of

crude oil, natural gas and refined products, our ability to meet social and environmental legislation and policies, the expectation that the location of our assets in North America limits our exposure to risks and uncertainties, the amounts, types, terms and conditions of financing that may be made available to us, our estimated capitalization and adequacy thereof and the financing plans and initiatives that may be undertaken by us.

Readers are cautioned not to place undue reliance on forward-looking statements contained in this annual information form, which reflect the analysis of our management only as of the date of this annual information form. All such forward-looking statements are subject to important risks, uncertainties and assumptions. These statements are forward-looking because they are based on our current expectations, estimates and assumptions. Some of the assumptions, risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this annual information form include, but are not limited to: volatility of and assumptions regarding oil and gas prices, assumptions based upon our current guidance, fluctuations in currency and interest rates, product supply and demand, market competition, risks inherent in our and our subsidiaries' marketing operations, including credit risks, imprecision of reserves estimates and estimates of recoverable quantities of oil, bitumen, natural gas and NGLs from properties and other sources not currently classified as proved or probable and life index of proved reserves, our and our subsidiaries' ability to replace and expand oil and gas reserves, the ability of ConocoPhillips and Cenovus to successfully manage and operate the North American integrated heavy oil business and the ability of the parties to obtain regulatory approvals, refining and marketing margins, potential disruption or unexpected technical difficulties in developing new products and manufacturing processes, 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 synthetic crude oil, risks

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associated with technology and the application thereof to our business, our ability to generate sufficient cash flow from operations to meet our current and future obligations, our ability to access external sources of debt and equity capital, the timing and the costs of well and pipeline construction, our and our subsidiaries' ability to secure adequate product transportation, changes in royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations or the interpretations of such laws or regulations, political and economic conditions in the countries in which we and our subsidiaries operate, the risk of war, terrorist threats, hostilities, civil insurrection and instability affecting countries in which we and our subsidiaries operate, risks associated with existing and potential future lawsuits and regulatory actions made against us and our subsidiaries, the financing plans and initiatives that may be undertaken by us, the capitalization and adequacy thereof for us, the expected impacts of the Arrangement on our employees, operations, suppliers, business partners and stakeholders, our ability to obtain financing in the future on a stand alone basis, that the historical financial information pertaining to our assets as operated by EnCana prior to December 1, 2009 may not be representative of our results as an independent entity, that we have a limited operating history, as a separate entity, and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by us.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the foregoing list of important factors is not exhaustive. All such forward-looking statements are made pursuant to the "safe harbor" provisions of the United States *Private Securities Litigation Reform Act of 1995* and applicable Canadian securities legislation.

The forward-looking statements contained in this annual information form are made as of the date hereof and we do not undertake any obligation to release publicly the results of any revision to these forward-looking statements which may be made to reflect events or circumstances after the date of this annual information form or to reflect the occurrence of unanticipated events, except as required by applicable Canadian securities laws. The forward-looking statements contained in this annual information form are expressly qualified in their entirety by the foregoing.

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NOTE REGARDING RESERVES DATA AND OTHER OIL AND GAS INFORMATION

NI 51-101 imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. We have obtained an exemption from the Canadian securities regulatory authorities to permit us to provide disclosure in accordance with the relevant legal requirements of the SEC. This facilitates comparability of our oil and gas disclosure with that provided by U.S. and other international issuers, given that we are active in the U.S. capital markets. Accordingly, the proved and probable reserves data and much of the other oil and gas information included in this annual information form is disclosed in accordance with U.S. disclosure requirements. Such information, as well as the information that we anticipate disclosing in the future in reliance on such exemption, may differ from the corresponding information prepared in accordance with NI 51-101 standards.

In 2008, the SEC amended its oil and gas reporting requirements effective for Cenovus's 2009 year end reporting. The U.S. Financial Accounting Standards Board also amended its oil and gas reserve estimation and disclosure requirements to align with the amended SEC requirements. The amendments included changing the price used to calculate reserves from a year-end single day price to a historical 12-month average price, permitting optional disclosure of probable reserves and the sensitivity of reserves to price and requiring the separate disclosure of bitumen reserves from crude oil and NGLs reserves.

The primary differences between the current U.S. requirements and the NI 51-101 requirements are that: (i) the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves; and (ii) the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., historic 12-month average

price, whereas NI 51-101 requires disclosure of reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook, the reference source for the definition of proved reserves under NI 51-101, differences in the estimated proved reserves quantities based on constant prices should not be material.

According to the SEC, proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations. Prices include consideration of future price changes only to the extent provided by contractual arrangements in existence at year-end.

The current U.S. requirements permit, but do not require, the disclosure of probable reserves information. The SEC has defined probable reserves as those additional reserves that are less certain to be recovered than proved reserves, but which, together with proved reserves, are as likely as not to be recovered.

Under U.S. disclosure standards, reserves and production information is required to be disclosed on a net basis (after royalties). The Alberta Government has implemented an oilsands royalty scheme which ties the bitumen royalty rate to the West Texas Intermediate reference oil price, in Canadian dollars. Since oil price is unregulated and can have significant volatility, this in turn means the royalty rate can vary significantly. For example, our year-end 2008 proved bitumen reserves were subject to a forecasted average royalty rate of four percent, while year-end 2009 proved bitumen reserves face a forecasted average royalty rate of 16 percent. This oil price dependent volatility can mask the impact of our development activities. To provide more complete information on our business, we are voluntarily providing reserves and production information for both proved and probable reserves, on a before royalties basis, as well as on an after royalties basis.

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GLOSSARY

The following is a glossary of certain terms used in this annual information form:

"**2014 Notes**" means the $800,000,000 aggregate principal amount of 4.50% senior notes due September 15, 2014 issued by Subco on September 18, 2009;

"**2019 Notes**" means the $1,300,000,000 aggregate principal amount of 5.70% senior notes due October 15, 2019 issued by Subco on September 18, 2009;

"**2039 Notes**" means the $1,400,000,000 aggregate principal amount of 6.75% senior notes due November 15, 2039 issued by Subco on September 18, 2009;

"**7050372**" means 7050372 Canada Inc., a corporation incorporated under the CBCA, which amalgamated with Subco on the Effective Date with the resulting amalgamated corporation being named "Cenovus Energy Inc.";

"**Arrangement**" means an arrangement under Section 192 of the CBCA involving, among others, EnCana, 7050372 and Subco, which became effective on the Effective Date;

"**Arrangement Agreement**" means the Arrangement Agreement dated as of October 20, 2009 among EnCana, 7050372 and Subco;

"**Assumed Liabilities**" means the liabilities assumed by Subco pursuant to the Separation Agreement and described under "General Development of Our Business – The Arrangement";

"**Board**" means our board of directors;

"**Canadian GAAP**" means generally accepted accounting principles as in effect in Canada;

"**Canadian Tax Ruling**" means the advance income tax rulings and opinions received from the Canada Revenue Agency with respect to certain aspects of the Pre-Arrangement Reorganization, the Arrangement and certain other transactions, and includes any replacements thereof and amendments and supplements thereto received or anticipated to be received from the Canada Revenue Agency;

"**CBCA**" means the *Canada Business Corporations Act*, R.S.C. 1985, c.C-44, as amended, and the regulations thereunder;

"**Cenovus Assets**" means the assets transferred by EnCana to Subco pursuant to the Separation Agreement and described under "General Development of Our Business – The Arrangement";

"**Cenovus Businesses**" means, collectively, the Integrated Oil Division and the Canadian Plains Division of EnCana as they existed prior to the Effective Date;

"**Cenovus Options**" means the options to acquire Common Shares, including any associated tandem stock appreciation rights, granted by us pursuant to the Cenovus Employee Stock Option Plan and, unless otherwise specified, includes Cenovus Replacement Options;

"**Cenovus Replacement Options**" means the options to acquire Common Shares, including any associated tandem stock appreciation rights, granted by us to the holders of options of EnCana pursuant to the Arrangement;

"**Common Shares**" means the common shares in the capital of Cenovus Energy Inc.;

"**CORE**" means the coker and refinery expansion project at the Wood River Refinery in Illinois, United States;

"**Dissenting Shareholder**" means a shareholder of EnCana that validly exercised its dissent rights in connection with the special resolution to approve the Arrangement;

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"**EDGAR**" means the U.S. Electronic Data-Gathering Analysis and Retrieval system;

"**Effective Date**" means November 30, 2009, the date upon which the Arrangement became effective;

"**Employee Matters Agreement**" means the employee and benefits matters agreement dated November 23, 2009 among EnCana, 7050372 and Subco regarding certain transitional employee matters in respect of us and EnCana after completion of the Arrangement, as it may be amended, modified or supplemented from time to time in accordance with its terms;

"**EnCana**" means EnCana Corporation, a corporation existing under the CBCA;

"**EnCana Replacement Options**" means the options to acquire common shares of EnCana, including any associated tandem stock appreciation rights, granted by EnCana to the holders of options to acquire common shares of EnCana pursuant to the Arrangement;

"**FCCL**" means FCCL Partnership, a general partnership formed under the *Partnership Act*, R.S.A. 2000, c.P-3, as amended;

"**First Preferred Shares**" means the first preferred shares in the capital of Cenovus Energy Inc.;

"**NI 51-101**" means National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators;

"**Note Indenture**" means the indenture dated as of September 18, 2009 between Subco and The Bank of New York Mellon;

"**Notes**" means, collectively, the 2014 Notes, the 2019 Notes and the 2039 Notes;

"**NYSE**" means the New York Stock Exchange;

"**Plan of Arrangement**" means the plan of arrangement involving, among others, Cenovus Energy Inc. and EnCana;

"**Pre-Arrangement Reorganization**" means the reorganization mechanics effected prior to the Arrangement becoming effective;

"**Preferred Shares**" means, collectively, the First Preferred Shares and Second Preferred Shares;

"**Reorganization Time**" means the time that all or substantially all of the Cenovus Assets were transferred by EnCana to Subco and the Assumed Liabilities were assumed by Subco, which was 12:10 a.m. (Calgary time) on the Effective Date;

"**SAGD**" means steam assisted gravity drainage;

"**SEC**" means the U.S. Securities and Exchange Commission;

"**Second Preferred Shares**" means the second preferred shares in the capital of Cenovus Energy Inc.;

"**SEDAR**" means the Canadian System for Electronic Document Analysis and Retrieval;

"**Separation Agreement**" means the separation and transition agreement dated November 30, 2009 involving, among others, EnCana, 7050372 and Subco regarding the transfer of the Cenovus Assets from EnCana to Subco, the assumption of the Assumed Liabilities by 7050372 and Subco and certain transitional arrangements after completion of the Arrangement, as it may be amended, modified or supplemented from time to time in accordance with its terms;

"**Shareholder Rights Plan**" means our shareholder rights plan dated as of October 20, 2009 and restated as of November 30, 2009;

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"**Subco**" means Cenovus Energy Inc. (formerly EnCana Finance Ltd.), a corporation continued under the CBCA, which amalgamated with 7050372 on the Effective Date with the resulting amalgamated corporation being named "Cenovus Energy Inc.";

"**TSX**" means the Toronto Stock Exchange;

"**United States**" and "**U.S.**" means the United States of America;

"**U.S. GAAP**" means generally accepted accounting principles as in effect in the United States;

"**U.S. Securities Act**" means the United States *Securities Act of 1933*, as amended;

"**U.S. Tax Ruling**" means the private letter ruling received from the U.S. Internal Revenue Service confirming the U.S. federal income tax consequences of certain aspects of the Pre-Arrangement Reorganization, the Arrangement and certain other transactions, and includes any amendments and supplements thereto; and

"**WRB**" means WRB Refining LLC.

ABBREVIATIONS

Oil and Natural Gas Liquids	
bbl	barrel
bbls/d	barrels per day
Mbbls/d	thousand barrels per day
MMbbls	million barrels
NGLs	natural gas liquids
BOE	barrel of oil equivalent
BOE/d	barrel of oil equivalent per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day

Natural Gas	
Tcf	trillion cubic feet
Bcf	billion cubic feet
Mcf	thousand cubic feet
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMbtu	million British thermal units

In this annual information form, certain natural gas volumes have been converted to BOE or MBOE on the basis of six Mcf to one bbl. BOE and MBOE 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 well head.

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APPENDIX A

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the Board of Directors of Cenovus Energy Inc. (the "Corporation"):

1. We have evaluated the Corporation's reserves data as at December 31, 2009. The reserves data consists of the following:

   (a) estimated proved and probable oil and gas reserves quantities as at December 31, 2009 using constant prices and costs; and

   (b) the related estimates of discounted future net cash flows under the standardized measure calculation for proved oil and gas reserves quantities.

2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) with the necessary modifications to reflect definitions and standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and the legal requirements of the U.S. Securities and Exchange Commission ("SEC Requirements").

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with the principles and definitions outlined above.

4. The following table sets forth both the estimated proved reserves quantities (after royalties) and related estimates of future net cash flows (before deduction of income taxes) assuming constant prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2009:

		Estimated Proved Reserves Quantities After Royalty		
Evaluator and Preparation Date of Report	**Reserves Location**	**Liquids**	**Gas**	**Related Estimates of Future Net Cash Flow BTax, 10% discount rate**
		(MMbbl)	(Bcf)	(US$MM)
McDaniel & Associates Consultants Ltd. January 11, 2010	Canada	879	1,386	8,881
GLJ Petroleum Consultants Ltd. January 11, 2010	Canada	72	88	1,004
Totals		951	1,474	9,885

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook as modified by the FASB Standards and SEC Requirements.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

/s/ McDaniel & Associates Consultants Ltd.
McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

/s/ GLJ Petroleum Consultants Ltd.
GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 9, 2010

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APPENDIX B

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management and directors of Cenovus Energy Inc. (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. In the case of the Corporation, the regulatory requirements are covered under NI 51-101, as amended by a Decision dated October 20, 2009, and require disclosure of information contemplated by, and consistent with, U.S. Disclosure Requirements (as defined in the Decision). Required information includes reserves data, which consist of the following:

(i) proved oil and gas reserves quantities estimated as at December 31, 2009 using constant prices and costs; and

(ii) the related estimates of discounted future net cash flows under the standardized measure calculation for proved oil and gas reserves quantities.

The Corporation will also be disclosing optional reserves information, consisting of probable oil and gas reserves quantities estimated as at December 31, 2009 using constant prices and costs.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. A report from the independent qualified reserves evaluators dated February 9, 2010 (the "IQRE Report"), highlighting the standards they followed and their results, accompanies this Report.

The Reserves Committee of the board of directors of the Corporation, which Committee is comprised exclusively of non-management and unrelated directors, has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions placed by management affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data as outlined in the IQRE Report with management and each of the independent qualified reserves evaluators.

The board of directors of the Corporation (the "Board of Directors") has reviewed the standardized measure calculation with respect to the Corporation's proved oil and gas reserves quantities. The Board of Directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved:

(a) the content and filing with securities regulatory authorities of the proved oil and gas reserves quantities, related standardized measure calculation, probable oil and gas reserves quantities and other oil and gas activity information contained in the annual information form of the Corporation accompanying this Report;

(b) the filing of the IQRE Report; and

(c) the content and filing of this Report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

/s/ Brian C. Ferguson
Brian C. Ferguson
President & Chief Executive Officer

/s/ Judy A. Fairburn
Judy A. Fairburn
Executive Vice-President, Environment and Strategic Planning

/s/ Michael A. Grandin
Michael A. Grandin
Director and Chair of the Board

/s/ Wayne G. Thomson
Wayne G. Thomson
Director and Chair of the Reserves Committee

February 10, 2010

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APPENDIX C

AUDIT COMMITTEE MANDATE

I. PURPOSE

The Audit Committee (the "Committee") is appointed by the Board of Directors of Cenovus Energy Inc. ("Cenovus" or the "Corporation") to assist the Board in fulfilling its oversight responsibilities.

The Committee's primary duties and responsibilities are to:

- Review and approve management's identification of principal financial risks and monitor the process to manage such risks.
- Oversee and monitor the Corporation's compliance with legal and regulatory requirements.
- Receive and review the reports of the Audit Committee of any subsidiary with public securities.
- Oversee and monitor the integrity of the Corporation's accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting and accounting compliance.
- Oversee audits of the Corporation's financial statements.
- Oversee and monitor the qualifications, independence and performance of the Corporation's external auditors and internal auditing department.
- Provide an avenue of communication among the external auditors, management, the internal auditing department, and the Board of Directors.
- Report to the Board of Directors regularly.

The Committee has the authority to conduct any review or investigation appropriate to fulfilling its responsibilities. The Committee shall have unrestricted access to personnel and information, and any resources necessary to carry out its responsibility. In this regard, the Committee may direct internal audit personnel to particular areas of examination.

II. COMPOSITION AND MEETINGS

Committee Member's Duties in addition to those of a Director

The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board of Directors.

Composition

The Committee shall consist of not less than three and not more than eight directors as determined by the Board, all of whom shall qualify as independent directors pursuant to National Instrument 52-110 *Audit Committees* (as implemented by the Canadian Securities Administrators and as amended from time to time) ("NI 52-110").

All members of the Committee shall be financially literate, as defined in NI 52-110, and at least one member shall have accounting or related financial managerial expertise. In particular, at least one member shall have, through (i) education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions; (ii) experience actively supervising a principal financial officer, principal

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accounting officer, controller, public accountant, auditor or person performing similar functions; (iii) experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or (iv) other relevant experience:

- An understanding of generally accepted accounting principles and financial statements;
- The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;
- Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements, or experience actively supervising one or more persons engaged in such activities;
- An understanding of internal controls and procedures for financial reporting; and
- An understanding of audit committee functions.

Committee members may not, other than in their respective capacities as members of the Committee, the Board or any other committee of the Board, accept directly or indirectly any consulting, advisory or other compensatory fee from the Corporation or any subsidiary of the Corporation, or be an "affiliated person" (as such term is defined in the *United States Securities Exchange Act of 1934* , as amended (the *"Exchange Act"*), and the rules adopted by the U.S. Securities and Exchange Commission ("SEC") thereunder) of the Corporation or any subsidiary of the Corporation. For greater certainty, directors' fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Corporation that are not contingent on continued service should be the only compensation an audit committee member receives from the Corporation.

At least one member shall have experience in the oil and gas industry.

Committee members shall not simultaneously serve on the audit committees of more than two other public companies, unless the Board first determines that such simultaneous service will not impair the ability of the relevant members to effectively serve on the Committee, and required public disclosure is made.

The non-executive Board Chairman shall be a non-voting member of the Committee. See “Quorum” for further details.

Appointment of Members

Committee members shall be appointed by the Board, effective after the election of directors at the annual meeting of shareholders, provided that any member may be removed or replaced at any time by the Board and shall, in any event, cease to be a member of the Committee upon ceasing to be a member of the Board.

The Nominating and Corporate Governance Committee will recommend for approval to the Board an unrelated Director to act as Chairman of the Committee. The Board shall appoint the Chairman of the Committee.

If the Chairman of the Committee is unavailable or unable to attend a meeting of the Committee, the Chair shall ask another member to chair the meeting, failing which a member of the Committee present at the meeting shall be chosen to preside over the meeting by a majority of the members of the Committee present at such meeting.

The Chairman of the Committee presiding at any meeting of the Committee shall not have a casting vote.

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The items pertaining to the Chairman in this section should be read in conjunction with the Committee Chair section of the *Chair of the Board of Directors and Committee Chair General Guidelines*.

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

The Corporate Secretary or one of the Assistant Corporate Secretaries of the Corporation or such other person as the Corporate Secretary of the Corporation shall designate from time to time shall be the Secretary of the Committee and shall keep minutes of the meetings of the Committee.

Meetings

Committee meetings may, by agreement of the Chairman of the Committee, be held in person, by video conference, by means of telephone or by a combination of any of the foregoing.

The Committee shall meet at least quarterly. The Chairman of the Committee may call additional meetings as required. In addition, a meeting may be called by the non-executive Board Chairman, the President & Chief Executive Officer, or any member of the Committee or by the external auditors.

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Committee Chairman or by a majority of the members of the Committee.

The Committee may, by specific invitation, have other resource persons in attendance.

The President & Chief Executive Officer, the Executive Vice-President & Chief Financial Officer, the Comptroller and the head of internal audit are expected to be available to attend the Committee’s meetings or portions thereof.

Notice of Meeting

Notice of the time and place of each Committee meeting may be given orally, or in writing, or by facsimile, or by electronic means to each member of the Committee at least 24 hours prior to the time fixed for such meeting. Notice of each meeting shall also be given to the external auditors of the Corporation.

A member and the external auditors may, in any manner, waive notice of the Committee meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

Quorum

A majority of Committee members, present in person, by video conference, by telephone, or by a combination thereof, shall constitute a quorum. In addition, if an ex officio, non-voting member’s presence is required to attain a quorum of the Committee, then the said member shall be allowed to cast a vote at the meeting.

Minutes

Minutes of each Committee meeting should be succinct yet comprehensive in describing substantive issues discussed by the Committee. However, they should clearly identify those items of responsibilities scheduled by the Committee for the meeting that have been discharged by the Committee and those items of responsibilities that are outstanding.

Minutes of Committee meetings shall be sent to all Committee members and to the external auditors.

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The full Board of Directors shall be kept informed of the Committee's activities by a report following each Committee meeting.

III. RESPONSIBILITIES

Review Procedures

Review and update the Committee's mandate annually, or sooner, where the Committee deems it appropriate to do so. Provide a summary of the Committee's composition and responsibilities in the Corporation's annual report or other public disclosure documentation.

Provide a summary of all approvals by the Committee of the provision of audit, audit-related, tax and other services by the external auditors for inclusion in the Corporation's annual report filed with the SEC.

Annual Financial Statements

1. Discuss and review with management and the external auditors the Corporation's and any subsidiary with public securities annual audited financial statements and related documents prior to their filing or distribution. Such review to include:

   (a) The annual financial statements and related footnotes including significant issues regarding accounting principles, practices and significant management estimates and judgments, including any significant changes in the Corporation's selection or application of accounting principles, any major issues as to the adequacy of the Corporation's internal controls and any special steps adopted in light of material control deficiencies.

   (b) Management's Discussion and Analysis.

   (c) A review of the use of off-balance sheet financing including management's risk assessment and adequacy of disclosure.

   (d) A review of the external auditors' audit examination of the financial statements and their report thereon.

   (e) Review of any significant changes required in the external auditors' audit plan.

   (f) A review of any serious difficulties or disputes with management encountered during the course of the audit, including any restrictions on the scope of the external auditors' work or access to required information.

   (g) A review of other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards.

2. Review and formally recommend approval to the Board of the Corporation's:

   (a) Year-end audited financial statements. Such review shall include discussions with management and the external auditors as to:

      (i) The accounting policies of the Corporation and any changes thereto.
      (ii) The effect of significant judgments, accruals and estimates.
      (iii) The manner of presentation of significant accounting items.
      (iv) The consistency of disclosure.

   (b) Management's Discussion and Analysis.

   (c) Annual Information Form as to financial information.

   (d) All prospectuses and information circulars as to financial information.

   The review shall include a report from the external auditors about the quality of the most critical accounting principles upon which the Corporation's financial status

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depends, and which involve the most complex, subjective or significant judgmental decisions or assessments.

Quarterly Financial Statements

3. Review with management and the external auditors and either approve (such approval to include the authorization for public release) or formally recommend for approval to the Board the Corporation's:

   (a) Quarterly unaudited financial statements and related documents, including Management's Discussion and Analysis.

   (b) Any significant changes to the Corporation's accounting principles.

   Review quarterly unaudited financial statements of any subsidiary of the Corporation with public securities prior to their distribution.

Other Financial Filings and Public Documents

4. Review and discuss with management financial information, including earnings press releases, the use of "pro forma" or non-GAAP financial information and earnings guidance, contained in any filings with the securities regulators or news releases related thereto (or provided to analysts or rating agencies) and consider whether the information is consistent with the information contained in the financial statements of the Corporation or any subsidiary with public securities. Such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made).

Internal Control Environment

5. Ensure that management, the external auditors, and the internal auditors provide to the Committee an annual report on the Corporation's control environment as it pertains to the Corporation's financial reporting process and controls.

6. Review and discuss significant financial risks or exposures and assess the steps management has taken to monitor, control, report and mitigate such risk to the Corporation.

7. Review significant findings prepared by the external auditors and the internal auditing department together with management's responses.

8. Review in consultation with the internal auditors and the external auditors the degree of coordination in the audit plans of the internal auditors and the external auditors and enquire as to the extent the planned scope can be relied upon to detect weaknesses in internal controls, fraud, or other illegal acts. The Committee will assess the coordination of audit effort to assure completeness of coverage and the effective use of audit resources. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and discussed with management.

Other Review Items

9. Review policies and procedures with respect to officers' and directors' expense accounts and perquisites, including their use of corporate assets, and consider the results of any review of these areas by the internal auditor or the external auditors.

10. Review all related party transactions between the Corporation and any officers or directors, including affiliations of any officers or directors.

11. Review with the General Counsel, the head of internal audit and the external auditors the results of their review of the Corporation's monitoring compliance with each of the Corporation's published codes of business conduct and applicable legal requirements.

12. Review legal and regulatory matters, including correspondence with regulators and governmental agencies, that may have a material impact on the interim or annual

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financial statements, related corporation compliance policies, and programs and reports received from regulators or governmental agencies. Members from the Legal and Tax departments should be at the meeting in person to deliver their reports.

13. Review policies and practices with respect to off-balance sheet transactions and trading and hedging activities, and consider the results of any review of these areas by the internal auditors or the external auditors.

14. Ensure that the Corporation's presentations on net proved reserves have been reviewed with the Reserves Committee of the Board.

15. Review management's processes in place to prevent and detect fraud.

16. Review procedures for the receipt, retention and treatment of complaints received by the Corporation, including confidential, anonymous submissions by employees of the Corporation, regarding accounting, internal accounting controls, or auditing matters.

17. Review with the President & Chief Executive Officer, the Executive Vice-President & Chief Financial Officer of the Corporation and the external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of the Corporation's internal controls and procedures for financial reporting which could adversely affect the Corporation's ability to record, process, summarize and report financial information required to be disclosed by the Corporation in the reports that it files or submits under the *Exchange Act* or applicable Canadian federal and provincial legislation and regulations within the required time periods, and (ii) any fraud, whether or not material, that

involves management of the Corporation or other employees who have a significant role in the Corporation's internal controls and procedures for financial reporting.

18. Meet on a periodic basis separately with management.

External Auditors

19. Be directly responsible, in the Committee's capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, review or attest services for the Corporation. The external auditors shall report directly to the Committee.

20. Meet on a regular basis with the external auditors (without management present) and have the external auditors be available to attend Committee meetings or portions thereof at the request of the Chairman of the Committee or by a majority of the members of the Committee.

21. Review and discuss a report from the external auditors at least quarterly regarding:

    (a) All critical accounting policies and practices to be used;

    (b) All alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with management, including the ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and

    (c) Other material written communications between the external auditors and management, such as any management letter or schedule of unadjusted differences.

22. Obtain and review a report from the external auditors at least annually regarding:

    (a) The external auditors' internal quality-control procedures.

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    (b) Any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with those issues.

    (c) To the extent contemplated in the following paragraph, all relationships between the external auditors and the Corporation.

23. Review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation, (i) receiving and reviewing, as part of the report described in the preceding paragraph, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation and its affiliates, (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (iii) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence.

24. Review and evaluate:

    (a) The external auditors' and the lead partner of the external auditors' team's performance, and make a recommendation to the Board of Directors regarding the reappointment of the external auditors at the annual meeting of the Corporation's shareholders or regarding the discharge of such external auditors.

    (b) The terms of engagement of the external auditors together with their proposed fees.

    (c) External audit plans and results.

    (d) Any other related audit engagement matters.

    (e) The engagement of the external auditors to perform non-audit services, together with the fees therefor, and the impact thereof, on the independence of the external auditors.

25. Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 21 through 24, evaluate the external auditors' qualifications, performance and independence, including whether or not the external auditors' quality controls are adequate and the provision of permitted non-audit services is compatible with maintaining auditor independence, taking into account the opinions of management and the head of internal audit. The Committee shall present its conclusions with respect to the external auditors to the Board.

26. Ensure the rotation of partners on the audit engagement team in accordance with applicable law. Consider whether, in order to assure continuing external auditor independence, it is appropriate to adopt a policy of rotating the external auditing firm on a regular basis.

27. Set clear hiring policies for the Corporation's hiring of employees or former employees of the external auditors.

28. Consider with management and the external auditors the rationale for employing audit firms other than the principal external auditors.

29. Consider and review with the external auditors, management and the head of internal audit:

    (a) Significant findings during the year and management's responses and follow-up thereto.

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    (b) Any difficulties encountered in the course of their audits, including any restrictions on the scope of their work or access to required information, and management's response.

    (c) Any significant disagreements between the external auditors or internal auditors and management.

    (d) Any changes required in the planned scope of their audit plan.

    (e) The resources, budget, reporting relationships, responsibilities and planned activities of the internal auditors.

    (f) The internal audit department mandate.

    (g) Internal audit's compliance with the Institute of Internal Auditors' standards.

Internal Audit Department and Independence

30. Meet on a periodic basis separately with the head of internal audit.

31. Review and concur in the appointment, compensation, replacement, reassignment, or dismissal of the head of internal audit.

32. Confirm and assure, annually, the independence of the internal audit department and the external auditors.

Approval of Audit and Non-Audit Services

33. Review and, where appropriate, approve the provision of all permitted non-audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors (subject to the de minimus exception for non-audit services described in the *Exchange Act* or applicable Canadian federal and provincial legislation and regulations which are approved by the Committee prior to the completion of the audit).

34. Review and, where appropriate and permitted, approve the provision of all audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors.

35. If the pre-approvals contemplated in paragraphs 33 and 34 are not obtained, approve, where appropriate and permitted, the provision of all audit and non-audit services promptly after the Committee or a member of the Committee to whom authority is delegated becomes aware of the provision of those services.

36. Delegate, if the Committee deems necessary or desirable, to subcommittees consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 33 through 35. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

37. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 33 and 34, so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation of the Committee's responsibilities under the *Exchange Act* or applicable Canadian federal and provincial legislation and regulations to management.

Other Matters

38. Review and concur in the appointment, replacement, reassignment, or dismissal of the Chief Financial Officer.

39. Upon a majority vote of the Committee outside resources may be engaged where and if deemed advisable.

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40. Report Committee actions to the Board of Directors with such recommendations, as the Committee may deem appropriate.

41. Conduct or authorize investigations into any matters within the Committee's scope of responsibilities. The Committee shall be empowered to retain, obtain advice or otherwise receive assistance from independent counsel, accountants, or others to assist it in the conduct of any investigation as it deems necessary and the carrying out of its duties.

42. The Corporation shall provide for appropriate funding, as determined by the Committee in its capacity as a committee of the Board, for payment (i) of compensation to the external auditors for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation, (ii) of compensation to any advisors employed by the Committee and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

43. Obtain assurance from the external auditors that disclosure to the Committee is not required pursuant to the provisions of the *Exchange Act* regarding the discovery of illegal acts by the external auditors.

44. The Committee shall review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Board for approval.

45. The Committee's performance shall be evaluated annually by the Nominating and Corporate Governance Committee of the Board of Directors.

46. Perform such other functions as required by law, the Corporation's mandate or bylaws, or the Board of Directors.

47. Consider any other matters referred to it by the Board of Directors.

Approved: November 30, 2009

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APPENDIX D

BOARD OF DIRECTORS' MANDATE

The fundamental responsibility of the Board of Directors (the "Board") of Cenovus Energy Inc. ("Cenovus" or the "Corporation") is to appoint a competent executive team and to oversee the management of the business, with a view to maximizing shareholder value and ensuring corporate conduct in an ethical and legal manner via an appropriate system of corporate governance and internal control.

Executive Team Responsibility

- Appoint the Chief Executive Officer ("CEO") and senior officers, approve their compensation, and monitor the CEO's performance against a set of mutually agreed corporate objectives directed at maximizing shareholder value.
- In conjunction with the CEO, develop a clear mandate for the CEO, which includes a delineation of management's responsibilities.
- Ensure that a process is established that adequately provides for succession planning, including the appointing, training and monitoring of senior management.
- Establish limits of authority delegated to management.

Operational Effectiveness and Financial Reporting

- Annual review and adoption of a strategic planning process and approval of the corporate strategic plan, which takes into account, among other things, the opportunities and risks of the business.
- Ensure that a system is in place to identify the principal risks to the Corporation and that the best practical procedures are in place to monitor and mitigate the risks.
- Ensure that processes are in place to address applicable regulatory, corporate, securities and other compliance matters.
- Ensure that processes are in place for the Corporation to mitigate environmental impacts, address health and safety matters that may arise with our activities, and operate in a manner consistent with recognized standards.
- Ensure that an adequate system of internal control exists.
- Ensure that due diligence processes and appropriate controls are in place with respect to applicable certification requirements regarding the Corporation's financial and other disclosure.
- Review and approve the Corporation's financial statements and oversee the Corporation's compliance with applicable audit, accounting and reporting requirements.
- Approve annual operating and capital budgets.

- Review and consider for approval all amendments or departures proposed by management from established strategy, capital and operating budgets or matters of policy which diverge from the ordinary course of business.

- Review operating and financial performance results relative to established strategy, budgets and objectives.

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Integrity / Corporate Conduct

- Approve a communications policy or policies to ensure that a system for corporate communications to all stakeholders exists, including processes for consistent, transparent, regular and timely public disclosure, and to facilitate feedback from stakeholders.

- Approve a code of business conduct and ethics for directors, officers, employees, contractors and consultants and monitor compliance with the Practice and approve any waivers of the Practice for officers and directors.

Board Process / Effectiveness

- Ensure that Board materials are distributed to directors in advance of regularly scheduled meetings to allow for sufficient review of the materials prior to the meeting. Directors are expected to attend all meetings.

- Engage in the process of determining Board member qualifications with the Nominating and Corporate Governance Committee including ensuring that a majority of directors qualify as independent directors pursuant to National Instrument 58-101 *Disclosure of Corporate Governance Practices* (as implemented by the Canadian Securities Administrators and as amended from time to time).

- Approve the nomination of directors.

- Provide a comprehensive orientation to each new director.

- Establish an appropriate system of corporate governance including practices to ensure the Board functions independently of management.

- Establish appropriate practices for the regular evaluation of the effectiveness of the Board, its committees and its members.

- Establish committees and approve their respective mandates and the limits of authority delegated to each committee.

- Review and re-assess the adequacy of the Audit Committee Mandate on a regular basis, but not less frequently than on an annual basis.

- Review the adequacy and form of the directors' compensation to ensure it realistically reflects the responsibilities and risks involved in being a director.

- Each member of the Board is expected to understand the nature and operations of the Corporation's business, and have an awareness of the political, economic and social trends prevailing in all countries or regions in which the Corporation invests, or is contemplating potential investment.

- Independent directors shall meet regularly, and in no case less frequently than quarterly, without non-independent directors and management participation.

- In addition to the above, adherence to all other Board responsibilities as set forth in the Corporation's By-Laws, applicable policies and practices and other statutory and regulatory obligations, such as approval of dividends, issuance of securities, etc., is expected.

Approved: November 30, 2009

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cenovus ENERGY

Cenovus Energy Inc.

Management's Discussion and Analysis
For the year ended December 31, 2009
(U.S. Dollars)

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("Cenovus" or "the Company") should be read with the audited Cenovus Energy Inc. Consolidated Financial Statements for the year ended December 31, 2009 (the "Consolidated Financial Statements") as well as EnCana Corporation's ("EnCana") Information Circular Relating to an Arrangement Involving Cenovus Energy Inc. (the "Information Circular") dated October 20, 2009. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this document and such similar legal advisories contained in the Information Circular.

Management is responsible for preparing the MD&A, while the audit committee of the Board of Directors of Cenovus (the "Board") reviews the MD&A and recommends its approval by the Board.

The Consolidated Financial Statements and comparative information have been prepared in United States ("U.S.") dollars, except where another currency has been indicated, and in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Production and reserves volumes are presented on an after royalties basis consistent with U.S. protocol reporting. This document is dated February 17, 2010.

Readers can find the definition of certain terms used in this document in the disclosure regarding Oil and Gas Information and Currency, Non-GAAP Measures and References to Cenovus contained in the Advisory section located at the end of this document, and such similar advisories set out in the Information Circular.

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INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

Cenovus is an integrated oil company headquartered in Calgary, Alberta. Our operations include enhanced oil recovery ("EOR") properties and established crude oil and natural gas production in Alberta and Saskatchewan. We also have ownership interests in two refineries in Illinois and Texas, USA.

We began independent operations on December 1, 2009 following the Arrangement with EnCana Corporation which created two independent publicly traded energy companies – Cenovus and EnCana (the "Arrangement"). Although we are a new company, we have operated a number of assets for decades.

Our operations include our technology-driven EOR properties, coupled with established crude oil and natural gas production in Alberta and Saskatchewan. Three of our four enhanced oil properties (Foster Creek, Christina Lake and Pelican Lake) are located in the Athabasca region in northeast Alberta. The fourth, the Weyburn carbon dioxide ("CO_2") sequestration EOR project, is located in southeastern Saskatchewan. We also have a 50 percent ownership interest in two refineries in Illinois and Texas, USA, enabling us to capture the full value from crude oil production through to refined products such as gasoline, diesel and jet fuel.

Our operational focus over the next five years will be to increase production predominantly from our steam-assisted gravity drainage ("SAGD") operations at Foster Creek and Christina Lake. We have proven our expertise and low cost EOR development approach. Our established crude oil and natural gas production base is expected to generate stable production and cash flows which will enable further development of our core bitumen assets. In all our operations, whether bitumen, crude oil or natural gas, technology plays a key role in extracting the resource, increasing the amount recovered, reducing costs and improving the way we extract the resources. 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.

Our future lies in developing the vast land position we hold in the Athabasca region in northeast Alberta. In addition to our Foster Creek and Christina Lake properties, we currently have two emerging properties in this area: Borealis and Narrows Lake. A joint application to the Energy Resources Conservation Board and Alberta Environment for the development of Borealis has been submitted for the construction of a SAGD facility with production capacity of 35,000 barrels ("bbls") of bitumen per day. We hold a 50 percent interest in the Narrows Lake play, through our interest in the FCCL Partnership, which is located within the greater Christina Lake regional area. We are preparing development plans and regulatory applications for a project at Narrows Lake that would include two to three phases with each phase expected to add approximately 40,000 barrels per day ("bbls/d") of bitumen production capacity.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our extensive bitumen resource. Most of the bitumen resource is undeveloped and the resource is currently expected to assist in meeting consumer demand for decades to come. Growth at these enhanced oil operations is expected to be internally funded through cash flow generated from our established crude oil and natural gas production base. Our natural gas production also provides a natural economic hedge for the natural gas required as a fuel source at our upstream and downstream operations. Our low-cost refineries operated by ConocoPhillips, an unrelated U.S. public company, enable us to integrate our bitumen production with the sale of refined products.

OUR BUSINESS STRUCTURE

Our operations are organized into two operating divisions:

- **Integrated Oil** Division, which includes all of the assets within the upstream and downstream integrated oil business with our joint venture partner, as well as other bitumen interests and the Athabasca natural gas assets. The Integrated Oil Division has assets in both Canada and the U.S. including two major enhanced oil recovery properties: (i) Foster Creek; and (ii) Christina Lake; as well as two refineries: (i) Wood River; and (ii) Borger.

- **Canadian Plains** Division, which contains established crude oil and natural gas development assets in Alberta and Saskatchewan and includes two major enhanced oil recovery properties: (i) Weyburn; and

(ii) Pelican Lake; as well as the Southern Alberta oil and gas properties. The division 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.

For financial statement reporting purposes, our operating and reportable segments are:

- **Upstream Canada,** which includes Cenovus's development and production of bitumen, crude oil, natural gas and natural gas liquids ("NGLs"), and other related activities in Canada. This includes the Foster Creek and Christina Lake operations which are jointly owned with ConocoPhillips and operated by Cenovus.

- **Downstream Refining,** which is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips and operated by ConocoPhillips.

- **Corporate and Eliminations,** which mainly includes unrealized gains or losses recorded on derivative financial instruments as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, 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 2009

This past year was highlighted by a number of significant factors that had major influences on our activities and financial results. The most significant factor was the global credit crisis and recession which resulted in lower commodity prices, uncertainty in the financial markets and delayed our creation. However, in September 2009, with some improvement in economic conditions apparent, we were able to arrange a committed Canadian $2.5 billion bank credit facility and successfully raise $3.5 billion in unsecured notes. This allowed us to move forward with the Arrangement, and on November 25, 2009, over 99 percent of the votes cast by EnCana shareholders were in favour of our creation. The global recession also impacted commodity prices which were depressed for most of 2009; however we did benefit from our natural gas and crude oil hedging program, and realized $692 million of after-tax financial hedging gains in 2009.

As a result of the markets uncertainty, we increased focus on cost control and discipline in 2009 through our "10 percent challenge" initiative. Through this focus on cost reduction, we identified opportunities to reduce operating costs and adjust and redirect our capital program. Our reduction of capital expenditures was partly responsible for the nine percent decrease in natural gas production; and although we did reduce spending on our oil projects as well, our average daily production grew 10 percent, with Foster Creek and Christina Lake production increasing 43 percent. Consistent with our long-term strategy to develop our integrated oil business, we continued with our development work at both Foster Creek and Christina Lake, as well as the Coker and Refinery Expansion ("CORE") project at the Wood River refinery.

As part of the creation of Cenovus, EnCana's Canadian oil and gas partnership was dissolved, resulting in an acceleration of Cenovus's share of current tax of approximately $400 million in 2009. This current tax is not added tax but are amounts which otherwise would have been paid in 2010 had the dissolution not occurred. This cash tax significantly reduced our Cash Flow for the fourth quarter of 2009. Also, we were part of EnCana for 11 months of the year, and therefore our reported results for 2009 may not be typical of the results that we will achieve in future years as a stand-alone entity.

In addition to the above, the specific financial and operating highlights of 2009 are:

- 160 million barrels, after royalties, of proved bitumen reserves extensions and discoveries mainly due to projects sanctioned in the year; year over year bitumen reserves, after royalties, grew eight percent;
- Low commodity prices reduced our revenues by 39 percent;
- Production from our Foster Creek and Christina Lake enhanced oil recovery properties increased 43 percent; Foster Creek production exceeded 100,000 bbls/d (on a 100 percent basis) for the first time in December;
- Operating Cash Flows from Upstream decreased by $706 million on lower commodity prices;
- Operating Cash Flows from Downstream Refining operations increased by $551 million;
- Realized financial hedge gains of $692 million, net of tax; (2008 – loss of $213 million, net of tax);
- Operating earnings decreased by $317 million;
- Construction on the CORE project at the Wood River refinery progressed to approximately 71 percent complete at the end of the year and is on schedule and on budget;
- Acquisition and divestiture activity for the year generated net proceeds of $206 million and added additional bitumen lands at Narrows Lake; and
- Declared and paid dividends of $151 million ($0.20 per share) in December. The December dividend reflects an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

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 selected market benchmark prices and foreign exchange rates to assist in understanding our financial results:

(Average for the year)	**2009**	**2009 vs 2008**	2008	2008 vs 2007	2007
Crude Oil Price *($/bbl)*					
West Texas Intermediate (WTI)	**62.09**	**-38%**	99.75	38%	72.41
Western Canadian Select (WCS)	**52.43**	**-34%**	79.70	61%	49.50
Differential - WTI/WCS	**9.66**	**-52%**	20.05	-12%	22.91
WCS as % of WTI	**84%**		80%		68%
Refining Margin 3-2-1 Crack Spread [1] *($/bbl)*					
Chicago	**8.54**	**-24%**	11.22	-37%	17.67

Midwest Combined ("Group 3")	**8.09**	**-27%**	11.03	-42%	19.11
Natural Gas Price					
AECO *(C$/Mcf)*	**4.19**	**-48%**	8.13	23%	6.61
NYMEX *($/MMBtu)*	**3.99**	**-56%**	9.04	32%	6.86
Basis Differential - AECO/NYMEX *($/MMBtu)*	**0.40**	**-67%**	1.23	64%	0.75
Average Foreign Exchange					
Average U.S./Canadian Dollar Exchange Rate	**0.876**	**-7%**	0.938	1%	0.930

(1) 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.

After reaching record highs in July of 2008, the price of WTI decreased over the remainder of the year to a closing price of $44.60 per bbl at December 31, 2008. However, by December 31, 2009, WTI had increased to $79.36 per bbl on signs of an economic recovery and production discipline by OPEC. Consistent with the increase in WTI, WCS increased 103 percent from December 31, 2008 to December 31, 2009. During 2009, the average differential between WTI and WCS narrowed to less than $10 per bbl for the year as WCS averaged 84 percent of WTI.

During 2009, U.S. refining crack spreads reflected lower consumer demand, in response to the depressed economy. This reduction in U.S. demand occurred during an overall increase in global refinery capacity.

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2009 was the second consecutive annual decline in the consumption of refined products in the United States which resulted in lower prices for refined products and narrowing crack spreads.

Throughout 2009, natural gas prices in North America declined due to a combination of low demand in response to economic conditions and an increase in supply as new prolific shale gas plays began production and associated drilling commitments were completed. The result was above average volumes in storage during 2009 which decreased the price for natural gas. Cold weather during the latter part of 2009, particularly in the eastern United States, helped the AECO price at December 31, 2009 increase from earlier lows of $2.56 per Mcf to $5.25 per Mcf but still remained below last year's year end level.

Our risk mitigation strategy has reduced our exposure to commodity price volatility through our hedging program. Further information regarding this program can be found in the Risk Management section of this MD&A and the notes to the Consolidated Financial Statements.

ANNUAL FINANCIAL INFORMATION

The Consolidated Financial Statements include the results for the period from January 1 to November 30, 2009 (prior to the start of our independent operations on December 1, 2009) in addition to the results for the period from December 1 to December 31, 2009. The historical consolidated financial information prior to December 1, 2009 has been derived from the accounting records of EnCana using the historical results of operations and historical basis of assets and liabilities of the businesses subsequently transferred to Cenovus on a carve-out accounting basis. Further details are provided in the notes to the Consolidated Financial Statements.

SELECTED ANNUAL CONSOLIDATED FINANCIAL RESULTS

($ millions, except per share amounts)	2009	2009 vs 2008	2008	2008 vs 2007	2007
Revenues, Net of Royalties	**$ 10,140**	**-39%**	$ 16,559	24%	$ 13,406
Operating Cash Flow [1]	**3,695**	**-4%**	3,850	-11%	4,344
Cash Flow [1]	**2,472**	**-20%**	3,088	-13%	3,536
- per share – diluted [2]	**3.29**		4.11		4.62
Operating Earnings [1]	**1,312**	**-19%**	1,629	-10%	1,802
- per share – diluted [2]	**1.74**		2.17		2.36
Net Earnings	**648**	**-73%**	2,368	69%	1,404
- per share – basic [2]	**0.86**		3.16		1.87
- per share – diluted [2]	**0.86**		3.15		1.84
Total Assets	**20,552**	**11%**	18,466	-12%	20,987
Total Long-Term Debt	**3,493**	**15%**	3,036	-18%	3,690
Other Long-Term Obligations	**6,043**	**1%**	5,968	-7%	6,437
Capital Expenditures	**1,892**	**-8%**	2,046	39%	1,475
Free Cash Flow [1]	**580**	**-44%**	1,042	-49%	2,061
Cash Dividends [3]	**151**		-		-

(1) Non-GAAP measures which are defined within this MD&A.
(2) Any per share amounts prior to December 1, 2009 have been calculated using EnCana's common share balances based on the terms of the Arrangement where EnCana shareholders received one common share of Cenovus and one common share of the new EnCana.
(3) We declared and paid a dividend of $0.20 per share in December 2009. The December dividend reflects an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

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REVENUE VARIANCE

($ millions)			
2008 Revenue, Net of Royalties		$	16,559
Upstream	Price		(2,138)
	Realized hedging		1,328
	Volume		(15)
	Other [1]		(549)
Downstream			(3,731)
Corporate	Unrealized hedging		(1,366)
	Other		52
2009 Revenue, Net of Royalties		**$**	**10,140**

(1) Revenue dollars reported include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and selling expense.

Total Revenues, Net of Royalties decreased $6,419 million in 2009 compared to 2008 primarily as a result of lower average commodity prices, consistent with decreased benchmark prices for 2009.

OPERATING CASH FLOW

($ millions)	**2009**	2008	2007
Crude Oil and NGLs			
Foster Creek and Christina Lake	**$ 596**	$ 421	$ 213
Canadian Plains	**941**	1,508	946
Natural Gas	**1,798**	2,099	2,049
Other Upstream Operations	**50**	63	62
	3,385	4,091	3,270
Downstream	**310**	(241)	1,074
Operating Cash Flow	**$ 3,695**	$ 3,850	$ 4,344

Operating Cash Flow is a non-GAAP measure defined as Revenue, Net of Royalties less production and mineral taxes, transportation and selling, operating and purchased product expenses and 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 periods.

In total, Operating Cash Flow from our Upstream and Downstream segments decreased by $155 million. Detail of the components that explain changes to Operating Cash Flow from 2008 can be found in the Divisional Results 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.

($ millions)	**2009**	2008	2007
Cash From Operating Activities	**$ 3,496**	$ 2,687	$ 3,014
(Add back) deduct:			
Net change in other assets and liabilities	**(23)**	(89)	(48)
Net change in non-cash working capital	**1,047**	(312)	(474)
Cash Flow	**$ 2,472**	$ 3,088	$ 3,536

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Our Cash Flow decreased to $2,472 million in 2009, a decrease of $616 million from 2008 ($3,088 million). The decrease was the result of:
- Decrease in the average natural gas price, excluding financial hedging, of $4.16 per Mcf or 54 percent from 2008;
- Decrease in the average liquids selling price, excluding financial hedging, of $23.13 per bbl, or 31 percent, from 2008;
- Current tax increased $513 million primarily due to accelerated income tax as a result of the dissolution of a partnership as part of the Arrangement; and
- Decline of nine percent in our production of natural gas.

The decreases in our 2009 Cash Flow were offset by:
- Realized financial hedging gains of $692 million, after tax, compared to realized hedging losses of $213 million, after tax, in 2008;
- An improvement in our operating cash flow from downstream operations of $551 million;
- A decrease in our transportation and selling and operating expenses of $360 million; and
- 10 percent increase in our crude oil and NGLs production volumes compared to 2008.

Our Cash Flow in 2008 of $3,088 million was lower than 2007 Cash Flow of $3,536 million by $448 million, primarily due to:
- Operating cash flows from downstream operations decreased $1,315 million primarily due to weaker refining margins and higher purchased product costs;
- Realized financial crude oil, natural gas and other commodity hedging losses of $213 million after-tax in 2008, compared to gains of $97 million after-tax in 2007;
- Natural gas production volumes in 2008 decreased six percent compared to 2007; and

- Increases in transportation and selling, operating, interest and general and administrative expenses.

The decreases in our 2008 Cash Flow were offset by:
- Higher average natural gas prices, excluding financial hedges, of $7.76 per Mcf in 2008 compared to $6.08 per Mcf in 2007; and
- Higher average liquids prices, excluding financial hedges of $74.00 per bbl in 2008 compared to $46.69 per bbl in 2007.

OPERATING EARNINGS

($ millions)	2009	2008	2007
Net Earnings, as reported	**$ 648**	$ 2,368	$ 1,404
Add back (losses) and deduct gains:			
Unrealized mark-to-market accounting gain (loss), after-tax [1]	**(473)**	519	(244)
Non-operating foreign exchange gain (loss), after-tax [2]	**(191)**	220	(301)
Future tax recovery due to tax rate reductions	**-**	-	147
Operating Earnings	**$ 1,312**	$ 1,629	$ 1,802

(1) The unrealized mark-to-market accounting gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods. The realized gains (losses), after-tax represents the recording of the final settlement of hedge positions.
(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax realized foreign exchange gains (losses) on settlement of intercompany transactions and future 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 non-operating items including the after-tax effect of unrealized mark-to-market accounting gains (losses) on derivative instruments, after-tax gains (losses) on translation of U.S. dollar denominated debt issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, future income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

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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 below that affected our Net Earnings also impacted our Operating Earnings.

NET EARNINGS

Net Earnings in 2009 of $648 million were $1,720 million lower compared to 2008. The items identified above that affected our 2009 Cash Flow also impacted Net Earnings. Other significant factors that reduced our 2009 Net Earnings included an unrealized mark-to-market loss of $667 million, compared to a $734 million gain in 2008 and unrealized foreign exchange loss of $313 million in 2009 compared to a gain in 2008 of $259 million. These reductions to Net Earnings and the increased current tax, which impacted Cash Flow, were offset by a recovery of future income tax in 2009 of $551 million, compared to a future income tax expense of $385 million in 2008.

Our Net Earnings in 2008 were $2,368 million, which were $964 million higher than Net Earnings of $1,404 million in 2007. The items identified above that affected our 2008 Cash Flow also impacted Net Earnings. Other significant factors that increased our 2008 Net Earnings included an unrealized mark-to-market gain, after-tax, of $519 million, compared to a $244 million loss in 2007, non-operating foreign exchange gains of $220 million, after-tax, in 2008 compared to losses of $301 million after-tax in 2007 as well as a $108 million decrease in depreciation, depletion and amortization.

As a means of managing the volatility of commodity prices, we enter into various financial instrument agreements. Changes in the mark-to-market gain or loss on these agreements affect our Net Earnings and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts. Our 2009 and 2008 Net Earnings benefitted overall from this program, while in 2007, we reported a reduction in Net Earnings from our hedging program. The following information has been provided in order to provide information that is more comparable between periods:

($ millions)	2009	2008	2007
Unrealized Mark-to-Market Gains (Losses), after-tax [1]	**$ (473)**	$ 519	$ (244)
Realized Hedging Gains (Losses), after-tax [2]	**692**	(213)	97
Hedging Impacts on Net Earnings	**$ 219**	$ 306	$ (147)

(1) Included in Corporate financial results. Further detail on unrealized mark-to-market gains (losses) can be found in the Corporate and Eliminations section of this MD&A.
(2) Included in Divisional financial results.

NET CAPITAL INVESTMENT

($ millions)	2009	2008	2007
Integrated Oil - Upstream	**$ 476**	$ 644	$ 450
Canadian Plains	**478**	872	795
Downstream Refining	**907**	478	220
Other	**31**	52	10
Capital Investment	**1,892**	2,046	1,475
Acquisitions	**3**	-	14
Divestitures	**(209)**	(47)	-
Net Capital Investment	**$ 1,686**	$ 1,999	$ 1,489

Capital investment in 2009 was primarily focused on the continued development of our EOR properties (Foster Creek, Christina Lake, Pelican Lake and Weyburn) and the expansion of our downstream heavy oil refining capacity. During 2009, part of the reduction in our capital investment reflected our internal "10 percent challenge", as we scrutinized our spending in an effort to reduce costs. Capital investment for each of 2009, 2008 and 2007 was funded by Cash

Flow. Further information regarding our capital investment can be found in the Divisional Results section of this MD&A.

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Acquisitions and Divestitures

In 2009, acquisition and divestiture activity resulted in net proceeds of $206 million from various divestitures, including the sale of the Senlac heavy oil assets, a farm-out transaction and one minor acquisition.

Our acquisitions and divestitures in 2009 also included a property swap under the terms of which we acquired strategic bitumen lands at Narrows Lake in exchange for certain non-core lands.

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, which is defined as Cash Flow in excess of Capital Investment, excluding acquisitions and divestitures. Cash Flow is a non-GAAP measure and is defined under the Cash Flow section of this MD&A.

In 2009, our Free Cash Flowwas $580 million, which was $462 million lower than our Free Cash Flow of $1,042 million in 2008 (2007 - $2,061 million) primarily due to lower cash flow, partially offset by less capital investment during the year. Additional explanations for the decrease in total Cash Flow and Capital Investment are discussed under the Cash Flow, Net Capital Investment and Divisional Results sections of this MD&A.

($ millions)	**2009**	2008	2007
Cash Flow	**$ 2,472**	$ 3,088	$ 3,536
Capital Investment	**1,892**	2,046	1,475
Free Cash Flow	**$ 580**	$ 1,042	$ 2,061

FOREIGN EXCHANGE

As disclosed in the Business Environment section of this MD&A, the average U.S./Canadian dollar exchange rate was lower in 2009 than both 2008 and 2007. The table below summarizes the impact of the lower foreign exchange rate on reported amounts when compared to the prior years.

	2009	2008	2007
Average U.S./Canadian Dollar Exchange Rate	**$ 0.876**	$ 0.938	$ 0.930
Dollar Change from prior year	**$ (0.062)**	$ 0.008	$ 0.048
Percentage change from prior year	**-7%**	1%	5%
($ millions)			
Increase (decrease) in:			
Capital Investment	**$ (82)**	$ (12)	$ 80
Operating Expense	**(46)**	7	40
Administrative Expense	**(9)**	1	6
DD&A Expense	**(82)**	13	73

The U.S. to Canadian dollar exchange rate strengthened from a December 31, 2008 spot rate of $0.824 to a December 31, 2009 spot rate of $0.955. The $0.131 increase resulted in a Foreign Currency Translation Adjustment of $2.0 billion, net of tax for 2009 which increased our Comprehensive Income. As the U.S. to Canadian dollar exchange rate weakened from a rate of $1.007 at December 31, 2007 to $0.824 at December 31, 2008 our Foreign Currency Translation Adjustment for 2008 reduced our Comprehensive Income by $2.2 billion, net of tax.

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RESULTS OF OPERATIONS

Crude Oil and NGLs Production Volumes

	2009	**2009 vs 2008**	2008	2008 vs 2007	2007
Crude Oil *(bbls/d)*					
Foster Creek	**36,654**	**41%**	25,947	7%	24,262
Christina Lake	**6,527**	**54%**	4,236	66%	2,552
Weyburn	**14,948**	**7%**	14,031	-5%	14,771
Pelican Lake	**20,105**	**-9%**	21,975	-5%	23,253
Southern Alberta	**22,406**	**-7%**	24,153	-10%	26,776
Integrated Oil - Other	**2,553**	**-6%**	2,729	2%	2,688
Canadian Plains - Other	**5,405**	**-10%**	5,998	-2%	6,139
NGLs *(bbls/d)*	**1,186**	**-%**	1,181	-6%	1,260
	109,784	**10%**	100,250	-1%	101,701

Production volumes at Foster Creek and Christina Lake increased in 2009 as a result of the commissioning and ramp up of new expansion phases at each

property, slightly offset by higher royalty rates as a result of the new Alberta royalty framework (effective January 1, 2009), which reduced the production volumes. Weyburn production increased from 2008 to 2009 as a result of well optimizations and lower royalties. The decrease in production at Pelican Lake for 2009 was a result of natural production declines and a scheduled facility turnaround partially offset by fewer operational issues at the facility. Crude oil production from Southern Alberta decreased in 2009 compared to 2008 due to expected natural declines partially offset by lower royalty rates and production from new wells.

Natural Gas Production Volumes

Natural Gas *(MMcf/d)*	**2009**	**2009 vs 2008**	2008	2008 vs 2007	2007
Southern Alberta	**739**	**-8%**	800	-4%	832
Canadian Plains - Other	**36**	**-14%**	42	-2%	43
Integrated Oil - Other	**49**	**-22%**	63	-31%	91
	824	**-9%**	905	-6%	966

The decline in Southern Alberta natural gas production in 2009 compared to 2008 was the result of expected natural production declines and capacity restrictions in response to the lower commodity price. These production decreases were partially offset by a slight reduction in the royalty rates as a result of declining prices.

Operating Netbacks

	2009		2008		2007	
	Liquids ($/bbl)	**Natural Gas ($/Mcf)**	Liquids ($/bbl)	Natural Gas ($/Mcf)	Liquids ($/bbl)	Natural Gas ($/Mcf)
Price	**$ 50.87**	**$ 3.60**	$ 74.00	$ 7.76	$ 46.69	$ 6.08
Expenses						
Production and mineral taxes	**0.62**	**0.04**	1.08	0.11	0.76	0.10
Transportation and selling	**1.55**	**0.14**	1.71	0.24	1.72	0.27
Operating	**10.41**	**0.76**	11.59	0.84	10.27	0.74
Netback excluding Realized Financial Hedging	**38.29**	**2.66**	59.62	6.57	33.94	4.97
Realized Financial Hedging Gain (Loss)	**0.98**	**3.22**	(6.07)	(0.30)	(3.40)	0.75
Netback including Realized Financial Hedging	**$ 39.27**	**$ 5.88**	$ 53.55	$ 6.27	$ 30.54	$ 5.72

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Our average netback for both liquids and natural gas (excluding realized financial hedging) was lower in 2009 primarily as a result of lower average prices for the year, consistent with the reduction in benchmark prices.

As part of ongoing efforts to maintain financial resilience and flexibility, we reduced our pricing risk through a commodity price hedging program. In 2009, our hedging program added $0.98 per bbl of liquids and $3.22 per Mcf of natural gas. Further information regarding this program can be found in the Risk Management section of this MD&A and the notes to the Consolidated Financial Statements.

DIVISIONAL RESULTS

Our Upstream Canada segment includes the upstream activities of the Integrated Oil Division and the Canadian Plains Division. Our Downstream Refining segment includes the Downstream Refining business of the Integrated Oil Division.

INTEGRATED OIL DIVISION

We are a 50 percent partner in an integrated North American oil business with ConocoPhillips that consists of an upstream and a downstream entity. The upstream entity includes the Foster Creek and Christina Lake oil properties in northeast Alberta, while the downstream entity includes the Wood River and Borger refineries located in Illinois and Texas, USA, respectively.

FOSTER CREEK AND CHRISTINA LAKE

Financial Results

($ millions)	**2009**	2008	2007
Revenues, Net of Royalties and excluding hedging	**$ 1,165**	$ 1,184	$ 781
Realized Financial Hedging Gain (Loss)	**37**	(67)	(43)
Expenses			
Transportation and selling	**430**	526	366
Operating	**176**	170	159
Operating Cash Flow	**$ 596**	$ 421	$ 213

Production Volumes

Heavy Crude Oil (bbls/d)	**2009**	**2009 vs 2008**	2008	2008 vs 2007	2007
	36,654	**41%**	25,947	7%	24,262
Foster Creek					
Christina Lake	**6,527**	**54%**	4,236	66%	2,552
	43,181	**43%**	30,183	13%	26,814

Revenue Variance

($ millions)	2008 Revenues Net of Royalties	Revenue Variances in: Price[1]	Volume	Other[2]	**2009 Revenues Net of Royalties**
Foster Creek and Christina Lake	$ 1,117	$ (94)	$ 286	$ (107)	**$ 1,202**

(1) Includes the impact of realized financial hedging.
(2) Revenue dollars reported include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and selling expense.

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Revenues, net of royalties, excluding realized financial hedging, decreased $19 million in 2009 compared to 2008 as a result of lower average crude oil prices offset by an increase in crude oil production of 43 percent. During 2009, financial hedging activities realized a gain of $37 million ($2.35 per bbl) compared to a loss of $67 million ($6.11 per bbl) in 2008 (2007 – loss of $43 million; $3.88 per bbl).

Our average crude oil sales price decreased 20 percent to $49.71 per bbl in 2009 from $62.44 per bbl in 2008 primarily due to a 38 percent decrease in average WTI prices over the year offset somewhat by the narrowing of the WCS differential.

Production at Foster Creek increased 41 percent in 2009 compared to 2008 as a result of production from the phase C and D/E expansions, as well as additional production from wedge wells, offset slightly by higher royalty rates. Production from phase C reached capacity of 60,000 bbls/d in the third quarter of 2008. Production from the phase D/E expansion commenced late in the first quarter of 2009 and ramped up throughout the year.

Production at Christina Lake increased 54 percent in 2009 compared to 2008 as a result of higher production from the phase B expansion which commenced production in the second quarter of 2008 slightly offset by higher royalty rates in 2009.

Transportation and selling costs are comprised mostly of condensate costs, as blending condensate with bitumen enables the product to be transported. During 2009, condensate volumes increased due to the higher production noted above, offset by a 45 percent decrease in the average price of condensate used for blending. This resulted in a reduction of transportation and selling costs to $430 million in 2009 from $526 million in 2008 (2007 - $366 million).

Operating costs in 2009 increased slightly to $176 million compared to $170 million in 2008 due to the significant increase in volumes combined with additional repairs and maintenance and a scheduled turnaround at Christina Lake in the fall of 2009. The increase in operating costs was offset by lower fuel costs due to declining natural gas prices as well as higher volumes of Athabasca natural gas production being used internally at Foster Creek, requiring less fuel to be purchased in the market.

DOWNSTREAM REFINING

Financial Results

($ millions)	**2009**	2008	2007
Revenues	**$ 5,280**	$ 9,011	$ 7,315
Expenses			
Operating	**453**	492	428
Purchased product	**4,517**	8,760	5,813
Operating Cash Flow	**$ 310**	$ (241)	1,074

Refinery Operations [1]

	2009	2008	2007
Crude oil capacity *(Mbbls/d)*	**452**	452	452
Crude oil runs *(Mbbls/d)*	**394**	423	432
Crude utilization *(%)*	**87**	93	96
Refined products *(Mbbls/d)*	**417**	448	457

(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, as well as processing capability to refine approximately 145,000 bbls/d of heavy crude oil (approximately 70,000 bbls/d of bitumen equivalent). Upon completion of the Wood River CORE project in 2011 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.

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During 2009, our refineries operated at an average of 87 percent of their capacity compared to 93 percent in 2008. Utilization was lower in 2009 primarily due to refinery optimization based on weakened market crack spreads, increased number of turnarounds at Wood River to advance the CORE project and unplanned maintenance at both refineries.

Revenues have decreased 41 percent and purchased product has decreased 48 percent in 2009, consistent with the decrease in crude oil prices. Purchased product, consisting mainly of crude oil, represented 91 percent of total expenses in 2009 compared to 95 percent in 2008. Operating costs, consisting mainly of labour, utilities and supplies, decreased eight percent in 2009 due to lower prices for electricity and fuel gas consumed at the refineries.

Operating Cash Flow for 2009 was $551 million higher than 2008 mainly due to lower purchased product costs more than offsetting lower refined product sales. The increase was partially offset by lower refinery utilization.

INTEGRATED OIL DIVISION - OTHER PROPERTIES

The Integrated Oil Division also manages our 100 percent owned natural gas operations in Athabasca. For 2009, natural gas production volumes from Athabasca decreased to 49 MMcf/d (2008 – 63 MMcf/d; 2007 – 91 MMcf/d) primarily as a result of increased usage of natural gas as a source of fuel for the Foster Creek operations as well as natural declines.

In November 2009, we sold our Senlac heavy oil assets for proceeds of approximately $83 million. Prior to the divestiture, Senlac production was 2,553 bbls/d in 2009 compared to 2,729 bbls/d in 2008 (2007 – 2,688 bbls/d).

INTEGRATED OIL DIVISION - CAPITAL INVESTMENT

($ millions)	**2009**	2008	2007
Upstream	**$ 476**	$ 644	$ 450
Downstream Refining	**907**	478	220
Total Integrated Oil Division	**$ 1,383**	$ 1,122	$ 670

Our Upstream capital investment in 2009 was primarily focused on the continued development of the next phases of the Foster Creek and Christina Lake properties. Capital investment was lower in 2009 because of lower drilling costs as we drilled fewer stratigraphic test wells at Foster Creek, Christina Lake and Borealis, combined with a lower foreign exchange rate. Our current plan is to increase production capacity at Foster Creek and Christina Lake to approximately 218,000 bbls/d of bitumen with the completion of Christina Lake phase C in 2011 and phase D in 2013. We have chosen to accelerate completion of Christina Lake phase D which we expect will advance start up by approximately six months.

Our Downstream Refining capital investment in 2009 continued to focus on the CORE project at the Wood River refinery, as we significantly increased capital expenditures to $907 million in 2009 from $478 million in 2008 (2007 - $220 million). The CORE project is expected to cost approximately $1.8 billion (net to Cenovus) and is anticipated to be completed and in operation in 2011. The expansion is expected to increase crude oil refining capacity by 50,000 bbls/d to 356,000 bbls/d and more than double heavy crude oil refining capacity at Wood River to 240,000 bbls/d. At December 31, 2009, construction on the CORE project was approximately 71 percent complete and continued to be on schedule and within budgeted costs.

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CANADIAN PLAINS DIVISION

Crude Oil and NGLs

Financial Results

($ millions)	**2009**	2008	2007
Revenues, Net of Royalties and excluding hedging	**$ 1,371**	$ 2,256	$ 1,540
Realized Financial Hedging Gain (Loss)	**2**	(150)	(87)
Expenses			
Production and mineral taxes	**24**	38	29
Transportation and selling	**179**	321	263
Operating	**229**	239	215
Operating Cash Flow	**$ 941**	$ 1,508	$ 946

Production Volumes

	2009	**2009 vs 2008**	2008	2008 vs 2007	2007
Heavy Oil *(bbls/d)*					
Pelican Lake	**20,105**	**-9%**	21,975	-5%	23,253
Southern Alberta	**12,038**	**-8%**	13,054	-16%	15,530
Light and Medium Oil *(bbls/d)*					
Weyburn	**14,948**	**7%**	14,031	-5%	14,771
Southern Alberta	**10,368**	**-7%**	11,099	-1%	11,246
Other	**5,405**	**-10%**	5,998	-2%	6,139
NGLs *(bbls/d)*	**1,186**	**0%**	1,181	-6%	1,260

Revenue Variance

($ millions)	2008 Revenues Net of Royalties	Revenue Variances in: Price[1]	Volume	Other[2]	**2009 Revenues Net of Royalties**
Canadian Plains	$ 2,106	$ (501)	$ (104)	$ (128)	**$ 1,373**

(1) Includes the impact of realized financial hedging.
(2) Revenue dollars reported include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and selling expense.

Crude oil and NGL revenues, net of royalties, excluding realized financial hedging, decreased $885 million in 2009 compared to 2008 due to lower commodity prices and production volumes.

The average crude oil sales price, excluding realized hedging, decreased 35 percent to $51.80 per bbl in 2009 from $79.09 per bbl in 2008, consistent with changes in the benchmark WTI and WCS crude oil prices. During 2009, crude oil and NGLs realized financial hedging gains were $2 million ($0.10 per bbl) compared to losses of $150 million ($6.02 per bbl) in 2008 (2007 – loss of $87 million; $3.32 per bbl).

Production volumes at Weyburn were seven percent higher in 2009 compared to 2008 mainly due to well optimizations and lower royalty rates partially offset by natural declines. At Pelican Lake, volumes were nine percent lower in 2009 compared to 2008 mainly due to natural declines and a scheduled facility turnaround partially offset by less facility downtime. Southern Alberta oil production was down eight percent from 2008 primarily due to expected natural declines partially offset by production from new wells.

Production and mineral taxes of $24 million in 2009 decreased from $38 million in 2008 (2007 - $29 million) consistent with lower crude oil prices.

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Transportation and selling costs of $179 million in 2009 decreased from $321 million in 2008 (2007 - $263 million) due to a 39 percent decrease in the average price and a nine percent decrease in volume of condensate used for blending with heavy oil.

Operating costs decreased to $229 million in 2009 from $239 million in 2008 (2007 - $215 million) due to a lower foreign exchange rate and lower workover activity partially offset by higher chemical usage and electricity costs. NGLs are a byproduct obtained through the production of natural gas and therefore operating costs associated with the production of NGLs are included with natural gas.

Natural Gas

Financial Results

($ millions)	**2009**	2008	2007
Revenues, Net of Royalties and excluding hedging	**$ 1,022**	$ 2,392	$ 1,946
Realized Financial Hedging Gain (Loss)	**880**	(91)	240
Expenses			
Production and mineral taxes	**13**	36	34
Transportation and selling	**39**	71	82
Operating	**210**	241	221
Operating Cash Flow	**$ 1,640**	$ 1,953	$ 1,849

Production Volumes

	2009	**2009 vs 2008**	2008	2008 vs 2007	2007
Natural Gas *(MMcf/d)*					
Southern Alberta	**739**	**-8%**	800	-4%	832
Other	**36**	**-14%**	42	-2%	43
	775		842		875

Revenue Variance

($ millions)	2008 Revenues Net of Royalties	Revenue Variances in: Price[1]	Volume	**2009 Revenues Net of Royalties**
Canadian Plains	$ 2,301	$ (210)	$ (189)	**$ 1,902**

(1) Includes the impact of realized financial hedging.

Natural gas revenues, net of royalties, excluding realized financial hedging, decreased $1,370 million in 2009 compared to 2008, primarily due to lower natural gas prices as well as lower production volumes. Average natural gas prices, excluding the impact of financial hedges, decreased to $3.62 per Mcf in 2009 from $7.77 per Mcf in 2008 consistent with the reduction in the benchmark AECO price. In 2009, we realized a financial hedging gain of $880 million ($3.11 per Mcf) compared to a loss of $91 million ($0.29 per Mcf) in 2008 (2007 – gain of $240 million; $0.75 per Mcf).

Production volumes for Southern Alberta decreased eight percent in 2009 compared to 2008 due to expected natural declines and lower drilling and tie-in activity in response to lower commodity prices partially offset by lower royalty rates.

Production and mineral taxes of $13 million in 2009 decreased from $36 million in 2008 (2007 - $34 million) primarily as a result of lower natural gas prices and lower production volumes.

Transportation and selling costs of $39 million in 2009 decreased from $71 million in 2008 (2007 - $82 million) due to lower volumes being shipped to eastern Canada and the eastern United States and the

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lower foreign exchange rate.

Operating expenses in 2009 decreased to $210 million from $241 million in 2008 (2007 - $221 million) mostly as a result of the lower foreign exchange rate

combined with a lower level of repair, maintenance and workover activity.

Canadian Plains - Other

Financial Results

($ millions)	2009	2008	2007
Revenues, Net of Royalties and excluding hedging	**$ 868**	$ 1,137	$ 1,824
Expenses			
Transportation and selling	**-**	-	10
Operating	**18**	22	23
Purchased product	**832**	1,101	1,751
Operating Cash Flow	**$ 18**	$ 14	$ 40

The Canadian Plains Division markets all of our crude oil and natural gas, including third party purchases and sales of product, in order to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification. The decrease in both revenues and purchased product expenses for 2009 compared to 2008 is consistent with decreased average market prices during 2009. Canadian Plains – Other also includes a small amount of third party processing fee income.

Capital Investment

Canadian Plains capital investment in 2009 was $478 million (2008 - $872 million; 2007 - $795 million). The $394 million decrease from 2008 was primarily the result of management's decision to reduce capital investment in response to lower commodity prices in 2009. The reduction came primarily from lower natural gas drilling, completion and tie-in activity, as well as the lower foreign exchange rate, and lower land acquisition expenditures, partially offset by higher heavy crude oil drilling activity. Canadian Plains drilled 614 net wells in 2009 compared to 1,476 net wells in 2008 (2007 – 2,264 net wells).

CORPORATE AND ELIMINATIONS

Financial Results

($ millions)	2009	2008	2007
Revenues	**$ (738)**	$ 576	$ (437)
Expenses			
Operating	**30**	(11)	(2)
Purchased product	**(99)**	(151)	(88)
Depreciation, depletion and amortization	**50**	23	45
General and administrative	**188**	167	145
Interest, net	**218**	218	187
Accretion of asset retirement obligation	**39**	39	28
Foreign exchange (gain) loss, net	**290**	(250)	380
(Gain) loss on divestitures	**(2)**	3	4
Segment Income (Loss)	**$ (1,452)**	$ 538	$ (1,136)

The Corporate and Eliminations segment includes revenues that represent the unrealized mark-to-market gains or losses related to derivative financial instruments used to mitigate fluctuations in commodity prices. The segment also includes inter-segment 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. Operating expenses primarily relate to mark-to-market gains and losses on long-term power purchase contracts and downstream crude oil supply positions. Depreciation, Depletion and Amortization

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("DD&A") includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

General and administrative expenses increased $21 million in 2009 compared to 2008 primarily due to higher long-term compensation costs as a result of the increased share price and expenses related to the creation of Cenovus offset by a lower foreign exchange rate.

Interest expense in 2009 was $218 million, unchanged from 2008 interest expense, of $218 million (2007 - $187 million) primarily as a result of our average level of debt outstanding and interest rates being consistent between 2008 and 2009. Our weighted average interest rate on outstanding debt at December 31, 2009 was 5.8 percent, compared to 5.5 percent in 2008.

We reported a foreign exchange loss of $290 million in 2009 compared to a gain of $250 million in 2008 (2007 – loss of $380 million), the majority of which was unrealized. We are exposed to foreign exchange gains and losses primarily on our U.S. dollar partnership contribution receivable and our U.S. dollar denominated debt issued from Canada. The strengthening of the Canadian dollar during 2009 led to unrealized losses on our partnership contribution receivable, which was partially offset by unrealized gains on our U.S. dollar debt. We also reported an unrealized foreign exchange loss of $107 million during the year relating to the translation of our U.S. dollar risk management assets and liabilities, compared to an unrealized gain of $2 million in 2008 (2007 – unrealized loss of $34 million). The loss incurred in 2009 was also primarily due to the strengthening of the Canadian dollar during the year.

Depreciation, Depletion and Amortization

In 2009, DD&A was $1,343 million compared to $1,318 million in 2008 (2007 - $1,426 million). We use full cost accounting for our upstream oil and gas activities and calculate DD&A on a country-by-country cost centre basis. Upstream DD&A of $1,101 million in 2009 was consistent with 2008 DD&A of $1,107 million (2007 - $1,222 million) as a result of a higher DD&A rate offset by a lower foreign exchange rate and slightly lower production volumes. In 2009, DD&A on our Downstream Refining assets was $192 million, which was consistent with 2008 DD&A of $188 million (2007 - $159 million). DD&A in the Corporate and Eliminations segment was $50 million for 2009 compared to $23 million for 2008 (2007 - $45 million).

Income Tax

Total income tax expense in 2009 was $302 million, which was $423 million lower than 2008 mainly due to lower earnings before income tax. Current income tax expense in 2009 was $853 million compared to $340 million in 2008, with the increase largely being attributable to the acceleration of income tax arising from the dissolution of EnCana's Canadian oil and gas partnership in connection with the Arrangement, as well as the realization of significant hedging gains in 2009. This accelerated current tax was offset by a future tax recovery for the tax that would have been paid in 2010. Current tax expense for the three years is primarily an allocation of EnCana's income tax liability on a carve-out accounting basis our portion of which was settled as part of the Arrangement and therefore we do not have any income tax payable at December 31, 2009.

In 2009, we had a future income tax recovery of $551 million compared to an expense of $385 million in 2008. The significant net recovery in 2009 is due to the reversal of the future tax which offsets the accelerated current income tax on partnership income, as noted above, as well as 2008 unrealized mark-to-market hedging gains.

In 2009, our effective tax rate was 31.8 percent compared to 23.4 percent in 2008. The increase is primarily due to the provision of future income tax on unrealized foreign exchange gains as well as a variety of rate differences.

Additional information regarding our effective tax rate can be found in the notes to the Consolidated Financial Statements. 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

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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;
- International financing; and
- Foreign exchange (gains) losses 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. As a result, there are usually some tax matters under review. We believe that our provision for taxes is adequate.

Summary of Unrealized Mark-to-Market Gains (Losses)

The volatility of commodity prices has a significant impact on our Net Earnings, and as a means of managing this volatility, we enter into various financial instrument agreements. The financial instrument agreements were recorded at the date of the financial statements based on mark-to-market accounting. Changes in the mark-to-market gain or loss reflected in corporate revenues 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 year. Additional information regarding financial instrument agreements can be found in the notes to the Consolidated Financial Statements.

($ millions)	**2009**	2008	2007
Revenues			
Crude Oil	**$ (98)**	$ 212	$ (161)
Natural Gas	**(541)**	515	(188)
	(639)	727	(349)
Expenses	**28**	(7)	(1)
	(667)	734	(348)
Income Tax Expense (Recovery)	**(194)**	215	(104)
Unrealized Mark-to-Market Gains (Losses), after tax	**$ (473)**	$ 519	$ (244)

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QUARTERLY FINANCIAL DATA

($ millions, except per share amounts)	**2009**				2008			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Revenues, Net of Royalties	**$ 2,835**	**$ 2,714**	**$ 2,429**	**$ 2,162**	$ 3,207	$ 5,533	$ 4,381	$ 3,438
Operating Cash Flow [1]	**909**	**1,032**	**1,008**	**746**	101	1,133	1,518	1,098
Cash Flow [1]	**225**	**841**	**811**	**595**	(174)	1,123	1,228	911
- per share – diluted [2]	**0.30**	**1.12**	**1.08**	**0.79**	(0.23)	1.50	1.63	1.21
Operating Earnings [1]	**152**	**382**	**447**	**331**	(123)	611	710	431
- per share – diluted [2]	**0.20**	**0.51**	**0.59**	**0.44**	(0.16)	0.81	0.95	0.57
Net Earnings	**24**	**63**	**149**	**412**	380	1,299	522	167
- per share – basic [2]	**0.03**	**0.08**	**0.20**	**0.55**	0.51	1.73	0.70	0.22
- per share – diluted [2]	**0.03**	**0.08**	**0.20**	**0.55**	0.51	1.73	0.70	0.22
Capital expenditures	**481**	**471**	**416**	**524**	626	469	435	516
Free Cash Flow [1]	**(256)**	**370**	**395**	**71**	(800)	654	793	395
Cash Dividends [3]	**151**	**-**	**-**	**-**	-	-	-	-

(1) Non-GAAP measures which are defined in this MD&A.
(2) Any per share amounts prior to December 1, 2009 have been calculated using EnCana's common share balances based on the terms of the Arrangement where EnCana shareholders received one common share of Cenovus and one common share of the new EnCana.
(3) We declared and paid a dividend of $0.20 per share in December 2009. The December dividend reflects an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

Our Cash Flow in the fourth quarter of 2009 increased $399 million compared to the fourth quarter of 2008. The main drivers for the increase in Cash Flow were:

- The improvement of downstream operating cash flow in 2009 was the result of the fourth quarter in 2008 being impacted by a 50 percent drop in crude oil prices compared to the third quarter of 2008, resulting in a much lower inventory carrying value at December 31, 2008, thereby resulting in much higher purchased product costs;
- Increase in the average liquids sales price, before hedging, to $61.08 per bbl compared to $30.47 per bbl in 2008; and
- Increase in crude oil and NGLs production of 11 percent.

Partially offsetting the increases were the following:

- An increase in current tax of $360 million on the acceleration of current tax payable, resulting in no income tax payable at December 31, 2009, due to the dissolution of EnCana's Canadian oil and gas partnership in connection with the Arrangement;
- A decrease in natural gas average sales prices, excluding hedging, of 30 percent; and
- A decrease in natural gas production of 13 percent.

Our Net Earnings in the fourth quarter of 2009 were $24 million, which were $356 million lower than 2008. The factors that increased Cash Flow in the fourth quarter increased Net Earnings but were offset by the following factors that resulted in an overall decrease to Net Earnings:

- Unrealized hedging loss of $143 million compared to a gain of $386 million in the fourth quarter of 2008; and
- Higher Operating, General and Administrative and DD&A expenses.

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OIL AND GAS RESERVES

PROVED AND PROBABLE RESERVES AS AT DECEMBER 31

Constant Prices After Royalties	Bitumen (millions of barrels)			Crude Oil and NGLs[1] (millions of barrels)			Natural Gas (billions of cubic feet)		
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Proved	**719**	668	596	**232**	241	231	**1,474**	1,855	2,019
Probable	**403**	624	537	**127**	136	119	**405**	522	569

(1) Crude Oil and NGLs include condensate.

All of our bitumen, crude oil, NGLs and natural gas reserves are located in Canada. Each year, we engage independent qualified reserves evaluators to prepare reports on 100 percent of our reserves. We have a Reserves Committee of independent members of our Board, which reviews the qualifications and appointment of the independent qualified reserves evaluators. The Reserves Committee also reviews the procedures for providing information to the evaluators. Our disclosure of reserves data is prescribed by National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") of the Canadian Securities Administrators as amended by a Decision dated October 20, 2009 permitting the adoption of U.S. reporting standards, including compliance with the practices and procedures of the U.S. Securities and Exchange Commission ("SEC") and U.S. Financial Accounting Standards Board ("FASB") reserves reporting requirements.

As of December 31, 2009, the SEC requires companies to determine their oil and gas reserves using an average price based upon the prior 12-month period, rather than year-end prices. The SEC also now permits companies to disclose their probable and possible reserves in their SEC filings.

PROVED RESERVES RECONCILIATION

Constant Prices after Royalties As at December 31, 2009	Bitumen (millions of barrels)	Crude Oil and NGLs[1] (millions of barrels)	Natural Gas (billions of cubic feet)
Beginning of year	668	241	1,855
Revisions and improved recovery	(88)	8	(128)
Extensions and discoveries	160	6	50
Divestitures	(4)	-	(2)
Production	(17)	(23)	(301)
End of year	**719**	**232**	**1,474**

(1) Crude Oil and NGLs includes condensate.

In 2009, our bitumen reserves extensions and discoveries were approximately 160 million barrels, primarily as a result of Christina Lake phase D receiving approval to proceed. The increase was partially offset by negative revisions of approximately 88 million barrels attributed to higher royalty rates resulting from a higher WTI price. In addition, as a result of the new Alberta Royalty Framework, where royalties are determined on a sliding scale depending on the price of bitumen, when prices are between C$55 per barrel and C$120 per barrel, pre-payout royalty rates range from one to nine percent of gross revenue. Once a project reaches payout the royalty is based on the greater of one to nine percent of a project's gross revenue or 25 to 40 percent of net revenue. Our crude oil and NGLs reserves decreased by approximately four percent year over year as aggregate revisions and improved recoveries and extensions and discoveries did not fully offset our production. Our natural gas reserves negative revisions were approximately 128 billion cubic feet mainly due to low natural gas prices.

Additional disclosure relating to our oil and gas reserves is contained in our Annual Information Form for the year ended December 31, 2009 which can be accessed at www.sedar.com and on our website atwww.cenovus.com.

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LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2009	2008	2007
Net cash from (used in)			
Operating activities	**$ 3,496**	$ 2,687	$ 3,014
Investing activities	**(1,780)**	(1,964)	(1,533)
Net cash provided before Financing activities	**1,716**	723	1,481
Financing activities	**(1,730)**	(852)	(1,292)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**9**	(20)	7
Increase (decrease) in cash and cash equivalents	**$ (5)**	$ (149)	$ 196

OPERATING ACTIVITIES

Net cash from operating activities increased to $3,496 million in 2009 compared to $2,687 million in 2008 (2007 - $3,014 million). Cash Flow was $2,472 million during 2009 compared to $3,088 million in 2008. Reasons for this change are discussed under the Cash Flow section of this MD&A. Cash from operating activities was also impacted by net changes in other assets and liabilities and net changes in non-cash working capital, primarily from increases in inventories, accounts receivable and accrued revenues and current income taxes partially offset by increases in accounts payable and accrued liabilities.

Excluding the impact of risk management assets and liabilities, we had working capital of $457 million at December 31, 2009 compared to a working capital deficit of $191 million at December 31, 2008. We anticipate that we will continue to meet the payment terms of our suppliers.

INVESTING ACTIVITIES

Net cash used for investing activities in 2009 decreased to $1,780 million from $1,964 million in 2008. Capital expenditures decreased in 2009 to $1,895 million compared to $2,046 million in 2008. Divestitures were $162 million higher than 2008 and were substantially offset with increases in cash used for investing activities from net changes in non-cash working capital. The decreased capital expenditures are discussed under the Net Capital Investment and Divisional Results sections of this MD&A.

FINANCING ACTIVITIES

On September 18, 2009, a predecessor entity of Cenovus completed a private offering of senior unsecured notes for an aggregate principal amount of $3.5 billion, issued in three tranches, which are exempt from the registration requirements of the U.S. Securities Act of 1933 under Rule 144A and Regulation S. The net proceeds of the private offering, along with $151 million deposited by the Company, were placed into an escrow account pending the completion of the Arrangement with EnCana. Upon completion of the Arrangement, funds were released from escrow and the proceeds of the notes were then used to pay the note payable to EnCana of $3.5 billion as part of the Arrangement. On November 30, 2009, the notes became the direct, unsecured obligations of Cenovus.

We currently have in place an unsecured credit facility in the amount of Canadian $2.5 billion or its equivalent amount in U.S. dollars. The revolving syndicated credit facility consists of two tranches, a Canadian $2.0 billion 3-year tranche and a Canadian $500 million 364-day tranche. At December 31, 2009, we had available $2.3 billion (Canadian $2.4 billion) in unused credit capacity under this facility. We are currently in compliance with all of our financial covenants under this credit facility.

We declared and paid a dividend of $151 million ($0.20 per share) in December 2009. The December dividend reflects an amount determined in connection with the Arrangement based on carved-out earnings and cash flows. Future dividends will be at the sole discretion of the Board and considered quarterly.

It is Cenovus's intention to maintain investment grade credit ratings on our senior unsecured debt. DBRS Limited has assigned a rating of "A (low)" with a "Stable" outlook, Standard & Poor's Corporation has assigned a rating of BBB+ with a "Stable" outlook and Moody's Investors Service, Inc. has assigned a rating of Baa2 with a "Stable" outlook.

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As at December 31, 2008, our current and long-term debt represented an allocation of our proportionate share of EnCana's consolidated current and long-term debt. As a result, the debt allocations presented in the Consolidated Financial Statements at December 31, 2008 represented intercompany balances between EnCana and Cenovus with the same terms and conditions as EnCana's long-term debt and in the same proportion of Canadian and U.S. dollar denominated debt.

Our net cash used in financing activities for 2009 of $1,730 million, includes $3,468 million of net proceeds from the private offering of the notes, as well as the repayment of the $3.5 billion demand promissory note to EnCana. Subsequent to the completion of the Arrangement, Cenovus made a payment to EnCana in the amount of $250 million to adjust the cash balances of both companies at November 30, 2009 to the agreed upon amounts pursuant to the Arrangement. Our debt, including current portion, was $3,493 million as at December 31, 2009 compared with $3,036 million as at December 31, 2008.

FINANCIAL METRICS

	2009	2008	2007
Debt to Capitalization	**28%**	28%	32%
Debt to Adjusted EBITDA (times)	**1.2x**	0.7x	1.0x

Cenovus monitors its capital structure and short-term financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. Capitalization is a non-GAAP measure defined as long-term debt including current portion plus Shareholders' Equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as Adjusted Earnings before Interest, Income Taxes, DD&A and foreign exchange gains/losses. These metrics are used to steward Cenovus's capital structure. Debt is defined as the current and long-term portions of long-term debt.

We target a Debt to Capitalization ratio between 30 to 40 percent and a Debt to Adjusted EBITDA between 1.0 to 2.0 times.

OUTSTANDING SHARE DATA

(millions)	2009
Common Shares issued pursuant to the Arrangement	751.3
Outstanding, End of year	751.3

Cenovus is authorized to issue an unlimited number of Common Shares (the "Common Shares"), an unlimited number of first preferred shares and an unlimited number of second preferred shares. There were no first preferred shares or second preferred shares outstanding as at December 31, 2009.

Pursuant to the Arrangement, each shareholder of EnCana received one new common share of EnCana (which continued to be represented by EnCana common share certificates outstanding prior to the Arrangement becoming effective) and one Common Share of Cenovus for every EnCana common share held. In aggregate, 751,273,307 Common Shares were issued pursuant to the Arrangement.

The Cenovus Employee Stock Option Plan permits our Board, from time to time, to grant to employees of Cenovus and its subsidiaries stock options to purchase our Common Shares. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. As at December 31, 2009, our options are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the date granted. Stock options granted have an associated Tandem Share Appreciation Right ("TSAR") attached, which gives employees the right to elect to receive a cash payment equal to the excess of the market price of our Common Shares over the exercise price of their stock option in exchange for surrendering their stock option. A portion of the TSARs have an additional vesting condition which is subject to the Company attaining prescribed performance relative to key pre-determined measures. Performance TSARs that do not vest when eligible are forfeited. The exercise of a TSAR for a

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cash payment does not result in the issuance of any additional Common Shares, thus it has no dilutive effect.

In accordance with the Arrangement with EnCana, each holder of EnCana TSARs and stock options disposed of a portion of their right to Cenovus in exchange for Cenovus Replacement Units and to EnCana for EnCana Replacement Units. The terms and conditions of the Cenovus Replacement Units are similar to the terms and conditions of the original EnCana units, which are also similar, to the terms and conditions of Cenovus TSARs and stock options. The original exercise price of the EnCana units were apportioned to the Cenovus and EnCana Replacement Units based on the one-day weighted average trading price of Cenovus's common share price relative to that of EnCana's common share price on the TSX on December 2, 2009.

At December 31, 2009, Cenovus employees held approximately 16 million Cenovus TSARs, of which 6 million were exercisable.

At December 31, 2009 EnCana employees held approximately 23 million Cenovus TSARs, of which 10 million were exercisable. EnCana is required to reimburse Cenovus in respect of cash payments made to EnCana employees for the Cenovus TSARs held. No further Cenovus TSARs will be granted to EnCana's employees. Cenovus is required to reimburse EnCana in respect of cash payments made to Cenovus employees for the Cenovus Replacement Units held. No further EnCana Replacement Units will be granted to Cenovus's employees.

At December 31, 2009 there were approximately 0.2 million options without TSARs attached outstanding, all of which were exercisable.

Cenovus employees hold Cenovus Share Appreciation Rights, Cenovus Deferred Share Units, EnCana Tandem Share Appreciation Rights and EnCana Share Appreciation Rights and Cenovus directors hold Cenovus Deferred Share Units for which Cenovus is responsible. These units do not result in the issuance of any additional Cenovus Common Shares and therefore have no dilutive effect.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS[1]

	Expected Payment Date						
($ millions)	2010	2011	2012	2013	2014	2015+	Total
Long-Term Debt[2]	$ -	$ -	$ 56	$ -	$ 800	$ 2,700	$ 3,556
Partnership Contribution Payable[2]	325	345	366	388	412	1,021	2,857
Asset Retirement Obligation	68	11	11	12	16	5,312	5,430
Pipeline Transportation	101	95	68	141	141	923	1,469
Purchase of Goods and Services	98	9	4	3	-	-	114
Product Purchases	26	23	22	22	22	28	143
Operating Leases [3]	26	27	34	72	76	1,575	1,810
Capital Commitments	105	85	33	-	-	-	223
Total Payments	$ 749	$ 595	$ 594	$ 638	$ 1,467	$ 11,559	$ 15,602
Product Sales	$ 46	$ 48	$ 52	$ 53	$ 55	$ 119	$ 373
Partnership Contribution Receivable[2]	$ 330	$ 347	$ 366	$ 386	$ 407	$ 998	$ 2,834

(1) In addition, we have commitments related to our risk management program (see notes to the Consolidated Financial Statements), and an obligation to fund our defined benefit pension and Other Post-Employment Benefit plans as disclosed in the notes to the Consolidated Financial Statements.
(2) Principal component only. See notes to the Consolidated Financial Statements.
(3) Operating leases consist of building leases.

We have entered into various commitments in the normal course of operations primarily related to debt, demand charges on firm transportation agreements, capital commitments and marketing agreements.

As at December 31, 2009, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 33 MMcf/d, with varying terms and volumes through

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2017. The total volume to be delivered within the terms of these contracts is 85 Bcf at a weighted average price of $4.39 per Mcf.

In the normal course of business, we also lease office space for personnel who support field operations and for corporate purposes.

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 risks (such as commodity price, foreign exchange and interest rates), credit and liquidity risks;
- Operational risks including capital, operating and reserves replacement risks; and
- Safety, environmental and regulatory risks.

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 Corporate Risk Management 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 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 identifying and managing these issues.

FINANCIAL RISKS

Financial risks are defined as the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on our business.

We continue to implement our business model which focuses on developing low-risk and low-cost long-life resource properties. Management has been monitoring our operational and financial risk strategies to proactively respond to the changing economic conditions and to mitigate or reduce risk. The prudent and conservative capital budget for 2010 continues to be monitored and it contains the flexibility to allow spending to be reduced or increased as commodity prices and forecasts are revised. Cost containment and reduction strategies are in place to help ensure our controllable costs are efficiently managed. Counterparty and credit risks are closely monitored as is our liquidity to help ensure our ability to access cost effective credit is maintained and that sufficient cash resources are in place to fund capital expenditures. Further insight into these risks and strategies is summarized below.

We partially mitigate our exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative instruments is governed under formal policies and is subject to limits established in our Market Risk Mitigation Policy. As a means of mitigating exposure to commodity price risk volatility, we have entered into various financial instrument agreements in respect of our operations. The details of these instruments, including any unrealized gains or losses, as of December 31, 2009, are disclosed in the notes to the Consolidated Financial Statements.

Policies, practices and procedures are in place with respect to the required documentation and approvals for the use of derivative financial instruments and specifically tie their use, in the case of commodities, to the mitigation of price risk to achieve targeted investment returns and growth objectives, while maintaining prescribed financial metrics.

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With respect to transactions involving our production or assets, the financial instruments generally used are swaps or options which are entered into with major financial institutions, integrated energy companies or commodities trading institutions.

COMMODITY PRICE

Commodity price risk is defined as the uncertainties and fluctuations of future market prices for commodities. To partially mitigate the commodity price risk, we enter into swaps and puts, which establish NYMEX floor prices. For crude oil, we have partially mitigated our exposure to commodity price risk on our crude oil sales and condensate supply with fixed price swaps. For natural gas, to partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, Cenovus has entered into basis swaps to manage the price differentials between these production areas and various sales points. We have mitigated some of our exposure to electricity consumption costs, with two derivative contracts which do not expire until December 31, 2018.

CREDIT

Credit risk is defined as the potential for loss if a counterparty in a transaction fails to meet its obligations in accordance with agreed terms. A substantial portion of our accounts receivable is with customers in the oil and gas industry. This credit exposure is mitigated through the use of our Board-approved credit policies governing our credit portfolio and with credit practices that limit transactions according to counterparties' credit quality and transactions that are fully collateralized. All financial derivative agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings.

LIQUIDITY

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including: cash and cash equivalents, cash from operating activities and undrawn credit facilities. At December 31, 2009, Cenovus had approximately $2.3 billion in unused credit capacity available on its committed bank credit facility.

FOREIGN EXCHANGE

Foreign exchange risk is defined as the risk of gains or losses that could result from changes in foreign currency exchange rates. As we operate in North America, fluctuations in the exchange rate between the U.S. and Canadian dollar can have a significant effect on our reported results.

As a means of mitigating the exposure to fluctuations in the U.S./Canadian dollar exchange rate, we may enter into foreign exchange contracts, in conjunction with crude oil marketing transactions. In addition, we may hedge commodity exposures in Canadian dollars. Gains or losses on these contracts are recognized when the difference between the average month spot rate and the rate on the date of settlement is determined. All foreign exchange agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. By maintaining U.S. and Canadian operations, we have a natural hedge to some foreign exchange exposure.

We also have the flexibility to maintain a mix of both U.S. dollar and Canadian dollar debt, which helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, we may enter into cross currency swaps on a portion of our debt as a means of managing the U.S./Canadian dollar debt mix.

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INTEREST RATES

Interest rate risk is defined as the impact of changing interest rates on earnings, cash flows and valuations. Although the majority of our debt portfolio was fixed rate debt at December 31, 2009, we have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of our bank credit facilities. We may also enter into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

OPERATIONAL RISKS

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on our ability to achieve our objectives.

Our ability to operate, generate cash flows, complete projects and value reserves is dependent on financial risks, including commodity prices mentioned above, continued market demand for our products and other risk factors outside of our control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for our commitments; the ability to obtain necessary approvals; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour; and reservoir quality.

If we fail to acquire or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels and, therefore, our cash flows are highly dependent upon successfully exploiting current reserves and acquiring, discovering or developing additional reserves.

To mitigate these risks, as part of the capital approval process, we evaluate projects on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a process called Lookback and Learning. In this process, each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the operational issues that had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these Lookback and Learning results are analyzed for our capital program with the results and identified learnings shared across our company.

We utilize a peer review process to ensure that capital projects are appropriately risked and that knowledge is shared across our company. Peer reviews are undertaken primarily for early stage properties, although they may occur for any type of project.

When making operating and investing decisions, our business model allows flexibility in capital allocation to optimize investments focused on strategic fit, project returns, long-term value creation, and risk mitigation. We also mitigate operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program in respect of our assets and operations.

SAFETY, ENVIRONMENTAL AND REGULATORY RISKS

We are engaged in relatively high risk activities of integrated enhanced oil development and natural gas production. We are committed to safety in our operations and with high regard for the environment and stakeholders, including regulators. These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, we maintain a system, in respect of our assets and operation, that identifies, assesses and controls safety, security and environmental risk and requires regular reporting to Senior Management and our Board. The Safety, Environment and Responsibility Committee of our Board provides recommended environmental policies for approval by our Board and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental

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and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation strategies are utilized to restore the environment. In addition, security risks are managed through a security program designed to protect our personnel and assets.

We have an Investigations Committee with the mandate to address potential violations of policies and practices and an Integrity Helpline that can be used to raise any concerns regarding operations, accounting or internal control matters which includes any such matters associated with us.

Our operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact our existing and planned projects as well as impose a cost of compliance.

Regulatory and legal risks are identified by the operating divisions and corporate groups, and our compliance with the required laws and regulations is monitored by our legal group in respect of our assets and operations. Our legal and environmental policy groups stay abreast of new developments and changes in laws and regulations to ensure that we continue to comply with prescribed laws and regulations. Of note in this regard, our approach to changes in regulations relating to climate change and royalty frameworks is discussed below. To partially mitigate resource access risks, keep abreast of regulatory developments and be a responsible operator, we maintain relationships with key stakeholders and conduct other mitigation initiatives mentioned herein.

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 United States and Canada. These include proposed federal legislation and state actions in the United States to develop statewide or regional programs, each of which could impose reductions in GHG emissions. While some jurisdictions have provided details on these regulations, it is anticipated that other jurisdictions will announce emission reduction plans in the future. Adverse impacts to our business if comprehensive GHG legislation 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 adding costs to the products we produce and reduced 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 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.

The Alberta government has set targets for GHG emissions reductions. In March 2007, regulations were amended to require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline starting July 1, 2007. To comply, companies can make operating improvements, purchase carbon offsets (or emission performance credits) or make a C$15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. Cenovus currently has three facilities subject to this regulation that will report performance against their targets in March 2010 and for the 2009 compliance year does not anticipate material costs.

The American Clean Energy and Security Act (the "Act") was passed by the U.S. House of Representatives on June 26, 2009 and similar measures have been contemplated by the U.S. Senate. Some of the climate change bills being contemplated in the U.S. would require refiners to purchase credits equivalent to the

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CO_2 emissions from both their refineries and from consumer emissions. If this approach was enacted into law, this could have a material impact on the cost structure of refined petroleum products.

Our efforts with respect to emissions management are founded in our industry leadership in CO_2 sequestration, a focus on energy efficiency and the development of technology to reduce GHG emissions. In particular, our industry leading steam to oil ratio at Foster Creek and Christina Lake translates directly into lower emissions intensity. Given the uncertainty in North American carbon legislation, our strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

1. Manage Existing Costs
   When regulations are implemented, a cost is placed on our emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking attention to fuel consumption and a focus on minimizing our steam to oil ratio help to support and drive our focus on cost reduction.

2. Respond to Price Signals
   As regulatory regimes for GHGs develop in the jurisdictions where we work, inevitably price signals begin to emerge. We have initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of our operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon reduction, we are also attempting, where appropriate, to realize the associated value of our reduction projects.

3. Anticipate Future Carbon Constrained Scenarios
   We continue to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, we gain useful knowledge that allows us to explore different strategies for managing our emissions and costs. These scenarios inform our long range planning and our analyses on the implications of regulatory trends.

We incorporate the potential costs of carbon into future planning. Management and the Board review the impact of a variety of carbon constrained scenarios on our strategy, with a current price range from $15 to $65 per tonne of emissions applied to a range of emissions coverage levels. A major benefit of applying a range of carbon prices at the strategic level is that it provides direct guidance to the capital allocation process. We also examine the impact of carbon regulation on our major projects. Although uncertainty remains regarding potential future emissions regulation, our plan is to continue to assess and evaluate the cost of carbon relative to our investments across a range of scenarios.

We recognize that there is a cost associated with carbon emissions. We are confident that GHG regulations and the cost of carbon at various price levels have been adequately accounted for as part of our business planning and scenarios analysis. We believe that our development strategy is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. We are committed to transparency with our stakeholders and will keep them apprised of how these issues affect operations.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner which maintains and enhances our reputation and credibility. A central aspect of this commitment involves engagement with our various stakeholders, including shareholders and other investors, financial institutions, employees, business partners, communities, Aboriginal peoples, governments and non-governmental organizations. We will continue to disclose information about our business activities to

our stakeholders in a timely and transparent manner to maintain and advance our reputation as a responsible operator, as well as to develop trust with our stakeholders. We disclose information that is not only required by law and/or regulation, but also additional information that management regards as important to help stakeholders understand our activities, policies, opportunities and risks. Our engagement with stakeholders also allows us to determine how they are each affected by our business. Feedback that we receive from stakeholders enables us to better identify and manage our environmental and socio-economic risks.

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We are reviewing our existing Corporate Responsibility ("CR") policy to ensure that it not only continues to drive our commitments, strategy and reporting, but also that it maintains alignment with our business objectives and processes. Our reporting process will focus on improving performance through better data management, stakeholder engagement and continuous improvement. Our approach in this first year is to communicate our key performance indicators using the Cenovus website as the main reporting vehicle.

As our CR reporting process matures, additional indicators will be developed that better reflect Cenovus's operations and challenges. These indicators will be integrated into our CR reporting and will expand our online presence through our website.

We are committed to integrating the principles of corporate responsibility into the way we conduct our business across all of our operations and we recognize the importance of reporting to stakeholders in a transparent and accountable way.

ALBERTA'S NEW ROYALTY PROGRAMS

The Alberta Government's New Royalty Framework ("NRF") and Transitional Royalty Program ("TRP") came into effect on January 1, 2009. The NRF established new royalties for conventional oil, natural gas and bitumen that are linked to commodity prices, well production volumes and well depths for gas wells and oil quality for oil wells. These new rates apply to both new and existing conventional oil and gas activities and EOR properties in Alberta. The TRP allows for a one time option of selecting between transitional rates and the NRF rates on new natural gas or conventional oil wells drilled between 1,000 metres to 3,500 metres in depth. The TRP rates would apply until January 1, 2014, at which time all wells would be moved to the NRF.

On March 3, 2009, the Alberta Government announced an Energy Incentive Program that focuses on keeping drilling and service crews at work. There are two components of this program that affect us: the Drilling Royalty Credit and the New Well Incentive. The Drilling Royalty Credit is a depth related credit for the drilling of new conventional oil and gas wells between April 1, 2009 and March 31, 2011. The New Well Incentive provides a maximum five percent royalty rate for new gas and conventional oil wells that come on production between April 1, 2009 and March 31, 2011 for a period of 12 months or 0.5 billion cubic feet equivalent ("Bcfe") for gas wells or 50,000 barrels of oil equivalent ("BOE") for oil wells, whichever comes first.

Impacts as a result of the NRF, TRP and Energy Incentive Programs change the economics of operating in Alberta, and accordingly, are reflected in our capital programs in respect of our assets and operations.

We are committed to continuing to work with the Alberta Government during its competitive review process.

ACCOUNTING POLICIES AND ESTIMATES

Management is required to make judgments, assumptions and estimates in the application of GAAP that have a significant impact on our financial results. The basis of presentation for the Consolidated Financial Statements and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to understanding our financial results.

Basis of Presentation

Our results for the period from December 1 to December 31, 2009 represent our operations, cash flows and financial position as a stand-alone entity.

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Our results for the periods prior to the Arrangement with EnCana, being January 1 to November 30, 2009 as well as the years ended December 31, 2008 and 2007 have been prepared on a "carve-out" accounting basis, whereby the results have been derived from the accounting records of EnCana using the historical results of operations and historical basis of assets and liabilities of the businesses transferred to Cenovus. The historical consolidated financial statements include allocations of certain EnCana expenses, assets and liabilities. In the opinion of Management, the consolidated and the historical carve-out consolidated financial statements reflect all adjustments necessary for a fair statement of the financial position and the results of operations and cash flows in accordance with Canadian GAAP.

The presentation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. Management believes that the assumptions underlying the historical consolidated financial statements are reasonable. However, as we operated as part of EnCana and were not a stand-alone company prior to November 30, 2009, the historical consolidated financial statements included herein may not necessarily reflect our results of operations, financial position and cash flows had we been a stand-alone company during the periods presented.

Full Cost Accounting

Crude oil and natural gas properties are accounted for in accordance with the Canadian Institute of Chartered Accountants ("CICA") guideline on full cost accounting in the oil and gas industry. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the

acquisition of, exploration for, and the development of crude oil and natural gas reserves, are capitalized on a country-by-country cost centre basis and costs associated with production are expensed. The capitalized costs, including estimated future development costs, are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in reserves estimate could result in a higher DD&A charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserves estimates (see asset impairment discussion below), the excess must be written off as an expense charged against earnings. In the event of a property divestiture, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20 percent or greater.

Oil and Gas Reserves

All of our oil and gas reserves are evaluated and reported on by independent qualified reserves evaluators. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery based on cash flow forecasts.

Asset Impairments

Under full cost accounting, a ceiling test is performed to ensure that unamortized capitalized costs in each cost centre do not exceed their fair value. An impairment loss is recognized in Net Earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to an amount by which the carrying amount exceeds the sum of:

i) the fair value of proved and probable reserves; and
ii) the costs of unproved properties that have been subject to a separate impairment test.

An impairment loss is recognized on downstream refining property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual

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disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the refinery asset exceeds the discounted future cash flows from the refinery asset.

Our property, plant and equipment has been assessed for impairment as at December 31, 2009 and it has been determined that no write-down was required under Canadian GAAP.

Asset Retirement Obligations

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made. Asset retirement obligations are legal obligations associated with the requirement to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing plants and refining facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings. Amounts recorded for asset retirement obligations are based on estimates of reserves and on retirement costs, which will not be incurred for several years. Actual expenditures incurred are charged against the accumulated obligation.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to the country cost centre level, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of Goodwill and comparing that amount to the book value of the reporting unit's Goodwill. Any excess of the book value of Goodwill over the implied fair value of Goodwill is the impairment amount.

Our Goodwill has been assessed for impairment as at December 31, 2009 and it has been determined that no write-down was required.

Income Taxes

Income taxes are accounted for using the liability method. Under this method, future income taxes are estimated and recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in Net Earnings in the period that the change occurs.

Tax interpretations, regulations and legislation in the various jurisdictions in which we (and our subsidiaries) operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Derivative Financial Instruments

We may use derivative financial instruments to manage exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Derivative financial instruments are not used for speculative purposes.

We enter into financial transactions to help reduce exposure to price fluctuations with respect to commodity purchase and sale transactions to achieve targeted investment returns and growth objectives,

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while maintaining prescribed financial metrics. These transactions generally are swaps, collars or options and are generally entered into with major financial institutions or commodities trading institutions.

We may also use derivative financial instruments, such as interest rate swap agreements, to manage the fixed and floating interest rate mix of our total debt portfolio and related overall cost of borrowing. Interest rate swap agreements involve the periodic exchange of payments, without the exchange of the normal principal amount upon which the payments are based, and are recorded as an adjustment of interest expense on the hedged debt instrument.

We may also purchase foreign exchange forward contracts to hedge anticipated sales to customers in the United States. Foreign exchange translation gains and losses on these instruments are recognized as an adjustment of the revenues when the sale is recorded.

Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in Net Earnings. Realized gains or losses from financial derivatives related to crude oil and natural gas prices are recognized in revenues as the related sales occur. Unrealized gains and losses are recognized in revenues at the end of each respective reporting period. The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts. The estimated fair value of financial assets and liabilities, by their very nature, is subject to measurement uncertainty.

In 2009, we elected not to designate any of our price risk management activities as accounting hedges and, accordingly, accounted for all derivatives using the mark-to-market accounting method. Mark-to-market gains and losses resulting from derivative financial instruments entered into by EnCana have been allocated to Cenovus based on the related product volumes.

We also have obligations for payments (to employees of Cenovus) under the share appreciation rights, stock options with TSARs attached, performance share appreciation rights, and performance TSARs of EnCana. The financial liability for this obligation is accrued using the fair value method, and therefore fluctuations in the fair value of the rights will affect the accrued compensation expense that is recognized. The fair value of the obligation fluctuates, as it is based on assumptions for risk-free discount rate, dividend yield, as well as the volatility of our Cenovus share price.

Pensions and Other Post-Employment Benefits

Accruals for the obligations under the employee benefit plans and the related costs are recorded net of plan assets.

The cost of pensions and other post-employment benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The accrued benefit obligation is discounted using the market interest rate on high quality corporate debt instruments as at the measurement date.

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. The amortization period covers the expected average remaining service lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plan.

Pension and other post-employment benefits costs, assets and liabilities have been allocated to us based on Management's best estimate of how services were historically provided by existing employees. Costs,

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assets and liabilities associated with retired employees remain with EnCana. Where service amounts are provided by an individual to both EnCana and Cenovus, those costs including salaries, benefits, pension and long-term incentives have been allocated equally between EnCana and Cenovus.

Performance TSARs and Performance SARs

These plans provide for a range of payouts, based on key predetermined performance measures. The cost of these plans is expensed based on expected payouts. However, the amounts to be paid, if any, may vary from the current estimate. Further details on these plans are disclosed in the notes to our Consolidated Financial Statements.

NEW ACCOUNTING STANDARDS ADOPTED

On January 1, 2009, we adopted the CICA Handbook Section 3064 "Goodwill and Intangible Assets". The adoption of this standard has had no material impact on our Consolidated Financial Statements. Additional information on the effects of the implementation of the new standard can be found in the notes to the Consolidated Financial Statements.

RECENT ACCOUNTING PRONOUNCEMENTS

As of January 1, 2011, we will be required to adopt the following CICA Handbook sections which have been converged with International Financial Reporting Standards ("IFRS"):

Business Combinations

"Business Combinations", Section 1582, replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a

business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of earnings. The adoption of this standard will impact the accounting treatment of future business combinations.

Consolidated Financial Statements

"Consolidated Financial Statements", Section 1601, which together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on our Consolidated Financial Statements.

Non-controlling Interests

"Non-controlling Interests", Section 1602, establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, Net Earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on our Consolidated Financial Statements.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In 2011, IFRS will replace Canadian GAAP for profit-oriented Canadian publicly accountable enterprises. We will be required to report our results in accordance with IFRS beginning with the 3 month period ending March 31, 2011.

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Our IFRS Transition Plan

We have developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative information for 2010. The key elements of our changeover plan include:

- Determine appropriate changes to accounting policies and required amendments to financial disclosures;
- Identify and implement changes in associated processes and information systems;
- Comply with internal control requirements;
- Communicate collateral impacts to internal business groups; and
- Educate and train internal and external stakeholders.

IFRS Accounting Policies

We have completed our analysis of accounting policy alternatives and determined the areas that will be most significantly affected by the adoption of IFRS. The areas identified as being significant have the greatest potential impact to our financial statements or the greatest risk in terms of complexity to implement. The most significant areas continue to include:

- Upstream Property, Plant and Equipment ("PP&E"), including
  - Transition on date of adoption of IFRS
  - Pre-exploration costs
  - Exploration and Evaluation costs
  - DD&A
  - Gains and losses on divestitures
- Impairment testing
- Asset retirement obligation
- Stock-based compensation
- Income taxes

Upstream PP&E

Upstream PP&E will be one of the most significant areas impacted by the adoption of IFRS. Under Canadian GAAP, we follow the CICA's guideline on full cost accounting, while IFRS has no equivalent guideline. In order to facilitate the transition to IFRS by full cost accounting companies, the International Accounting Standards Board ("IASB") released additional exemptions for first-time adopters of IFRS in July 2009. Included in the amendments is an exemption which permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) over reserves to the unit of account level upon transition to IFRS. We expect to adopt this exemption using the fair value of reserves as an allocation method. Without this exemption, we would have been required to retrospectively determine the carrying amount of oil and gas assets at the date of transition, or use the fair value or revaluation amount as our new deemed cost under IFRS. By using the exemption, the net book value of our upstream PP&E at the date of transition to IFRS will be the same as it was under Canadian GAAP, subject to any potential IFRS impairments that are recognized at the date of transition.

In moving to IFRS, we will be required to adopt different accounting policies for pre-exploration activities, exploration and evaluation costs, DD&A and the accounting for gains and losses on divestitures of properties.

Pre-exploration costs are costs incurred before the Company obtains the legal right to explore an area. Under Canadian GAAP, these costs are capitalized, while under IFRS, these costs must be expensed. At this time, we do not anticipate that this accounting policy difference will have a significant impact on our Consolidated Financial Statements.

During the exploration and evaluation phase ("E&E"), we capitalize costs incurred for these projects under Canadian GAAP. Under IFRS, we have the alternative to either continue capitalizing these costs until technical feasibility and commercial viability of the project has been determined, or expensing these costs as incurred. At this time, our IFRS accounting policy in relation to E&E activities has not been finalized.

Under Canadian GAAP, we calculate our DD&A rate at the country cost centre level. Under IFRS, this rate will be calculated at a lower unit of account level. At this time, we have not finalized our policy in this regard, and therefore the impact of this difference in accounting policy is not reasonably determinable.

Full cost accounting under Canadian GAAP requires that gains or losses on divestitures of properties are only recognized when the disposal would affect our DD&A rate by 20 percent or more. Under IFRS, there is no such exemption, and therefore we will be required to recognize all gains and losses on property divestitures. At this time, the impact of this difference in accounting policy is not reasonably determinable.

As a result of the additional exemption released by the IASB, we anticipate that all changes to our Upstream PP&E accounting policies will be adopted prospectively.

Impairment Testing

For the first step of all of our impairment tests (Upstream, Downstream, Goodwill) under Canadian GAAP, future cash flows are not discounted. Under IFRS, the future cash flows are discounted. In addition, for upstream PP&E, impairment testing is currently performed at the country cost centre level, while under IFRS, it will be performed at a lower level, referred to as a cash-generating unit. We expect to adopt these changes in accounting policy prospectively. At this time, the impact of accounting policy differences related to impairment testing is not reasonably determinable.

Asset Retirement Obligation

Under Canadian GAAP, the discount rate used to estimate the liability is not updated to current market discount rates, while under IFRS, the rate is updated each reporting period. We expect to adopt this change in accounting policy prospectively. We do not anticipate that this accounting policy difference will have a significant impact on our consolidated financial statements.

Stock-based Compensation

Under Canadian GAAP, obligations for cash payments under stock-based compensation plans are accrued using the intrinsic method, while under IFRS, these obligations must be accounted for using the fair value method. While the carrying value each reporting period will be different under IFRS, the cumulative expense recognized over the life of the instrument under both methods will be the same. We expect to adopt this change in accounting policy prospectively. At this time, the impact of this difference is not reasonably determinable.

Income Tax

In transitioning to IFRS, the carrying amount of our tax balances will be directly impacted by the tax effects resulting from changes required by the above IFRS accounting policy differences. Therefore, at this time the income tax impacts of our differences are not reasonably determinable.

Changes to IFRS Accounting Standards

Our analysis of accounting policy differences specifically considers the current IFRS standards that are in effect. We will continue to monitor any new or amended accounting standards that are issued by the IASB, including assessing any impact of the new joint ventures standard that the IASB expects to publish in the first quarter of 2010.

Preparation of the IFRS Opening Balance Sheet

We expect to commence working on the determination of our IFRS opening balance sheet in the first quarter of 2010.

Information Systems

We have completed the design of process and system changes that we expect will be required. We have performed preliminary testing of the changes and expect to finalize our testing in the first half of 2010. We plan to fully implement the system changes by June 30, 2010.

Internal Controls Over Financial Reporting

We are in the process of updating our internal controls documentation, and we do not anticipate that the transition to IFRS will have a significant impact on either our internal controls over financial reporting, or our disclosure controls and procedures.

Education and Training

All of the individuals that are involved in our financial reporting under Canadian GAAP have been engaged and involved in the IFRS transition project since 2008, and will continue to be involved in our IFRS transition throughout 2010 and 2011. Other individuals affected by the change from Canadian GAAP to IFRS will be educated and trained during 2010 as we identify and calculate the specific dollar value of differences arising from the changes to our accounting policies.

Impacts to our Business

We are not expecting that the adoption of IFRS in 2011 will have a significant impact or influence on our business activities, operations or strategies.

OUTLOOK

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

- Visible material growth in enhanced oil resource development, particularly with expansions at our Foster Creek and Christina Lake SAGD bitumen operations. We also have an extensive inventory of emerging bitumen plays;
- Leadership in low-cost SAGD development; enabled by technology and continued respect for our employee's safety, our stakeholders and the environment;
- Internally funded growth through free cash flow from our established crude oil and natural gas assets; and
- Maintaining a lower risk profile through natural gas and downstream integration as well as hedging execution.

We believe global oil demand will continue to increase. However, commodity price volatility, environmental regulations, government intervention and competitive pressures within our industry are the key hurdles that need to be effectively managed to enable our growth. Additional detail regarding the impact of these factors on our 2009 results is discussed in the Risk Management section of this MD&A. WTI and light-heavy differentials are likely to be relatively strong for the foreseeable future. Offsetting this is a relatively weak price outlook for natural gas and refining margins.

We expect our 2010 capital investment program to be funded from Cash Flow. Our crude oil and natural gas assets in Alberta and Saskatchewan will be key to providing free cash flow to enable our bitumen growth. We have chosen to accelerate completion of Christina Lake phase D which we expect will advance start up by approximately six months.

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 benefitted from this strategy in 2009 and 2008, we cannot ensure that we will continue to derive such benefits in the future.

One of the factors that will affect our future results will be our effective royalty rates. Based on current market pricing, we expect that the Foster Creek project will reach payout during 2010. Once the project

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reaches payout the applicable monthly royalty will be based on the greater of 1-9 percent of the project's gross revenue or 25-40 percent of the net revenue. The actual royalty rate that is payable within these ranges is determined based on the WTI U.S. dollar price of crude oil, translated into Canadian dollars.

As a new entity, the Company will continue to develop 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 STATEMENTS

In the interest of providing Cenovus shareholders and potential investors with information regarding the Company and its subsidiaries, including Management's assessment of Cenovus's and its subsidiaries' future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to: projections relating to the adequacy of our provision for taxes; the effect of our policies and programs to reduce safety, environmental and regulatory risks, including climate change; our estimate of the cost of carbon; the potential impact of the Alberta Royalty Framework, NRF, TRP and Energy Incentive Programs; projections and plans with respect to growth of natural gas production from unconventional properties and enhanced oil resources including with respect to the Foster Creek and Christina Lake properties, the CORE project and planned expansions of our downstream heavy oil processing capacity and the capital costs and expected timing of the same; our ability to meet consumer demand; projections relating to the volatility of crude oil prices in 2010 and beyond and the reasons therefor; commodity prices, including the WTI and light-heavy differentials; our projected capital investment levels for 2010, the flexibility of capital spending plans and the source of funding therefor; the effect of our risk management program, including the impact of derivative financial instruments and our access to various sources of capital; the adequacy of provisions made for legal proceedings against us; the impact of the changes and proposed changes in laws and regulations, including greenhouse gas, carbon and climate change initiatives on our operations and operating costs; our ability to realize the expected benefits of the Arrangement; potential dividends; our expected future attributes, business plan and operational focus; our ability to fund our 2010 capital program; the effect of our risk mitigation policies, systems, processes and insurance program; our expectations for future Debt to Capitalization and Debt to Adjusted EBITDA ratios; the expected impact and timing of various accounting pronouncements, rule changes and standards on us and our Consolidated Financial Statements; and projections relating to global oil demand, prices for natural gas and refining margins. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: volatility of and assumptions regarding oil and gas prices; assumptions based upon our current guidance; fluctuations in currency and interest rates; product supply and demand; market competition; risks inherent in our and our subsidiaries' marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our and our subsidiaries' ability to replace and expand oil and gas reserves; the ability of ourselves and ConocoPhillips to successfully manage and operate the North American integrated heavy oil business and the ability of the parties to obtain necessary regulatory approvals; refining and marketing margins; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; 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 synthetic crude oil; risks associated with

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technology and the application thereof to our business; our ability to generate sufficient cash flow from operations to meet our current and future obligations; our ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; our and our subsidiaries' ability to

secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which we and our subsidiaries operate; the risk of war, terrorist threats, hostilities, civil insurrection and instability affecting countries in which we and our subsidiaries operate; risks associated with existing and potential future lawsuits and regulatory actions made against us and our subsidiaries; the financing plans and initiatives that may be undertaken by us, the capitalization and adequacy thereof for us, the expected impacts of the Arrangement on our employees, operations, suppliers, business partners and stakeholders, our ability to obtain financing in the future on a stand alone basis, that the historical financial information pertaining to our assets as operated by EnCana prior to November 30, 2009 may not be representative of our results as an independent entity, that we have a limited operating history, as a separate entity, and other risks and uncertainties described from time to time in the reports and filings we have made with securities regulatory authorities. Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Although we believe that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date of this document, and except as required by law, we do not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

We previously disclosed and updated guidance relating to anticipated results for 2009. There were no material differences between (a) our actual cash flow, capital investment and operating costs in 2009 and (b) the amounts forecast in our most recently disclosed guidance (dated December 1, 2009). Explanations for any changes contained in any updated guidance, from guidance previously disclosed, were provided in the news release issued by Cenovus at the time the guidance was updated.

Our forward-looking information respecting anticipated 2010 cash flow, operating cash flow and pre-tax cash flow is based upon achieving average 2010 production of approximately 105,000 bbls/d to 111,500 bbls/d of crude oil and liquids and 720 MMcf/d to 740 MMcf/d of natural gas, average commodity prices for 2010 of a WTI price of $65 per bbl to $85 per bbl and a WCS price of $54 per bbl to $71 per bbl for oil, a NYMEX price of $5.50 per Mcf to $6.15 per Mcf and AECO price of $5.15 per GJ to $5.70 per GJ for natural gas, an average U.S./Canadian dollar foreign exchange rate of $0.85 to $0.96 US$/CDN$, an average Chicago 3-2-1 crack spread for 2010 of $7.50 per bbl to $9.50 per bbl for refining margins, and an average number of outstanding shares of approximately 750 million. Assumptions relating to forward-looking statements generally include our current expectations and projections made by the Company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

We are required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that we have previously disclosed to the public and the expected differences thereto. Such disclosure can be found in our news release dated February 11, 2010 which is available on www.sedar.com.

OIL AND GAS INFORMATION

Our disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to us by Canadian securities regulatory authorities that permits us to provide such disclosure in accordance with U.S. disclosure requirements. The information provided by us may differ from the corresponding information prepared in accordance with Canadian disclosure standards under NI 51-101.

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The reserves quantities disclosed by us represent net proved and probable reserves calculated using the standards contained in Regulation S-X of the U.S. Securities & Exchange Commission. Further information about the differences between the U.S. requirements and the NI 51-101 requirements is set forth under the heading "Note Regarding Reserves Data and Other Oil and Gas Information" in our Annual Information Form for the year ended December 31, 2009.

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 one barrel to six thousand cubic feet. 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 necessarily represent value equivalency at the well head.

CURRENCY

All information included in this document and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis unless otherwise noted.

NON-GAAP MEASURES

Certain measures in this document do not have any standardized meaning as prescribed by Canadian 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. Therefore, 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. Management's use of these measures has been disclosed further in this document as these measures are discussed and presented.

REFERENCES TO CENOVUS

For convenience, references in this document to "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 regarding Cenovus Energy Inc. can be accessed under our public filings, including our Annual Information Form for the year ended December 31, 2009, found at www.sedar.com and on our website at www.cenovus.com.

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Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2009

(U.S. Dollars)

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Report of Management

Management's Responsibility for the Consolidated Financial Statements

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. ("Cenovus") are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in United States dollars in accordance with Canadian generally accepted accounting principles and include certain estimates that reflect Management's best judgments.

The Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee which is made up of three independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation and the United States *Sarbanes-Oxley Act of 2002* and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets with Management and the independent auditors at least on a quarterly basis to review and approve interim Consolidated Financial Statements and Management's Discussion and Analysis prior to their release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

Management's Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the design and effectiveness of internal control over financial reporting as at December 31, 2009. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control–Integrated Framework to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that internal control over financial reporting was effective as at that date.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2009 as stated in their Auditors' Report. PricewaterhouseCoopers LLP has provided such opinions.

/s/ Brian C. Ferguson

Brian C. Ferguson
President &
Chief Executive Officer
Cenovus Energy Inc.

/s/ Ivor M. Ruste

Ivor M. Ruste
Executive Vice-President &
Chief Financial Officer
Cenovus Energy Inc.

February 17, 2010

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Independent Auditors' Report

To the Shareholders of Cenovus Energy Inc.

We have completed integrated audits of Cenovus Energy Inc.'s 2009 and 2008 consolidated financial statements and of its internal control over financial reporting as of December 31, 2009 and an audit of its 2007 consolidated financial statements. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Cenovus Energy Inc. as at December 31, 2009 and December 31, 2008, and the related consolidated statements of earnings and comprehensive income, shareholders' equity, and cash flows for each of the years in the three year period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company's financial statements as at December 31, 2009 and December 31, 2008 and for each of the years in the two year period ended December 31, 2009 in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). We conducted our audit of the Company's financial statements for the year ended December 31, 2007 in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and December 31, 2008 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

Internal Control over Financial Reporting

We have also audited Cenovus Energy Inc.'s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control over Financial Reporting. Our responsibility is to express an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the

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maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009 based on criteria established in Internal Control — Integrated Framework issued by the COSO.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
Canada

February 17, 2010

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CONSOLIDATED STATEMENT OF EARNINGS AND COMPREHENSIVE INCOME

For the years ended December 31, (US$ millions, except per share amounts)		2009	2008	2007
Revenues, Net of Royalties	*(Note 1)*	**10,140**	16,559	13,406
Expenses	*(Note 1)*			
Production and mineral taxes		**38**	75	63
Transportation and selling		**672**	963	756
Operating		**1,154**	1,223	1,114
Purchased product		**5,250**	9,710	7,476
Depreciation, depletion and amortization		**1,343**	1,318	1,426
General and administrative		**188**	167	145
Interest, net	*(Note 6)*	**218**	218	187
Accretion of asset retirement obligation	*(Note 14)*	**39**	39	28
Foreign exchange (gain) loss, net	*(Note 7)*	**290**	(250)	380
Other (income) loss, net		**(2)**	3	4
		9,190	13,466	11,579
Earnings Before Income Tax		**950**	3,093	1,827
Income tax expense	*(Note 8)*	**302**	725	423
Net Earnings		**648**	2,368	1,404
Other Comprehensive Income, Net of Tax				
Foreign Currency Translation Adjustment		**1,979**	(2,246)	1,265
Comprehensive Income		**2,627**	122	2,669
Net Earnings per Common Share	*(Note 19)*			
Basic		**0.86**	3.16	1.86
Diluted		**0.86**	3.15	1.84

See accompanying Notes to Consolidated Financial Statements.

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CONSOLIDATED BALANCE SHEET

As at December 31, (US$ millions)		2009	2008
Assets			
Current Assets			
Cash and cash equivalents		**148**	153
Accounts receivable and accrued revenues		**874**	598
Income tax receivable		**38**	-
Current portion of Partnership Contribution Receivable	*(Note 9)*	**330**	313
Risk management	*(Note 18)*	**58**	681
Inventories	*(Note 10)*	**836**	503
		2,284	2,248
Property, Plant and Equipment, net	*(Notes 1, 11)*	**14,537**	12,260
Partnership Contribution Receivable	*(Note 9)*	**2,504**	2,834
Risk Management	*(Note 18)*	**1**	38
Other Assets	*(Note 12)*	**131**	150
Goodwill	*(Note 1)*	**1,095**	936
		20,552	18,466
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**1,444**	1,114
Income tax payable		**-**	254
Current portion of Partnership Contribution Payable	*(Note 9)*	**325**	306
Risk management	*(Note 18)*	**67**	40
Current portion of long-term debt	*(Note 13)*	**-**	84
		1,836	1,798
Long-Term Debt	*(Note 13)*	**3,493**	2,952
Partnership Contribution Payable	*(Note 9)*	**2,532**	2,857
Risk Management	*(Note 18)*	**4**	-
Asset Retirement Obligation	*(Note 14)*	**1,096**	648
Other Liabilities		**54**	52
Future Income Taxes	*(Note 8)*	**2,357**	2,411
		11,372	10,718
Commitments and Contingencies	*(Note 20)*		
Shareholders' Equity	*(Note 15)*	**9,180**	7,748
		20,552	18,466

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board

/s/ Michael A. Grandin
Michael A. Grandin
Director
Cenovus Energy Inc.

/s/ Patrick D. Daniel
Patrick D. Daniel
Director
Cenovus Energy Inc.

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CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

(US$ millions)	Share Capital *(Note 15)*	Paid in Surplus *(Note 15)*	Retained Earnings	AOCI*	Owner's Net Investment	Total
Balance as of December 31, 2006	-	-	-	1,169	6,145	7,314
Net earnings	-	-	-	-	1,404	1,404
Net distribution to owner	-	-	-	-	(1,976)	(1,976)
Other comprehensive income (loss)	-	-	-	1,265	-	1,265
Balance as of December 31, 2007	-	-	-	2,434	5,573	8,007
Net earnings	-	-	-	-	2,368	2,368
Net distribution to owner	-	-	-	-	(381)	(381)
Other comprehensive income (loss)	-	-	-	(2,246)	-	(2,246)
Balance as of December 31, 2008	-	-	-	188	7,560	7,748
Net earnings	-	-	-	-	609	609
Net distribution to owner	-	-	-	-	(1,045)	(1,045)
Other comprehensive income (loss)	-	-	-	1,908	-	1,908
Owner's Net Investment at Arrangement date – November 30, 2009	-	-	-	2,096	7,124	9,220
Issuance of common stock in connection with the Arrangement	2,222	-	-	-	(2,222)	-
Reclassification of owner's net investment to paid in surplus in connection with the Arrangement	-	4,902	-	-	(4,902)	-
Net earnings – December 1 to December 31	-	-	39	-	-	39
Dividends on common shares	-	(151)	-	-	-	(151)
Common shares issued under option plans	1	-	-	-	-	1
Other comprehensive income (loss)	-	-	-	71	-	71
Balance as of December 31, 2009	**2,223**	**4,751**	**39**	**2,167**	**-**	**9,180**

*Accumulated Other Comprehensive Income

See accompanying Notes to Consolidated Financial Statements.

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CONSOLIDATED STATEMENT OF CASH FLOWS

For the years ended December 31, (US$ millions)		2009	2008	2007
Operating Activities				
Net earnings		**648**	2,368	1,404
Depreciation, depletion and amortization		**1,343**	1,318	1,426
Future income taxes	*(Note 8)*	**(551)**	385	(182)
Unrealized (gain) loss on risk management	*(Note 18)*	**667**	(734)	348
Unrealized foreign exchange (gain) loss		**313**	(259)	383
Accretion of asset retirement obligation	*(Note 14)*	**39**	39	28
Other		**13**	(29)	129
Net change in other assets and liabilities		**(23)**	(89)	(48)
Net change in non-cash working capital		**1,047**	(312)	(474)
Cash From Operating Activities		**3,496**	2,687	3,014
Investing Activities				
Capital expenditures	*(Note 1)*	**(1,895)**	(2,046)	(1,489)
Proceeds from divestitures	*(Note 5)*	**209**	47	-
Net change in other assets		**(18)**	(48)	(34)
Net change in non-cash working capital		**(76)**	83	(10)
Cash (Used in) Investing Activities		**(1,780)**	(1,964)	(1,533)
Net Cash Provided before Financing Activities		**1,716**	723	1,481
Financing Activities				
Net issuance (repayment) of revolving long-term debt		**(304)**	(503)	(148)
Issuance of long-term debt		**173**	268	931
Repayment of long-term debt		**(88)**	(236)	(99)
Issuance of U.S. Unsecured Notes	*(Note 13)*	**3,468**	-	-
Payment of note payable to EnCana	*(Note 13)*	**(3,500)**	-	-
Payment of transition account payable to EnCana		**(250)**	-	-
Net financing transactions with EnCana		**(1,045)**	(381)	(1,976)
Issuance of common shares		**1**	-	-
Dividends on common shares		**(151)**	-	-
Other		**(34)**	-	-
Cash (Used in) Financing Activities		**(1,730)**	(852)	(1,292)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**9**	(20)	7
Increase (Decrease) in Cash and Cash Equivalents		**(5)**	(149)	196
Cash and Cash Equivalents, Beginning of Year		**153**	302	106

Cash and Cash Equivalents, End of Year	**148**	153	302
Supplemental Cash Flow Information	*(Note 19)*		

See accompanying Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in US$ millions, unless otherwise indicated
For the year ended December 31, 2009

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. ("Cenovus" or the "Company") is in the business of the development, production and marketing of bitumen, crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States.

The Company is headquartered in Calgary, Alberta and its common shares are listed on the Toronto and New York stock exchanges. Information on the Company's background and the basis of presentation for these financial statements are found in Note 2.

Cenovus is organized into two operating divisions:

- **Integrated Oil** Division, which includes all of the assets within the upstream and downstream integrated oil business with our joint venture partner, as well as other bitumen interests and the Athabasca natural gas assets. The Integrated Oil Division has assets in both Canada and the U.S. including two major enhanced oil recovery properties: (i) Foster Creek; and (ii) Christina Lake; as well as two refineries: (i) Wood River; and (ii) Borger.

- **Canadian Plains** Division, which contains established crude oil and natural gas development assets in Alberta and Saskatchewan and includes two major enhanced oil recovery properties: (i) Weyburn; and (ii) Pelican Lake; as well as the Southern Alberta oil and gas properties. The division 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.

For financial statement reporting purposes, our operating and reportable segments are:

- **Upstream Canada,** which includes Cenovus's development and production of bitumen, crude oil, natural gas and natural gas liquids ("NGLs"), and other related activities in Canada. This includes the Foster Creek and Christina Lake operations which are jointly owned with ConocoPhillips, an unrelated U.S. public company, and operated by Cenovus.

- **Downstream Refining,** which is focused on the refining of crude oil into petroleum and chemical products at two refineries located in the United States. The refineries are jointly owned with ConocoPhillips and operated by ConocoPhillips.

- **Corporate and Eliminations,** which primarily includes unrealized gains or losses recorded on derivative financial instruments as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, 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.

The operating and reportable segments shown above have been changed from those presented in prior periods to match Cenovus's structure. All prior periods have been restated to reflect this presentation.

The tabular financial information which follows presents the segmented information first by segment and geographic location, then by product and operating division. Capital expenditures, goodwill, sales information and information relating to Cenovus's major customers are summarized at the end of the note.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in US$ millions, unless otherwise indicated
For the year ended December 31, 2009

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Results of Operations

Segment and Geographic Information

	Upstream Canada			Downstream Refining		
For the years ended December 31, (US$ millions)	**2009**	2008	2007	**2009**	2008	2007

Revenues, Net of Royalties	**5,598**	6,972	6,528	**5,280**	9,011	7,315
Expenses						
Production and mineral taxes	**38**	75	63	**-**	-	-
Transportation and selling	**672**	963	756	**-**	-	-
Operating	**671**	742	688	**453**	492	428
Purchased product	**832**	1,101	1,751	**4,517**	8,760	5,813
Operating cash flow	**3,385**	4,091	3,270	**310**	(241)	1,074
Depreciation, depletion and amortization	**1,101**	1,107	1,222	**192**	188	159
Segment Income (Loss)	**2,284**	2,984	2,048	**118**	(429)	915
Property, Plant & Equipment	**9,660**	8,148	9,574	**4,767**	4,032	3,706
Goodwill	**1,095**	936	1,159	**-**	-	-
Total Assets	**14,481**	12,863	15,569	**5,660**	4,637	4,887

	Corporate and Eliminations			Consolidated		
For the years ended December 31, (US$ millions)	**2009**	2008	2007	**2009**	2008	2007
Revenues, Net of Royalties	**(738)**	576	(437)	**10,140**	16,559	13,406
Expenses						
Production and mineral taxes	**-**	-	-	**38**	75	63
Transportation and selling	**-**	-	-	**672**	963	756
Operating	**30**	(11)	(2)	**1,154**	1,223	1,114
Purchased product	**(99)**	(151)	(88)	**5,250**	9,710	7,476
	(669)	738	(347)	**3,026**	4,588	3,997
Depreciation, depletion and amortization	**50**	23	45	**1,343**	1,318	1,426
Segment Income (Loss)	**(719)**	715	(392)	**1,683**	3,270	2,571
General and Administrative	**188**	167	145	**188**	167	145
Interest, net	**218**	218	187	**218**	218	187
Accretion of asset retirement obligation	**39**	39	28	**39**	39	28
Foreign exchange (gain) loss, net	**290**	(250)	380	**290**	(250)	380
Other (income) loss, net	**(2)**	3	4	**(2)**	3	4
	733	177	744	**733**	177	744
Earnings Before Income Tax				**950**	3,093	1,827
Income tax expense				**302**	725	423
Net Earnings (Loss)				**648**	2,368	1,404
Property, Plant & Equipment	**110**	80	104	**14,537**	12,260	13,384
Goodwill	**-**	-	-	**1,095**	936	1,159
Total Assets	**411**	966	531	**20,552**	18,466	20,987

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in US$ millions, unless otherwise indicated
For the year ended December 31, 2009

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Upstream Canada Product and Divisional Information

(US$ millions)	Crude Oil & NGLs								
	Integrated Oil			Canadian Plains			Total		
For the years ended December 31,	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Revenues, Net of Royalties	**1,202**	1,117	738	**1,373**	2,106	1,453	**2,575**	3,223	2,191
Expenses									
Production and mineral taxes	**-**	-	-	**24**	38	29	**24**	38	29
Transportation and selling	**430**	526	366	**179**	321	263	**609**	847	629
Operating	**176**	170	159	**229**	239	215	**405**	409	374
Purchased product	**-**	-	-	**-**	-	-	**-**	-	-
Operating Cash Flow	**596**	421	213	**941**	1,508	946	**1,537**	1,929	1,159

(US$ millions)	Natural Gas								
	Integrated Oil			Canadian Plains			Total		
For the years ended December 31,	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Revenues, Net of Royalties	**180**	192	252	**1,902**	2,301	2,186	**2,082**	2,493	2,438
Expenses									
Production and mineral taxes	**-**	-	-	**13**	36	34	**13**	36	34
Transportation and selling	**2**	7	12	**39**	71	82	**41**	78	94
Operating	**20**	39	40	**210**	241	221	**230**	280	261
Purchased product	**-**	-	-	**-**	-	-	**-**	-	-
Operating Cash Flow	**158**	146	200	**1,640**	1,953	1,849	**1,798**	2,099	2,049

(US$ millions)	Other								
	Integrated Oil			Canadian Plains			Total		
For the years ended December 31,	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Revenues, Net of Royalties	**73**	119	75	**868**	1,137	1,824	**941**	1,256	1,899
Expenses									
Production and mineral taxes	**1**	1	-	**-**	-	-	**1**	1	-
Transportation and selling	**22**	38	23	**-**	-	10	**22**	38	33
Operating	**18**	31	30	**18**	22	23	**36**	53	53
Purchased product	**-**	-	-	**832**	1,101	1,751	**832**	1,101	1,751
Operating Cash Flow	**32**	49	22	**18**	14	40	**50**	63	62

(US$ millions)	Total Upstream Canada								
	Integrated Oil			Canadian Plains			Total		
For the years ended December 31,	**2009**	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Revenues, Net of Royalties	**1,455**	1,428	1,065	**4,143**	5,544	5,463	**5,598**	6,972	6,528
Expenses									
Production and mineral taxes	**1**	1	-	**37**	74	63	**38**	75	63
Transportation and selling	**454**	571	401	**218**	392	355	**672**	963	756
Operating	**214**	240	229	**457**	502	459	**671**	742	688
Purchased product	**-**	-	-	**832**	1,101	1,751	**832**	1,101	1,751
Operating Cash Flow	**786**	616	435	**2,599**	3,475	2,835	**3,385**	4,091	3,270

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in US$ millions, unless otherwise indicated
For the year ended December 31, 2009

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES (continued)

Capital Expenditures

For the years ended December 31, (US$ millions)	**2009**	2008	2007
Integrated Oil	**476**	644	450
Canadian Plains	**478**	872	795
Upstream Canada	**954**	1,516	1,245
Downstream Refining	**907**	478	220
Corporate	**31**	52	10
	1,892	2,046	1,475
Acquisition Capital			
Integrated Oil	**-**	-	14
Canadian Plains	**3**	-	-
Total	**1,895**	2,046	1,489

In addition to the above, in 2009 we acquired strategic bitumen lands in exchange for certain non-core holdings.

Goodwill Additions

There were no additions to goodwill during 2009, 2008 or 2007; changes in the goodwill balance result from changes in foreign exchange rates.

Export Sales

Sales of crude oil, natural gas and NGLs produced or purchased in Canada delivered to customers outside of Canada were $544 million (2008–$1,296 million; 2007–$943 million).

Major Customers

In connection with the marketing and sale of Cenovus's own and purchased crude oil, natural gas and refined products for the year ended December 31, 2009, Cenovus had two customers (2008–two; 2007–two) which individually accounted for more than 10 percent of its consolidated revenues, net of royalties. Sales to these customers, major international integrated energy companies with an investment grade credit rating, were approximately $5,658 million (2008–$8,979 million; 2007–$6,916 million).

2. BACKGROUND & BASIS OF PRESENTATION

Cenovus was created on November 30, 2009 and began independent operations on December 1, 2009, as a result of the Arrangement involving EnCana Corporation ("EnCana") whereby EnCana was split into two independent energy companies, one a natural gas company, EnCana and the other an integrated oil company, Cenovus. In connection with the Arrangement, EnCana common shareholders received one share in each of the new EnCana and Cenovus in exchange for each EnCana share held. Common shares of Cenovus began trading on a "when issued" basis on the Toronto ("TSX") and New York ("NYSE") stock exchanges on November 2, 2009. Regular trading of the Cenovus shares began on the TSX on December 3, 2009 and on the NYSE on December 9, 2009.

Cenovus has entered into various transitional agreements with EnCana for the use of certain technical services, the marketing of crude oil, natural gas and NGLs and office space lease arrangements. These agreements reflect terms negotiated in anticipation of each company being stand-alone public companies, each with independent boards of directors and management teams.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in US$ millions, unless otherwise indicated
For the year ended December 31, 2009

2. BACKGROUND & BASIS OF PRESENTATION (continued)

Accordingly, up until the completion of the Arrangement, EnCana was considered a related party due to its parent-subsidiary relationship with the Cenovus entities. However, subsequent to the Arrangement, EnCana is no longer a related party as defined by the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3840 – Related Party Transactions.

Basis of presentation / Carve-out financial information

The Consolidated Financial Statements for the year ended December 31, 2009 include the results for the period from January 1 to November 30, 2009 prior to the Arrangement with EnCana, in addition to the results for the period from December 1 to December 31, 2009 as described below. The consolidated financial results for the periods prior to December 1, 2009 represent the financial position, results of operations and cash flows of the businesses transferred to Cenovus on a carve-out basis.

The historical financial information prior to December 1, 2009 has been derived from the accounting records of EnCana using the historical results of operations and historical basis of assets and liabilities of the businesses transferred to Cenovus on a carve-out accounting basis.

As the Company operated as part of EnCana and was not a stand-alone entity prior to November 30, 2009, the historical Consolidated Financial Statements include allocations of certain EnCana revenues, expenses, assets and liabilities, including the items described below.

The operating results of Cenovus were specifically identified based on EnCana's divisional organization. Certain other expenses presented in the Consolidated Statement of Earnings and Comprehensive Income represent allocations and estimates of the cost of services incurred by EnCana. These allocations and estimates include unrealized mark-to-market gains and losses, general and administrative costs, net interest, foreign exchange gains and losses and income tax expenses. The majority of the assets and liabilities of Cenovus have been identified based on the divisional structure, with the most significant exceptions being property, plant and equipment ("PP&E"), income taxes payable and long-term debt.

Downstream refining, crude oil and natural gas marketing and corporate depreciation, depletion and amortization have been specifically identified based on EnCana's existing divisional structure where possible. Depletion related to upstream properties has been allocated to Cenovus based on the related production volumes utilizing the depletion rate calculated for EnCana's consolidated Canadian cost centre.

Mark-to-market gains and losses resulting from derivative financial instruments entered into by EnCana have been allocated to Cenovus based on the related product volumes.

Salaries, benefits, pension, long-term incentives and other post-employment benefits costs, assets and liabilities have been allocated to Cenovus based on Management's best estimate of how services were historically provided by existing employees. Costs, assets and liabilities associated with retired employees remain with EnCana.

Net interest expense has been calculated primarily using the debt balance allocated to Cenovus.

Income taxes have been recorded as if Cenovus and its subsidiaries had been separate tax paying legal entities, each filing a separate tax return in its local jurisdiction. The calculation of income taxes is based on a number of assumptions, allocations and estimates, including those used to prepare the Cenovus Carve-out Consolidated Financial Statements. Prior to the Arrangement, Cenovus's tax pools were allocated for the Canadian cost centre based on the fair value allocation of PP&E for carve-out purposes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in US$ millions, unless otherwise indicated
For the year ended December 31, 2009

2. BACKGROUND & BASIS OF PRESENTATION (continued)

PP&E related to upstream oil and gas activities are accounted for by Cenovus using the full cost method of accounting. PP&E related to upstream oil and gas activities has been determined based on an allocation process which used the ratio of future net revenue, discounted at 10 percent, of the respective divisions to the future net revenue, discounted at 10 percent, of all proved properties in Canada at December 31, 2008 and December 31, 2007, respectively. Future net revenue is the estimated net amount to be received with respect to development and production of crude oil and natural gas reserves.

Goodwill has been allocated to Cenovus based on the properties associated with the former business combinations on which it arose.

For the purpose of preparing the Carve-out Consolidated Financial Statements, it was determined that Cenovus should maintain approximately the same Debt to Capitalization ratio as consolidated EnCana. As a result, prior to the Arrangement, debt was allocated to Cenovus based on this ratio. Debt is defined as the current and long-term portions of Long-term Debt. Capitalization is not a term that has a prescribed meaning under generally accepted accounting principles ("non-GAAP") and is a measure defined as Debt plus Shareholders' Equity.

Management believes the assumptions underlying the Cenovus Carve-out Consolidated Financial Statements are reasonable. However, the Cenovus Consolidated Financial Statements herein may not reflect Cenovus's financial position, results of operations, and cash flows had Cenovus been a stand-alone company during the periods presented or what Cenovus's operations, financial position, and cash flows will be in the future. EnCana's direct investment in Cenovus is shown as Net Investment in place of Shareholders' Equity because a direct ownership by shareholders in Cenovus did not exist prior to November 30, 2009. EnCana's investment includes the accumulated net earnings, other comprehensive income and net cash distributions to EnCana.

In the opinion of Management, the Consolidated and the historical Carve-out Consolidated Financial Statements reflect all adjustments (including normal recurring adjustments) necessary for a fair statement of the financial position and the results of operations and cash flows in accordance with Canadian generally accepted accounting principles ("Canadian GAAP").

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In these Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in United States (U.S.) dollars. While Cenovus's reporting currency is U.S. dollars, the functional currency is Canadian dollars. All references to US$ or $ are to U.S. dollars and references to C$ are to Canadian dollars.

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries and are presented in accordance with Canadian GAAP. Information prepared in accordance with GAAP in the United States is included in Note 21.

Investments in jointly controlled partnerships and unincorporated joint ventures carry on certain of Cenovus's development, production and crude oil refining businesses and are accounted for using the proportionate consolidation method, whereby Cenovus's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

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3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

B) Foreign Currency Translation

The accounts of self-sustaining operations are translated using the current rate method, whereby assets and liabilities are translated at period end exchange rates, while revenues and expenses are translated using average rates over the period. Translation gains and losses relating to the self-sustaining operations are included in Accumulated Other Comprehensive Income ("AOCI") as a separate component of Shareholders' Equity. As at December 31, 2009, AOCI is comprised solely of foreign currency translation adjustments.

Monetary assets and liabilities of Cenovus that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statement of Earnings.

C) Measurement Uncertainty

The timely preparation of the Consolidated Financial Statements in conformity with Canadian GAAP requires that Management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of crude oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the Consolidated Financial Statements of future periods could be material.

The values of pension assets and obligations and the amount of pension costs charged to net earnings depend on certain actuarial and economic assumptions which, by their nature, are subject to measurement uncertainty.

The amount of compensation expense accrued for long-term performance-based compensation arrangements is subject to Management's best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty.

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus operates are subject to change. As such, income taxes are subject to measurement uncertainty.

D) Revenue Recognition

Revenues associated with the sales of Cenovus's crude oil, natural gas, NGLs and petroleum and refined products are recognized when title passes from the Company to its customer. Realized gains and losses from crude oil and natural gas commodity price risk management activities are recorded in revenue when the product is sold.

Revenues and purchased product are recorded on a gross basis when the title to product passes and the risks and rewards of ownership have been transferred. Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided as agent are recorded as the services are provided.

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3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Unrealized gains and losses from natural gas and crude oil commodity price risk management activities are recorded as revenue based on the related mark-to-market calculations at the end of the respective period.

E) Production and Mineral Taxes

Costs paid to non-mineral interest owners based on production of crude oil, natural gas and NGLs are recognized when the product is produced.

F) Transportation and Selling Costs

Costs paid for the transportation and selling of crude oil, natural gas and NGLs, including diluent, are recognized when the product is delivered and the services provided.

G) Employee Benefit Plans

Accruals for obligations under the employee benefit plans and the related costs are recorded net of plan assets.

The cost of pensions and other post-employment benefits is actuarially determined using the projected benefit method based on length of service, and reflects Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected future health care costs. The expected return on plan assets is based on the fair value of those assets. The accrued benefit obligation is discounted using the market interest rate on high quality corporate debt instruments as at the measurement date.

Pension expense for the defined benefit pension plan includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of the net transitional obligation, the amortization of adjustments arising from pension plan amendments and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets. Amortization is done on a straight-line basis over a period covering the expected average remaining service lives of employees covered by the plans.

Pension expense for the defined contribution pension plans is recorded as the benefits are earned by the employees covered by the plans.

H) Income Taxes

Cenovus follows the liability method of accounting for income taxes, where future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

I) Earnings Per Share Amounts

Basic net earnings per common share is computed by dividing the net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share amounts are calculated giving effect to the potential dilution that would occur if stock options, without tandem share appreciation rights attached, were exercised or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options without tandem share appreciation rights attached and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options without tandem share appreciation rights attached are used to repurchase common shares at the average market price.

J) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

K) Inventories

Product inventories, including petroleum and refined products, are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis.

L) Property, Plant and Equipment

Upstream Canada

Crude oil and natural gas properties are accounted for in accordance with the CICA guideline on full cost accounting in the oil and gas industry. Under this method, all costs, including internal costs and asset retirement costs, directly associated with the acquisition of, the exploration for, and the development of bitumen, crude oil and natural gas reserves, are capitalized on a country-by-country cost centre basis.

Costs accumulated within each cost centre are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For purposes of this calculation, natural gas is converted to oil on an energy equivalent basis. Capitalized costs subject to depletion include estimated future costs to be incurred in developing proved reserves. Proceeds from the divestiture of properties are normally deducted from the full cost pool without recognition of gain or loss unless that deduction would result in a change to the rate of depreciation, depletion and amortization of 20 percent or greater, in which case a gain or loss is recorded. Costs of major development projects and costs of acquiring and evaluating significant unproved properties are excluded, on a cost centre basis, from the costs subject to depletion until it is determined whether or not proved reserves are attributable to the properties, or impairment has occurred. Costs that have been impaired are included in the costs subject to depreciation, depletion and amortization.

An impairment loss is recognized in net earnings when the carrying amount of a cost centre is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from proved reserves. If the sum of the cash flows is less than the carrying amount, the impairment loss is limited to the amount by which the carrying amount exceeds the sum of:

i. the fair value of proved and probable reserves; and
ii. the costs of unproved properties that have been subject to a separate impairment test.

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3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Downstream Refining

The initial acquisition costs of refinery property, plant and equipment are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use and the associated asset retirement costs. Capitalized costs are not subject to depreciation until the asset is put into use, after which they are depreciated on a straight-line basis over the estimated service lives of each component of the downstream facilities.

An impairment loss is recognized on refinery property, plant and equipment when the carrying amount is not recoverable and exceeds its fair value. The carrying amount is not recoverable if the carrying amount exceeds the sum of the undiscounted cash flows from expected use and eventual disposition. If the carrying amount is not recoverable, an impairment loss is measured as the amount by which the refinery asset exceeds the fair value.

Other

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 25 years. Assets under construction are not subject to depreciation until put into use.

M) Capitalization of Costs

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred.

N) Amortization of Other Assets

Items included in Other Assets are amortized, where applicable, on a straight-line basis over the estimated useful lives of the assets.

O) Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually. Goodwill and all other assets and liabilities have been allocated to the country cost centre level, referred to as a reporting unit. To assess impairment, the fair value of the reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

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3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

P) Asset Retirement Obligation

The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made.

Asset retirement obligations include those legal obligations where Cenovus will be required to retire tangible long-lived assets such as producing well sites, natural gas processing plants, and refining facilities. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

Amortization of asset retirement costs are included in depreciation, depletion and amortization in the Consolidated Statement of Earnings. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statement of Earnings.

Actual expenditures incurred are charged against the accumulated obligation.

Q) Stock-Based Compensation

Obligations for payments, cash or common shares, under Cenovus's stock options with tandem share appreciation rights attached, share appreciation rights and deferred share units plans are accrued using the intrinsic method as compensation cost over the vesting period. Fluctuations in the price of Cenovus's common shares change the accrued compensation cost and are recognized when they occur.

EnCana replacement share options with tandem share appreciation rights attached and share appreciation rights held by Cenovus employees are accrued using the fair value method. The fair value is recognized as compensation cost over the vesting period. Fluctuations in the fair value of the rights change the accrued compensation cost and are recognized when they occur.

R) Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument, except for certain related party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as "held-for-trading", "available-for-sale", "held-to-maturity", "loans and receivables", or "other financial liabilities" as defined by the accounting standard.

Financial assets and financial liabilities "held-for-trading" are measured at fair value with changes in those fair values recognized in net earnings. Financial assets "available-for-sale" are measured at fair value, with changes in those fair values recognized in Other Comprehensive Income ("OCI"). Financial assets "held-to-maturity", "loans and receivables" and "other financial liabilities" are measured at amortized cost using the effective interest method of amortization.

Cash and cash equivalents are designated as "held-for-trading" and are measured at fair value. Accounts receivable and accrued revenues and the Partnership Contribution Receivable are designated as "loans and receivables". Accounts payable and accrued liabilities, the Partnership Contribution Payable and long-term debt are designated as "other financial liabilities". Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt and amortized using the effective interest method.

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3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Derivative Financial Instruments

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or liability with changes in fair value recognized in net earnings. Realized gains or losses from financial derivatives related to natural gas and crude oil commodity prices are recognized in natural gas and crude oil revenues as the related sales occur. Realized gains or losses from financial derivatives related to power commodity prices are recognized in operating costs as the related power costs are incurred. Unrealized gains and losses are recognized at the end of each respective reporting period. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Derivative financial instruments are not used for speculative purposes.

Policies and procedures are in place with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated from budgeted capital programs, and in other cases to the mitigation of market price risks for specific assets and obligations. When applicable, the Company identifies relationships between financial instruments and anticipated transactions, as well as its risk management objective and the strategy for undertaking the economic hedge transaction. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

S) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2009.

T) Recent Accounting Pronouncements

In February 2008, the CICA's Accounting Standards Board confirmed that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP in 2011 for profit-oriented Canadian publicly accountable enterprises. Cenovus will be required to report its results in accordance with IFRS beginning in 2011. Cenovus has developed a changeover plan to complete the transition to IFRS by January 1, 2011, including the preparation of required comparative

information. The impact of IFRS on the Consolidated Financial Statements is not reasonably determinable at this time.

In addition, there are three recent accounting pronouncements as noted below, which Cenovus will be required to adopt as of January 1, 2011. All of these standards are converged with IFRS.

- "Business Combinations", Section 1582, which replaces the previous Business Combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the Statement of Earnings. The adoption of this standard will impact the accounting treatment of future business combinations.

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3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

- "Consolidated Financial Statements", Section 1601, which together with Section 1602 below, replace the former consolidated financial statement standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard should not have a material impact on Cenovus's Consolidated Financial Statements.

- "Non-controlling Interests", Section 1602, which establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest to be classified as a separate component of equity. In addition, net earnings, and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard should not have a material impact on the Consolidated Financial Statements.

4. CHANGES IN ACCOUNTING POLICIES AND PRACTICES

On January 1, 2009, Cenovus adopted the CICA Handbook Section "Goodwill and Intangible Assets", Section 3064. The new standard replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard had no material impact on the Consolidated Financial Statements.

5. DIVESTITURES

For the years ended December 31, (US$ millions)	2009	2008	2007
Integrated Oil	**83**	8	-
Canadian Plains	**123**	39	-
Corporate	**3**	-	-
Canada	**209**	47	-

As part of on-going portfolio management efforts, in 2009 Cenovus received cash proceeds of $209 million related to the divestiture of certain oil and gas assets.

6. INTEREST, NET

For the years ended December 31, (US$ millions)	2009	2008	2007
Interest Expense–Long-Term Debt	**187**	194	185
Interest Expense–Other	**194**	213	225
Interest Income	**(163)**	(189)	(223)
	218	218	187

Interest Expense–Other and Interest Income are primarily due to the Partnership Contribution Payable and Receivable, respectively (See Note 9).

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7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31, (US$ millions)	2009	2008	2007

Unrealized Foreign Exchange (Gain) Loss on:			
Translation of U.S. dollar debt issued from Canada	**(357)**	351	(268)
Translation of U.S. dollar Partnership Contribution Receivable issued from Canada	**478**	(608)	617
Other Foreign Exchange (Gain) Loss	**169**	7	31
	290	(250)	380

Other foreign exchange (gain) loss in 2009 includes a $107 million unrealized loss on the translation of U.S. dollar risk management assets and liabilities (2008–unrealized gain of $2 million; 2007–unrealized loss of $34 million) and a $50 million realized loss related to the timing of receipt of the $3.5 billion debt offering proceeds from escrow (see Note 13).

8. INCOME TAXES

The provision for income taxes is as follows:

For the years ended December 31, (US$ millions)	2009	2008	2007
Current			
Canada	**896**	362	432
United States	**(43)**	(22)	173
Total Current Tax	**853**	340	605
Future Tax	**(551)**	385	(182)
	302	725	423

The income tax provision in 2009 reflects the acceleration of the income tax impact of the dissolution of a partnership during the fourth quarter in conjunction with the Arrangement with EnCana.

Total income tax expense in 2009 was $302 million, which was $423 million lower than in 2008 due to lower earnings before income tax. Current income tax expense in 2009 was $853 million, compared to $340 million in 2008. The increase is largely attributable to the acceleration of income tax arising from the dissolution of EnCana's Canadian oil and gas partnership in connection with the Arrangement and the realization of significant hedging gains in 2009. Current tax expense for the three years is primarily an allocation of EnCana's income tax liability on a carve-out accounting basis and as a result, there is no income tax payable by Cenovus at the end of 2009. For 2009, there was a recovery of future income tax expense of $551 million compared to an expense of $385 million in 2008. The significant net recovery was due to the 2009 reversal of future tax on partnership income and unrealized mark-to-market hedging gains.

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8. INCOME TAXES (continued)

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

For the years ended December 31, (US$ millions)	2009	2008	2007
Earnings Before Income Tax	**950**	3,093	1,827
Canadian Statutory Rate	**29.2%**	29.7%	32.3%
Expected Income Tax	**277**	917	590
Effect on Taxes Resulting from:			
Statutory and other rate differences	**(4)**	(79)	17
Effect of tax rate changes	**-**	-	(147)
Effect of legislative changes	**-**	-	(76)
Non-taxable downstream partnership (income) loss	**6**	6	(70)
International financing	**(118)**	(127)	-
Foreign exchange (gains) losses not included in net earnings	**67**	11	-
Non-taxable capital (gains) losses	**11**	(50)	45
Other	**63**	47	64
	302	725	423
Effective Tax Rate	**31.8%**	23.4%	23.2%

The net future income tax liability is comprised of:

As at December 31, (US$ millions)	2009	2008
Future Tax Liabilities		
Property, plant and equipment in excess of tax values	**2,535**	1,810
Timing of partnership items	**9**	470
Risk management	**16**	185
Other	**59**	-
Future Tax Assets		
Non-capital and net capital losses carried forward	**(231)**	(19)
Risk management	**(31)**	-
Other	**-**	(35)
Net Future Income Tax Liability	**2,357**	2,411

The approximate amounts of tax pools available are as follows:

As at December 31, (US$ millions)	2009	2008
Canada	**3,543**	4,092

United States	**2,489**	1,805
	6,032	5,897

Included in the above tax pools are $731 million (2008–$77 million) related to non-capital and net operating losses available for carry forward to reduce taxable income in future years. These losses expire no earlier than 2028.

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9. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

In connection with the Arrangement with EnCana, Cenovus acquired EnCana's assets which are jointly controlled with ConocoPhillips. On January 2, 2007, EnCana became a 50 percent partner in an integrated, North American oil business with ConocoPhillips which consists of an upstream entity and a downstream entity. The upstream entity contribution included assets from EnCana, primarily the Foster Creek and Christina Lake properties, with a fair value of $7.5 billion and a note receivable (Partnership Contribution Receivable) contributed from ConocoPhillips of an equal amount. For the downstream entity, ConocoPhillips contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of $7.5 billion and EnCana contributed a note payable (Partnership Contribution Payable) of $7.5 billion.

In accordance with Canadian GAAP, these entities have been accounted for using the proportionate consolidation method with the results of operations included in the Integrated Oil Division (See Note 1).

Partnership Contribution Receivable

This note receivable bears interest at a rate of 5.3 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term Partnership Contribution Receivable shown in the Consolidated Balance Sheet represents Cenovus's 50 percent share of this promissory note, net of payments to date.

Mandatory Receipts

(US$ millions)	2010	2011	2012	2013	2014	Thereafter	Total
Partnership Contribution Receivable	330	347	366	386	407	998	**2,834**

Partnership Contribution Payable

This note payable bears interest at a rate of 6.0 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term Partnership Contribution Payable amounts shown in the Consolidated Balance Sheet represents Cenovus's 50 percent share of this promissory note, net of payments to date.

Mandatory Payments

(US$ millions)	2010	2011	2012	2013	2014	Thereafter	Total
Partnership Contribution Payable	325	345	366	388	412	1,021	**2,857**

10. INVENTORIES

As at December 31, (US$ millions)	2009	2008
Product		
Upstream Canada	**255**	165
Downstream Refining	**563**	323
Parts and Supplies	**18**	15
	836	503

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10. INVENTORIES (continued)

As a result of a significant decline in commodity prices in the latter half of 2008, Cenovus recorded a write-down of its product inventory by $152 million from

cost to net realizable value. At December 31, 2009, the product turnover during the current year and the improvement in commodity prices resulted in a reversal of the prior year's write-down of $144 million.

The total amount of inventories recognized as an expense during the year was $4,442 million (2008–$8,749 million; 2007–$5,752 million).

11. PROPERTY, PLANT AND EQUIPMENT, NET

As at December 31, (US$ millions)	2009			2008		
	Cost	Accumulated DD&A*	Net	Cost	Accumulated DD&A*	Net
Upstream Canada	**20,626**	**(10,966)**	**9,660**	16,638	(8,490)	8,148
Downstream Refining	**5,256**	**(489)**	**4,767**	4,347	(315)	4,032
Corporate and Eliminations	**373**	**(263)**	**110**	190	(110)	80
	26,255	**(11,718)**	**14,537**	21,175	(8,915)	12,260

* Depreciation, depletion and amortization

Upstream Canada property, plant and equipment includes internal costs directly related to exploration, development and construction activities of $103 million (2008–$96 million). Costs classified as general and administrative expenses have not been capitalized as part of the capital expenditures.

Costs in respect of significant unproved properties and major development projects are excluded from the country cost centre's depletable base. Downstream Refining assets not put into use are excluded from depreciable costs. At the end of the year these costs were:

As at December 31, (US$ millions)	2009	2008	2007
Upstream Canada	**615**	227	223
Downstream Refining	**1,305**	488	139
	1,920	715	362

The Canadian prices used in the ceiling test evaluation of Cenovus's crude oil and natural gas reserves at December 31, 2009 were:

	2010	2011	2012	2013	2014	Cumulative % Change to 2021
Crude Oil (C$/barrel)	59.82	62.61	65.57	60.79	59.93	(10)%
Natural Gas Liquids (C$/barrel)	65.72	65.93	66.14	67.03	66.32	1%
Natural Gas (C$/Mcf)	5.31	6.21	6.09	5.88	5.86	-%

12. OTHER ASSETS

As at December 31, (US$ millions)	2009	2008
Deferred Asset–Downstream Refining	**116**	134
Deferred Pension Plan and Savings Plan	**9**	8
Other	**6**	8
	131	150

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13. LONG-TERM DEBT

As at December 31, (US$ millions)	Note	2009	2008
Canadian Dollar Denominated Debt			
Bank credit facilities	A	**31**	
U.S. Dollar Denominated Debt			
Bank credit facilities	A	**25**	
Unsecured notes	B	**3,500**	
		3,525	
Total Debt Principal		**3,556**	
Debt Discounts and Transaction Costs	C	**(63)**	
Current Portion of Long-Term Debt	D	**-**	
		3,493	2,952

Long-term debt at December 31, 2008 represents an allocation of Cenovus's proportionate share of EnCana's consolidated debt as at December 31, 2008. Long-term debt was allocated to Cenovus on the same proportion of Canadian and U.S. dollar denominated debt and with the same terms and conditions as EnCana's long-term debt. The effective average interest rate for long-term debt in 2009 was 5.7 percent (2008–5.5 percent).

A) Bank Credit Facilities

At December 31, 2009, Cenovus had in place an unsecured credit facility in the amount of C$2.5 billion or its equivalent amount in U.S. dollars. The revolving syndicated credit facility consists of two tranches, a C$2.0 billion 3-year tranche and a C$500 million 364-day tranche. The 3-year tranche matures in November 2012 and is extendible from time to time for a period of up to three years at the option of Cenovus and upon agreement from the lenders. The

364-day tranche matures in November 2010 and is extendible from time to time for a period of up to 364 days at the option of Cenovus and upon agreement from the lenders. If the facilities are not extended, the full amount of the outstanding principal will come due on the respective maturity dates.

Borrowings under both tranches are available by way of Bankers Acceptances, LIBOR based loans, prime rate loans or U.S. base rate loans. Bank credit outstanding at December 31, 2009 was drawn on the 3-year tranche and included prime rate and LIBOR based loans of $56 million.

B) U.S. Unsecured Notes

On September 18, 2009, a predecessor entity of Cenovus completed a private offering of senior unsecured notes for an aggregate principal amount of $3.5 billion, issued in three tranches, which are exempt from the registration requirements of the U.S. Securities Act of 1933 under Rule 144A and Regulation S. The net proceeds of the private offering along with $151 million deposited by the Company were placed into an escrow account pending the completion of the Arrangement with EnCana. Upon completion of the Arrangement, funds were released from escrow and the proceeds of the notes were then used to pay the note payable to EnCana of $3.5 billion as part of the Arrangement. On November 30, 2009, these notes became the direct, unsecured obligations of Cenovus.

(US$ millions)	2009
4.50% due September 15, 2014	**800**
5.70% due October 15, 2019	**1,300**
6.75% due November 15, 2039	**1,400**
	3,500

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13. LONG-TERM DEBT (continued)

Cenovus has agreed to use its commercially reasonable efforts to cause a registration statement with respect to an offer to exchange the U.S. unsecured notes for a new issue of notes registered under the U.S. Securities Act to be declared effective no later than September 18, 2010.

At December 31, 2009, the Company is in compliance with all of the terms of its debt agreements.

C) Debt Discounts and Transaction Costs

During 2009, $67 million in transaction costs and discounts were recorded within long-term debt relating to the issuance of the U.S. unsecured notes and the placement of the bank credit facilities. The costs are being amortized using the effective interest method. For comparative purposes, the transaction costs and discounts allocated to Cenovus for 2008 were $2 million.

D) Mandatory Debt Payments

($ millions)	C$ Principal Amount	US$ Principal Amount	Total US$ Equivalent
2010	-	-	-
2011	-	-	-
2012	32	25	56
2013	-	-	-
2014	-	800	800
Thereafter	-	2,700	2,700
	32	3,525	3,556

14. ASSET RETIREMENT OBLIGATION

The aggregate carrying amount of the obligation associated with the retirement of upstream oil and gas assets and downstream refining facilities is as follows:

As at December 31, (US$ millions)	2009	2008
Asset Retirement Obligation, Beginning of Year	**648**	703
Liabilities Incurred	**5**	20
Liabilities Settled	**(33)**	(49)
Liabilities Divested	**(9)**	(1)
Change in Estimated Future Cash Flows	**342**	69
Accretion Expense	**39**	39
Foreign Currency Translation	**104**	(133)
Asset Retirement Obligation, End of Year	**1,096**	648

The change estimated future cash flows in 2009 is due to the increased estimate of costs to be incurred and the rate of discount used for the current year estimate. The total undiscounted amount of estimated cash flows required to settle the obligation is $5,430 million (2008–$3,189 million), which has been discounted using a weighted average credit-adjusted risk free rate of 6.23 percent (2008–6.76 percent). Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general resources at that time.

15. SHARE CAPITAL

Authorized

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.

Issued and Outstanding

Under the terms of the Arrangement described in Note 2, EnCana shareholders exchanged their EnCana share for one new EnCana Common Share and one Cenovus Common Share.

As at December 31, 2009		
	Number of Common Shares (millions)	Amount ($ millions)
Common Shares Issued Pursuant to the Arrangement	751.3	2,222
Common Shares Issued under Option Plans	-	1
Outstanding, End of Year	751.3	2,223

To determine Cenovus's share capital amount, EnCana's stated capital immediately prior to the Arrangement was split based on the relative fair market values of the EnCana and Cenovus Common Shares at the time of the initial exchange. Cenovus's share capital amount was deducted from EnCana's net investment with the remaining $4,902 million reclassified as Paid in Surplus. In December, Cenovus declared its share of a pre-Arrangement dividend of $0.20 per share, which was charged to Paid in Surplus. This dividend reflects an amount determined in connection with the Arrangement based on carve-out earnings and cash flows.

Under carve-out accounting, Owner's Net Investment represents the accumulated net earnings of the operations and the accumulated net distributions to EnCana. Accumulated Other Comprehensive Income ("AOCI") includes accumulated foreign currency translation adjustments. At the date of the Arrangement, EnCana's net investment in Cenovus was $7,124 million.

At December 31, 2009, there were 24 million Common Shares available for future issuance under stock option plans. There were no Preferred Shares outstanding as at December 31, 2009.

Net Investment

EnCana's net investment in the operations of Cenovus prior to the Arrangement is presented as total Net Investment in the Consolidated Financial Statements. Total Net Investment consists of Owner's Net Investment and AOCI.

Option Plans

Options granted under the plans are generally fully exercisable after three years and expire five years after the date granted.

15. SHARE CAPITAL (continued)

Cenovus Employee Stock Option Plan

Cenovus has stock-based compensation plans that allow employees to purchase Common Shares of the Company. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, and are fully exercisable after three years and expire five years after the original grant date. Options granted under predecessor and/or related company replacement plans expire up to 10 years from the date the options were granted. In addition, certain stock options granted are performance based. The performance based stock options vest and expire under the same terms and service conditions as the underlying option, and vesting is subject to Cenovus attaining prescribed performance relative to pre-determined key measures. All new options issued by the Company have an associated Tandem Share Appreciation Right ("TSAR") attached to them (see Note 17).

Cenovus Replacement Tandem Share Appreciation Rights ("Cenovus Replacement TSARs") Held By EnCana Employees

Under the terms of the Arrangement, each original EnCana TSAR was replaced with one EnCana Replacement TSAR and one Cenovus Replacement TSAR with terms and conditions similar to the original EnCana TSAR. EnCana is required to reimburse Cenovus in respect of cash payments made by Cenovus to EnCana's employees when these employees exercise a Cenovus Replacement TSAR and therefore, no compensation expense is recognized. No further

Cenovus Replacement TSARs will be granted to EnCana employees.

EnCana employees can choose to exercise the Cenovus Replacement TSAR in exchange for a Cenovus common share or for cash. Cenovus has recorded a liability in the Consolidated Balance Sheet for Cenovus Replacement TSARs held by EnCana employees using the fair value method, with an offsetting account receivable from EnCana. The fair value of each Cenovus Replacement TSAR held by EnCana employees was estimated using the Black-Scholes-Merton model with weighted average assumptions as follows:

	2009
Risk Free Rate	**1.46%**
Dividend Yield	**3.16%**
Volatility	**34.18%**
Cenovus's Closing Common Share Price at December 31, 2009	**C$26.50**

The following tables summarize information related to the Cenovus Replacement TSARs held by EnCana employees:

As at December 31, 2009			
	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price (C$)
Replacement TSARs – Pursuant to the Arrangement	**23,047,704**	**10,491,119**	**27.14**
Exercised – SARs	**(29,840)**	**-**	**18.57**
Exercised – Options	**(1,206)**	**-**	**16.77**
Forfeited	**(71,321)**	**(28,476)**	**29.50**
Outstanding, End of December 31, 2009	**22,945,337**	**10,462,643**	**27.14**
Exercisable, End of December 31, 2009	**9,972,272**	**2,236,641**	**25.29**

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15. SHARE CAPITAL (continued)

	Outstanding TSARs				Exercisable TSARS		
Range of Exercise Price (C$)	Total Number of TSARs	Performance TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (C$)	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price (C$)
15.00 to 19.99	**1,097,538**	**-**	**0.13**	**18.21**	**1,097,538**	**-**	**18.21**
20.00 to 24.99	**3,965,161**	**-**	**1.13**	**22.95**	**3,948,676**	**-**	**22.94**
25.00 to 29.99	**12,096,882**	**7,280,249**	**3.12**	**26.50**	**3,340,019**	**1,563,747**	**26.75**
30.00 to 34.99	**5,593,956**	**3,182,394**	**3.08**	**32.83**	**1,528,499**	**672,894**	**32.68**
35.00 to 39.99	**109,450**	**-**	**3.41**	**37.14**	**32,835**	**-**	**37.14**
40.00 to 44.99	**80,850**	**-**	**3.44**	**42.77**	**24,255**	**-**	**42.77**
45.00 to 49.99	**1,500**	**-**	**3.39**	**45.56**	**450**	**-**	**45.56**
	22,945,337	**10,462,643**	**2.62**	**27.14**	**9,972,272**	**2,236,641**	**25.29**

16. CAPITAL STRUCTURE

Cenovus's capital structure is comprised of Shareholders' Equity plus Long-Term Debt. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure and short-term financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength. Debt is defined as the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable.

Cenovus targets a Debt to Capitalization ratio of between 30 and 40 percent.

As at December 31, (US$ millions)	2009	2008
Debt	**3,493**	3,036
Shareholders' Equity	**9,180**	7,748
Total Capitalization	**12,673**	10,784
Debt to Capitalization ratio	**28%**	28%

Cenovus targets a Debt to Adjusted EBITDA of between 1.0 and 2.0 times.

As at December 31, (US$ millions)	2009	2008	2007
Debt	**3,493**	3,036	3,690
Net Earnings	**648**	2,368	1,404
Add (deduct):			
Interest, net	**218**	218	187

Income tax expense	**302**	725	423
Depreciation, depletion and amortization	**1,343**	1,318	1,426
Accretion of asset retirement obligation	**39**	39	28
Foreign exchange (gain) loss, net	**290**	(250)	380
Other (income) loss, net	**(2)**	3	4
Adjusted EBITDA	**2,838**	4,421	3,852
Debt to Adjusted EBITDA	**1.2x**	0.7x	1.0x

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16. CAPITAL STRUCTURE (continued)

It is Cenovus's intention to maintain an investment grade rating to ensure it has continuous access to capital and the financial flexibility to fund its capital programs, meet its financial obligations and finance potential acquisitions. Cenovus will maintain a high level of capital discipline and manage its capital structure to ensure sufficient liquidity through all stages of the economic cycle. To manage the capital structure, Cenovus may adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facility or repay existing debt.

Cenovus's capital structure, objectives and targets have remained unchanged over the periods presented. At December 31, 2009, Cenovus is in compliance with all of the terms of its debt agreements.

17. COMPENSATION PLANS

Cenovus has in place a number of programs whereby employees may be granted the following share-based long-term incentives:

- **Tandem Share Appreciation Rights ("TSARs")**
  All options to purchase Common Shares issued under the Cenovus Employee Stock Option Plan, with the exception of a limited number of Cenovus Replacement Options, as described in Note 15, have an associated TSAR attached to them whereby the option holder has the right to receive a cash payment equal to the excess of the market price of Cenovus's Common Shares at the time of exercise over the exercise price of the right in lieu of exercising the option. The TSARs vest and expire under the same terms and conditions as the underlying option. Certain of the TSARs ("Performance TSARS") have an additional vesting requirement which is subject to the achievement of prescribed performance relative to key pre-determined measures. Performance TSARs that do not vest when eligible are forfeited.

- **Share Appreciation Rights ("SARs")**
  Share Appreciation Rights ("SARs") entitle the employee to receive a cash payment equal to the excess of the market price of Cenovus's Common Shares at the time of exercise over the exercise price of the right. SARs are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years and expire five years after the original grant date. Certain of the SARs ("Performance SARs") have an additional vesting requirement which is subject to the achievement of prescribed performance relative to key pre-determined measures. Performance SARs that do not vest when eligible are forfeited.

In accordance with the Arrangement with EnCana described in Note 2, each Cenovus employee holding an original EnCana long-term incentive unit of the same nature transferred their right to Cenovus in exchange for a Cenovus Replacement Unit and to EnCana for an EnCana Replacement Unit. The terms and conditions of the Cenovus and EnCana Replacement Units are similar to the terms and conditions of the original EnCana unit. The original exercise price of the EnCana unit was apportioned to the Cenovus and EnCana Replacement Units based on the one day weighted average trading price of Cenovus's common share price relative to that of EnCana's common share price on the TSX on December 2, 2009. Cenovus is required to reimburse EnCana in respect of cash payments made by EnCana to Cenovus employees for the EnCana Replacement Units they hold. No further EnCana Replacement Units will be granted to Cenovus employees.

All of these share-based long-term incentive programs have similar vesting provisions as the Cenovus stock option plan. Cenovus Units and Cenovus Replacement Units are measured against the Cenovus common share price and EnCana Replacement Units are measured against the EnCana common share price.

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17. COMPENSATION PLANS (continued)

The Company has recorded a liability in the Consolidated Balance Sheet for EnCana Replacement Units held by the Company's employees using the fair value method. The fair value of each EnCana Replacement Unit granted is estimated using the Black-Scholes-Merton model with weighted average assumptions as follows:

	2009
Risk Free Rate	1.46%
Dividend Yield	2.45%
Volatility	26.17%
EnCana's Closing Common Share Price at December 31, 2009	C$34.11

A) Tandem Share Appreciation Rights

The following tables summarize the information related to the TSARs held by Cenovus employees:

As at December 31, 2009			
	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price (C$)
Replacement TSARs – November 30, 2009	16,431,032	8,053,074	27.51
Granted	67,500	-	25.66
Exercised – SARs	(12,755)	-	18.43
Exercised – Options	(31,050)	-	18.13
Outstanding, End of December 31, 2009	16,454,727	8,053,074	27.52
Exercisable, End of December 31, 2009	6,107,015	1,526,893	25.68

	Outstanding TSARs				Exercisable TSARs		
Range of Exercise Price (C$)	Total Number of TSARs	Performance TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (C$)	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price (C$)
15.00 to 19.99	661,202	-	0.13	18.25	661,202	-	18.25
20.00 to 24.99	2,298,334	-	1.17	22.94	2,261,029	-	22.94
25.00 to 29.99	8,878,174	5,390,982	3.33	26.46	1,988,135	964,003	26.76
30.00 to 34.99	4,418,817	2,662,092	3.11	32.90	1,137,189	562,890	32.82
35.00 to 39.99	124,350	-	3.45	37.14	37,305	-	37.14
40.00 to 44.99	71,850	-	3.45	43.31	21,555	-	43.31
45.00 to 49.99	2,000	-	3.39	45.56	600	-	45.56
	16,454,727	8,053,074	2.84	27.52	6,107,015	1,526,893	25.68

For the year ended December 31, 2009, Cenovus recorded a reduction of compensation cost of $4 million related to TSARs.

B) Share Appreciation Rights

The following tables summarize the information related to the SARs held by Cenovus employees:

As at December 31, 2009			
	Total Number of SARs	Performance SARs	Weighted Average Exercise Price (C$)
Replacement SARs – November 30, 2009	44,657	23,932	29.38
Outstanding, December 31, 2009	44,657	23,932	29.38
Exercisable, December 31, 2009	4,557	2,532	32.96

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17. COMPENSATION PLANS (continued)

	Outstanding SARs				Exercisable SARs		
Range of Exercise Price (C$)	Total Number of SARs	Performance SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (C$)	Total Number of SARs	Performance SARs	Weighted Average Exercise Price (C$)
25.00 to 29.99	25,925	11,950	4.13	26.79	-	-	-
30.00 to 34.99	18,732	11,982	3.12	32.96	4,557	2,532	32.96
	44,657	23,932	3.71	29.38	4,557	2,532	32.96

For the year ended December 31, 2009, Cenovus has not recorded any compensation costs related to the SARs.

C) EnCana Replacement Tandem Share Appreciation Rights

The following tables summarize information related to the EnCana Replacement TSARs held by Cenovus employees:

As at December 31, 2009

	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price (C$)
Replacement TSARs – November 30, 2009	16,431,032	8,053,074	30.41
Exercised – SARs	(73,322)	(1,382)	20.67
Exercised – Options	(1,050)	-	17.96
Outstanding, End of December 31, 2009	16,356,660	8,051,692	30.46
Exercisable, End of December 31, 2009	6,076,448	1,525,511	28.43

	Outstanding EnCana Replacement TSARs				Exercisable EnCana Replacement TSARs		
Range of Exercise Price (C$)	Total Number of TSARs	Performance TSARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (C$)	Total Number of TSARs	Performance TSARs	Weighted Average Exercise Price (C$)
15.00 to 19.99	2,960	-	0.08	19.08	2,960	-	19.08
20.00 to 24.99	652,542	-	0.18	20.27	646,942	-	20.25
25.00 to 29.99	10,800,826	5,389,600	2.89	28.39	4,035,672	962,621	27.17
30.00 to 34.99	411,720	-	2.41	32.29	264,565	-	32.09
35.00 to 39.99	4,341,562	2,662,092	3.12	36.47	1,082,194	562,890	36.46
40.00 to 44.99	74,200	-	3.49	42.28	22,260	-	42.28
45.00 to 49.99	70,850	-	3.45	47.94	21,255	-	47.94
50.00 to 54.99	2,000	-	3.39	50.39	600	-	50.39
	16,356,660	8,051,692	2.84	30.46	6,076,448	1,525,511	28.43

For the year ended December 31, 2009, the Company recorded compensation costs of $55 million related to the EnCana Replacement TSARs.

D) EnCana Replacement Share Appreciation Rights
The following tables summarize information related to the EnCana Replacement SARs held by Cenovus employees:

As at December 31, 2009			
	Total Number of SARs	Performance TSARs	Weighted Average Exercise Price (C$)
EnCana Replacement SARs – November 30, 2009	44,657	23,932	32.48
Outstanding, End of December 31, 2009	44,657	23,932	32.48
Exercisable, End of December 31, 2009	4,557	2,532	36.44

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17. COMPENSATION PLANS (continued)

	Outstanding EnCana Replacement SARs				Exercisable EnCana Replacement SARs		
Range of Exercise Price (C$)	Total Number of SARs	Performance SARs	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (C$)	Total Number of SARs	Performance SARs	Weighted Average Exercise Price (C$)
25.00 to 29.99	22,925	11,950	4.09	29.23	-	-	-
30.00 to 34.99	3,000	-	4.45	32.55	-	-	-
35.00 to 39.99	18,732	11,982	3.12	36.44	4,557	2,532	36.44
	44,657	23,932	3.71	32.48	4,557	2,532	36.44

For the year ended December 31, 2009, the Company has not recorded any compensation costs related to the EnCana Replacement SARs.

E) Deferred Share Units ("DSUs")

Cenovus has in place a program whereby directors, officers and employees are issued Deferred Share Units ("DSUs"), which are equivalent in value to a common share of the Company. Commencing in 2009, employees had the option to convert either 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, can be redeemed in accordance with terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

Pursuant to the terms of the Arrangement, EnCana DSUs credited to directors, officers and employees of Cenovus were exchanged for Cenovus DSUs. The fair value of the Cenovus DSUs credited to each holder was based on the fair market value of Cenovus Common Shares relative to EnCana common shares prior to the effective date of the Arrangement.

As at December 31, 2009	
	Outstanding DSUs
Outstanding, November 30, 2009	762,011

Units in Lieu of Dividends	**6,092**
Outstanding, End of December 31, 2009	**768,103**

For the year ended December 31, 2009, the Company has not recorded any compensation costs related to DSUs.

F) EnCana Pre-Arrangement Stock-Based Compensation Costs

Included in the financial information prior to the Arrangement, the Company recorded compensation costs for the following EnCana plans:

(US$ millions)	**2009**	2008	2007
EnCana TSARs	**4**	(9)	83
EnCana SARs	**1**	-	-
EnCana DSUs	**2**	1	7
EnCana PSUs	**-**	-	16

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17. COMPENSATION PLANS (continued)

G) Pensions and Other Post-Employment Benefits

The Company sponsors defined benefit and defined contribution plans, providing pension and other post-employment benefits ("OPEB") to its employees.

The Company is required to file an actuarial valuation of its pension plans with the provincial regulator at least every three years. An actuarial valuation as at November 30, 2009 will be filed during the first half of 2010.

Pursuant to the Arrangement, the liabilities and assets related to Cenovus employees, as determined by actuarial consultants, transferred to the Cenovus Pension Plans effective November 30, 2009. The 2009 Pension and OPEB amounts reflect activity since the effective date.

The 2008 Pension and OPEB amounts represent Cenovus's proportionate share of EnCana's pension plans related to active employees. The going concern liabilities and assets related to retirees prior to the Arrangement remained with EnCana.

Information related to defined benefit pension and other post-employment benefit plans, based on actuarial estimations as at December 31, 2009 is as follows:

Accrued Benefit Obligation

	Pension Benefits		OPEB	
As at December 31, (US$ millions)	**2009**	2008	**2009**	2008
Accrued Benefit Obligation Pursuant to the Arrangement	**50**		**11**	
Current service cost	**-**		**-**	
Interest cost	**-**		**-**	
Benefits paid	**-**		**-**	
Actuarial (gain) loss	**3**		**-**	
Foreign exchange (gain) loss	**1**		**-**	
Accrued Benefit Obligation, End of Year	**54**	36	**11**	7

Plan Assets

	Pension Benefits		OPEB	
As at December 31, (US$ millions)	**2009**	2008	**2009**	2008
Fair Value of Plan Assets Pursuant to the Arrangement	**50**		**-**	
Actuarial gain (loss) on return of plan assets	**1**		-	
Employer contributions	**-**		-	
Benefits paid	**-**		-	
Foreign exchange (gain) loss	**1**		-	
Fair Value of Plan Assets, End of Year	**52**	32	**-**	-

Accrued Benefit Asset (Liability)

	Pension Benefits		OPEB	
As at December 31, (US$ millions)	**2009**	2008	**2009**	2008
Funded Status–Plan Assets (less) than Benefit Obligation	**(2)**		**(11)**	
Amounts Not Recognized:				
Unamortized net actuarial (gain) loss	**14**		**(1)**	
Unamortized past service cost	**-**		**1**	
Accrued Benefit Asset (Liability)	**12**	6	**(11)**	(6)

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17. COMPENSATION PLANS (continued)

	Pension Benefits		OPEB	
As at December 31, (US$ millions)	**2009**	2008	**2009**	2008
Prepaid Benefit Cost	**12**		-	
Accrued Benefit Cost	**-**		**(11)**	
Net Amount Recognized	**12**	6	**(11)**	(6)

The Company's OPEB plans are funded on an as required basis.

The weighted average assumptions used to determine benefit obligations are as follows:

As at December 31,	**2009**	2008	**2009**	2008
Discount Rate	**6.00%**	6.25%	**6.00%**	6.25%
Rate of Compensation Increase	**4.05%**	4.16%	**5.77%**	6.00%

The average remaining service period of the active employees covered by the defined benefit pension plan is 4 years. The average remaining service period of the active employees covered by the OPEB plan is 11 years.

Assumed health care cost trend rates are as follows:

As at December 31,	**2009**	2008
Health Care Cost Trend Rate for Next Year	**10.00%**	9.50%
Rate that the Trend Rate Gradually Trends To	**5.00%**	5.00%
Year that the Trend Rate Reaches the Rate which it is Expected to Remain At	**2020**	2017

Assumed health care cost trend rates have an effect on the amounts reported for the OPEB plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

(US$ millions)	One Percentage Point Increase	One Percentage Point Decrease
Effect on Post-Retirement Benefit Obligation	1	(1)

The Company's pension plan asset allocations are as follows:

	Normal	Range	**As at December 31, 2009**	As at December 31, 2008	Rate of Return
Domestic Equity	35	25-45	**39**	34	
Foreign Equity	30	20-40	**23**	25	
Bonds	30	20-40	**29**	33	
Real Estate and Other	5	0-20	**9**	8	
Total	100		**100**	100	6.75%

The expected rate of return on plan assets is based on historical and projected rates of return for each asset class in the plan investment portfolio. The objective of the asset allocation policy is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The Supplemental Pension Plan is funded through a retirement compensation arrangement and is subject to the applicable Canada Revenue Agency regulations.

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17. COMPENSATION PLANS (continued)

The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment, credit rating categories and foreign currency exposure.

The Company's contributions to the pension plans are subject to the results of the actuarial valuation and direction by the Human Resources and Compensation Committee of the Board.

Estimated future payment of pension and other benefits are as follows:

(US$ millions)	Pension Benefits	OPEB
2010	1	-
2011	1	-
2012	2	-
2013	2	1
2014	3	1
2015 – 2019	20	6
Total	29	8

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Cenovus's consolidated financial assets and liabilities are comprised of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, the Partnership Contribution Receivable and Payable, risk management assets and liabilities, and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments. Fair values of financial assets and liabilities, summarized information related to risk management positions, and discussion of risks associated with financial assets and liabilities are presented as follows. The information contained within Note 18 is based on carve-out information for the periods prior to December 1, 2009.

A) Fair Value of Financial Assets and Liabilities

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amount due to the short-term maturity of those instruments.

The fair values of the Partnership Contribution Receivable and Partnership Contribution Payable approximate their carrying amount due to the specific non-tradeable nature of these instruments in relation to the creation of the integrated oil business venture.

Risk management assets and liabilities are recorded at their estimated fair value based on mark-to-market accounting, using quoted market prices or, in their absence, third-party market indications and forecasts.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on market information.

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18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

The fair value of financial assets and liabilities, including current portions thereof were as follows:

As at December 31, (US$ millions)	2009		2008	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial Assets				
Held-for-trading:				
Cash and cash equivalents	**148**	**148**	153	153
Risk management assets	**59**	**59**	719	719
Loans and Receivables:				
Accounts receivable and accrued revenues	**874**	**874**	598	598
Partnership Contribution Receivable	**2,834**	**2,834**	3,147	3,147
Financial Liabilities				
Held-for-trading:				
Risk management liabilities	**71**	**71**	40	40
Other Financial Liabilities:				
Accounts payable and accrued liabilities	**1,444**	**1,444**	1,114	1,114
Long-term debt	**3,493**	**3,788**	3,036	3,036
Partnership Contribution Payable	**2,857**	**2,857**	3,163	3,163

B) Risk Management Assets and Liabilities

Under the terms of the Arrangement with EnCana, the risk management positions at November 30, 2009 were allocated to Cenovus based upon Cenovus's proportion of the related volumes covered by the contracts. To effect the allocation, Cenovus entered into a contract with EnCana with the same terms and conditions as between EnCana and the third parties to the existing contracts. All positions entered into after the Arrangement have been negotiated between Cenovus and third parties.

Net Risk Management Position

As at December 31, (US$ millions)	**2009**	2008
Risk Management		
Current asset	**58**	681
Long-term asset	**1**	38
	59	719
Risk Management		
Current liability	**67**	40
Long-term liability	**4**	-
	71	40
Net Risk Management Asset (Liability)	**(12)**	679

Of the $12 million net risk management liability balance at December 31, 2009, a liability of $14 million relates to the contract with EnCana.

Summary of Unrealized Risk Management Positions

As at December 31, (US$ millions)	2009			2008		
	Risk Management			Risk Management		
	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Natural Gas	**51**	**-**	**51**	618	-	618
Crude Oil	**8**	**63**	**(55)**	92	40	52
Power	**-**	**8**	**(8)**	9	-	9
Total Fair Value	**59**	**71**	**(12)**	719	40	679

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18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Net Fair Value Methodologies Used to Calculate Unrealized Risk ManagementPositions

As at December 31, (US$ millions)	2009	2008
Prices actively quoted	**7**	521
Prices sourced from observable data or market corroboration	**(19)**	158
Total Fair Value	**(12)**	679

Prices actively quoted refers to the fair value of contracts valued using quoted prices in an active market. Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

Net Fair Value of Commodity Price Positions at December 31,2009

(US$ millions)	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
WTI NYMEX Fixed Price	24,600 bbls/d	2010	76.99 US$/bbl	**(47)**
Other Financial Positions *				**(8)**
Crude Oil Fair Value Position				**(55)**
Natural Gas Contracts				
Fixed Price Contracts				
NYMEX Fixed Price	437 MMcf/d	2010	6.08 US$/Mcf	**52**
NYMEX Fixed Price	56 MMcf/d	2011	6.75 US$/Mcf	**10**
Basis Contracts**				
Canada	28 MMcf/d	2010		**(2)**
Canada		2011-2013		**(9)**
Natural Gas Fair Value Position				**51**
Power Purchase Contracts				
Power Fair Value Position				**(8)**

* Other financial positions are part of ongoing operations to market the Company's production.
**Cenovus has entered into swaps to protect against widening natural gas price differentials between production areas in Canada and various sales points. These basis swaps are priced using both fixed prices and basis prices determined as a percentage of NYMEX.

Earnings Impact of Realized and Unrealized Gains (Losses) on RiskManagement Positions

	Realized Gain (Loss)		
For the years ended December 31, (US$ millions)	2009	2008	2007
Revenues, Net of Royalties	**1,005**	(323)	136
Operating Expenses and Other	**(32)**	24	3
Gain (Loss) on Risk Management	**973**	(299)	139

	Unrealized Gain (Loss)		
For the years ended December 31, (US$ millions)	2009	2008	2007
Revenues, Net of Royalties	**(639)**	727	(349)
Operating Expenses and Other	**(28)**	7	1
Gain (Loss) on Risk Management	**(667)**	734	(348)

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Reconciliation of Unrealized Risk Management Positions

For the years ended December 31, (US$ millions)	2009		2008	2007
	Fair Value	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**653**			
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**306**	**306**	435	(215)
Other	**-**	**-**	-	6
Foreign Exchange Gain (Loss) on Canadian Dollar Contracts	**2**	**-**	-	-
Fair Value of Contracts Realized During the Year	**(973)**	**(973)**	299	(139)
Fair Value of Contracts, End of Year	**(12)**	**(667)**	734	(348)

Commodity Price Sensitivities

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices, with all other variables held constant. When assessing the potential impact of these commodity price changes, Management believes 10 percent volatility is a reasonable measure. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting net earnings as at December 31, 2009 as follows:

(US$ millions)	10% Price Increase	10% Price Decrease
Natural gas price	**(102)**	**102**
Crude oil price	**(82)**	**82**
Power price	**5**	**(5)**

C) Risks Associated with Financial Assets and Liabilities

Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is not to use derivative financial instruments for speculative purposes.

Crude Oil – The Company has partially mitigated its exposure to the commodity price risk on its crude oil sales and condensate supply with fixed price swaps.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX prices. To help protect against widening natural gas price differentials in various production areas, Cenovus has entered into swaps to manage the price differentials between these production areas and various sales points.

Power – The Company has in place two Canadian dollar denominated derivative contracts, which commenced January 1, 2007 for a period of 11 years, to manage its electricity consumption costs.

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. All foreign currency agreements are with major financial institutions in Canada and the United States or with counterparties having investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at December 31, 2009, over 98 percent (2008–95 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties.

At December 31, 2009, Cenovus had two counterparties (2008–two counterparties) whose net settlement position individually account for more than 15 percent of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets and the Partnership Contribution Receivable is the total carrying value. The current concentration of this credit risk resides with EnCana and a AAA rated counterparty. Cenovus's exposure to EnCana is expected to reduce substantially by the end of the first quarter 2010 as Cenovus begins to market its own physical gas to the market. Cenovus's exposure to its counterparties is acceptable and

within Credit Policy tolerances.

Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity through the active management of cash and debt. As disclosed in Note 16, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities and undrawn credit facilities. At December 31, 2009, Cenovus had approximately $2.3 billion in unused credit capacity available on its committed bank credit facility.

It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt. DBRS Limited ("DBRS") has assigned a rating of A (low) with a "Stable" outlook, Standard and Poor's Corporation has assigned a rating of BBB+ with a "Stable" outlook and Moody's Investors Service Inc. has assigned a rating of Baa2 with a "Stable" outlook.

Cash outflows relating to financial liabilities are outlined in the table below:

(US$ millions)	Less than 1 Year	1 - 3 Years	4 - 5 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	1,444	-	-	-	**1,444**
Risk Management Liabilities	67	4	-	-	**71**
Long-Term Debt*	227	468	1,209	5,433	**7,337**
Partnership Contribution Payable*	489	978	978	1,099	**3,544**

* Principal and interest, including current portion.

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18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Included in Cenovus's long-term debt obligations of $3,493 million at December 31, 2009, are $56 million in principal obligations related to prime rate and LIBOR based loans. These amounts are fully supported by the Company's revolving syndicated credit facility, which have no repayment requirements within the next year. All outstanding amounts related to the prime rate and LIBOR based loans were drawn on the 3-year tranche of the revolving syndicated credit facility. Based on the current maturity dates of the 3-year tranche, these amounts are included in cash outflows for the period disclosed as "1-3 Years." Further information on Long-Term Debt is included in Note 13.

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on reported results. Cenovus's functional currency is Canadian dollars; however, the Company reports its results in U.S. dollars, unless otherwise indicated. As the effects of foreign exchange fluctuations are embedded in the Company's results, the total effect of foreign exchange fluctuations is not separately identifiable.

As disclosed in Note 7, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada and the translation of the U.S. dollar Partnership Contribution Receivable issued from Canada. At December 31, 2009, Cenovus had $3,525 million in U.S. dollar debt issued from Canada ($1,804 million at December 31, 2008) and $2,834 million related to the U.S. dollar Partnership Contribution Receivable ($3,147 million at December 31, 2008). A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $7 million change in foreign exchange (gain) loss at December 31, 2009 (2008-$11 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At December 31, 2009, the majority of the Company's debt is fixed-rate debt and as a result, the increase or decrease in net earnings for each one percent change in interest rates on floating rate debt amounts to nil (December 31, 2008–$4 million; 2007–$5 million).

19. SUPPLEMENTARY INFORMATION

A) Per Share Amounts

For the years ended December 31, (millions)	2009	2008	2007
Weighted Average Common Shares Outstanding – Basic	**751.0**	750.1	756.8
Effect of Stock Options and Other Dilutive Securities	**0.4**	1.7	7.8
Weighted Average Common Shares Outstanding – Diluted	**751.4**	751.8	764.6

Since Cenovus's shares were issued pursuant to the Arrangement, the per share amounts disclosed above are based on EnCana's common shares.

19. SUPPLEMENTARY INFORMATION (continued)

B) Supplementary Cash Flow Information

For the years ended December 31, (US$ millions)	2009	2008	2007
Interest Paid	**376**	395	408
Income Taxes Paid	**1,145**	508	536

Income taxes paid in 2009 includes amounts paid to EnCana as a result of the dissolution of a partnership as part of the Arrangement.

20. COMMITMENTS AND CONTINGENCIES

Commitments

As part of normal operations, the Company has committed to certain amounts over the next five years and thereafter as follows:

(US$ millions)	2010	2011	2012	2013	2014	Thereafter	Total
Operating Leases (Building Leases)	26	27	34	72	76	1,575	1,810
Pipeline Transportation	101	95	68	141	141	923	1,469
Purchases of Goods and Services	98	9	4	3	-	-	114
Capital Commitments	105	85	33	-	-	-	223
Product Purchases	26	23	22	22	22	28	143
Total Payments	356	239	161	238	239	2,526	3,759
Product Sales	46	48	52	53	55	119	373

In addition to the above, Cenovus's share of commitments related to its risk management program are disclosed in Note 18.

Contingencies

Legal Proceedings

Cenovus is involved in various legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims.

20. COMMITMENTS AND CONTINGENCIES (continued)

Asset Retirement

Cenovus is responsible for the retirement of long-lived assets related to its oil and gas properties, refining facilities and Midstream facilities at the end of their useful lives. Cenovus has recognized a liability of $1,096 million based on current legislation and estimated costs. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Income Tax Matters

The tax interpretations, regulations and legislation in the various jurisdictions that Cenovus operates in are continually changing. As a result, there are usually some tax matters under review. Management believes that the provision for taxes is adequate.

21. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The Cenovus Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP") which, in most respects, conform to accounting principles generally accepted in the United States ("U.S. GAAP"). The significant differences between Canadian GAAP and U.S. GAAP are described in this note. The most notable differences are:

- full cost accounting;
- pensions and other post-employment benefits;
- liability-based stock compensation plans;
- income taxes;
- other comprehensive income;
- joint venture accounting; and
- inventories.

RECONCILIATION OF NET EARNINGS UNDER CANADIAN GAAP TO U.S. GAAP

For the years ended December 31, (US$ millions)	Note 21	2009	2008	2007
Net Earnings–Canadian GAAP		**648**	2,368	1,404
Increase (Decrease) in Net Earnings Under U.S. GAAP:				
Revenues, net of royalties		**-**	-	(5)
Expenses				
Operating	*C ii)*	**4**	(12)	1
Depreciation, depletion and amortization	*A, C ii)*	**209**	29	148
General and administrative	*C ii)*	**8**	(14)	1
Stock-based compensation–options		**-**	1	(3)
Income tax expense	D	**(184)**	(32)	(87)
Net Earnings–U.S. GAAP		**685**	**2,340**	1,459

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CONSOLIDATED STATEMENT OF EARNINGS AND COMPREHENSIVE INCOME – U.S. GAAP

For the years ended December 31, (US$ millions)	Note 21	2009	2008	2007
Revenues, Net of Royalties		**10,140**	16,559	13,401
Expenses				
Production and mineral taxes		**38**	75	63
Transportation and selling		**672**	963	756
Operating	*C ii)*	**1,150**	1,235	1,113
Purchased product		**5,250**	9,710	7,476
Depreciation, depletion and amortization	*A, C ii)*	**1,134**	1,289	1,278
General and Administrative	*C ii)*	**180**	181	144
Interest, net		**218**	218	187
Accretion of asset retirement obligation		**39**	39	28
Foreign exchange (gain) loss, net		**290**	(250)	380
Stock-based compensation–options		**-**	(1)	3
Other (gain) loss, net		**(2)**	3	4
Earnings Before Income Tax		**1,171**	3,097	1,969
Income tax expense	D	**486**	757	510
Net Earnings–U.S. GAAP		**685**	2,340	1,459
Other Comprehensive Income, Net of Tax				
Foreign Currency Translation Adjustment		**1,872**	(2,075)	1,133
Compensation Plans		**31**	(8)	-
Comprehensive Income		**2,588**	257	2,592

CONDENSED CONSOLIDATED BALANCE SHEET – U.S. GAAP

		2009		2008	
As at December 31, (US$ millions)	Note 21	**As Reported**	**U.S. GAAP**	As Reported	U.S. GAAP
Assets					
Current Assets	*G*	**2,284**	**2,284**	2,248	2,248
Property, Plant and Equipment (includes unproved properties and major development projects of $1,921 and $715 as of December 31, 2009 and 2008, respectively)	*A, C ii)*	**26,255**	**26,237**	21,175	21,182
Accumulated Depreciation, Depletion and Amortization		**(11,718)**	**(12,523)**	(8,915)	(9,798)
Property, Plant and Equipment, net (Full Cost Method for Oil and Gas Activities)		**14,537**	**13,714**	12,260	11,384
Other Assets	*C i)*	**131**	**138**	150	133
Partnership Contribution Receivable		**2,504**	**2,504**	2,834	2,834
Risk Management		**1**	**1**	38	38
Goodwill		**1,095**	**1,095**	936	936
		20,552	**19,736**	18,466	17,573
Liabilities and Net Investment					
Current Liabilities	*C i), C ii), D*	**1,836**	**1,937**	1,798	1,918
Long-Term Debt		**3,493**	**3,493**	2,952	2,952
Other Liabilities	*C i), C ii)*	**54**	**55**	52	65
Partnership Contribution Payable		**2,532**	**2,532**	2,857	2,857
Risk Management		**4**	**4**	-	-
Asset Retirement Obligation		**1,096**	**1,096**	648	648
Deferred Income Taxes	D	**2,357**	**2,187**	2,411	2,093
		11,372	**11,304**	10,718	10,533
Shareholders' Equity	*E*	**9,180**	**8,432**	7,748	7,040
		20,552	**19,736**	18,466	17,573

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CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS – U.S. GAAP

For the years ended December 31, (US$ millions)	2009	2008	2007
Operating Activities			
Net earnings	**685**	2,340	1,459
Depreciation, depletion and amortization	**1,134**	1,289	1,278
Deferred income taxes	**(371)**	416	(168)
Unrealized (gain) loss on risk management	**667**	(734)	353
Unrealized foreign exchange (gain) loss	**313**	(259)	383
Accretion of asset retirement obligation	**39**	39	28
Other (income) loss, net	**1**	(2)	124
Net change in other assets and liabilities	**(23)**	(89)	(48)
Net change in non-cash working capital	**1,051**	(316)	(417)
Cash From Operating Activities	**3,496**	2,684	2,992
Cash (Used in) Investing Activities	**(1,780)**	(1,964)	(1,533)
Net Cash Provided before Financing Activities	**1,716**	720	1,459
Cash From (Used in) Financing Activities	**(1,730)**	(849)	(1,270)

Notes:

A) Full Cost Accounting

Under U.S. GAAP, a ceiling test is applied to ensure the unamortized capitalized costs in each cost centre do not exceed the sum, net of applicable income taxes, of the present value, discounted at 10 percent, of the estimated future net revenues calculated on the basis of estimated value of future production from proved reserves using oil and gas prices at the balance sheet date, less related unescalated estimated future development and production costs, plus unimpaired unproved property costs. For 2009, depletion charges under U.S. GAAP were also calculated by reference to proved reserves estimated using an average price for the prior 12-month period. For 2008 and 2007, depletion charges under U.S. GAAP were calculated by reference to proved reserves estimated using oil and gas prices at the balance sheet date.

Under Canadian GAAP, a similar ceiling test calculation is performed with the exception that cash flows from proved reserves are undiscounted and utilize forecast pricing and future development and production costs to determine whether impairment exists. The impairment amount is measured using the fair value of proved and probable reserves. Depletion charges under Canadian GAAP are also calculated by reference to proved reserves estimated using estimated future prices and costs.

At December 31, 2008, Cenovus's capitalized costs of oil and gas properties in Canada exceeded the full cost ceiling resulting in a non-cash U.S. GAAP write-down of $60 million charged to DD&A (2007–nil). Additional depletion was also recorded in 2006, and certain prior years, as a result of the ceiling test difference between Canadian GAAP and U.S. GAAP. As a result, the depletion base of unamortized capitalized costs is less for U.S. GAAP purposes.

The U.S. GAAP adjustment for the difference in depletion calculations results in an impact to DD&A charges and foreign currency translation adjustment of $207.8 million decrease and $13.9 million increase respectively (2008–$92.4 million decrease and $8.5 million decrease; 2007–$147.8 million decrease and $8.9 million increase).

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21. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (continued)

B) Property, Plant and Equipment Allocation

Net property, plant and equipment related to Canadian upstream oil and gas activities have been allocated for U.S. GAAP carve-out purposes using the same methodology as the carve-out allocation for Canadian GAAP purposes.

The balances related to Canadian upstream operations have been allocated between Cenovus and EnCana in accordance with the CICA Handbook Accounting Guideline ACG-16, based on the ratio of future net revenue, discounted at 10 percent, of the properties carved out to the discounted future net revenue of all proved properties in Canada using the reserve reports dated December 31, 2008 and December 31, 2007. Future net revenue is the estimated net amount to be received with respect to development and production of crude oil and natural gas reserves, the value of which has been determined by independent reserve evaluators.

C) Compensation Plans

i) Pensions and Other Post-Employment Benefits

Under U.S. GAAP, ASC 715-30, *"Compensation – Retirement Benefits*", requires Cenovus to recognize the over-funded or under-funded status of defined benefit and post-employment plans on the balance sheet as an asset or liability and to recognize changes in the funded status through Other Comprehensive Income. Canadian GAAP does not require Cenovus to recognize the funded status of these plans on its balance sheet.

ii) Liability-Based Stock Compensation Plans

Under Canadian GAAP, obligations for liability-based stock compensation plans are recorded using the intrinsic-value method of accounting. For U.S. GAAP purposes, Cenovus adopted ASC 718, *"Compensation – Stock Compensation*" for the year ended December 31, 2006 using the modified-prospective approach. Under ASC 718, liability-based stock compensation plans, including tandem share appreciation rights, performance tandem share appreciation rights, share appreciation rights, performance share appreciation rights and deferred share units, are required to be re-measured at fair value at each reporting period up until the settlement date.

To the extent compensation cost relates to employees directly involved in crude oil and natural gas development activities, certain amounts are capitalized to property, plant and equipment. Amounts not capitalized are recognized as administrative expenses or operating expenses. The current period adjustments have the following impact:

- Net property, plant and equipment decreased by $24.2 million (2008–$14.6 million increase)

· Current liabilities decreased by $39.5 million (2008–$41.4 million increase)
· Other liabilities increased by $1.6 million (2008–$0.2 million decrease)
· Other comprehensive income–nil (2008–$3.0 million increase)
· Operating expenses decreased by $3.8 million (2008–$11.6 million increase)
· Administrative expenses decreased by $7.9 million (2008–$14.5 million increase)
· Depreciation, depletion and amortization expenses decreased by $1.6 million (2008–$3.8 million increase)

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21. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (continued)

D) Income Taxes

U.S. GAAP uses enacted tax rates and legislative changes to calculate current and deferred income taxes, whereas Canadian GAAP uses substantively enacted tax rates and legislative changes. In 2007, a Canadian tax legislative change was substantively enacted for Canadian GAAP; however, this tax legislative change was not considered enacted for U.S. GAAP by December 31, 2007 and 2008. This tax legislative change is still not considered enacted. Accordingly, there was no difference in 2009 (2008–nil; 2007–increase to income tax expense of $76 million) for U.S. GAAP.

The remaining differences resulted from the deferred income tax adjustments included in the Reconciliation of Net Earnings under Canadian GAAP to U.S. GAAP and the Condensed Consolidated Balance Sheet include the effect of such rate differences, if any, as well as the tax effect of the other reconciling items noted.

In 2009, Cenovus incurred losses in one of its subsidiary company which were recognized and included in calculating future income taxes for Canadian GAAP purposes on the basis that the tax legislative changes noted above were substantially enacted. For U.S. GAAP, these losses can not be recognized as the tax legislative changes have not been enacted by December 31, 2009. The income tax expense has been increased by $124.0 million (2008 and 2007–nil) to record the difference between Canadian and U.S. GAAP.

The following table provides a reconciliation of the statutory rate to the actual tax rate:

For the years Ended December 31, (US$ millions)	2009	2008	2007
Net Earnings Before Income Tax–U.S. GAAP	**1,171**	3,097	1,969
Canadian Statutory Rate	**29.2%**	29.7%	32.3%
Expected Income Tax	**342**	919	636
Effect on Taxes Resulting from:			
Statutory and other rate differences	**(9)**	(79)	17
Effect of tax rate changes	**-**	-	(147)
Non-taxable downstream partnership income	**6**	6	(70)
International financing	**(118)**	(127)	-
Foreign exchange (gains) losses not included in net earnings	**67**	11	-
Non-taxable capital (gains) losses	**11**	(50)	45
Unrecognized non-capital losses	**124**	-	-
Other	**63**	77	29
Income Tax–U.S. GAAP	**486**	757	510
Effective Tax Rate	**41.5%**	24.4%	25.9%

The net deferred income tax liability is comprised of:

As at December 31, (US$ millions)	2009	2008
Deferred Tax Liabilities		
Property, plant and equipment in excess of tax values	**2,224**	1,737
Timing of partnership items	**9**	470
Risk management	**16**	-
Other	**75**	185
Deferred Tax Assets		
Non-capital and net operating losses carried forward	**(106)**	(19)
Other	**(31)**	(280)
Net Deferred Income Tax Liability	**2,187**	2,093

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21. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (continued)

E) Other Comprehensive Income

ASC 715-30 requires a change in the funded status of defined benefit and post-employment plans to be recognized on the balance sheet and changes in the funded status through comprehensive income. In 2009, a gain of $30.9 million, net of tax was recognized in other comprehensive income (2008–loss of $7.5 million) as noted in D i). On adoption of ASC 715-30, as required, the transitional amount of $12 million, net of tax was booked directly to Accumulated Other Comprehensive Income.

The foreign currency translation adjustment includes the effect of the accumulated U.S. GAAP differences.

F) Joint Venture with ConocoPhillips

Under Canadian GAAP, the Integrated Oil operations that are jointly controlled are proportionately consolidated. U.S. GAAP requires the Downstream Refining operations included in the Integrated Oil Division be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission, accounting for jointly controlled investments does not require reconciliation from Canadian to U.S. GAAP if the joint venture is jointly controlled by all parties having an equity interest in the entity, which is the case for the Downstream Refining operations. Equity accounting for the Downstream Refining operations would have no impact on Cenovus's net earnings or retained earnings. As required, the following disclosures are provided for the Downstream Refining operations of the joint venture.

Consolidated Statement of Earnings		
For the year ended December 31, (US$ millions)	**2009**	2008
Operating Cash Flow (See Note 1)	**310**	(241)
Depreciation, depletion and amortization	**(192)**	(188)
Other	**(11)**	19
Net Earnings (Loss)	**107**	(410)

Consolidated Balance Sheet		
As at December 31, (US$ millions)	**2009**	2008
Current Assets	**771**	321
Long-term Assets	**4,872**	4,157
Current Liabilities	**489**	422
Long-term Liabilities	**391**	35

Consolidated Statement of Cash Flows		
For the year ended December 31, (US$ millions)	**2009**	2008
Cash From/(Used in) Operating Activities	**(54)**	118
Cash (Used in) Investing Activities	**(905)**	(519)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in US$ millions, unless otherwise indicated
For the year ended December 31, 2009

21. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING (continued)

G) Inventories

For Canadian GAAP purposes, for the year ended December 31, 2009, the Company recorded an increase in inventory values resulting from a subsequent improvement in commodity prices following a write-down of product inventory. Under U.S. GAAP, this increase in inventory value is not permitted. Since the majority of the impaired inventory was sold during the year, the impact to net earnings for this reconciling difference was immaterial.

H) Recent Accounting Pronouncements

During the year, Cenovus adopted the following pronouncements for U.S. GAAP purposes:

- ASC 805-10, *"Business Combinations,"* which is a revised standard and requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. Acquisition-related and restructuring costs are recognized separately from the business combination. This standard was adopted prospectively as of January 1, 2009. The adoption of this standard had no material impact on Cenovus's U.S. GAAP accounting treatment of business combinations entered into after January 1, 2009.
- ASC 810-10 *"Consolidation,"* which requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. The standard also changes the way the U.S. GAAP consolidated statement of earnings is presented by requiring net earnings to include the amounts attributable to both the parent and the non-controlling interest and to disclose these respective amounts. This standard was adopted as of January 1, 2009. The adoption of this standard had no material impact on Cenovus's Consolidated Financial Statements.
- In June 2009, the U.S. Financial Accounting Standards Board ("FASB") issued the Accounting Standards Update (ASU) 2009-01, *"The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles."* This update establishes the FASB Accounting Standards Codification ("Codification") as the source of authoritative U.S. generally accepted accounting principles effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Codification did not change existing requirements under U.S. GAAP and as a result, did not impact Cenovus's Consolidated Financial Statements.
- The U.S. Securities Exchange Commission's project, *"Modernization of Oil and Gas Reporting"* and FASB's Accounting Standards Update 2010-03 "*Oil and Gas Reserve Estimation and Disclosures,"* which include provisions that permit the use of new technologies to establish proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes. Additionally, oil and gas reserves are now reported using an average price based upon the prior 12-month period rather than year-end prices. The new rules and standards were adopted prospectively by Cenovus on December 31, 2009 and affected the reserve estimate used in the calculation of the ceiling test for U.S. GAAP. There was no effect on the ceiling test for the change in rules and standards noted above for 2009. In addition, the FASB standard affected the amounts reported in the Supplementary Oil and Gas Information Topic 932 as discussed in that supplementary information.

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ADDITIONAL DISCLOSURE

Certifications and Disclosure Regarding Controls and Procedures.

(a) Certifications. See Exhibits 99.1, 99.2, 99.3 and 99.4 to this Annual Report on Form 40-F.

(b) Disclosure Controls and Procedures. As of the end of the registrant's fiscal year ended December 31, 2009, an evaluation of the effectiveness of the registrant's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was carried out by the registrant's management with the participation of the principal executive officer and principal financial officer. Based upon that evaluation, the registrant's principal executive officer and principal financial officer have concluded that as of the end of that fiscal year, the registrant's disclosure controls and procedures are effective to ensure that information required to be disclosed by the registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's (the "Commission") rules and forms and (ii) accumulated and communicated to the registrant's management, including its principal executive and principal financial officers, or persons performing similar functions, to allow timely decisions regarding required disclosure.

It should be noted that while the registrant's principal executive officer and principal financial officer believe that the registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the registrant's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

(c) Management's Annual Report on Internal Control Over Financial Reporting. The required disclosure is included in the "Management Report" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2009, filed as part of this Annual Report on Form 40-F.

(d) Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the "Auditors' Report" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2009, filed as part of this Annual Report on Form 40-F.

(e) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2009, there was no change in the registrant's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

Notices Pursuant to Regulation BTR.

None.

Audit Committee Financial Expert.

The registrant's board of directors has determined that Colin Taylor, a member of the registrant's audit committee, qualifies as an "audit committee financial expert" (as such term is defined in Form 40-F), and is "independent" as that term is defined in the rules of the New York Stock Exchange.

Code of Ethics.

The registrant has adopted a "code of ethics" (as that term is defined in Form 40-F), entitled the "Code of Business Conduct & Ethics", that applies to all of its employees, including its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions.

The Code of Business Conduct & Ethics is available for viewing on the registrant's website at www.cenovus.com, and is available in print to any person without charge, upon request. Requests for copies of the Code of Business Conduct & Ethics should be made by contacting: Kerry D. Dyte, Executive Vice-President, General Counsel & Corporate Secretary, Cenovus Energy Inc., 4000, 421-7th Avenue S.W., Calgary, Alberta, Canada T2P 4K9. Alternatively, requests for a copy of the Code of Business Conduct & Ethics may be made by contacting the registrant's Corporate Secretarial Department at (403) 766-2000 (Fax: (403) 766-7600).

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Since the adoption of the Code of Business Conduct & Ethics, there have not been any waivers, including implicit waivers, granted from any provision of the Code of Business Conduct & Ethics.

Principal Accountant Fees and Services.

The required disclosure is included under the heading "Audit Committee—External Auditor Service Fees" in the registrant's Annual Information Form for the fiscal year ended December 31, 2009, filed as part of this Annual Report on Form 40-F.

Pre-Approval Policies and Procedures.

The required disclosure is included under the heading "Audit Committee Information—Pre-Approval Policies and Procedures" in the registrant's Annual Information Form for the fiscal year ended December 31, 2009, filed as part of this Annual Report on Form 40-F.

Off-Balance Sheet Arrangements.

The registrant does not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Tabular Disclosure of Contractual Obligations.

The required disclosure is included under the heading "Contractual Obligations and Contingencies" in the registrant's Management's Discussion and Analysis for the fiscal year ended December 31, 2009, filed as part of this Annual Report on Form 40-F.

Identification of the Audit Committee.

The registrant has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Patrick D. Daniel, Valerie A. A. Nielsen, Colin Taylor and Michael A. Grandin (ex-officio).

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UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

The registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process

(1) The registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

(2) Any change to the name or address of the agent for service of process of the registrant shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the registrant.

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SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 18, 2010

CENOVUS ENERGY INC.

By: /s/ Ivor M. Ruste
Name: Ivor M. Ruste
Title: Executive Vice-President & Chief Financial Officer

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EXHIBIT INDEX

Exhibits	**Documents**

99.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934
99.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934
99.3	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
99.4	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
99.5	Consent of PricewaterhouseCoopers LLP
99.6	Consent of McDaniel & Associates Consultants Ltd.
99.7	Consent of GLJ Petroleum Consultants Ltd.

Exhibit 99.1

Certification Pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Brian C. Ferguson, certify that:

1. I have reviewed this annual report on Form 40-F of Cenovus Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 18, 2010

/s/ Brian C. Ferguson
Brian C. Ferguson

President & Chief Executive Officer
(Principal Executive Officer)

Exhibit 99.2

Certification Pursuant to Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

I, Ivor M. Ruste, certify that:

1. I have reviewed this annual report on Form 40-F of Cenovus Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent function):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 18, 2010

/s/ Ivor M. Ruste
Ivor M. Ruste

Executive Vice-President & Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.3

Certification Pursuant To 18 U.S.C. Section 1350, As Adopted Pursuant To Section 906 of the Sarbanes Oxley Act Of 2002

In connection with the Annual Report of Cenovus Energy Inc. (the "Company") on Form 40-F for the year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian C. Ferguson, President & Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By: /s/ Brian C. Ferguson
Brian C. Ferguson
President & Chief Executive Officer

February 18, 2010

Exhibit 99.4

Certification Pursuant To 18 U.S.C. Section 1350, As Adopted Pursuant To Section 906 of the Sarbanes-Oxley Act Of 2002

In connection with the Annual Report of Cenovus Energy Inc. (the "Company") on Form 40-F for the year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ivor M. Ruste, Executive Vice-President & Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By: /s/ Ivor M. Ruste
Ivor M. Ruste
Executive Vice-President & Chief Financial Officer

February 18, 2010

Exhibit 99.5



CONSENT OF PRICEWATERHOUSECOOPERS LLP

We hereby consent to (i) the inclusion in Cenovus Energy Inc.'s Annual Report on Form 40-F for the year ended December 31, 2009; and (ii) the incorporation by reference in Cenovus Energy Inc.'s Registration Statement on Form S-8 (File No. 333-163397), of our audit report dated February 17, 2010, relating to the Cenovus Energy Inc. Consolidated Financial Statements as of December 31, 2009 and December 31, 2008, and for each of the years in the three year period ended December 31, 2009 and the effectiveness of internal control over financial reporting of Cenovus Energy Inc. as of December 31, 2009.

/s/ PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
February 17, 2010

EXHIBIT 99.6



CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the use and reference to our name and reports evaluating a portion of Cenovus Energy Inc.'s proved and probable oil and gas reserves quantities, as of December 31, 2009, and the related estimates of discounted future net cash flows for proved oil and gas reserves quantities, and the information derived from our reports, as described or incorporated by reference in Cenovus Energy Inc.'s Annual Report on Form 40-F for the year ended December 31, 2009 and Cenovus Energy Inc.'s registration statement on Form S-8 (File No. 333-163397), filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ P.A. Welch
P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
February 18, 2010

2200, Bow Valley Square 3, 255 - 5 Avenue SW, Calgary AB T2P 3G6 Tel: (403) 262-5506 Fax: (403) 233-2744 www.mcdan.com

Exhibit 99.7



GLJ Petroleum Consultants

Principal Officers:

Harry Jung, P. Eng.
President, C.E.O.
Dana B. Laustsen, P. Eng.
Executive V.P., C.O.O.
Keith M. Braaten, P. Eng.
Executive V.P.

Officers / Vice Presidents:

Terry L. Aarsby, P. Eng.
Jodi L. Anhorn, P. Eng.
Neil I. Dell, P. Eng.
David G. Harris, P. Geol.
Myron J. Hladyshevsky, P. Eng.
Bryan M. Joa, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

CONSENT OF INDEPENDENT PETROLEUM ENGINEER

We hereby consent to the use and reference to our name and reports evaluating a portion of Cenovus Energy Inc.'s proved and probable oil and gas reserves quantities, as of December 31, 2009, and the related estimates of discounted future net cash flows for proved oil and gas reserves quantities, and the information derived from our reports, as described or incorporated by reference in Cenovus Energy Inc.'s Annual Report on Form 40-F for the year ended December 31, 2009 and Cenovus Energy Inc.'s registration statement on Form S-8 (File No. 333-163397), filed with the U.S. Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

Your truly,

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Harry Jung
Harry Jung, P. Eng.
President

Calgary, Alberta
February 18, 2010