Annual Information Form

for the year ended December 31, 2010

February 24, 2011

cenovus ENERGY

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FORWARD-LOOKING INFORMATION

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

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

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

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and our access to various sources of capital; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining a desirable debt to cash flow ratio; our ability to access external sources of debt and equity capital; success of hedging strategies; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in manufacturing, transporting or refining of crude oil into petroleum and chemical products at two refineries; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in Alberta's regulatory framework, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in this AIF. Readers should also refer to "Risk Management" in our current Management's Discussion and Analysis and to the risk factors described in other documents we file from time to time with securities regulatory authorities, available at www.sedar.com, www.sec.gov and www.cenovus.com.

CORPORATE STRUCTURE

Cenovus was formed under the *Canada Business Corporations Act* ("CBCA") by amalgamation of 7050372 Canada Inc. and Cenovus Energy Inc. (formerly Encana Finance Ltd. and referred to as "Subco") on November 30, 2009 pursuant to an arrangement under the CBCA (the "Arrangement") involving, among others, 7050372 Canada Inc., Subco and Encana Corporation ("Encana"). On January 1, 2011, we amalgamated with our wholly owned subsidiary, Cenovus Marketing Holdings Ltd., through a plan of arrangement approved by the Alberta Court of Queen's Bench.

Unless otherwise specified or the context otherwise requires, reference to "we", "us", "our", "its", "Company" or "Cenovus" includes reference to subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries and, when in reference to prior period information, as held by Encana prior to the closing of the Arrangement.

Our principal and registered office is located at 4000, 421 – 7 Avenue S.W., Calgary, Alberta, Canada T2P 4K9.

Intercorporate Relationships

The following table summarizes our principal subsidiaries and partnerships at January 1, 2011:

Subsidiaries & Partnerships	Percentage Owned(1)	Jurisdiction of Incorporation, Continuance, Formation or Organization
Cenovus FCCL Ltd.	100	Alberta
Cenovus US Refinery Holdings(2)	100	Delaware
FCCL Partnership ("FCCL")(3)	50	Alberta
WRB Refining LP ("WRB")(4)	50	Delaware

Notes:

(1) Includes direct and indirect ownership.
(2) A Delaware partnership; effective January 1, 2011, received assigned interest from Cenovus Refinery Services LLC.
(3) Cenovus interest held through Cenovus FCCL Ltd., the operator and managing partner of FCCL Partnership.
(4) On December 31, 2010, WRB Refining LLC was converted from a limited liability company to a limited partnership, WRB Refining LP.

The above table includes our subsidiaries and partnerships which have total assets that exceed 10 percent of our total consolidated assets, or sales and revenues which exceed 10 percent of our total consolidated sales and revenues. 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 at and for the year ended December 31, 2010.

GENERAL DEVELOPMENT OF OUR BUSINESS

Cenovus is a Canadian oil company headquartered in Calgary, Alberta. Our operations include oil sands 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, U.S.A.

We began independent operations on December 1, 2009 following the split of Encana into two independent publicly traded energy companies, Cenovus and Encana.

Our Business

Our operating and reportable segments are as follows:

- **Upstream**, which includes Cenovus's development and production of crude oil, natural gas and NGLs in Canada, is organized into two reportable operations:
    - **Oil Sands,** which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company and operated by Cenovus.
    - **Conventional,** which includes the development and production of conventional crude oil, natural gas and NGLs in western Canada.
- **Refining and Marketing,** which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.
- **Corporate and Eliminations**, which primarily includes unrealized gains or losses recorded on derivative financial instruments as well as other Cenovus-wide costs for general and administrative and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

The operating and reportable segments shown above were changed from those presented in prior periods to better align with our long range business plan. All prior periods have been restated to reflect this presentation.

Three Year History

The following describes the significant events of the last three years in respect of our business:

2010

- At the end of the second quarter, an application for the Narrows Lake project in the Christina Lake Region was submitted to the Energy Resources Conservation Board ("ERCB") and Alberta Environment. The project is jointly owned with ConocoPhillips and is expected to be developed in two or three phases with a production capacity of 130,000 barrels per day of bitumen.
- In the third quarter of 2010, regulatory approval was received for Foster Creek phases F, G and H. Planned production capacity for each expansion phase is 30,000 barrels per day for a total of 90,000 barrels per day of bitumen.
- In the fourth quarter of 2010, we started up our Grand Rapids pilot project after receiving project approval from Alberta Environment. We had previously received project approval from the ERCB in the second quarter of 2010.

2009

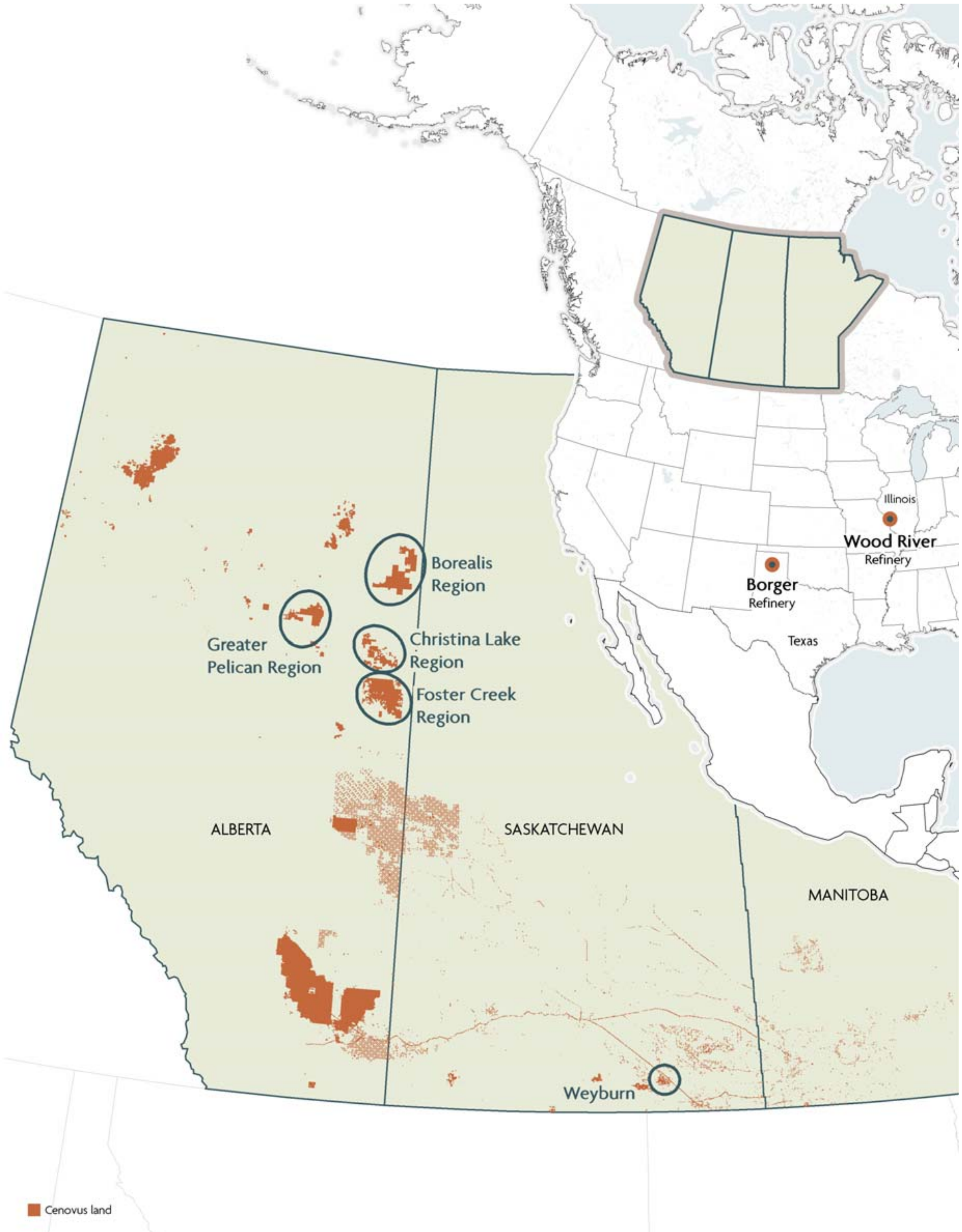
- In the first quarter of 2009, two new expansion phases at Foster Creek were commissioned. Phases D and E added capacity of 60,000 barrels per day of bitumen, increasing production capacity of Foster Creek to approximately 120,000 barrels per day of bitumen.
- In the second quarter of 2009, a joint regulatory application for Foster Creek phases F, G and H was submitted to the ERCB and Alberta Environment.
- 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.
- On December 1, 2009, we began independent operations as a publicly traded company having completed the Arrangement with Encana. In connection with the Arrangement, Encana shareholders received one Cenovus common share and one new Encana common share for each Encana common share held.

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 of the Coker and Refinery Expansion ("CORE") project. 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.

NARRATIVE DESCRIPTION OF OUR BUSINESS

The following map outlines the location of our assets, including our refining assets at December 31, 2010.



Overview

One hundred percent of our reserves and production are located in Canada. At December 31, 2010, we had a land base of approximately 7.2 million net acres and proved reserves (our share before royalties) of approximately 1,154 million barrels of bitumen, 169 million barrels of heavy oil, 111 million barrels of light and medium oil and NGLs and 1,390 billion cubic feet of natural gas. The estimated proved reserves life index at December 31, 2010 was approximately 18 years. We also had probable reserves (our share before royalties) of approximately 523 million barrels of bitumen, 97 million barrels of heavy oil, 49 million barrels of light and medium oil and NGLs and 410 billion cubic feet of natural gas at December 31, 2010.

The following narrative describes our operations in greater detail.

Oil Sands

Oil Sands includes our producing bitumen assets at Foster Creek and Christina Lake, as well as heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. The Foster Creek and Christina Lake operations as well as the Narrows Lake property are jointly owned with ConocoPhillips, an unrelated U.S. public company.

FCCL owns the Foster Creek, Christina Lake and Narrows Lake properties, as well as other bitumen interests. Cenovus FCCL Ltd., our wholly owned subsidiary, is the operating and managing partner of FCCL, and owns 50 percent of FCCL. FCCL has a management committee, which is composed of three Cenovus representatives and three ConocoPhillips representatives, with each company holding equal voting rights.

In 2010, the capital investment of $867 million in our Oil Sands business was primarily related to the expansion of FCCL's production capacity. FCCL plans to increase production capacity to approximately 218,000 barrels per day of bitumen from the combined facilities at Foster Creek and Christina Lake following the completion of Christina Lake phase C, expected in 2011 and phase D expansion, expected in 2013. In 2010, we received regulatory approval for the next three phases of expansion at Foster Creek, phases F, G and H. Oil Sands also continued to develop our new resource play assets, including the drilling of stratigraphic test wells. In 2010, capital investment for Pelican Lake was primarily related to capital maintenance and polymer injection investment on producing assets.

Plans for 2011 include significant capital expenditures on our expansion phases at both Foster Creek and Christina Lake, additional capital investment at our Pelican Lake property, as well as an active stratigraphic test well program in order to enhance our understanding of our new resource play assets and move projects toward the submission of regulatory applications.

At December 31, 2010, we held bitumen rights of approximately 1,162,000 gross acres (859,000 net acres) within the Athabasca and Cold Lake areas, as well as the exclusive rights to lease an additional 582,880 net acres on our behalf and/or our assignee's behalf on the Cold Lake Air Weapons Range.

The following table summarizes our landholdings at December 31, 2010.

Landholdings – Oil Sands	**Developed**		**Undeveloped**		**Total**		**Average Working**
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Interest**
Foster Creek	7	4	65	32	72	36	50%
Christina Lake	1	-	24	12	25	12	50%
Pelican Lake	134	133	294	279	428	412	96%
Athabasca	528	448	345	280	873	728	83%
Other	26	12	1,117	852	1,143	864	76%
Total	696	597	1,845	1,455	2,541	2,052	81%

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

Production – Oil Sands	**Crude Oil and NGLs (bbls/d)**		**Natural Gas (MMcf/d)**		**Total Production (BOE/d)**	
(annual average)	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Foster Creek	51,147	37,725	-	-	51,147	37,725
Christina Lake	7,898	6,698	-	-	7,898	6,698
Pelican Lake	22,966	24,870	-	-	22,966	24,870
Athabasca	-	-	40	50	6,667	8,333
Other	-	3,057	3	3	500	3,557
Total	82,011	72,350	43	53	89,178	81,183

The following table summarizes our interests in producing wells at December 31, 2010. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2010.

Producing Wells – Oil Sands	**Producing Oil Wells**		**Producing Gas Wells**		**Total Producing Wells**	
(number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Foster Creek	183	91	-	-	183	91
Christina Lake	19	10	-	-	19	10
Pelican Lake	448	448	11	11	459	459
Athabasca	-	-	459	436	459	436
Other	-	-	20	20	20	20
Total	650	549	490	467	1,140	1,016

Foster Creek

We have a 50 percent interest in Foster Creek, an oil sands property which uses steam-assisted gravity drainage ("SAGD") technology and produces from the McMurray formation. We hold surface access rights from the Governments of Canada and Alberta and bitumen rights from the Government of Alberta for exploration, development and transportation from areas within the Cold Lake Air Weapons Range. 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 gross production capacity of approximately 60,000 barrels per day of bitumen and increasing total gross production capacity to approximately 120,000 barrels per day of bitumen.

In the third quarter of 2010, we received regulatory approval for phases F, G and H which are expected to add approximately 90,000 barrels per day of gross bitumen production capacity.

We have successfully piloted and implemented 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. This technology requires minimal additional steam, thus it helps reduce the overall steam-oil ratio. In 2010, we drilled 20 wedge wells (2009 - 18 wells), and at December 31, 2010, there were 33 wedge wells producing.

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 oil sands project at Christina Lake which produces from the McMurray formation. The phase B expansion was completed in 2008 which increased gross production capacity to approximately 18,000 barrels per day of bitumen.

Christina Lake phase C was approximately 88 percent complete at December 31, 2010, on budget and on schedule for first production in the third quarter of 2011. This phase is expected to increase total gross bitumen production capacity to approximately 58,000 barrels per day.

We have accelerated the planned completion of phase D by approximately six months and it is expected to be completed in 2013. Regulatory approval for this additional phase was received in 2008.

Additionally, we drilled four wedge wells at Christina Lake in 2010, and at December 31, 2010, there was one wedge well producing.

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 Solvent Aided Process ("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.

Pelican Lake

Using a pattern, horizontal well polymer flood, we produce heavy oil from the Cretaceous Wabiskaw formation at our Pelican Lake property, which is located within the Greater Pelican Region in northeast Alberta. In 2010, expansion of the facility infrastructure continued in order to accommodate higher total fluid production volumes associated with infill drilling as well as the continued rollout of the polymer injection program. The polymer flood program was expanded by six new injection wells and 11 new production wells in 2010.

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, expected to be in-service in mid-2011. This pipeline will be used to transport heavy oil from the Greater Pelican Region 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 pipeline's in-service date.

New Resource Play assets

Our new resource play assets include our emerging oil sands properties such as Narrows Lake, Grand Rapids and Telephone Lake.

Through our interest in FCCL, we hold an approximate 50 percent interest in the Narrows Lake property, which is located within the Christina Lake Region. In the first quarter of 2010, we initiated the regulatory approval process for Narrows Lake by filing proposed terms of reference for an environmental impact assessment ("EIA") and began public consultation for the project. In the second quarter of 2010, final terms of reference were issued by Alberta Environment and a joint application and EIA was filed. The project includes gross production capacity of 130,000 barrels per day of bitumen to be added in three phases, with the first phase expected to have production capacity of approximately 40,000 barrels per day of bitumen. The project is expected to begin producing in 2016. Our submitted application includes the option to implement the SAP technology at Narrows Lake which would allow the project to be developed in two phases of 65,000 barrels per day, rather than three phases.

Our Grand Rapids project is located in the Greater Pelican Region, where large deposits of bitumen have been identified in the Cretaceous Grand Rapids formation. During the second quarter of 2010, we received approval from the ERCB to begin a pilot project at Grand Rapids. In the fourth quarter of 2010, we received approval from Alberta Environment to start this pilot project. The drilling of a SAGD well pair and construction of associated facilities is complete and steam injection commenced in late 2010. If this pilot is successful, we expect to file a regulatory application by the end of 2011 for a commercial operation with bitumen production capacity of 180,000 barrels per day.

Our Telephone Lake property is located in the Borealis Region. A joint application and EIA was submitted in 2007 to the ERCB and Alberta Environment for the development of the property, including the construction of a facility with production capacity of 35,000 barrels per day of bitumen. We plan to file an updated joint application and EIA in the fourth quarter of 2011.

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 ERCB decisions made between 2003 and 2009 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 23 million cubic feet per day in 2010 (25 million cubic feet per day in 2009). The Government of Alberta'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.

Conventional

We have conventional crude oil and natural gas development and production activities in Alberta and Saskatchewan. Conventional also includes the Weyburn carbon dioxide (“CO_2”) miscible flood project as well as our emerging Bakken and Shaunavon properties.

At December 31, 2010, we had an established land position of approximately 5.4 million gross acres (5.2 million net acres), of which approximately 3.7 million gross acres (3.5 million net acres) are developed. The mineral rights on approximately 60 percent of our net landholdings 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. We may lease out a portion of our fee lands in areas where the land is not consistent with our long range business plan. We lease Crown lands in some areas in Alberta, mainly in the Early Cretaceous geological formations, primarily in the Suffield and Wainwright areas. In Saskatchewan, the majority of our current production comes from lands leased from the Province of Saskatchewan.

In 2010, we had capital investment of approximately $523 million and drilled approximately 676 net wells. Of our capital expenditures, 68 percent was oil focused, while 32 percent was natural gas focused.

Plans for 2011 include continued drilling, well optimizations, well recompletions (including coalbed methane (“CBM”)) and investment in facility infrastructure necessary for continued development of our assets.

The following table summarizes our landholdings at December 31, 2010.

Landholdings – Conventional	**Developed**		**Undeveloped**		**Total**		**Average Working**
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Interest**
Suffield	916	907	89	86	1,005	993	99%
Brooks North	570	568	8	8	578	576	100%
Langevin	761	720	415	399	1,176	1,119	95%
Drumheller	359	348	16	13	375	361	96%
Wainwright	361	336	210	205	571	541	95%
Boyer	594	559	280	235	874	794	91%
Weyburn	100	89	384	364	484	453	94%
Shaunavon / Bakken	3	3	72	71	75	74	99%
Other	3	3	261	261	264	264	100%
Total	3,667	3,533	1,735	1,642	5,402	5,175	96%

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

Production – Conventional	**Crude Oil and NGLs (bbls/d)**		**Natural Gas (MMcf/d)**		**Total Production (BOE/d)**	
(annual average)	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Suffield	12,742	13,822	200	223	46,075	50,989
Brooks North	1,637	1,104	240	260	41,637	44,437
Langevin	7,728	8,386	152	181	33,062	38,553
Drumheller	2,109	2,127	72	82	14,109	15,794
Wainwright	4,414	5,589	3	5	4,914	6,422
Boyer	13	13	24	29	4,013	4,846
Weyburn	16,537	17,791	-	-	16,537	17,791
Shaunavon / Bakken	1,996	656	3	4	2,496	1,323
Total	47,176	49,488	694	784	162,843	180,155

The following table summarizes our interests in producing wells at December 31, 2010. These figures exclude wells which were capable of producing, but that were not producing, as of December 31, 2010.

Producing Wells – Conventional	**Producing Oil Wells**		**Producing Gas Wells**		**Total Producing Wells**	
(number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Suffield	741	741	10,705	10,683	11,446	11,424
Brooks North	80	80	7,546	7,417	7,626	7,497
Langevin	244	240	4,856	4,840	5,100	5,080
Drumheller	103	100	1,597	1,540	1,700	1,640
Wainwright	452	417	14	4	466	421
Boyer	6	1	1,152	1,150	1,158	1,151
Weyburn	751	457	-	-	751	457
Shaunavon / Bakken	25	25	-	-	25	25
Total	2,402	2,061	25,870	25,634	28,272	27,695

Oil Properties

We hold interests in multiple zones in the Suffield, Brooks North, Langevin, Drumheller, and Wainwright areas in southern Alberta with a mix of medium and heavy oil production. Development in these areas focuses on infill drilling, optimization of existing wells and other specialized oil recovery methods. We operate water handling facilities to effectively manage oil production.

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 of crude oil with a CO_2 miscible flood project. At December 31, 2010, approximately 70 percent of the approved CO_2 flood pattern development at the Weyburn unit was complete. Since the inception of the project, approximately 16.5 million tonnes of CO_2 have been injected as part of the program. The CO_2 is delivered by pipeline directly to the Weyburn facility from a coal gasification project in North Dakota.

In 2010, we continued evaluating and started developing medium and light oil prospects in the Bakken and lower Shaunavon zones in Saskatchewan, where we drilled 36 wells and increased production to approximately 2,000 barrels per day. Most of the sections of land that we hold in these areas are Crown land.

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

			Production			
Net Wells Drilled and Production	**Net Wells Drilled**		**Light / Medium (bbls/d)**		**Heavy Oil (bbls/d)**	
(annual average)	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Suffield	43	40	-	-	12,717	13,798
Brooks North	41	18	1,458	894	-	-
Langevin	22	14	7,529	8,160	-	-
Drumheller	30	28	1,403	1,421	-	-
Wainwright	3	-	452	1,472	3,942	4,090
Boyer	-	-	12	12	-	-
Weyburn	3	-	16,534	17,784	-	-
Shaunavon / Bakken	36	5	1,958	651	-	-
Other	2	-	-	-	-	-
Total	180	105	29,346	30,394	16,659	17,888

Natural Gas Properties

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

Development in these areas 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 for the periods indicated.

Net Wells Drilled and Production	**Net Wells Drilled**		**Gas Production (MMcf/d)**	
(annual average)	**2010**	**2009**	**2010**	**2009**
Suffield	292	170	200	223
Brooks North	149	163	240	260
Langevin	24	109	152	181
Drumheller	29	56	72	82
Other	1	4	30	38
Total	495	502	694	784

Suffield is one of the core areas of our crude oil and natural gas production in Alberta. 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, 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.

Included in the Brooks North and Langevin areas is the Belly River Cretaceous formation where Cenovus is producing CBM. In 2010, approximately 900 wells were recompleted which added approximately 17 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.

Refining and Marketing

Refining

Through WRB Refining LP ("WRB") we have a 50 percent interest in both the Wood River and Borger Refineries located in Roxana, Illinois and Borger, Texas respectively. ConocoPhillips is the operator and manager of WRB. WRB has a management committee, which is composed of three Cenovus representatives and three ConocoPhillips representatives, with each company holding equal voting rights.

At December 31, 2010, WRB had processing capability to refine approximately 452,000 barrels per day of crude oil. With the completion of the CORE project, the Wood River Refinery will have the ability to process a wider variety of heavy crude oil feedstocks. Our two refineries will then have a combined capacity to process as much as 275,000 barrels per day of heavy crude oil.

Wood River Refinery

At December 31, 2010, 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 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 U.S. 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 construction of the CORE project at Wood River. At December 31, 2010, the CORE project was approximately 91 percent complete. Commissioning of several of the process units has been completed with an expected coker start up in the fourth quarter of 2011. At the time of coker start up, we expect that CORE expenditures will reach approximately US$3.7 billion (US$1.85 billion net to Cenovus). The total estimated cost of the CORE project is expected to be approximately US$3.9 billion (US$1.95 billion net to Cenovus), or about 10 percent higher than originally forecast. The expansion is expected to increase crude oil refining capacity by 50,000 barrels per day to 356,000 barrels per day and more than double heavy crude oil refining capacity at Wood River to 240,000 barrels per day.

Borger Refinery

At December 31, 2010, the Borger refinery had a processing capacity of approximately 146,000 barrels per day of crude oil, including approximately 35,000 barrels per day of heavy 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 key operational results for our refineries in the periods indicated.

Refinery Operations[1]	2010	2009
Crude Oil Capacity (Mbbls/d)	452	452
Crude Oil Runs (Mbbls/d)	386	394
Crude Utilization (%)	86	87
Refined Products (Mbbls/d)		
Gasoline	204	223
Distillates	123	120
Other	78	74
Total	405	417

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

Marketing

Our Marketing group is focused on enhancing the netback price of our production. As part of these activities, the group carries out third-party purchases and sales of product to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

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 audited consolidated financial statements for the year ended December 31, 2010.

Crude Oil Marketing

We manage the transportation and marketing of crude oil for our upstream operations. 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 2010, our blend volumes (which include diluent added to create a product suitable for pipeline transportation) marketed on behalf of FCCL were 163,472 barrels per day (2009 - 120,894 barrels per day), while our wholly-owned blend, light and medium crude oil volumes marketed were 73,238 barrels per day (2009 - 78,303 barrels per day).

Natural Gas Marketing

Our natural gas is primarily marketed to industrials, other producers and energy marketing companies. In 2010, approximately 20 percent of our sales of natural gas were directly marketed by us to industrials (2009 – approximately 25 percent). The remaining 80 percent of sales of natural gas were marketed to other producers and energy marketing companies (2009 – approximately 75 percent). 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.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

As a Canadian issuer, we are subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Prior to the year ended December 31, 2010, we presented our reserves estimates in accordance with U.S. disclosure requirements pursuant to an exemption from certain of the NI 51-101 requirements. The exemption expired at the end of 2010. As a result, reserves information for the year ending December 31, 2009 is presented as previously disclosed, using 2009 12 month average constant prices and costs as prescribed by the U.S. Securities and Exchange Commission ("SEC"), and has also been restated to comply with NI 51-101, using McDaniel & Associates Consultants Ltd. ("McDaniel") January 1, 2010 forecast prices and costs, consistent with the presentation format for December 31, 2010 reserves disclosures, which use McDaniel January 1, 2011 forecast prices and costs. The reserves, contingent resources and prospective resources information provided herein conforms with the disclosure requirements of NI 51-101.

We retain two independent qualified reserves evaluators ("IQREs"), McDaniel and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and prepare reports on 100 percent of our bitumen, heavy oil, light and medium oil, NGLs, natural gas, and CBM reserves annually. McDaniel evaluated approximately 93 percent of our total proved reserves, located throughout Alberta and Saskatchewan, and GLJ evaluated approximately seven percent of our total proved reserves, located at Boyer and Weyburn. We also engaged McDaniel to evaluate 100 percent of our contingent and prospective bitumen resources.

The Reserves Committee of our Board of Directors ("Board"), composed of independent Board members, reviews the qualifications and appointment of the IQREs, the procedures relating to the disclosure of information with respect to oil and gas activities and the procedures for providing information to the IQREs. The Reserves Committee meets with management and each IQRE to determine whether any restrictions affect the ability of the IQRE to report on the reserves data without reservation, to review the reserves data and the report of the IQRE thereon, and to recommend approval of the reserves and resources disclosure to the Board.

The company's reserves are located in Alberta and Saskatchewan, Canada. 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 and water 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.

Classifications of reserves as proved or probable are only attempts to define the degree of certainty associated with the estimates. There are numerous uncertainties inherent in estimating quantities of bitumen, oil and natural gas reserves. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. Readers should review the definitions and information contained in "Definitions, Notes to Reserves Data Tables and Pricing Assumptions" in conjunction with the disclosure in this statement. The estimates of bitumen, light and medium oil, heavy oil, NGLs, natural gas and CBM reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates disclosed. See "Risk Factors – Uncertainty of Reserves, Resources and Future Net Revenue Estimates" in this AIF for additional information.

This reserves data and other oil and gas information contained in this AIF is dated February 16, 2011, with an effective date of December 31, 2010. McDaniel's preparation date of the information is February 16, 2011, and GLJ's preparation date is January 26, 2011.

Disclosure of Reserves Data

The reserves data presented summarizes our bitumen, heavy oil, light and medium oil plus NGLs, and natural gas plus CBM reserves and the net present values of future net revenue for these reserves. The reserves data uses forecast prices and costs prior to provision for interest, general and administrative expenses, cost associated with environmental regulations, the impact of any hedging activities or the liability associated with certain abandonment and all well, pipeline, facilities and reclamation costs. Future net revenues have been presented on a before and after tax basis.

We hold significant freehold title rights which generate production for our account from third parties leasing those lands ("Royalty Interest production"). The Before Royalty volumes presented do not include reserves ("Royalty Interest reserves") associated with this Royalty Interest production. The After Royalty volumes presented include our Royalty Interest reserves. See "Definitions, Notes to Reserves Tables Data, and Pricing Assumptions" below for further information on our Royalty Interests.

Summary of Oil and Gas Reserves at December 31, 2010
(Forecast Prices and Costs)

Company Interest Before Royalties[1]

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	126	111	79	1,292
Developed Non-Producing	20	13	5	62
Undeveloped	1,008	45	27	36
Total Proved Reserves	1,154	169	111	1,390
Probable Reserves	523	97	49	410
Total Proved plus Probable Reserves	1,677	266	160	1,800

Note:
(1) Does not include Royalty Interest reserves associated with Royalty Interest production received by Cenovus.

Bitumen accounts for approximately 69 percent of our proved reserves Before Royalties, heavy oil accounts for approximately 10 percent, light and medium oil and NGLs account for approximately seven percent, and natural gas and CBM for approximately 14 percent. Before Royalties, approximately 87 percent of Cenovus's proved bitumen reserves are undeveloped. The distinction between developed and undeveloped bitumen reserves, and the strategy for their development, is described further under "Undeveloped Reserves".

Company Interest After Royalties[1]

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	96	92	67	1,292
Developed Non-Producing	14	10	4	61
Undeveloped	760	36	21	36
Total Proved Reserves	870	138	92	1,389
Probable Reserves	404	72	39	391
Total Proved plus Probable Reserves	1,274	210	131	1,780

Note:
(1) Includes Royalty Interest reserves associated with Royalty Interest production received by Cenovus.

After Royalties, bitumen accounts for approximately 65 percent of our proved reserves, heavy oil accounts for approximately 10 percent, light and medium oil and NGLs account for approximately seven percent, and natural gas and CBM for approximately 18 percent. In the presented After Royalties reserves, Royalty Interest reserves constitute approximately three percent of natural gas, approximately five percent of light and medium oil and NGL reserves, and approximately one percent of heavy oil reserves. We have no bitumen Royalty Interest reserves.

Summary of Net Present Value of Future Net Revenue at December 31, 2010
(Forecast Prices and Costs)

	Before Income Taxes Discounted at % / year ($ millions)					Unit Value Before Income Tax Discounted at 10% (1)
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**$/BOE**
Proved Reserves						
Developed Producing	16,118	12,796	10,619	9,102	7,986	22.60
Developed Non-Producing	1,423	888	604	435	325	15.53
Undeveloped	36,936	13,789	6,302	3,300	1,872	7.66
Total Proved Reserves	54,477	27,473	17,525	12,837	10,183	13.16
Probable Reserves	21,163	12,192	6,879	4,031	2,466	11.84
Total Proved plus Probable Reserves	75,640	39,665	24,404	16,868	12,649	12.76

Note:
(1) Unit values have been calculated using the Company Interest After Royalties reserves

	After Income Taxes(1) Discounted at % / year ($ millions)				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Reserves					
Developed Producing	12,683	10,153	8,480	7,308	6,443
Developed Non-Producing	1,070	666	454	328	245
Undeveloped	27,637	10,359	4,720	2,442	1,349
Total Proved Reserves	41,390	21,178	13,654	10,078	8,037
Probable Reserves	15,783	9,073	5,076	2,923	1,737
Total Proved plus Probable Reserves	57,173	30,251	18,730	13,001	9,774

Note:
(1) After income tax values are calculated by considering the Company's existing tax pools

Total Future Net Revenue (undiscounted) at December 31, 2010
(Forecast Prices and Costs) ($ millions)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs (1)	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Proved Reserves	132,911	29,190	38,802	9,414	1,028	54,477	13,087	41,390
Proved plus Probable Reserves	186,276	40,718	53,511	15,234	1,173	75,640	18,467	57,173

Note:
(1) The abandonment costs only include downhole abandonment costs for the wells considered in the IQREs' evaluation of reserves. Abandonment of other wells, surface reclamation, asset recovery and facility site reclamation costs are not included.

Future Net Revenue by Production Group at December 31, 2010
(Forecast Prices and Costs)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10% / year) ($ millions)	Unit Value (Company Interest After Royalties Reserves) ($ / BOE)
Proved Reserves	Bitumen	8,907	10.24
	Heavy Oil [(1)]	1,977	14.32
	Light and Medium Crude Oil [(1)]	2,290	24.89
	Natural Gas [(2)]	4,351	18.79
	Total	**17,525**	**13.16**
Proved plus Probable Reserves	Bitumen	12,819	10.06
	Heavy Oil [(1)]	2,870	13.67
	Light and Medium Crude Oil [(1)]	3,136	23.94
	Natural Gas [(2)]	5,579	18.81
	Total	**24,404**	**12.76**

Notes:
(1) Including solution gas and other by-products
(2) Including by-products, but excluding solution gas from oil wells

Definitions, Notes to Reserves Data Tables and Pricing Assumptions

The following pricing assumptions, definitions and notes are applicable to the disclosure in this AIF. For definitions in relation to our contingent and prospective resources disclosure, see "Contingent and Prospective Resources" below.

Definitions

1. **After Royalties** means volumes after deduction of royalties and including any royalty interests.
2. **Before Royalties** means volumes before deduction of royalties and excluding any royalty interests.
3. **Company Interest** means, in relation to production, reserves, resources and property, the interest (operating or non-operating) held by Cenovus.
4. **Gross** means:
   (a) in relation to wells, the total number of wells in which we have an interest; and
   (b) in relation to properties, the total area of properties in which we have an interest.
5. **Net** means:
   (a) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
   (b) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.
6. **Reserves** are estimated remaining quantities anticipated to be recoverable from known accumulations, from a given date forward, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology and specified economic conditions.

   Reserves are classified according to the degree of certainty associated with the estimates:

   - **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
   - **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories:

- **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
    - **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
    - **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.
- **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, similar to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

7. **Royalty Interest** means:

    (a) in relation to reserves, those reserves related to our royalty entitlement on lands to which we hold freehold title which have been leased to third parties, or reserves related to other royalty interests, such as overriding royalties to which we are entitled.

    (b) in relation to production, the production generated for Cenovus's account pursuant to leasing agreements of our freehold title lands, and other royalty entitlement agreements.

Notes to Reserves Data Tables

- The estimates of future net revenue presented do not represent fair market value.
- For disclosure purposes, we have included NGLs with light and medium oil, and CBM gas with natural gas, as the reserves of each of NGLs and CBM gas are not material relative to the other reported product types.
- Only estimated future well abandonment costs related to reserves wells have been taken into account by the IQREs in determining the aggregate future net revenue therefrom. Further, the abandonment costs only include downhole abandonment costs for the wells considered in the IQREs' evaluation of reserves. Abandonment of other wells, surface reclamation, asset recovery and facility site reclamation costs are not included.
- Future net revenue from reserves excludes cash flows related to our risk management activities.

Pricing Assumptions

The forecast price and cost assumptions assume the continuance of current laws and take into account inflation with respect to future operating and capital costs. The forecast prices are provided in the table below and reflect McDaniel's January 1, 2011 price forecast as referred to in the McDaniel & Associates Consultants Ltd. Summary of Price Forecasts dated January 1, 2011.

	Oil					Natural Gas		
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Edmonton Par Price 40 API ($C/bbl)**	**Cromer Medium 29.3 API ($C/bbl)**	**Hardisty Heavy 12 API ($C/bbl)**	**Western Canadian Select ($C/bbl)**	**AECO Gas Price ($C/MMBtu)**	**Inflation Rate (%/year)**	**Exchange Rate ($US/$C)**
2011	85.00	84.20	77.20	66.70	71.10	4.25	2.0	0.975
2012	87.70	88.40	80.40	68.70	73.20	4.90	2.0	0.975
2013	90.50	91.80	82.50	68.60	73.30	5.40	2.0	0.975
2014	93.40	94.80	85.20	70.80	75.60	5.90	2.0	0.975
2015	96.30	97.70	87.90	73.00	78.00	6.35	2.0	0.975
2016	99.40	100.90	90.70	75.40	80.50	6.75	2.0	0.975
2017	101.40	102.90	92.50	76.90	82.10	7.10	2.0	0.975
2018	103.40	104.90	94.30	78.40	83.70	7.40	2.0	0.975
2019	105.40	107.00	96.20	80.00	85.40	7.60	2.0	0.975
2020	107.60	109.20	98.20	81.60	87.10	7.75	2.0	0.975
There-after	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.975

Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue calculated utilizing forecast prices and costs, undiscounted and using a discount rate of 10 percent per annum for the years indicated.

Reserves Category ($ millions)	**2011**	**2012**	**2013**	**2014**	**2015**	**Remainder**	**Total Undiscounted**	**Total Discounted at 10%**
Proved Reserves	790	745	436	327	195	6,921	9,414	3,388
Proved plus Probable Reserves	1,080	1,258	1,106	921	710	10,159	15,234	6,680

We believe that internally generated cash flows, existing credit facilities and access to capital markets will be sufficient to fund our future development costs. However, there can be no guarantee that funds will be available or that we will allocate funding to develop all of our reserves. Failure to develop those reserves would have a negative impact on our future net revenue.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce future net revenue depending upon the funding sources utilized. We do not believe that interest or other funding costs would make development of any property uneconomic.

Reserves Reconciliation

The following tables provide a reconciliation of our company interest reserves Before Royalties for bitumen, heavy oil, light and medium oil and NGLs, and natural gas for the year ended December 31, 2010, presented using forecast prices and costs. All reserves are located in Canada.

Reserves Reconciliation by Principal Product Type and Reserves Category (Forecast Prices and Costs)

Company Interest Proved – Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2009 (SEC)[1]	866	165	112	1,529
Transition to NI 51-101 Standards[2]	-	(1)	(3)	128
December 31, 2009 (NI 51-101)	866	164	109	1,657
Extensions and Improved Recovery	270	9	11	45
Discoveries	-	-	-	-
Technical Revisions	40	15	1	60
Economic Factors	-	-	-	(18)
Acquisitions	-	-	-	-
Dispositions	-	(5)	-	(87)
Production[3]	(22)	(14)	(10)	(267)
December 31, 2010	**1,154**	**169**	**111**	**1,390**

Company Interest Probable – Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2009 (SEC) [1]	479	104	53	436
Transition to NI 51-101 Standards[2]	-	(1)	(2)	52
December 31, 2009 (NI 51-101)	479	103	51	488
Extensions and Improved Recovery	132	5	(1)	12
Discoveries	-	-	-	-
Technical Revisions	(88)	(10)	(1)	(82)
Economic Factors	-	-	-	7
Acquisitions	-	-	-	-
Dispositions	-	(1)	-	(15)
Production	-	-	-	-
December 31, 2010	**523**	**97**	**49**	**410**

Company Interest Proved plus Probable – Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas (Bcf)
December 31, 2009 (SEC) [1]	1,345	269	165	1,965
Transition to NI 51-101 Standards[2]	-	(2)	(5)	180
December 31, 2009 (NI 51-101)	1,345	267	160	2,145
Extensions and Improved Recovery	402	14	10	57
Discoveries	-	-	-	-
Technical Revisions	(48)	5	-	(22)
Economic Factors	-	-	-	(11)
Acquisitions	-	-	-	-
Dispositions	-	(6)	-	(102)
Production[3]	(22)	(14)	(10)	(267)
December 31, 2010	**1,677**	**266**	**160**	**1,800**

Notes:

(1) References in the tables to December 31, 2009 (SEC) numbers are to the previously disclosed estimates as of that date prepared by the IQREs in accordance with U.S. disclosure requirements using constant prices and costs as prescribed by the SEC.

(2) The change in reserves disclosed in the transition from SEC to NI 51-101 is a result of (i) the forecast prices and costs used under NI 51-101 were higher than the SEC prescribed constant prices and costs, restoring previously uneconomic gas reserves, and (ii) the removal of Royalty Interest reserves from the Before Royalties reserves totals.

(3) Production used for the reserves reconciliation differs from reported production. Company Interest Before Royalties production for reserves includes Cenovus's share of gas volumes provided to Cenovus's share of the FCCL partnership for steam generation, but does not include royalty interest production, as prescribed by NI 51-101.

In 2010, proved and proved plus probable bitumen reserves increased by approximately 33 and 25 percent respectively. This was primarily a result of receiving regulatory approval to expand the development area at Foster Creek and from improvements to overall recovery based on operating performance. Incremental recovery from wedge wells, drilled between existing producers, and improved recovery resulting from better than expected drainage from existing wells also contributed to the increase.

In 2010, proved heavy oil reserves increased by approximately two percent primarily as a result of expanding polymer flood areas and their successful performance at Pelican Lake. Probable heavy oil reserves decreased by approximately seven percent as result of transfers to proved reserves. Proved plus probable reserves decreased by approximately one percent.

In 2010, proved light and medium oil and NGLs reserves decreased by approximately one percent, primarily as a result of expanding waterflood and carbon dioxide flood areas and their successful performance at Weyburn being offset by current year production. Probable light and medium oil and NGLs reserves decreased by eight percent as a result of transfers to proved reserves. Proved plus probable reserves decreased by approximately three percent.

In 2010, proved natural gas reserves declined by approximately nine percent as extensions and technical revisions did not offset production and the divestiture of some of our natural gas assets. Probable natural gas reserves and proved plus probable reserves declined by approximately six percent and eight percent respectively.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Proved and probable undeveloped reserves have been estimated by the IQREs in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation ("COGE") Handbook. In general, undeveloped reserves are scheduled to be developed within the next one to 40 years.

Proved Undeveloped Reserves – Company Interest Before Royalties

	Bitumen (MMbbls)		Light and Medium Oil and NGLs (MMbbls)		Heavy Oil (MMbbls)		Natural Gas & CBM (Bcf)	
	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End
Prior[1]	617	617	30	30	31	31	226	226
2008	6	560	8	29	16	45	46	150
2009	190	734	7	28	8	46	10	35
2010	295	1,008	5	27	5	45	18	36

Probable Undeveloped Reserves – Company Interest Before Royalties

	Bitumen (MMbbls)		Light and Medium Oil and NGLs (MMbbls)		Heavy Oil (MMbbls)		Natural Gas & CBM (Bcf)	
	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End
Prior[1]	616	616	- [2]	- [2]	- [2]	- [2]	- [2]	- [2]
2008	12	625	- [2]	- [2]	- [2]	- [2]	- [2]	- [2]
2009	5	467	26	26	43	43	38	38
2010	171	506	2	21	-	37	16	30

Notes:

(1) First Attributed Undeveloped Reserves have been estimated as equal to Total at Year-End Undeveloped Reserves as historical information is not available.

(2) Historical information is not available.

Development of Proved Undeveloped Reserves

Bitumen

At the end of 2010, we had proved undeveloped bitumen reserves of 1,008 million barrels Before Royalties, or approximately 87 percent of our total proved bitumen reserves. Of our 523 million barrels of probable bitumen reserves, 506 million barrels, or approximately 97 percent are undeveloped. For this evaluation, it is assumed that these reserves will be recovered using SAGD technology.

Typical SAGD project development involves the initial installation of a steam generation facility, at a cost much greater than drilling a production/injection well pair, and then progressively drilling sufficient SAGD wells to fully utilize the available steam.

Bitumen reserves can be classified as proved when there is sufficient stratigraphic drilling to have demonstrated to a high degree of certainty the presence of the bitumen in commercially recoverable volumes. Our IQRE standard for sufficient drilling is a minimum eight wells per section with 3D seismic, or 16 wells per section with no seismic. Additionally, all requisite legal and regulatory approvals must have been obtained, operator and partner funding approvals must be in place, and a reasonable development timetable must be established. 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.

Development of probable reserves requires sufficient drilling of stratigraphic wells to establish reservoir suitability for SAGD. Reserves will be classified as probable if the stratigraphic well requirement for proved reserves is not met, or if the reserves are not located within an approved development plan area. The IQRE standard for probable reserves is a minimum of four stratigraphic wells per section. Once that is established and the reserves lie outside the approved development area, approval to include those reserves in the development plan area must be obtained before development drilling of SAGD well pairs can commence.

Development of the proved undeveloped reserves will take place in an orderly manner as additional well pairs are drilled to utilize the available steam when existing well pairs reach the end of their steam injection phase. 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 take about ten years.

Oil

We have a significant medium oil CO_2 EOR project at Weyburn and a significant heavy oil 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 anticipated improved recovery associated with development of the EOR schemes. Extending both EOR schemes within the projects requires intensive capital investment in infrastructure development and will occur over many years.

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

Significant Factors or Uncertainties Affecting Reserves Data

The evaluation of reserves is a continuous process, one that can be significantly impacted by a variety of internal and external influences. Revisions are often required resulting from changes in pricing, economic conditions, regulatory changes, and historical performance.

While the above factors, and many others, can be considered, certain judgments and assumptions are always required. As new information becomes available these areas are reviewed and revised accordingly. For a summary of risks and uncertainties affecting Cenovus please refer to “Risk Factors” in this AIF.

Contingent and Prospective Resources

We retain McDaniel to evaluate and prepare reports on all of our bitumen contingent and prospective resources. The following resources information is derived from the reports prepared for us by McDaniel.

The evaluations by McDaniel are conducted from the fundamental petrophysical, geological, engineering, financial and accounting data. Processes and procedures are in place to ensure that McDaniel is in receipt of all relevant information. Contingent and prospective resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. SAGD projects that are producing from the McMurray-Wabiskaw formations at Foster Creek and Christina Lake are used as performance analogs for the majority of our properties with contingent and prospective resources. McDaniel also tests contingent resources for economic viability using the same forecast prices and costs used for our reserves. Refer to “Pricing Assumptions” in this AIF.

This evaluation assumes that the majority of our bitumen resources will be recovered and produced using SAGD or cyclic steam stimulation (“CSS”) technologies. SAGD involves injecting steam into horizontal wells drilled into the bitumen formation and recovering heated bitumen and water from producing wells located below the injection wells. CSS involves injecting steam into a well and then producing water and heated bitumen from the same wellbore. Such alternating injection and production cycles are repeated a number of times for a given wellbore. Both of these techniques have a surface footprint comparable to conventional oil production. We have no bitumen resources that require mining techniques for recovery.

All of Cenovus’s current contingent and prospective resources are associated with clastic or sandstone formations. Cenovus has also identified significant amounts of bitumen in the Grosmont carbonate formation for which we have extensive mineral rights. To date, McDaniel has not recognized the commercial viability of recovery processes in any carbonate formation, including the Grosmont. A successful pilot in the Grosmont or a commercial project in an analogous carbonate reservoir would have to take place before McDaniel would consider bitumen from these carbonates to be exploitable or recoverable. Cenovus is planning a pilot for carbonate oil production from the Grosmont formation and there are other industry pilots planned or underway.

In addition to the reserve definitions provided in the preceding sections, the following definitions from the COGE Handbook were used to prepare the disclosure that follows.

> **Contingent Resources** are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The estimate of contingent resources has not been adjusted for risk based on the chance of development.
>
> For Cenovus, contingencies which must be overcome to enable the reclassification of bitumen contingent resources as reserves include regulatory application submission with no major issues raised, access to markets, and intent to proceed by the operator and partners as evidenced by a development plan with major capital expenditures planned within five years.
>
> **Economic Contingent Resources** are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus’s case, contingent resources were evaluated using the same commodity price

assumptions that were used for the 2010 reserves evaluation, which comply with NI 51-101 requirements.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity. The estimate of prospective resources has not been adjusted for risk based on the chance of discovery or the chance of development.

Best Estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent confidence level that the actual quantities recovered will equal or exceed the estimate.

Low Estimate is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources at the low end of the estimate range have the highest degree of certainty - a 90 percent confidence level – that the actual quantities recovered will equal or exceed the estimate.

High Estimate is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will meet or exceed the high estimate. Those resources at the high end of the estimate range have a lower degree of certainty - a 10 percent confidence level - that the actual quantities recovered will equal or exceed the estimate.

The economic contingent resources were estimated on a project level. The high and low estimates are arithmetic sums of multiple estimates which statistical principles indicate may be misleading as to volumes that may actually be recovered. The aggregated low estimate results shown may have a higher level of confidence than the individual projects, and the aggregated high estimate results shown may have a lower level of confidence than the individual projects.

Economic Contingent and Prospective Resources		
Company Interest Before Royalties, Billions of barrels	**December 31, 2009**(1)	**December 31, 2010**(2)
Economic Contingent Resources(3)		
Low Estimate	3.9	4.4
Best Estimate	5.4	6.1
High Estimate	7.3	8.0
Prospective Resources(4)		
Low Estimate	7.8	7.3
Best Estimate	12.6	12.3
High Estimate	21.4	21.7

Notes:

(1) Refers to previously disclosed estimates prepared by McDaniel, using 2009 constant prices and costs.

(2) Refers to estimates prepared by McDaniel using the same forecast prices and costs as used in the 2010 reserves estimates, McDaniel January 1, 2011 forecast prices and costs.

(3) There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(4) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Prospective resources are not screened for economic viability.

Best estimate economic contingent resources increased 0.7 billion barrels or 13 percent relative to 2009. This increase is primarily a result of our stratigraphic well drilling converting prospective resources to contingent resources, and positive technical revisions to volumetric and recovery factor estimates. There are no material differences in bitumen economic contingent resource estimates determined using either SEC or NI 51-101 pricing.

Best estimate prospective resources declined 0.3 billion barrels or two percent relative to 2009, primarily as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic drilling.

A more detailed annual reconciliation is shown in the following table:

Bitumen Proved plus Probable Reserves, Contingent Resources and Prospective Resources Reconciliation and Category Movements			
Company Interest Before Royalties, Billions of barrels	**Proved plus Probable Reserves**	**Best Estimate Contingent Resources(1)**	**Best Estimate Prospective Resources(2)**
Opening Balance, December 31, 2009(3)	1.345	5.4	12.6
Transfers between Categories			
Additions from other resource categories	0.138	0.6	-
Reductions to other resource categories	-	(0.1)	(0.6)
Additions and Revisions Net of Transfers	0.216	0.3	0.3
Net Acquisitions and Dispositions	-	(0.1)	-
Production	(0.022)	-	-
Closing Balance, December 31, 2010	**1.677**	**6.1**	**12.3**

Notes:

(1) There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(2) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Prospective resources are not screened for economic viability.

(3) Refers to previously disclosed estimates prepared by McDaniel, using 2009 constant prices and costs.

We are systematically progressing our bitumen prospective resources to contingent resources and then to reserves, and ultimately to production and cash flow. For example, approval for expansion of the Foster Creek development area, in addition to moving some probable reserves to proved reserves, also moved some contingent resources to proved and probable reserves. Similarly, the stratigraphic well program at Pelican Lake moved some prospective resources to contingent resources. The overall reduction of prospective resources is the expected outcome of a successful stratigraphic well program, which converts undiscovered resources to discovered resources.

All classifications of bitumen reserves and resources increased because of higher recoveries due to the improvement in bitumen recovery performance at our Foster Creek and Christina Lake projects resulting from improved operating performance and the use of wedge wells. Analysis of core data in the steamed portions of the reservoir has revealed that the efficiency of the SAGD process in extracting bitumen from the reservoir is greater than previously anticipated. We expect to improve overall recovery from our bitumen assets as technology develops.

Other Oil and Gas Information

Oil and Gas Properties and Wells

The following table summarizes our interests in producing wells, at December 31, 2010.

Producing wells(1)(2)	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta:						
Oil Sands	650	549	490	467	1,140	1,016
Conventional	1,626	1,579	25,870	25,634	27,496	27,213
Total Alberta	2,276	2,128	26,360	26,101	28,636	28,229
Saskatchewan:						
Conventional	776	482	-	-	776	482
Total Saskatchewan	776	482	-	-	776	482
Total	3,052	2,610	26,360	26,101	29,412	28,711

Notes:

(1) Cenovus also has varying royalty interests in 7,577 natural gas wells and 3,906 crude oil wells which are producing.

(2) Includes wells containing multiple completions as follows: 23,854 gross natural gas wells (23,625 net wells) and 1,516 gross crude oil wells (1,306 net wells).

The following table summarizes our interests in non-producing wells at December 31, 2010.

Non-producing wells(1)	Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta:						
Oil Sands	241	162	689	605	930	767
Conventional	655	634	969	948	1,624	1,582
Total Alberta	896	796	1,658	1,553	2,554	2,349
Saskatchewan:						
Conventional	137	94	36	36	173	130
Total Saskatchewan	137	94	36	36	173	130
Total	1,033	890	1,694	1,589	2,727	2,479

Note:

(1) Non-producing wells include wells which are capable of producing, but which are currently not producing. Non-producing wells does not include other types of wells such as stratigraphic test wells, service wells, or wells that have been abandoned.

Exploration and Development 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**
2010:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	26	26	-	-	1	1	27	27	21	48	27
Total Canada	26	26	-	-	1	1	27	27	21	48	27
2009:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	4	4	-	-	-	-	4	4	8	12	4
Total Canada	4	4	-	-	-	-	4	4	8	12	4
2008:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	1	1	5	3	2	1	8	5	34	42	5
Total Canada	1	1	5	3	2	1	8	5	34	42	5

Development Wells Drilled

	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Gross**	**Net**
2010:											
Oil Sands	82	47	-	-	-	-	82	47	8	90	47
Conventional	160	154	499	495	-	-	659	649	204	863	649
Total Canada	242	201	499	495	-	-	741	696	212	953	696
2009:											
Oil Sands	50	29	8	8	8	8	66	45	10	76	45
Conventional	102	101	555	502	2	2	659	605	261	920	605
Total Canada	152	130	563	510	10	10	725	650	271	996	650
2008:											
Oil Sands	41	21	13	13	4	4	58	38	41	99	38
Conventional	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

In addition to the disclosure above, we drilled stratigraphic test wells during the year ended December 31, 2010, with Oil Sands having drilled 259 gross wells (178 net wells) and Conventional having drilled 11 gross wells (9 net wells).

In addition to the disclosure above, we drilled service wells during the year ended December 31, 2010, with Oil Sands having drilled 68 gross wells (44 net wells) and Conventional having drilled 30 gross wells (20 net wells).

Interest in Material Properties

The following table summarizes our developed, undeveloped and total landholdings at December 31, 2010.

	Developed		Undeveloped[1]		Total[2]	
	Gross	Net	Gross	Net	Gross	Net
			(thousands of acres)			
Alberta:						
Oil Sands						
– Crown[3]	696	597	1,845	1,455	2,541	2,052
Conventional						
– Fee[4]	1,913	1,913	440	440	2,353	2,353
– Crown[3]	1,571	1,463	372	306	1,943	1,769
– Freehold[5]	51	42	35	32	86	74
Total Alberta	4,231	4,015	2,692	2,233	6,923	6,248
Saskatchewan:						
Conventional						
– Fee[4]	69	69	437	437	506	506
– Crown[3]	47	34	162	141	209	175
– Freehold[5]	13	9	28	25	41	34
Total Saskatchewan	129	112	627	603	756	715
Manitoba:						
Conventional – Fee[4]	3	3	261	261	264	264
Total Manitoba	3	3	261	261	264	264
Total	4,363	4,130	3,580	3,097	7,943	7,227

Notes:

(1) Undeveloped includes land that has not yet been drilled, as well as land with wells that have never produced hydrocarbons or that do not currently allow for the production of hydrocarbons.

(2) This table excludes approximately 2.4 million gross acres under lease or sublease, reserving to us, royalties or other interests.

(3) 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.

(4) 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 summary now includes all fee titles owned by us, that have one or more zones that remain unleased or available for development.

(5) Freehold lands are those lands owned by individuals (other than a government or Cenovus) in which Cenovus holds a working interest lease.

Properties With No Attributed Reserves

We have approximately 5.1 million gross acres (4.7 million net acres) of unproved properties. These properties are planned for current and future development in both our oil sands and conventional oil and gas operations.

We have rights to explore, develop, and exploit approximately 90,000 net acres that could potentially expire by December 31, 2011, which relate entirely to Crown and Freehold land.

For areas where we hold interests in different formations under the same surface area through separate leases, we have calculated our gross and net acreage on the basis of each individual lease.

Additional Information Concerning Abandonment & Reclamation Costs

The estimated total future abandonment and reclamation costs is based on management's estimate of costs to remediate, reclaim and abandon wells and facilities having regard to our working interest and the estimated timing of the costs to be incurred in future periods. We have developed a process to calculate these estimates, which considers applicable regulations, actual and anticipated costs, type and size of the well or facility and the geographic location.

We have estimated the undiscounted future cost of abandonment and reclamation costs at approximately $6 billion (approximately $529 million, discounted at 10 percent) at December 31, 2010, of which we expect to pay approximately $104 million in the next three financial years. We expect to incur these costs on approximately 35,000 net wells.

Of the undiscounted future cost of abandonment and reclamation costs to be incurred over the life of our proved reserves, approximately $1 billion has been deducted in estimating the future net revenue, which only represents our abandonment obligations for wells within reserves.

Tax Horizon

We expect to pay income tax in 2011.

Costs Incurred

The following table summarizes our costs incurred for the year ended December 31, 2010.

	2010
	($ millions)
Acquisitions	
– Unproved	31
– Proved	17
Total acquisitions	48
Exploration costs	114
Development costs	1,260
Total costs incurred	1,422

Forward Contracts

Cenovus has, as part of our ordinary business operations, a number of delivery commitments to provide crude oil and natural gas. We believe that we have sufficient reserves of natural gas and crude oil to meet these commitments.

Production Estimates

The following table summarizes the estimated 2011 average daily volume of gross production for all properties held on December 31, 2010 using forecast prices and costs, all of which will be produced in Canada. These estimates assume certain activities take place, such as the development of undeveloped reserves, and that there are no dispositions.

2011 Estimated Production Forecast Prices and Costs	**Proved**	**Proved plus Probable**
Bitumen (bbls/d)[(1)]	62,775	63,925
Light and Medium Crude Oil (bbls/d)	28,861	30,803
Heavy Oil (bbls/d)	38,486	40,530
Natural Gas (MMcf/d)	646	671
Natural Gas Liquids (bbls/d)	816	882
Total Production (BOE/d)[(2)]	238,535	247,956
Less: Royalty Interest Production (BOE/d)[(3)]	(8,961)	(9,382)
Total Company Interest Before Royalties Production (BOE/d)	229,574	238,574

Notes:

(1) Includes Foster Creek production of 52,662 bbls/d for Proved and 53,350 bbls/d for Proved plus Probable.

(2) Includes Royalty Interest production.

(3) Not derived from IQRE reports. Represents a Company estimate derived from the ratio of 2010 Royalty Interest Production to 2010 total production excluding bitumen. There is no Royalty Interest production associated with our bitumen.

Production History

The following tables summarize our daily production volumes, before deduction of royalties, on a quarterly basis for the periods indicated.

	Production Volumes - 2010				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
PRODUCTION VOLUMES					
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands – Heavy Oil					
Foster Creek	51,147	52,183	50,269	51,010	51,126
Christina Lake	7,898	8,606	7,838	7,716	7,420
Pelican Lake	22,966	21,738	23,259	23,319	23,565
	82,011	82,527	81,366	82,045	82,111
Conventional Liquids					
Heavy Oil	16,659	16,553	16,921	16,205	16,962
Light and Medium Oil	29,346	29,323	28,608	29,150	30,320
Natural Gas Liquids [(1)]	1,171	1,190	1,172	1,166	1,156
Total Crude Oil and Natural Gas Liquids	129,187	129,593	128,067	128,566	130,549
Natural Gas (MMcf/d)					
Oil Sands	43	39	44	46	45
Conventional	694	649	694	705	730
Total Natural Gas Production	737	688	738	751	775
Total (BOE/d)	252,020	244,260	251,067	253,733	259,716

Note:

(1) Natural gas liquids include condensate volumes.

	Production Volumes - 2009				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands – Heavy Oil					
Foster Creek	37,725	47,017	40,367	34,729	28,554
Christina Lake	6,698	7,319	6,305	6,530	6,635
Pelican Lake	24,870	23,804	25,671	23,989	26,029
Senlac [(1)]	3,057	2,221	5,080	2,574	2,334
	72,350	80,361	77,423	67,822	63,552
Conventional Liquids					
Heavy Oil	17,888	17,127	18,073	18,074	18,290
Light and Medium Oil	30,394	30,644	29,749	30,189	31,004
Natural Gas Liquids [(2)]	1,206	1,183	1,242	1,184	1,213
Total Oil and Natural Gas Liquids	121,838	129,315	126,487	117,269	114,059
Natural Gas (MMcf/d)					
Oil Sands	53	47	55	57	52
Conventional	784	750	775	799	814
Total Natural Gas Production	837	797	830	856	866
Total (BOE/d)	261,338	262,148	264,820	259,936	258,392

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

	Production Volumes - 2008				
	Year	Q4	Q3	Q2	Q1
PRODUCTION VOLUMES					
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands – Heavy Oil					
Foster Creek	26,220	29,241	27,289	21,244	27,062
Christina Lake	4,279	6,170	4,620	3,670	2,630
Pelican Lake	27,324	24,975	27,826	27,306	29,211
Senlac	3,223	2,623	3,135	3,281	3,861
	61,046	63,009	62,870	55,501	62,764
Conventional Liquids					
Heavy Oil	19,062	17,834	18,354	19,383	20,694
Light and Medium Oil	31,492	31,173	31,100	31,306	32,399
Natural Gas Liquids [(1)]	1,203	1,158	1,167	1,204	1,283
Total Oil and Natural Gas Liquids	112,803	113,174	113,491	107,394	117,140
Natural Gas (MMcf/d)					
Oil Sands	88	65	91	103	93
Conventional	866	840	856	882	883
Total Natural Gas Production	954	905	947	985	976
Total (BOE/d)	271,803	264,007	271,324	271,561	279,807

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

Per-Unit Results

The following tables summarize our per-unit results on a quarterly basis, before deduction of royalties, for the periods indicated.

	Per-Unit Results–2010				
	Year	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek ($/bbl)					
Price(1)	58.76	58.76	58.51	54.75	63.33
Royalties	9.08	11.41	9.56	9.38	5.76
Transportation and blending	2.42	2.54	2.40	2.40	2.33
Operating	10.44	10.00	10.35	10.36	11.11
Netback	36.82	34.81	36.20	32.61	44.13
Heavy Oil – Christina Lake ($/bbl)					
Price(1)	57.96	58.42	56.45	54.99	62.27
Royalties	2.14	2.05	2.04	2.19	2.28
Transportation and blending	3.54	1.54	3.69	4.52	4.47
Operating	16.56	17.40	15.94	16.50	16.41
Netback	35.72	37.43	34.78	31.78	39.11
Heavy Oil – Pelican Lake ($/bbl)					
Price(1)	62.65	61.38	58.93	62.05	68.04
Royalties	12.96	12.76	10.62	14.06	14.34
Transportation and blending	1.42	1.04	1.77	1.52	1.30
Operating	12.76	13.37	13.26	13.29	11.23
Netback	35.51	34.21	33.28	33.18	41.17
Heavy Oil - Oil Sands ($/bbl)					
Price	59.76	59.35	58.41	56.83	64.61
Royalties	9.53	10.79	9.30	10.03	7.94
Production and mineral taxes	-	-	-	-	-
Transportation and blending	2.25	2.08	2.35	2.35	2.23
Operating	11.70	11.54	11.83	11.81	11.65
Netback	36.28	34.94	34.93	32.64	42.79
Heavy Oil - Conventional ($/bbl)					
Price	63.18	60.45	59.40	61.35	71.16
Royalties	9.01	8.01	7.29	9.65	10.99
Production and mineral taxes	0.19	0.05	0.17	0.10	0.44
Transportation and blending	0.56	0.45	0.60	0.60	0.59
Operating	12.08	12.47	11.52	12.95	11.45
Netback	41.34	39.47	39.82	38.05	47.69
Total - Heavy Oil ($/bbl)					
Price(1)	60.33	59.53	58.59	57.57	65.76
Royalties	9.44	10.36	8.95	9.97	8.48
Production and mineral taxes	0.03	0.01	0.03	0.02	0.08
Transportation and blending	1.97	1.83	2.04	2.06	1.94
Operating	11.77	11.68	11.77	11.99	11.61
Netback	37.12	35.65	35.80	33.53	43.65
Light and Medium Oil ($/bbl)					
Price	71.63	72.98	68.37	66.14	78.78
Royalties	9.30	7.69	9.32	10.17	10.05
Production and mineral taxes	2.55	2.45	2.44	3.08	2.25
Transportation and blending	1.66	1.89	1.81	1.51	1.45
Operating	12.27	12.99	12.02	12.84	11.25
Netback	45.85	47.96	42.78	38.54	53.78

	Per-Unit Results–2010				
	Year	Q4	Q3	Q2	Q1
Total - Crude Oil ($/bbl)					
Price	62.98	62.75	60.86	59.51	68.87
Royalties	9.41	9.72	9.03	10.01	8.85
Production and mineral taxes	0.62	0.59	0.59	0.71	0.59
Transportation and blending	1.90	1.84	1.99	1.94	1.83
Operating	11.89	11.99	11.83	12.19	11.52
Netback	39.16	38.61	37.42	34.66	46.08
Conventional - Natural Gas Liquids ($/bbl)					
Price	61.00	63.60	54.43	58.71	67.42
Royalties	1.12	0.75	1.29	1.16	1.39
Netback	59.88	62.85	53.14	57.55	66.03
Total Liquids ($/bbl)					
Price	62.96	62.75	60.80	59.50	68.85
Royalties	9.33	9.63	8.96	9.93	8.78
Production and mineral taxes	0.62	0.59	0.59	0.71	0.59
Transportation and blending	1.88	1.82	1.97	1.94	1.83
Operating	11.78	11.84	11.72	12.08	11.42
Netback	39.35	38.87	37.56	34.84	46.23
Total - Natural Gas ($/Mcf)					
Price	4.09	3.55	3.68	3.78	5.27
Royalties	0.07	(0.04)	0.08	0.07	0.14
Production and mineral taxes	0.02	0.02	0.03	(0.04)	0.07
Transportation and blending	0.17	0.16	0.15	0.15	0.21
Operating	0.96	1.02	0.94	0.94	0.94
Netback	2.87	2.39	2.48	2.66	3.91
Total ($/BOE)					
Price	44.01	42.82	41.49	41.46	50.16
Royalties	4.93	4.90	4.73	5.26	4.81
Production and mineral taxes	0.37	0.35	0.38	0.24	0.52
Transportation and blending	1.45	1.40	1.42	1.43	1.53
Operating(2)	8.81	9.08	8.70	8.93	8.53
Netback	28.45	27.09	26.26	25.60	34.77

Notes:

(1) The heavy oil price for the full year has been reduced by the cost of condensate purchases which are blended with the heavy oil, as follows: Foster Creek - $35.43/bbl; Christina Lake - $36.66/bbl; Pelican Lake - $14.69/bbl; Total – Heavy Oil - $26.88/bbl.

(2) Operating costs for the year include costs related to long-term incentives of $0.15 / BOE.

Impact of Realized Financial Hedging	2010	Q4	Q3	Q2	Q1
Liquids ($/bbl)	(0.36)	(1.29)	1.01	(0.40)	(0.78)
Natural Gas ($/Mcf)	1.07	1.50	1.09	1.22	0.53
Total ($/BOE)	2.99	3.65	3.77	3.37	1.20

	Per-Unit Results–2009				
	Year	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek ($/bbl)					
Price[1]	55.55	63.60	62.20	54.43	33.44
Royalties	1.42	2.31	1.85	0.66	0.22
Transportation and blending	2.51	1.71	2.50	3.45	2.69
Operating	11.87	10.43	10.85	11.81	15.91
Netback	39.75	49.15	47.00	38.51	14.62
Heavy Oil – Christina Lake ($/bbl)					
Price[1]	53.45	57.07	64.85	57.32	32.44
Royalties	1.24	2.04	1.72	0.83	0.23
Transportation and blending	3.09	0.96	5.36	2.83	3.38
Operating	16.31	18.06	15.31	13.69	18.21
Netback	32.81	36.01	42.46	39.97	10.62
Heavy Oil – Pelican Lake ($/bbl)					
Price[1]	54.77	62.73	61.87	55.39	38.66
Royalties	10.98	12.08	12.27	10.93	8.57
Transportation and blending	0.30	(0.02)	0.67	0.06	0.45
Operating	9.59	11.64	7.03	9.74	10.15
Netback	33.90	39.03	41.90	34.66	19.49
Heavy Oil - Oil Sands ($/bbl)					
Price	55.09	62.75	62.23	55.18	35.47
Royalties	4.98	5.37	5.66	4.86	3.69
Production and mineral taxes	0.04	0.02	0.07	0.06	-
Transportation and blending	1.81	1.14	2.15	2.16	1.85
Operating	11.49	11.41	9.69	11.53	13.89
Netback	36.77	44.81	44.66	36.57	16.04
Heavy Oil - Conventional ($/bbl)					
Price	55.29	62.09	64.62	56.00	37.71
Royalties	5.47	8.61	8.39	4.13	0.61
Production and mineral taxes	0.14	0.13	(0.04)	0.44	0.02
Transportation and blending	1.91	1.59	1.22	2.75	2.11
Operating	9.47	12.06	9.31	9.72	6.91
Netback	38.30	39.70	45.74	38.96	28.06
Total - Heavy Oil ($/bbl)					
Price[1]	55.14	62.63	62.72	55.36	35.99
Royalties	5.08	5.95	6.22	4.70	2.98
Production and mineral taxes	0.06	0.04	0.04	0.14	-
Transportation and blending	1.83	1.22	1.96	2.28	1.91
Operating	11.07	11.52	9.61	11.13	12.27
Netback	37.10	43.90	44.89	37.11	18.83
Light and Medium Oil ($/bbl)					
Price	63.34	71.82	68.15	65.28	48.09
Royalties	7.39	11.72	8.09	6.56	3.14
Production and mineral taxes	2.40	1.70	2.57	1.98	3.37
Transportation and blending	0.98	0.70	0.83	1.18	1.21
Operating	9.93	9.53	10.00	9.53	10.67
Netback	42.64	48.17	46.66	46.03	29.70
Total - Crude Oil ($/bbl)					
Price	57.22	64.85	64.00	57.95	39.40
Royalties	5.67	7.34	6.66	5.18	3.03
Production and mineral taxes	0.65	0.44	0.64	0.62	0.95
Transportation and blending	1.61	1.10	1.69	2.00	1.71
Operating	10.78	11.04	9.70	10.72	11.82
Netback	38.51	44.93	45.31	39.43	21.89

	Per-Unit Results–2009				
	Year	Q4	Q3	Q2	Q1
Conventional - Natural Gas Liquids ($/bbl)					
Price	49.08	59.06	49.17	44.65	43.42
Royalties	0.81	0.96	1.00	0.82	0.46
Netback	48.27	58.10	48.17	43.83	42.96
Total Liquids ($/bbl)					
Price	57.14	64.79	63.85	57.81	39.45
Royalties	5.62	7.28	6.60	5.14	3.00
Production and mineral taxes	0.65	0.44	0.63	0.61	0.94
Transportation and blending	1.60	1.09	1.67	1.98	1.69
Operating	10.67	10.94	9.61	10.61	11.69
Netback	38.60	45.04	45.34	39.47	22.13
Total - Natural Gas ($/Mcf)					
Price	4.15	4.17	3.14	3.80	5.47
Royalties	0.08	0.16	0.02	0.01	0.15
Production and mineral taxes	0.05	0.03	0.04	0.07	0.05
Transportation and blending	0.15	0.12	0.16	0.16	0.18
Operating	0.86	0.81	0.84	0.83	0.94
Netback	3.01	3.05	2.08	2.73	4.15
Total ($/BOE)					
Price	39.88	44.54	40.43	38.65	35.71
Royalties	2.87	4.05	3.22	2.35	1.81
Production and mineral taxes	0.46	0.30	0.43	0.52	0.58
Transportation and blending	1.24	0.91	1.29	1.41	1.34
Operating(2)	7.71	7.85	7.24	7.52	8.27
Netback	27.60	31.43	28.25	26.85	23.71

Notes:

(1) The heavy oil price for the full year has been reduced by the cost of condensate purchases which are blended with the heavy oil, as follows: Foster Creek - $27.45/bbl; Christina Lake - $28.90/bbl; Pelican Lake - $13.16/bbl; Total – Heavy Oil - $19.68/bbl.

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

Impact of Realized Financial Hedging	2009	Q4	Q3	Q2	Q1
Liquids ($/bbl)	1.10	(0.05)	(0.01)	1.54	3.29
Natural Gas ($/Mcf)	3.63	2.27	4.41	4.33	3.43
Total ($/BOE)	12.16	6.92	13.77	14.91	13.06

	Per-Unit Results–2008				
	Year	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek ($/bbl)					
Price[(1) (2)]	64.94	21.42	94.96	96.51	60.07
Royalties	0.66	0.35	0.96	0.91	0.53
Transportation and blending	2.33	2.28	2.03	2.63	2.44
Operating	15.04	12.09	14.74	19.87	14.80
Netback	46.91	6.70	77.23	73.10	42.30
Heavy Oil – Christina Lake ($/bbl)					
Price[(1) (2)]	62.87	35.46	89.43	81.81	56.97
Royalties	0.60	0.34	0.94	0.77	0.40
Transportation and blending	3.57	3.33	2.90	3.62	5.20
Operating	23.95	16.88	22.79	30.92	33.42
Netback	34.75	14.91	62.80	46.50	17.95
Heavy Oil – Pelican Lake ($/bbl)					
Price[(1)]	78.15	38.91	96.43	105.61	70.92
Royalties	15.75	7.85	19.88	21.82	13.29
Transportation and blending	0.31	0.07	0.80	0.23	0.14
Operating	8.01	8.39	6.02	9.80	7.83
Netback	54.08	22.60	69.73	73.76	49.66
Heavy Oil - Oil Sands ($/bbl)					
Price	71.28	30.11	95.59	99.82	65.57
Royalties	7.98	3.59	10.64	11.47	6.85
Production and mineral taxes	0.07	0.03	0.08	0.08	0.10
Transportation and blending	1.50	1.48	1.54	1.49	1.48
Operating	12.56	11.06	11.44	15.78	12.35
Netback	49.17	13.95	71.89	71.00	44.79
Heavy Oil - Conventional ($/bbl)					
Price	78.61	46.83	105.10	90.49	69.13
Royalties	10.95	6.45	14.17	12.98	9.75
Production and mineral taxes	0.08	0.20	0.18	(0.31)	0.26
Transportation and blending	2.72	2.82	3.57	2.59	2.06
Operating	8.42	6.85	7.69	9.29	9.37
Netback	56.44	30.51	79.49	65.94	47.69
Total - Heavy Oil ($/bbl)					
Price[(1)]	73.06	33.37	97.80	97.36	66.57
Royalties	8.70	4.15	11.46	11.87	7.66
Production and mineral taxes	0.07	0.06	0.10	(0.02)	0.14
Transportation and blending	1.79	1.74	2.01	1.78	1.64
Operating	11.55	10.24	10.56	14.07	11.52
Netback	50.95	17.18	73.67	69.66	45.61
Light and Medium Oil ($/bbl)					
Price	89.87	49.88	111.91	109.29	88.58
Royalties	11.22	4.10	14.90	14.87	11.03
Production and mineral taxes	3.45	2.55	4.71	3.99	2.57
Transportation and blending	1.23	1.19	1.39	1.22	1.11
Operating	9.66	9.19	8.33	11.14	9.97
Netback	64.31	32.85	82.58	78.07	63.90
Total - Crude Oil ($/bbl)					
Price	77.80	37.88	101.77	100.82	72.84
Royalties	9.41	4.14	12.43	12.74	8.62
Production and mineral taxes	1.02	0.74	1.39	1.14	0.83
Transportation and blending	1.63	1.59	1.84	1.61	1.49
Operating	11.02	9.95	9.94	13.22	11.08
Netback	54.72	21.46	76.17	72.11	50.82

	Per-Unit Results–2008				
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Conventional - Natural Gas Liquids ($/bbl)					
Price	82.32	54.51	102.20	97.32	75.33
Royalties	1.40	1.55	1.78	1.21	1.22
Netback	80.92	52.96	100.42	96.11	74.11
Total Liquids ($/bbl)					
Price	77.84	38.04	101.77	100.78	72.87
Royalties	9.32	4.11	12.32	12.61	8.54
Production and mineral taxes	1.01	0.73	1.38	1.13	0.82
Transportation and blending	1.62	1.58	1.82	1.60	1.47
Operating	10.90	9.85	9.83	13.08	10.95
Netback	54.99	21.77	76.42	72.36	51.09
Total - Natural Gas ($/Mcf)					
Price	8.17	6.82	8.97	9.58	7.21
Royalties	0.42	0.19	0.51	0.59	0.37
Production and mineral taxes	0.11	0.07	0.16	0.15	0.06
Transportation and blending	0.24	0.25	0.24	0.22	0.24
Operating	0.84	0.84	0.61	0.95	0.98
Netback	6.56	5.47	7.45	7.67	5.56
Total ($/BOE)					
Price	60.99	39.67	73.74	74.76	55.55
Royalties	5.35	2.43	6.91	7.18	4.85
Production and mineral taxes	0.80	0.54	1.13	0.99	0.54
Transportation and blending	1.51	1.54	1.61	1.44	1.45
Operating(3)	7.49	7.14	6.21	8.64	7.97
Netback	45.84	28.02	57.88	56.51	40.74

Notes:

(1) The heavy oil price for the full year has been reduced by the cost of condensate purchases which are blended with the heavy oil, as follows: Foster Creek - $48.61/bbl; Christina Lake - $47.93/bbl; Pelican Lake - $17.64/bbl; Total – Heavy Oil - $31.04/bbl.

(2) The Foster Creek price includes the impact of the write-down of condensate inventories to net realizable value (2008 - $5.52/bbl; Q4 2008 - $15.26/bbl; Q3 2008 - $3.73/bbl); the Christina Lake price includes the impact of the write-down of condensate inventories to net realizable value (2008 - $1.98/bbl; Q4 2008 - $5.34/bbl).

(3) Operating costs for the year include a recovery of costs related to long-term incentives of $0.10/BOE.

Impact of Realized Financial Hedging	**2008**	**Q4**	**Q3**	**Q2**	**Q1**
Liquids ($/bbl)	(5.35)	3.10	(8.03)	(11.05)	(5.89)
Natural Gas ($/Mcf)	(0.24)	1.27	(1.11)	(1.33)	0.32
Total ($/BOE)	(3.05)	5.67	(7.24)	(9.22)	(1.32)

Capital Expenditures, Acquisitions and Divestitures

We have a large inventory of internal growth opportunities and continue to examine select acquisition opportunities to develop and expand our oil and gas 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.

We also have an active program to divest of certain non-core assets, in order to increase our focus on our long range business plan as well as generate proceeds to partially fund our capital investment.

The following table summarizes our net capital investment for 2010 and 2009.

	2010	**2009**
	($ millions)	
Capital Investment		
Upstream		
Foster Creek	278	262
Christina Lake	346	224
Total	624	486
Pelican Lake	104	72
Other Oil Sands	139	71
Conventional	523	466
	1,390	1,095
Refining and Marketing	656	1,033
Corporate	76	34
Capital Investment	2,122	2,162
Acquisitions	86	148
Divestitures	(307)	(367)
Net Acquisition and Divestiture Activity	(221)	(219)
Net Capital Investment	1,901	1,943

OTHER INFORMATION

Competitive Conditions

All aspects of the oil and gas industry are highly competitive. Refer to “Risk Factors – Competition” for further information on the competitive conditions affecting Cenovus.

Environmental Considerations

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 reviews and recommends policies pertaining to corporate responsibility, including the environment, 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, 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 (“GHG”) 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 US$15 to US$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 can provide 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. For a discussion of the risks associated with this uncertainty, see “Risk Factors – Climate Change Regulations”.

We also examine the impact of carbon regulation on our major projects, including both our oil sands operations and refining assets. We continue to closely monitor potential GHG 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 GHGs, 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 2010, 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 2011. Refer to “Risk Factors – Environmental Regulations” for further information on environmental protection matters affecting Cenovus.

Social and Environmental Policies

Our operations are guided by a Corporate Responsibility (“CR”) Policy that clearly outlines accountabilities for all staff, including our leadership and the vendors and suppliers who work with Cenovus. During 2010 our CR policy was revised through a process focused on engagement with employees and industry experts. The policy commits us to conduct our business in a responsible, transparent and respectful way while complying with all relevant and applicable laws, regulations and industry standards. The revisions made to the policy were approved by both our executive team and our Board. It was officially launched on November 30, 2010 and is available on our website www.cenovus.com.

Cenovus’s CR policy focuses on six areas: (i) Leadership; (ii) Corporate Governance and Business Practices; (iii) People; (iv) Environmental Performance; (v) Stakeholder and Aboriginal Engagement; and (vi) Community Involvement and Investment. We will continue to externally report on our performance in these areas through our CR reporting, which is aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its

Responsible Canadian Energy program. The policy emphasizes our commitment to protect the health and safety of all individuals affected by our activities, including our workforce and the communities where we operate. 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 work environment and we expect our workers to comply with the health and safety practices established for their protection. Additionally, the policy includes reference to emergency response management, investment in efficiency projects, new technologies and research, and support of the principles of the Universal Declaration of Human Rights.

In 2011 Cenovus will continue to rollout the CR policy to ensure the commitments articulated are understood and embedded throughout the organization. This will include: 1) a new CR poster distributed across the company; 2) four videos highlighting different commitments of the CR policy; 3) a news feed highlighting related employee stories; 4) a new interactive employee e-learning training tool; and 5) a presentation delivered at on-boarding sessions for new hires.

In addition, the CR policy will be included as a component in the implementation of the new Cenovus Operating Management System, which will be introduced across the company in 2011. Current steps that Cenovus already has in place to ensure the successful integration of the policy include: (i) a security program to regularly assess security threats to business operations and to manage the associated risks; (ii) corporate responsibility performance metrics to track our progress; (iii) 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; (iv) an Investigations Practice and an Investigations Committee to review and resolve potential violations of Cenovus policies or practices and other regulations; (v) 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; (vi) related policies and practices such as an Alcohol and Drug Policy, a Code of Business Conduct & Ethics and guidelines for 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 (vii) a requirement for acknowledgement and sign-off on key policies from our Board and employees. Our Board approves the CR policy on recommendation of the Safety, Environment and Responsibility Committee, is advised of significant policy contraventions and receives updates on trends, issues or events which could impact Cenovus.

Employees

The following table summarizes our full-time equivalent ("FTE") employees at December 31, 2010.

	FTE Employees
Oil Sands	823
Conventional	527
Refining and Marketing	67
Cenovus-wide	958
Total	2,375

We also engage a number of contractors and service providers. Refer to "Risk Factors – Key Personnel" for further information on employee matters affecting Cenovus.

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 future operations and related assets outside North America may be adversely affected by changes in government 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. Refer to "Risk Factors – Foreign Exchange Rates" for further information on foreign exchange rate matters affecting Cenovus.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals presently serve as directors of Cenovus until the end of the next annual meeting of shareholders.

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Ralph S. Cunningham[2,4,5,7] Houston, Texas, United States	2009	Mr. Cunningham is Chairman of Enterprise Products Holdings, LLC, the successor general partner of Enterprise Products Partners L.P., a limited partnership. From August 2007 to November 2010, Mr. Cunningham served as a director and President & Chief Executive Officer of EPE Holdings, LLC, the sole general partner of Enterprise GP Holdings L.P., a publicly traded midstream energy holding company. From December 2005 to June 2007, Mr. Cunningham served as Group Executive Vice President and Chief Operating Officer of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners, LP, and as Interim President and Chief Executive Officer from June 2007 to July 2007. Mr. Cunningham served as a director with the same entity from December 2005 to May 2010. From December 2009 to November 2010 he served as a director of LE GP, LLC, the general partner of Energy Transfer Equity, LP. He is currently a director of Agrium, Inc. and a director and Chairman of TETRA Technologies, Inc. He is also a member of the Auburn University Chemical Engineering Advisory Council and the Auburn University Engineering Advisory Council.
Patrick D. Daniel[2,3,4,5] Calgary, Alberta, Canada	2009	Mr. Daniel is a director and President & Chief Executive Officer of Enbridge Inc., a publicly traded energy delivery company. 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. He is also a member of the National Petroleum Council (an oil and natural gas advisory committee to the U.S. Secretary of Energy), a director of the American Petroleum Institute and a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.
Ian W. Delaney[2,4,5,7] Toronto, Ontario, Canada	2009	Mr. Delaney is Chairman and Chief Executive Officer of Sherritt International Corporation, a publicly traded diversified natural resource company that produces nickel, cobalt, thermal coal, oil and gas and electricity. He is also Chairman of The Westaim Corporation and a director of OPTI Canada Inc.
Brian C. Ferguson[8] Calgary, Alberta, Canada	2009	Mr. Ferguson became President & Chief Executive Officer of Cenovus on November 30, 2009. He was previously appointed as Executive Vice-President & Chief Financial Officer of Encana in March 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 investor relations, business development, which included corporate strategic planning, acquisitions and divestitures, and corporate reserve evaluations, and the legal and corporate secretarial functions. Mr. Ferguson is currently serving on the board of the Canadian Association of Petroleum Producers. Mr. Ferguson is a Fellow of the Institute of Chartered Accountants of Alberta and a member of the Canadian Institute of Chartered Accountants (CICA) and the Canadian Council of Chief Executives. He previously served as Chairman of CICA's Risk Oversight and Governance Board.

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Michael A. Grandin[2,5,9] Calgary, Alberta, Canada	2009 (Chair)	Mr. Grandin is the Chair of our Board. He is also director of BNS Split Corp. II and HSBC Bank Canada. He was Chairman and Chief Executive Officer of Fording Canadian Coal 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 Corporation. Mr. Grandin served as Dean of the Haskayne School of Business, University of Calgary from April 2004 to January 2006.
Valerie A.A. Nielsen[2,3,5,6] Calgary, Alberta, Canada	2009	Ms. Nielsen is a director of Wajax Corporation. 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) regarding international trade matters pertaining to energy, chemicals and plastics from 1986 to 2002. Ms. Nielsen is also a past director of the Bank of Canada and of the Canada Olympic Committee.
Charles M. Rampacek[2,5,6,7] Dallas, Texas, United States	2009	Mr. Rampacek is a director of Enterprise Products Holdings, LLC, the sole general partner of Enterprise Products Partners, L.P., a director of Flowserve Corporation and a director and Chairman of the Board of Ardent Holdings, LLC. Mr. Rampacek also 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[3,4,5] Toronto, Ontario, Canada	2009	Mr. Taylor served two consecutive four-year terms as Chief Executive and Managing Partner of Deloitte & Touche LLP and then acted as Senior Counsel until his retirement in May 2008. Mr. Taylor is also a member of the Canadian Institute of Chartered Accountants and Fellow of the Institute of Chartered Accountants of Ontario.
Wayne G. Thomson[2,5,6,7] Calgary, Alberta, Canada	2009	Mr. Thomson is Chairman and President of Enviro Valve Inc., a private company manufacturing proprietary pressure relief valves. He is also a director of Virgin Resources Limited, the Chairman of TG World Energy Corp. and a director of Orion Oil & Gas Corporation. Mr. Thomson is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the World Presidents' Organization.

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, by standing invitation, 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.

Executive Officers

The following individuals currently serve as executive officers of Cenovus.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Brian C. Ferguson Calgary, Alberta, Canada	President & Chief Executive Officer Mr. Ferguson's biographical information is included under "Directors".
Ivor M. Ruste Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer Mr. Ruste became Executive Vice-President & Chief Financial Officer on November 30, 2009. From May 2006 to November 2009, Mr. Ruste held the following positions with Encana: Executive Vice-President, Corporate Responsibility & Chief Risk Officer effective May 2009; Executive Vice-President & Chief Risk Officer effective January 2008; Vice-President, Finance for the Integrated Oil Division effective January 2007; and Vice-President, Finance of the Corporate Finance Group effective May 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.
John K. Brannan Calgary, Alberta, Canada	Executive Vice-President & Chief Operating Officer Mr. Brannan became Executive Vice-President & Chief Operating Officer on December 1, 2010. From November 2009 to November 2010, Mr. Brannan was our Executive Vice-President (President, Integrated Oil Division). Prior to November 2009, Mr. Brannan held the following positions with Encana: Executive Vice-President (President, Integrated Oil Division) effective January 2007; Managing Director, Frontier and International New Ventures effective July 2005; and from November 2003 to June 2005, Managing Director, International & New Ventures.
Harbir S. Chhina Calgary, Alberta, Canada	Executive Vice-President, Oil Sands Mr. Chhina became Executive Vice-President, Oil Sands on December 1, 2010. From November 2009 to November 2010, Mr. Chhina was our Executive Vice-President, Enhanced Oil Development & New Resource Plays. Prior to November 2009, Mr. Chhina held the following positions with Encana: Vice-President, Upstream Operations, Integrated Oil Sands Division effective January 2007; and from April 2002 to December 2006, Vice-President, Oil Recovery Business Unit.
Kerry D. Dyte Calgary, Alberta, Canada	Executive Vice-President, General Counsel & Corporate Secretary Mr. Dyte became Executive Vice-President, General Counsel & Corporate Secretary on November 30, 2009. Prior to November 2009, Mr. Dyte held the following positions with Encana: from January 2007 to November 2009, Vice-President, General Counsel & Corporate Secretary; and from December 2002 to December 2006, General Counsel & Corporate Secretary.
Judy A. Fairburn Calgary, Alberta, Canada	Executive Vice-President, Environment & Strategic Planning Ms. Fairburn became Executive Vice-President, Environment & Strategic Planning on November 30, 2009. Prior to November 2009, Ms. Fairburn held the following positions with Encana: Vice-President, Environment & Corporate Responsibility effective May 2009; Vice-President, Environment & Strategic Planning effective December 2008; Vice-President, Downstream Operations effective January 2007; and Vice-President, Weyburn Business Unit effective July 2004.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Sheila M. McIntosh Calgary, Alberta, Canada	Executive Vice-President, Communications & Stakeholder Relations Ms. McIntosh became Executive Vice-President, Communications & Stakeholder Relations on November 30, 2009. Prior to November 2009, Ms. McIntosh held the following positions with Encana: Executive Vice-President, Corporate Communications effective January 2007; and from April 2002 to December 2006, Vice-President, Investor Relations.
Donald T. Swystun Calgary, Alberta, Canada	Executive Vice-President, Refining, Marketing, Transportation & Development Mr. Swystun became Executive Vice-President, Refining, Marketing, Transportation & Development on December 1, 2010. From November 2009 to November 2010, Mr. Swystun was our Executive Vice-President (President, Canadian Plains Division). Prior to November 2009, Mr. Swystun held the following positions with Encana: Executive Vice-President, (President, Canadian Plains Division) effective January 2007; Executive Vice-President, Corporate Development effective March 2006; and from September 2001 to February 2006, President, Ecuador Region.
Hayward J. Walls Calgary, Alberta, Canada	Executive Vice-President, Organization & Workplace Development Mr. Walls became Executive Vice-President, Organization & Workplace Development on November 30, 2009. Prior to November 2009, Mr. Walls held the following positions with Encana: Executive Vice-President, Corporate Services effective January 2006; and effective November 2003, Vice-President, Information Services & Chief Information Officer.

As of December 31, 2010, all of our directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 1,176,735 Common Shares or approximately 0.16 percent of the number of Common Shares that were outstanding as of such date.

Investors should be aware that some of our directors and officers are directors and officers of other private and public companies. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships which may create situations in which conflicts might arise. Any such conflicts shall be resolved in accordance with the procedures and requirements of the relevant provisions of the CBCA, including the duty of such directors and officers to act honestly and in good faith with a view to the best interests of Cenovus.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

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 (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 & Chief Executive Officer of Probex Corporation ("Probex") in 2003 when it filed a petition seeking relief under Chapter 7 of the Bankruptcy Code (United States). In 2005, as a result of the bankruptcy, two complaints seeking recovery of certain alleged losses were filed against former Probex officers and directors, including Mr. Rampacek. These complaints were defended by American International Group, Inc. ("AIG") in accordance with the Probex director and officer insurance policy and settlement was reached and paid by AIG, with bankruptcy court approval, in 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, with bankruptcy court approval, in 2006.

AUDIT COMMITTEE

The Audit Committee mandate is included as Appendix C to this annual information form.

Composition of the Audit Committee

The Audit Committee consists of three members, each of whom are independent and financially literate in accordance with 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

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., a publicly traded 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, a compression systems manufacturer. He is also a past director and Chair of the finance committee of Synenco Energy Inc., an oil sands mining company 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 and provided consulting services to the oil and gas industry for over 30 years. She has also completed several 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 is currently a director and serves on the audit committee of Wajax Corporation, a publicly traded company engaged in the sale and after-sales parts and service support of mobile equipment, diesel engines and industrial components. She is a past director of the Bank of Canada and of the Canada Olympic Committee.

Colin Taylor (Financial Expert and Audit Committee Chair)

Mr. Taylor is a chartered accountant, a member and Fellow of the Institute of Chartered Accountants of Ontario and a member of the Canadian Institute of Chartered Accountants. 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 of Deloitte & Touche LLP and continued as Senior Counsel 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, by standing invitation, an ex-officio member of our 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. Subject to the Audit Committee's discretion, the budget generally covers the period between the adoption of the budget and the next meeting of the Audit Committee. The list of permitted services is sufficiently detailed 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 $200,000, in the case of pre-approvals granted by the Chair of the Audit Committee, and (ii) may not exceed $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

The following table provides information about the fees billed to Cenovus for professional services rendered by PricewaterhouseCoopers LLP during fiscal 2010 and 2009.

($ thousands)	**2010**	**2009**[(5)]
Audit Fees[(1)]	1,996	-
Audit-Related Fees[(2)]	47	-
Tax Fees[(3)]	157	-
All Other Fees[(4)]	18	-
Total	2,218	-

Notes:

(1) Audit Fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit-Related Fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported as Audit Fees. During fiscal 2010, the services provided in this category included review of reserves disclosure as well as audit-related services in relation to our debt shelf prospectuses and Dividend Reinvestment Plan.

(3) Tax Fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2010, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns as well as assistance in respect of scientific research & experimental development claims.

(4) During fiscal 2010, the services provided in this category included the payment of maintenance fees associated with a research tool that grants access to a comprehensive library of financial reporting and assurance literature.

(5) 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.

DESCRIPTION OF CAPITAL STRUCTURE

The following is a summary of the rights, privileges, restrictions and conditions which are attached to common shares ("Common Shares") and our first and second preferred shares (collectively the "Preferred Shares"). We are authorized to issue an unlimited number of Common Shares and an unlimited number of First Preferred Shares and Second Preferred Shares. As of December 31, 2010, there were approximately 753 million Common Shares and no Preferred Shares outstanding.

Common Shares

The holders of Common Shares are entitled: (i) to receive dividends if, as and when declared by our Board; (ii) to receive notice of, to attend, and to vote on the basis of one vote per Common Share held, at all meetings of shareholders; and (iii) to participate in any distribution of our assets in the event of liquidation, dissolution or winding up or other distribution of our assets among our shareholders for the purpose of winding up our affairs.

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 $500 million.

Shareholder Rights Plan

We have a Shareholder Rights Plan that was adopted in 2009 to ensure, to the extent possible, that all our shareholders are treated fairly in connection with any take-over bid for Cenovus. 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 every third annual shareholder meeting, commencing in 2012.

Dividend Reinvestment Plan

During 2010, the Board approved a dividend reinvestment plan, which permits holders of Common Shares to automatically reinvest all or any portion of the cash dividends paid on their Common Shares in additional Common Shares. At the discretion of the Company, the additional Common Shares may be issued from treasury at the average market price or purchased on the market.

Employee Stock Option Plan

Our Employee Stock Option Plan provides employees with the opportunity to exercise options to purchase Common Shares. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. The options vest over three years with 30 percent vesting after each of the first and second anniversary of the grant date and the remaining 40 percent vesting after the third anniversary. Options granted prior to February 17, 2010 expire after five years; options granted on or after February 17, 2010 expire after seven years. Each option has an associated tandem stock appreciation right which gives employees the right to elect to receive a cash payment equal to the excess of the market price of the Common Shares at the time of exercise over the exercise price of the option in exchange for surrendering the option.

Ratings

The following information relating to our credit ratings is provided as it relates to our financing costs and liquidity. Specifically, credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current rating on our debt by our rating agencies or a negative change in our ratings outlook could adversely affect our cost of financing and our access to sources of liquidity and capital. See "Risk Factors" in this AIF for further information.

The following table outlines the ratings and outlooks of Cenovus's debt as of December 31, 2010:

	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, at any 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'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 A(low) by DBRS is within the third highest of ten categories and is assigned to debt securities considered to be of good credit quality. The capacity for payment of financial obligations is substantial, but of lesser credit quality than that of higher rated securities. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. DBRS's 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 good credit quality. The capacity for the payment of short-term financial obligations as they fall due is substantial. Overall strength is not as favorable as higher rating categories, may be vulnerable to future events, but qualifying negative factors are considered manageable.

DIVIDENDS

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

A first quarter dividend of $0.20 per share was declared payable on March 31, 2011 to holders of Common Shares of record as of March 15, 2011. In each of the four quarters in 2010, Cenovus paid a dividend of $0.20 per share ($0.80 per share annually). In the fourth quarter of 2009, Cenovus paid a dividend of US$0.20 per share.

MARKET FOR SECURITIES

All of the outstanding Common Shares are listed and posted for trading on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the symbol CVE. The following table outlines the share price trading range and volume of shares traded by month in 2010.

2010	**TSX**				**NYSE**			
	Share Price Trading Range				Share Price Trading Range			
	High	Low	Close	Share Volume	High	Low	Close	Share Volume
	($ per share)			(millions)	(US$ per share)			(millions)
January	27.84	24.52	24.71	51.2	26.79	22.96	23.15	24.9
February	27.67	24.26	25.70	45.8	26.58	22.87	24.50	18.4
March	27.16	24.93	26.53	51.4	26.68	24.21	26.21	12.8
April	30.63	26.75	29.87	59.6	30.66	26.49	29.30	17.8
May	30.44	25.83	29.06	50.3	30.10	23.84	26.94	26.2
June	30.49	26.76	27.40	58.5	30.00	25.26	25.79	29.6
July	31.00	26.75	28.95	40.9	30.12	25.09	28.20	20.2
August	29.56	26.19	28.69	44.1	29.17	24.61	26.91	19.9
September	30.19	27.60	29.59	46.4	29.22	26.66	28.77	16.6
October	30.62	28.31	28.38	31.5	30.41	27.78	27.82	15.2
November	30.34	28.50	29.53	31.1	30.23	28.00	28.77	19.5
December	33.40	29.76	33.28	32.7	33.37	29.25	33.24	23.3

RISK FACTORS

We have identified risks in three principal categories: financial, operational and regulatory. We believe that effectively managing risk is a competitive necessity and an integral part of creating shareholder value. We are continually working to mitigate the impact of potential risks to our business. Our approach to risk management includes an annual review and identification of principal risks, an analysis of the severity and likelihood of each principal risk, an evaluation of the effectiveness of the current mitigation and further mitigation or treatment of risks. We continuously monitor our risk profile as well as industry best practices.

Financial Risks

Financial risks include, but are not limited to, volatile financial markets, availability of credit and access to sufficient liquidity, fluctuations in commodity prices and foreign exchange and interest rates and risks related to our hedging activities. Some of these risks have intensified in recent years due to challenging market conditions caused by the global recession. These conditions have impacted and may continue to impact our customers and suppliers and may alter our spending and operating plans. There may be unexpected business impacts due to general market uncertainty. Continued economic uncertainty means that oil and gas producers, including Cenovus, may face the risk of restricted access to capital and increased borrowing costs.

Commodity Price Volatility

Our financial performance is substantially dependent on the prevailing prices of crude oil, natural gas and refined products. Crude oil prices are impacted by a number of factors including, but not limited to, the actions of the Organization of Petroleum Exporting Countries, world economic conditions, government regulation, political stability, the supply of crude oil, the availability of alternate fuel sources and weather conditions. Our natural gas price realizations are impacted by a number of factors including, but not limited to, North American supply and demand, developments related to the market for liquefied natural gas, weather conditions and prices of alternate sources of energy. Our refined products prices are impacted by a number of factors including, but not limited to, market competitiveness, weather, industry planned and unplanned refinery maintenance and global supply and demand for refined products. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in US dollars, are stated in Canadian dollars.

Our financial performance is dependant on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. For example, our natural gas is predominately produced, processed and sold in Alberta at prices discounted to the Nymex natural gas price. This discount is influenced by regional supply and demand factors, including weather and the availability and the cost of export pipeline capacity. Fluctuations in this discount further compound the volatility in the underlying commodity price. Future price differentials are uncertain and increases in natural gas differentials have a negative impact on our business.

Of particular importance are the price differentials between our light/medium oil, heavy oil and bitumen, predominately produced in Western Canada, compared to the quoted Nymex WTI price. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as pipeline transportation interruptions and the quality of the oil produced. For example, market prices for heavy oil are lower than market indices for light and medium grades of oil, due principally to the lower value of the product yield and the higher transportation and refining costs required to upgrade heavy oil to an equivalent market standard. Bitumen prices are lower than heavy oil prices due to the cost of adding diluent to create a blended product with an acceptable viscosity for efficient transportation to market. Any shortfall in the supply of diluent may cause its cost to increase thereby increasing our cost to transport bitumen to market which would correspondingly increase our transportation and blending costs. The market price for this blended product is influenced by regional supply and demand factors, including the availability and price of diluent and the availability and cost of export pipeline capacity. The markets for heavy oil and blended bitumen products are more limited than for light and medium grades, making them more susceptible to supply and demand changes. Future price differentials are uncertain and increases in heavy oil differentials could have a negative impact on our business.

The financial performance of our refining operations is impacted by the relationship, or margin, between refined product prices and the prices for refinery feedstock. Margin volatility is impacted by numerous conditions including, but not limited to: fluctuations in the supply and demand for refined products, market competitiveness, the costs of crude oil and other factors including weather. Refining margins are subject to seasonal factors as production changes to match seasonal demand. Sales volumes, prices, inventory levels and inventory values will fluctuate accordingly. Future refining margins are uncertain and decreases in refining margins have a negative impact on our business.

Fluctuations in the price of these commodities, associated price differentials and refining margins may impact our ability to meet guidance targets, fund growth projects, maintain our dividend program and also may affect our operations, the value and amount of our proved reserves, the value of our refining assets and the amount of our borrowings. Any substantial or extended decline in these commodity prices 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 a material adverse effect on our business, financial conditions, results of operations and cash flow.

We reduce exposure to commodity price volatility through an integrated business strategy whereby a portion of operating supplies and feedstock is provided from internal operations. For example, the cost of natural gas consumed in heavy oil operations is offset with revenue from natural gas production thereby reducing our exposure to gas price volatility. There are no assurances that we will be able to maintain natural gas production to keep pace with growing internal natural gas demands.

We conduct an annual assessment of the carrying value of our assets in accordance with Canadian generally accepted accounting principles. If crude oil and natural gas prices decline or remain at low levels for an extended period of time, the carrying value of our assets could be subject to financial downward revisions and our earnings could be adversely affected.

Hedging Activities

Our market risk mitigation policy, which has been approved by the Board, allows management to use derivative instruments to hedge the price risk of our crude oil and natural gas production, as well as refining margins. One of the objectives within this policy is to protect a portion of our subsequent years' estimated cash flows.

We also use derivative instruments in various operational markets to optimize our supply or production chain. For example we may hedge the forward price of diluent purchased to transport bitumen by pipeline or hedge the price of physical crude acquired to balance pipeline operations.

We monitor our exposure to fluctuations in interest rates and foreign exchange rates. We may utilize derivative financial instruments and physical delivery contracts, when considered appropriate, to help mitigate the potential impact of changes in interest rates and foreign exchange rates. Management may elect to use derivative instruments priced in Canadian dollars to partially mitigate our net exposure to Canadian dollar operating costs.

We mitigate the risks inherent in using derivative instruments through ongoing and thorough investigation of counterparties and use this analysis to set appropriate volume, term and credit limits. 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 due to hedging arrangements if we are unable to produce oil, natural gas or refined products to fulfill our delivery obligations or if counterparties are unable to fulfill their obligations.

Under Canadian generally accepted accounting principles, 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.

Credit and Liquidity

Unpredictable financial markets and the 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. This could have an adverse effect on us, as our ability to make future capital expenditures and to finance our capital and operating commitments is dependent on certain factors including, but not limited to, access to the debt and equity markets, interest in investments in the energy industry generally and interest in our securities in particular.

In September 2009, we issued US$3.5 billion in debt securities, substantially all of which were exchanged in June 2010 for debt securities registered under the Securities Act of 1933 with the same terms and conditions as the original issued securities. On September 15, 2014, the first tranche of the debt matures in the amount of US$800 million. We have a $2.5 billion committed credit facility, with a maturity of November 30, 2014, of which the entire amount was available at December 31, 2010 to meet operating and capital requirements. Despite the current state of our liquidity, an inability to access the credit markets or a sustained downturn in the prices of crude oil, natural gas or refined products or significant unanticipated expenses related to development or maintenance of our existing properties could seriously impact our liquidity and possibly impact our debt ratings should we seek additional capital. We are also required to comply with financial and operating covenants under our credit facility and indenture governing our debt securities. We routinely review the covenants and may make changes to our development plans or dividend policy to ensure compliance. In the event that we do not comply with such covenants, our access to capital could be restricted or repayment could be required. If external sources of capital become limited or unavailable, or if repayment is required before maturity, our ability to make capital investments, continue our growth plans and maintain existing properties may be impaired and our business, financial condition, results of operations and cash flow may be materially adversely affected as a result.

Foreign Exchange Rates

Foreign exchange rates will affect our results as global prices for crude oil, natural gas and refined products are set in U.S. dollars, while many of our operating and capital costs outside of the U.S. are denominated in Canadian dollars and our Consolidated Financial Statements are reported in Canadian dollars.

Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar creates uncertainty and impacts our capital expenditures and expenses. To the extent such fluctuations are unfavourable, it may have a material adverse effect on our business, financial condition, results of operations and cash flow. Our exposure to U.S. exchange rates is partially offset by our U.S. dollar obligations, such as interest costs on our U.S. dollar denominated debt. Additionally, when our U.S. dollar denominated notes mature, we may have exposure to U.S. dollar exchange rates on the principal repayment of the notes. Such a repayment of U.S. dollar denominated debt partially hedges us against the currency risk of U.S. dollar denominated revenues.

Interest Rates

Our credit facilities and commercial paper are exposed to floating interest rates which can impact our financial results, in particular our net interest expense. In addition, we are exposed to interest rate risk upon the refinancing of maturing long-term debt at prevailing interest rates.

Royalty Regimes

Our cash flow may be directly affected by changes to royalty regimes. The Governments of Alberta and Saskatchewan receive royalties on the production of hydrocarbons from lands in which they respectively own the mineral rights. The royalties that we pay on our oil sands properties are determined based on the Canadian dollar equivalent price of WTI, and therefore increases in WTI or decreases in the CDN$/US$ exchange rate could significantly increase our royalties, which could have a material adverse effect on our business, financial conditions, results of operations and cash flow. There is also a mineral tax in each province levied on hydrocarbon production from lands which the Crown does not own the mineral rights. Recent changes to the Alberta royalty and mineral tax regime, as well as the potential for changes in the royalty and mineral tax regimes applicable in other provinces, have created uncertainty relating to the ability of producers to accurately estimate future Crown burdens. An increase in the royalty or mineral tax rates applicable in one or both provinces would reduce our earnings and could make, in the respective province, future capital expenditures or existing operations uneconomic. A material increase in royalties or mineral taxes may reduce the value of our associated assets.

Tax Laws

Income tax laws or incentive programs relating to the oil and gas industry and in particular the oil sands sector may in the future be changed or interpreted in a manner that adversely affects us, our operations or our future expansion plans.

Arrangement Related Risk

Pursuant to the separation and transition agreement ("Separation Agreement") dated November 30, 2009 involving, among others, Encana, 7050372 Canada Inc. and Subco, Encana and Cenovus have each agreed to cooperate fully with each other and our respective counsels in the investigation, prosecution, defense and resolution of certain litigation matters, including, without limitation, certain judicial actions relating to coal bed methane involving Encana (collectively, the "Joint Litigation"). 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 effect 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 effect 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 relating to the Arrangement (the "Arrangement Agreement") and the 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 business and 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.

The Arrangement Agreement contains a number of representations, warranties and covenants, including agreement by each of Cenovus and Encana 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 advance income tax rulings and opinions received from the Canada Revenue Agency, and the private letter ruling received from the U.S. Internal Revenue Service, all with respect to income tax consequences of certain aspects of the Arrangement and certain other transactions. 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 10 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.

Any indemnification claim against us pursuant to the provisions of the Arrangement Agreement or Separation Agreement could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Operational Risks

Operational risks are those risks that affect our ability to continue operations in the ordinary course of business. In general, our operations are subject to common risks affecting the oil and gas industry. Our operational risks include, but are not limited to, uncertainty of reserves and resources estimates, operational hazards, pipeline transportation interruptions, phased growth execution, partner risks, competition, technology, third-party claims, land claims, key personnel and information systems.

Uncertainty of Reserves and Future Net Revenue Estimates

The reserves estimates included in this AIF are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows derived therefrom are based upon a number of variable factors and assumptions, including but not limited to, product prices, future operating and capital costs, historical production from the properties and the assumed effects of regulation by governmental agencies, including with respect to royalty payments and taxes, 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 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. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels and therefore our business, financial conditions, results of operations and cash flows are highly dependent upon successfully producing current reserves and acquiring, discovering or developing additional reserves.

Uncertainty of Contingent and Prospective Resource Estimates

The contingent resources and prospective resources results included in this AIF are estimates only. The same uncertainties inherent in estimating quantities of reserves apply to estimating quantities of contingent and prospective resources. In addition there are contingencies that prevent resources from being classified as reserves. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. Prospective resources are subject to contingencies and are also undiscovered, meaning that subsequent drilling may demonstrate actual results which may vary significantly from projected results. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. For additional information on resources and their associated contingencies, see “Contingent and Prospective Resources” in this AIF.

Operational and Safety Considerations

The operation of our properties is subject to the customary hazards of recovering, transporting and processing hydrocarbons, including but not limited to, blowouts, fires, explosions, gaseous leaks, migration of harmful substances, oil spills, corrosion, acts of vandalism and terrorism, any of which can interrupt operations, cause loss of or damage to equipment, loss of or injury to life and damage to the environment, property and informational technology systems and related data and control systems.

Our crude oil and natural gas operations are subject to all of the risks normally incidental to: (i) the storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; and (iii) the operation and development of crude oil and natural gas properties, including, but not limited to, 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.

Producing and refining 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. Delineation of the resources, the costs associated with production, including drilling wells for SAGD operations, and the costs associated with refining oil can entail significant capital outlays. The operating 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.

Our refining and marketing business is subject to all of the risks normally inherent in the operation of refineries, terminals, pipelines and other transportation and distribution facilities including, but not limited to, loss of product, slowdowns due to equipment or transportation failures, disruptions, fires, and explosions, unavailability of feedstock, and price and quality of feedstock.

We do not insure against all potential occurrences and disruptions and it cannot be guaranteed that our insurance will be sufficient to cover any such occurrences or disruptions. Our operations could also be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Pipeline Transportation Interruptions

Our production is transported through various pipelines and our refineries are reliant on various pipelines to receive feedstock. Disruptions in pipeline service could adversely affect our crude oil and natural gas sales, refining operations and our cash flow. Interruptions in the availability of these pipeline systems may limit the ability to deliver production volumes and could adversely impact commodity prices, sales volumes or the prices received for our products. These interruptions may be caused by the inability of the pipeline to operate, or they can be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. There can be no certainty that investments in pipelines which would result in excess long-term take-away capacity will be made by applicable third party pipeline providers. There is also no certainty that short-term operational constraints on the pipeline system, arising from pipeline interruption and/or increased supply of crude oil, will not occur. In addition, planned or unplanned shutdowns or closures of our refinery customers may limit our ability to deliver feedstock with negative implications on sales and cash from operating activities.

We reduce the exposure to these risks by allocating deliveries to multiple customers using multiple pipelines. We also maintain knowledge of the infrastructure operational issues and influence expansion proposals through industry organizations in order to assess and respond to delivery risks. We have limited capacity to mitigate these risks in respect of our refining operations.

Phased Growth Execution

There are certain risks associated with the execution of both our upstream and refining projects. These risks include, but are not limited to, our ability to obtain the necessary environmental and regulatory approvals, risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel, the impact of general economic, business and market conditions, the impact of weather conditions, the accuracy of project cost estimates, our ability to finance growth, and the effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving targets and objectives. Losses resulting from the occurrence of any of these risks could have a material adverse effect on our business, financial condition, results of operations and cash flow.

Partner Risks

Interests in certain of our upstream assets are held in a partnership with ConocoPhillips, an unrelated U.S. public company, and are operated by us. Our refining assets are also held in a partnership with ConocoPhillips and operated by ConocoPhillips. The success of our refining operations is dependant on the ability of ConocoPhillips to successfully operate this business and maintain the refining assets. We rely on the judgment and operating expertise of ConocoPhillips in respect of the operation of such refining assets and to provide us with information on the status of such refining assets and related results of operations.

ConocoPhillips, as an unrelated third party, may have objectives and interests that do not coincide with and may conflict with our interests. Major capital decisions affecting these upstream and refining assets require agreement between us and ConocoPhillips, while certain operational decisions may be made by the operator of the applicable assets. While Cenovus and ConocoPhillips generally seek consensus with respect to major decisions concerning the direction and operation of these upstream and refining assets, no assurance can be provided that the future demands or expectations of either party relating to such assets will be satisfactorily met or met in a timely manner or at all. Unmet demands or expectations by either party or demands and expectations which are not satisfactorily met may affect our participation in the operation of such assets or our ability to obtain or maintain necessary licenses or approvals or affect the timing of undertaking various activities.

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 results of our operations and our cashflow. 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 the 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.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new and existing sources of supply, the acquisition of crude oil and natural gas interests and the distribution and marketing of petroleum products. We compete with other producers and refiners, some of which may have lower operating costs and greater resources than we do. Competing producers may develop and implement recovery techniques and technologies which are superior to those we employ. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

Several companies have announced plans to enter the oil sands business, to begin production or to expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of crude oil in the marketplace and increase our input costs for labour and materials. Depending on the levels of future demand, increased supplies could have a negative impact on prices, which in turn may impact our business, financial condition, results of operations and cash flow.

Technology

Current SAGD technologies for the 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 varies and therefore impacts 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 business, financial condition, results of operations and cash flow. 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.

Third-Party Claims

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 in defence against any such litigation.

Land Claims

In Western Canada, aboriginal groups have historically filed claims in respect of their aboriginal rights and treaty rights against the Governments of Canada and Alberta, and other government bodies. No certainty exists that any lands currently unaffected by claims brought by aboriginal groups will remain unaffected by future claims.

Key Personnel

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.

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.

Regulatory Risks

Our industry is generally subject to regulation and intervention under federal, provincial, state and municipal legislation in Canada and the U.S. in matters such as land tenure, royalties, taxes (including income taxes), government fees, production rates, environmental protection controls, the reduction of GHG and other emissions, the export of crude oil, natural gas and other products, the awarding or acquisition of exploration and production, oil sands or other interests, the imposition of specific drilling obligations, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Regulatory Approvals

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 in certain circumstances. Changes to government regulation could impact our existing and planned projects.

Our operations require us to obtain approvals from various regulatory authorities and there are no guarantees 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 and aboriginal consultation, environmental impact assessments and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions, including, but not limited to, security deposit obligations, regulatory oversight of projects by third parties, mitigating or avoiding project impacts, 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.

Environmental Regulations

All phases of the crude oil, natural gas and refining operations 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 regulations"). Environmental regulations require 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 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 regulations can require significant expenditures, including expenditures for clean up costs and damages arising out of contaminated properties and failure to comply with environmental regulations 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 regulations in the future will not have such an effect. The implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry generally could reduce demand for crude oil and natural gas, increase our costs and have a material adverse effect on our business, financial condition, results of operations and cash flow.

Climate Change Regulations

The Canadian federal government and various provincial and United States federal and state governments have announced intentions to regulate GHG emissions and other air pollutants. These regulations are in various phases of review, discussion or implementation in the U.S. and Canada. Uncertainties exist relating to the timing and effects of these proposed regulations. Additionally, lack of certainty regarding how any future federal legislation will harmonize with provincial or state regulations makes it difficult to accurately determine the cost estimate of climate change legislation compliance with certainty, including the effects of compliance with such initiatives on our suppliers and service providers.

Adverse impacts to our business if comprehensive GHG legislation is enacted in any jurisdiction in which we operate or conduct business, may include, but are not limited to, increased compliance costs, permitting delays and/or 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. Emission allowances or offset credits may not be available for acquisition by our projects or may not be available on an economic basis. Required emission reductions may not be technically or economically feasible to implement, in whole or in part, and failure to meet such emission reduction requirements or other compliance mechanisms may have a material adverse effect on our business by resulting in, among other things, fines, permitting delays, penalties and the suspension of operations. Consequently, no assurances can be given that the effect of future federal climate change regulations will not be significant to us, which could result in a material adverse effect on our business, financial condition, results or operations and cash flow.

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

Carbon Fuel Standards

Existing and proposed environmental legislation in certain U.S. states and Canadian provinces regulating carbon fuel standards could result in increased costs and/or reduced revenue. The potential regulation may negatively affect the marketing of our bitumen, crude oil or refined products, or require us to purchase emissions credits in order to affect sales in such jurisdictions. For example, the United States federal government and certain U.S. states (California in particular), have passed, or are considering legislation, which in some circumstances takes into account the GHG emissions used to produce fuel, which may negatively impact marketing of our refined products and ultimately have a material impact on the cost of refined petroleum products.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of such 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.

Alberta’s Land-Use Framework

Alberta’s Land-Use Framework, which is to be implemented under the Alberta Land Stewardship Act (“ALSA”), sets out the Government of Alberta’s approach to managing Alberta’s land and natural resources to achieve long-term economic, environmental and social goals. ALSA contemplates the amendment or extinguishment of previously issued consents such as regulatory permits, licenses, approvals and authorizations in order to achieve or maintain an objective or policy resulting from the implementation of a regional plan. The Government of Alberta is expected to develop a regional plan for each of seven regions in the province and has identified the Lower Athabasca Regional Plan (“LARP”) as a priority. The LARP is intended to identify and set resource and environmental management outcomes for air, land, water and biodiversity, and guide future resource decisions while considering social and economic impacts. In August 2010, the Lower Athabasca Regional Advisory Council (“RAC”) provided its vision document to the Government of Alberta regarding the LARP.

Cenovus is actively participating in the feedback process as a stakeholder with significant activities in the region and will continue to monitor developments going forward. The Government of Alberta is expected to respond to the RAC advice with its own LARP recommendations. It is possible that the RAC vision, if adopted in its current form by the Government of Alberta, may negatively impact Cenovus's access to or our ability to conduct operations on certain resource properties or limit the pace of development due to environmental limits and thresholds.

Alberta's Regulatory Enhancement Project

As part of the Government of Alberta's competitiveness review, a comprehensive review of Alberta's regulatory system called the Regulatory Enhancement Project (the "Project") was initiated in March 2010. The Project's goal is to create an effective regulatory system that will contribute to Alberta's overall competitiveness while protecting the environment, ensuring public safety and conservation of resources. The Project involved engagement with a broad range of stakeholders, including industry and led to a recommendation to the Minister of Energy, in the fourth quarter of 2010, for adoption of a coordinated policy framework and an integrated regulatory system for the upstream oil and gas sector. The Government of Alberta has accepted the Project team's recommendations and is expected to begin implementing those recommendations in the first half of 2011.

Alberta Environment Water Licences

To operate our SAGD facilities we rely on water, which is obtained under licenses from Alberta Environment. There can be no assurance that the licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of our projects rely on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to us or at all, or that such additional water will in fact be available to divert under such licenses. While we currently re-use a percentage of the water which we withdraw under license, there are no guarantees that our operations will continue to efficiently use water.

Public Perception and Influence on Regulatory Regime

Development of the Alberta oil sands has received considerable attention in recent public commentary on the subjects of environmental impact, climate change and GHG emissions. Despite the fact that much of the focus is on bitumen mining operations and not in-situ production, public concerns about GHG emissions, and water and land use practices in oil sands developments may directly or indirectly impair the profitability of our current oil sands projects and the viability of future oil sands projects by creating significant regulatory uncertainty leading to uncertain economic modeling of current and future projects and delays relating to the sanctioning of future projects.

Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, extraordinary environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment. In addition, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil and reduce its price.

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, 2010 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.

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 that would likely be considered important to a reasonable investor in making an investment decision, 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.

INTEREST 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 10 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.

MATERIAL CONTRACTS

During the year ended December 31, 2010, we have not entered into any contracts, nor are there any contracts still in effect, that are material to our business, other than contracts entered into in the ordinary course of business, and each of the Arrangement Agreement and the Separation Agreement, as described under "Risk Factors – Arrangement Related Risk".

INTERESTS OF EXPERTS

Our independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditors' report dated February 18, 2011 in respect of our consolidated financial statements as at December 31, 2010 and December 31, 2009 and for each of the years in the three year period ended December 31, 2010 and Cenovus's internal control over financial reporting as at December 31, 2010. 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 were the auditors of Encana and, on November 30, 2009, were appointed auditors of Cenovus.

Information relating to reserves and resources 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:

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

In the United States:

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

ADDITIONAL INFORMATION

General

Additional information relating to us is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com. Information contained in or otherwise accessible through our website does not form a part of this AIF and is not incorporated by reference into this AIF.

Additional information, including directors' and officers' remuneration, principal holders of our securities, securities authorized for issuance under our equity-based compensation plans and our statement of governance practices, is included in our information circular for the 2011 annual meeting of shareholders, which involves the election of directors.

The corporate governance rules of the NYSE are generally not applicable to non-U.S. companies, however 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. Except as summarized on our website www.cenovus.com, we are in compliance with the NYSE corporate governance standards in all significant respects.

Additional financial information is contained in our audited consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2010.

Accounting Matters

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars. All references to "dollars", "C$" or to "$" are to Canadian dollars and all references to "US$" are to U.S. 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, 2010 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.

Promoter

Under applicable Canadian securities laws, Encana was considered a promoter of Cenovus in 2009 because it took the initiative in our founding for the purpose of implementing the Arrangement. As consideration for the acquisition of our assets pursuant to the Arrangement, we issued a demand note payable to Encana in the aggregate amount of US$3.5 billion. The value 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 completion of the Arrangement. Subsequent to the completion of the Arrangement, Cenovus made an additional US$250 million payment to Encana to adjust the cash balances of both companies 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. Refer to "Risk Factors - Arrangement Related Risk" for additional information regarding certain ongoing commitments, including the Separation Agreement, between Encana and Cenovus. Additional information regarding the Arrangement is available in our annual information form for the year ended December 31, 2009, available at www.cenovus.com and on SEDAR at www.sedar.com.

ABBREVIATIONS

<u>Oil and Natural Gas Liquids</u>

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	barrels of oil equivalent per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day

<u>Natural Gas</u>

Bcf	billion cubic feet
Mcf	thousand cubic feet
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMBtu	million British thermal units
CBM	Coal Bed Methane

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 wellhead.

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, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

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).

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 principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast 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, 2010.

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) $ millions
McDaniel & Associates Consultants Ltd.	Cenovus Energy Inc. Evaluation of a Portion of the Canadian Oil & Gas Reserves February 16, 2011	Canada	$21,724
GLJ Petroleum Consultants Ltd.	Cenovus Energy Inc. Corporate Evaluation January 26, 2011	Canada	$2,650
			$24,374

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, consistently applied.

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.

Executed as to our report referred to above:

(signed) P.A. Welsh
McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

(signed) Harry Jung
GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 17, 2011

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. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. A report from the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Corporation 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 affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and each of the independent qualified reserves evaluators.

The Board of Directors of the Corporation 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, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas activity information;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; 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.

(signed) Brian C. Ferguson
President & Chief Executive Officer

(signed) Judy A. Fairburn
Executive Vice-President, Environment and Strategic Planning

(signed) Michael A. Grandin
Director and Chair of the Board

(signed) Wayne G. Thomson
Director and Chair of the Reserves Committee

February 17, 2011

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 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.

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.

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

<u>Quarterly Financial Statements</u>

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 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.

    (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.

(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.

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.

421 – 7 Ave SW
PO Box 766
Calgary, AB T2P 0M5

Our 2010 Annual Report is
available on our website at
www.cenovus.com