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

FORM 40-F

[Check one]

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

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

For the fiscal year ended: December 31, 2013 **Commission File Number: 1-34513**

CENOVUS ENERGY INC.
(Exact name of Registrant as specified in its charter)

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

Canada
(Province or other jurisdiction of incorporation or organization)

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

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

2600, 500 Centre Street S.E.
Calgary, Alberta, Canada T2G 1A6
(403) 766-2000
(Address and telephone number of Registrant's principal executive offices)

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

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

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

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

None
(Title of Class)

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

None
(Title of Class)

For annual reports indicate by check mark the information filed with this Form:

☑ Annual information form ☑ Audited annual financial statements

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

756,045,621

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

Yes ☑ No ☐

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

Yes ☐ No ☐

The annual report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, each of the Registrant's Registration Statements under the Securities Act of 1933, as amended: Form S-8 (File No. 333-163397), Form F-3D (File No. 333-166419), and Form F-10 (File No. 333-188478).

Principal Documents

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

(a) Annual Information Form of Cenovus Energy Inc. for the fiscal year ended December 31, 2013.

(b) Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2013.

(c) Consolidated Financial Statements of Cenovus Energy Inc. for the fiscal year ended December 31, 2013.

(d) Supplementary Information – Oil and Gas Activities (unaudited) for the fiscal year ended December 31, 2013.

Annual Information Form

For the year ended December 31, 2013

February 12, 2014

TABLE OF CONTENTS

FORWARD-LOOKING INFORMATION

This Annual Information Form ("AIF") contains 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. This forward-looking information is identified by words such as "anticipate", "believe", "expect", "plan", "forecast", "target", "project", "could", "focus", "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, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, 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 Energy Inc. and others that apply to the industry in general. The factors or assumptions on which the forward-looking information is based include: assumptions inherent in our current guidance, available at 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 natural gas liquids ("NGLs") from properties and other sources not currently classified as proved; our 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 the success of our hedging strategies; the accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted earnings before interest, taxes, depreciation and amortization as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationship with our partners 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 producing, transporting or refining of crude oil into petroleum and chemical products; 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 including sufficient crude-by-rail or alternate transportation to address any gaps caused by operational constraints in the pipeline system; changes in the regulatory framework in any of the locations in which we operate, 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 on our website at cenovus.com.

CORPORATE STRUCTURE

Cenovus Energy Inc. was formed under the *Canada Business Corporations Act* ("CBCA") by amalgamation of 7050372 Canada Inc. ("7050372") 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, 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, references to "we", "us", "our", "its", "Company" or "Cenovus" mean Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries.

Our head and registered office is located at 2600, 500 Centre Street S.E., Calgary, Alberta, Canada T2G 1A6.

Intercorporate Relationships

The following table summarizes our principal subsidiaries and partnerships at December 31, 2013:

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

Notes:
(1) Includes direct and indirect ownership.
(2) Cenovus interest held through Cenovus FCCL Ltd., the operator and managing partner of FCCL.
(3) Cenovus interest held directly through Cenovus US Holdings Inc.

The above table includes our subsidiaries and partnerships which have total assets that exceed 10 percent of our total consolidated assets, or revenues which exceed 10 percent of our total consolidated revenues. The assets and revenues of our unidentified subsidiaries and partnerships did not exceed 20 percent of our total consolidated assets or total consolidated revenues at and for the year ended December 31, 2013.

GENERAL DEVELOPMENT OF OUR BUSINESS

Cenovus is a Canadian integrated oil company headquartered in Calgary, Alberta. We are in the business of developing, producing and marketing crude oil, NGLs and natural gas in Canada with refining operations in two refineries in the United States ("U.S.") in Illinois and Texas.

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 reportable segments are as follows:

- **Oil Sands**, which includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional**, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake. This segment also includes the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.
- **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 Phillips 66, an unrelated U.S. public company. 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 and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, research costs 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 have been changed from those presented in prior periods to match Cenovus's new operating structure. All prior periods have been restated to reflect this presentation.

Three Year History

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

2013

- In the first quarter, we submitted regulatory applications and environmental impact assessments ("EIAs") for Christina Lake phase H and Foster Creek phase J, with expected gross production capacity of 50,000 bbls/d from each phase.
- In the first quarter, we achieved first production from the second pilot well pair at Grand Rapids. We operated the pilot project at Grand Rapids throughout the year. The purpose of the pilot is to test reservoir performance.
- In the second quarter, we updated our 10 year strategic plan to increase our net oil sands bitumen production to approximately 435,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 525,000 barrels per day by the end of 2023.
- In the third quarter, we sold our Lower Shaunavon asset to an unrelated third party for proceeds of approximately $240 million plus closing adjustments.

- In the third quarter, phase E of Christina Lake achieved first production, with expected gross production capacity of 40,000 bbls/d.
- In the third quarter, we completed a public offering in the U.S. of senior unsecured notes of US$450 million with a coupon rate of 3.8 percent due September 15, 2023 and US$350 million senior unsecured notes with a coupon rate of 5.2 percent due September 15, 2043, for an aggregate amount of US$800 million. The net proceeds of the offering were used to partially fund the early redemption of our US$800 million senior unsecured notes due September 2014.
- In the third quarter, construction of the Narrows Lake phase A plant was initiated. Site construction, engineering and procurement at Narrows Lake are progressing as expected. Phase A has expected gross production capacity of 45,000 bbls/d.
- In the third quarter, we received regulatory approval for the optimization program at Christina Lake phases C, D and E. This program is expected to add up to 22,000 bbls/d of gross production capacity to the Christina Lake facility.
- In the fourth quarter, the Telephone Lake dewatering pilot was successfully completed. We effectively displaced water with compressed air, removing approximately 70 percent of below-ground top water.
- In the fourth quarter, we increased our rail shipping capacity to 10,000 bbls/d.
- In the fourth quarter, we received US$1.4 billion from ConocoPhillips, our partner in FCCL, representing the remaining principal and interest due under the Partnership Contribution Receivable through our interest in FCCL, net to Cenovus.
- Timing of optimization work for Foster Creek phases F, G and H has been reassessed as part of Cenovus's long-term reservoir management plan. Phases F, G and H are each expected to ramp-up to 30,000 bbls/d. Once these phases are complete, optimization work to lower steam to oil ratios, increase production and improve plant efficiency is expected to commence. Total gross production capacity from these three phases, including optimization, remains unchanged at 125,000 bbls/d.

2012

- In the second quarter, the expected gross production capacity for Christina Lake phase H was increased from 40,000 bbls/d to 50,000 bbls/d due to the addition of a fifth steam generator that will incorporate blowdown boiler technology. This is expected to increase steam capacity and enhance efficiency by increasing the water recycle rate, leading to fuel savings and a reduction in water use. We commercialized blowdown boiler technology in 2011 after testing it at Foster Creek.
- In the second quarter, we received regulatory approval for the Narrows Lake project, which includes the use of both traditional steam-assisted gravity drainage ("SAGD") and SAGD with the Solvent Aided Process ("SAP") enhancement. In the fourth quarter, phase A, which has planned gross production capacity of 45,000 bbls/d, received partner approval. The Narrows Lake project is currently expected to have gross production capacity of 130,000 bbls/d in three phases.
- In the second quarter, ConocoPhillips, our partner in FCCL and WRB, proceeded with the spin-off of its downstream business from its exploration and production business, which was announced in the third quarter of 2011. The exploration and production entity retained the ConocoPhillips name and continues to be our partner in FCCL. The downstream entity was named Phillips 66 and is our partner in WRB.
- In the third quarter, phase D of Christina Lake achieved first production, approximately three months ahead of schedule. Total gross production for phases A through D at Christina Lake averaged almost 64,000 bbls/d in 2012.
- In the third quarter, steam injection commenced on the second well pair at Grand Rapids, with first production achieved in the first quarter of 2013 from this pilot well.
- In the third quarter, we completed a public offering in the U.S. of senior unsecured notes of US$500 million, with a coupon rate of 3.00 percent, due August 15, 2022 and US$750 million of

senior unsecured notes with a coupon rate of 4.45 percent due September 15, 2042, for an aggregate amount of US$1.25 billion.

- In the fourth quarter, with the drilling and facility construction completed, operation of the Telephone Lake dewatering pilot commenced.
- In the fourth quarter, we received regulatory approval to add cogeneration facilities at Christina Lake and increase expected total gross production capacity by 10,000 bbls/d at each of phase F and G.
- In the fourth quarter, we acquired assets located adjacent to our proposed Telephone Lake oil sands project in northern Alberta for cash of $10 million and the assumption of related decommissioning obligations.

2011

- In the second quarter, we updated our 10 year strategic plan, identifying oil sands bitumen production of more than 400,000 bbls/d net and total oil production of approximately 500,000 bbls/d net, by the end of 2021.
- In the second quarter, we received regulatory approval for Christina Lake phases E, F and G. Planned gross production capacity for each expansion phase is 40,000 bbls/d for a total of 120,000 bbls/d of bitumen. Also in the second quarter, partner approval was received for phase E.
- In the second quarter, we received approval from the Alberta Department of Energy ("ADOE") to include all previous capital investment for Foster Creek expansion phases F, G and H as part of our existing Foster Creek royalty calculation.
- In the second quarter, we announced plans to increase gross production capacity at each of Foster Creek phases F, G and H from 30,000 to 35,000 bbls/d and received partner approval for each phase. Planned gross production capacity for each expansion phase was further increased to 40,000 bbls/d for phases G and H and to 45,000 bbls/d for phase F, due to the success of our Wedge Well™ technology and plant optimization. Total gross production capacity for these three phases at completion is expected to be 125,000 bbls/d of bitumen.
- In the third quarter, phase C of Christina Lake achieved first production ahead of schedule and with capital expenditures below budget for the entire phase. Net production at Christina Lake during 2011 averaged 11,665 bbls/d and ended 2011 at approximately 23,000 bbls/d.
- In the fourth quarter, we completed coker construction and start-up activities of the Coker and Refinery Expansion ("CORE") project, at the Wood River Refinery. CORE project capital expenditures were within 10 percent of its original budget. The CORE project has been successful and has resulted in the capability to increase clean product yield by up to five percent. The Wood River Refinery's total processing capability of heavy crude oil has also increased to up to 220,000 bbls/d.
- In the fourth quarter, Cenovus filed a joint application and EIA for a commercial SAGD operation at Grand Rapids with an expected gross production capacity of 180,000 bbls/d.
- In the fourth quarter, progressing the Telephone Lake project, we filed a revised joint regulatory application and EIA. This application updates the expected gross production capacity to 90,000 bbls/d from the original 35,000 bbls/d application that was filed in 2007.
- In the fourth quarter, we applied for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities and increasing expected total gross production capacity by 10,000 bbls/d at each of phase F and phase G.

NARRATIVE DESCRIPTION OF OUR BUSINESS

The following map outlines the location of our upstream and refining assets as at December 31, 2013:

Overview

All of our reserves and production are located in Canada, primarily within the provinces of Alberta and Saskatchewan. At December 31, 2013, we had a land base of approximately 7.0 million net acres. The estimated proved reserves life index based on working interest production at December 31, 2013 was approximately 24 years.

The following table summarizes our Company Interest Before Royalties proved and probable reserves at December 31, 2013:

Company Interest Before Royalties (1)		
	Proved	**Probable**
Bitumen (MMbbls)	1,846	683
Heavy Oil (MMbbls)	179	140
Light & Medium Oil and NGLs (MMbbls)	115	50
Natural Gas & CBM (Bcf)	865	300

Note:
(1) Does not include Royalty Interest Reserves. Please refer to the "Reserves Data and Other Oil and Gas Information" section for additional information.

The following narrative describes our operations in greater detail.

Oil Sands

Oil Sands includes our bitumen assets at Foster Creek, Christina Lake and Narrows Lake, as well as new resource play assets including Grand Rapids and Telephone Lake, plus our Athabasca natural gas assets. Foster Creek, Christina Lake and Narrows Lake are jointly owned through FCCL with ConocoPhillips, an unrelated U.S. public company.

Cenovus FCCL Ltd., our wholly owned subsidiary, is the operator 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 2013, our Oil Sands capital investment was $1,883 million, and was primarily related to the expansion of the production capacity of FCCL's assets. FCCL plans to increase gross production capacity to approximately 285,000 bbls/d of bitumen with the addition of Christina Lake phase E in the third quarter of 2013 and first production from Foster Creek phase F expected in the third quarter of 2014. Overall progress of Foster Creek expansion phases F, G and H is approximately 63 percent complete, while the phase F plant facility is approximately 90 percent complete. We also continued to assess the potential of our new resource play assets during 2013 with our stratigraphic test well program.

Plans for 2014 include the continued development of expansion phases at both Foster Creek and Christina Lake and engineering, procurement, and construction of the phase A plant at Narrows Lake. Overall Narrows Lake phase A is approximately 16 percent complete, while the central plant is approximately 21 percent complete. Plans for 2014 also include the continuation of an active stratigraphic test well drilling program with 291 gross wells planned. The dewatering pilot at Telephone Lake was completed in the fourth quarter of 2013 and we have effectively displaced water with compressed air, removing approximately 70 percent of below-ground top water in the pilot area. Steam injection commenced in the third quarter of 2012 on our second well pair at the Grand Rapids pilot and first production was achieved in February 2013.

At December 31, 2013, we held bitumen rights of approximately 1.4 million gross acres (1.1 million net acres) within the Athabasca and Cold Lake areas, as well as the exclusive rights to lease an additional 478,000 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, 2013:

Landholdings – Oil Sands	**Developed Acreage**		**Undeveloped Acreage**		**Total Acreage**		**Average Working**
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Interest**
Foster Creek	15	8	125	62	140	70	50%
Christina Lake	8	4	50	25	58	29	50%
Narrows Lake	-	-	26	13	26	13	50%
Grand Rapids	-	-	73	73	73	73	100%
Telephone Lake	16	16	142	142	158	158	100%
Athabasca	417	345	454	380	871	725	83%
Other	27	9	1,018	737	1,045	746	71%
Total	483	382	1,888	1,432	2,371	1,814	77%

The following table summarizes 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)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Foster Creek	53,190	57,833	-	-	53,190	57,833
Christina Lake	49,310	31,903	-	-	49,310	31,903
Athabasca [(1)]	-	-	21	30	3,500	5,000
Total	102,500	89,736	21	30	106,000	94,736

Note:
(1) Net of internal usage of natural gas used at Foster Creek to produce steam.

The following table summarizes our interests in producing wells at December 31, 2013. These figures exclude wells which were capable of producing, but that were not producing as of December 31, 2013:

Producing Wells – Oil Sands	**Producing Oil Wells**		**Producing Gas Wells**		**Total Producing Wells**	
(number of wells)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Foster Creek	236	118	-	-	236	118
Christina Lake	98	49	-	-	98	49
Grand Rapids	2	2	-	-	2	2
Athabasca	-	-	299	299	299	299
Other	2	2	-	-	2	2
Total	338	171	299	299	637	470

Foster Creek

We have a 50 percent working interest in Foster Creek, an oil sands property situated on the Cold Lake Air Weapons Range in northeastern Alberta that uses 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.

Expansion work at phases F, G and H at Foster Creek is proceeding as planned. Each phase is expected to ramp-up to its initial design capacity of 30,000 bbls/d. Once these phases are complete, optimization work will commence to reduce steam to oil ratio, increase production and improve plant efficiency. Total gross production capacity for these phases, including optimization work, is expected to reach 125,000 bbls/d. Production from phase F is expected to start in the third quarter of 2014 with production ramp-up to design capacity expected to take twelve to eighteen months. Production from phases G and H is expected in 2015 and 2016, respectively. We submitted a joint application and EIA to regulators in February 2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first quarter of 2015. With the addition of these four phases, Cenovus expects Foster Creek will have the capacity to produce 295,000 bbls/d gross and potentially as much as 310,000 bbls/d gross with optimization.

We have successfully piloted and implemented our Wedge Well™ technology at Foster Creek whereby an additional 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 to oil ratio. In 2013, 30 wells using our Wedge Well™ technology were drilled (2012 – no wells) at Foster Creek. At December 31, 2013 there were 65 gross producing wells of this type.

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 any excess power generated is being sold into the Alberta Power Pool.

Christina Lake

We have a 50 percent working interest in Christina Lake, an oil sands property in northeastern Alberta that uses SAGD technology and produces from the McMurray formation. Full capacity was reached at phase D in the first quarter of 2013 and phase E had first oil production in the third quarter of 2013. With the addition of phase E, gross production capacity at Christina Lake of 138,000 bbls/d is expected to be achieved in the first quarter of 2014. Phases F, including cogeneration, and G are expected to add approximately 50,000 bbls/d of gross production capacity from each phase. Expansion work is continuing as planned and we expect production from phases F and G in 2016 and 2017, respectively. In the third quarter of 2013, we received regulatory approval for the optimization program at phases C, D and E, which is expected to add up to 22,000 bbls/d of gross capacity in 2015. We submitted a joint application and EIA to regulators in the first quarter of 2013 for the phase H expansion, a 50,000 bbls/d phase for which we expect regulatory approval in the fourth quarter of 2014. With the addition of phases F, G and H, we believe Christina Lake has potential gross production capacity of 288,000 bbls/d, increasing to as much as 310,000 bbls/d with optimization. In 2013, we drilled 11 wells (2012 – three wells) at Christina Lake using our Wedge Well™ technology and at December 31, 2013 there were 10 gross wells of this type producing.

Several innovations to SAGD technology have been undertaken at Christina Lake over the past several years. One major innovation is SAP technology that is currently being piloted at Christina Lake. This SAP pilot utilizes a mixture of steam and solvent to enhance recovery of the bitumen by increasing production rates and overall oil recovery, as well as reducing the steam to oil ratio. Results from the pilot were as expected, and we plan to commercialize the SAP technology with phase A of our Narrows Lake project.

We have applied steam dilation technology as part of the Christina Lake phase C start-up and select wells on phases D and E. As steam is injected into the injector and producer wells, the force of the steam rearranges the sand grains and creates gaps, which are filled with water. This increases both porosity and water mobility, allowing fluid flow between the wells. Steam dilation requires minimal additional costs or surface facility modifications, takes less than one month and results in more uniform start-up along the full length of the well pairs. This allows the well to reach peak production rates more quickly. Steam dilation benefits include a faster start-up time, a reduction in steam circulation time and a decrease in cumulative steam to oil ratio.

Narrows Lake

We hold a 50 percent working interest in Narrows Lake, an oil sands property within the Christina Lake Region in northeastern Alberta. The project includes planned gross production capacity of 130,000 bbls/d of bitumen. In the second quarter of 2012, we received regulatory approval for the Narrows Lake project, which includes the use of both traditional SAGD and SAGD with the SAP enhancement. In the fourth quarter of 2012, phase A, which has planned gross production capacity of 45,000 bbls/d, received partner approval. During 2013, site preparation for the phase A plant at Narrows Lake was completed and construction of the plant commenced. Site construction, engineering and procurement, and construction of the phase A plant are progressing as planned. The project is expected to begin producing in 2017.

New Resource Play Assets

Our new resource play assets include our emerging oil sands properties as described below.

Grand Rapids

Our 100 percent owned Grand Rapids property is located in the Greater Pelican Region in northeastern Alberta, where large deposits of bitumen have been identified in the Cretaceous Grand Rapids formation. In the fourth quarter of 2011, we filed a joint application and EIA for a commercial operation with production capacity of 180,000 bbls/d and we anticipate regulatory approval in the first quarter of 2014. During 2013, we continued to operate the pilot project at Grand Rapids and achieved first production from the second well pair in the first quarter of 2013. The purpose of the pilot is to test reservoir performance.

Telephone Lake

Our 100 percent owned Telephone Lake property is located in the Borealis Region in northeastern Alberta. A revised joint application and EIA was submitted in the fourth quarter of 2011 to the Alberta Energy Regulator ("AER"), formerly the Alberta Energy Resources Conservation Board, and Alberta Environment and Sustainable Resource Development for the development of the property, including the construction of a facility with planned bitumen production capacity of 90,000 bbls/d. We anticipate receiving regulatory approval in the second quarter of 2014. In 2013, we effectively displaced water with compressed air, removing approximately 70 percent of below-ground top water. The water displaced was not potable and therefore not suitable to be used for human or other consumption. Capital investment decreased in 2013 with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012.

Other Assets

The Steepbank and East McMurray properties are also located in the Borealis Region, southwest of Telephone Lake. An active stratigraphic drilling program is being carried out at these properties. In 2013, 50 gross stratigraphic wells were drilled.

We have completed a pilot program which uses a helicopter and an experimental lightweight drilling rig to drill stratigraphic test wells. The SkyStrat™ drilling rig is a new rig we developed to improve stratigraphic drilling programs in the oil sands, as the rig is transported by helicopter which allows us to access remote exploratory drilling locations year-round. Transporting by helicopter eliminates the need for temporary roads, which significantly reduces the surface footprint and has the potential to reduce water use for the drilling operations by over 50 percent. In the second and third quarters of 2013, this rig was used to drill 24 stratigraphic wells. We expect to complete construction and testing of a second SkyStrat™ drilling rig by the end of the second quarter of 2014.

Athabasca Gas

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

Natural gas production continues to be impacted by the AER's 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 our annualized natural gas production of approximately 16 million cubic feet per day in 2013 (2012 – 19 million cubic feet per day). The ADOE provides financial assistance in the form of a royalty credit, which can equal up to approximately 50 percent of the cash flow lost as a result of the shut-in wells over a ten year period. This royalty credit is also dependent on natural gas prices. The royalty credit for some of these wells reached the end of the ten year period in the third quarter of 2013.

Conventional

Conventional includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.

At December 31, 2013, we had an established land position of approximately 5.4 million gross acres (5.2 million net acres), of which approximately 3.3 million gross acres (3.2 million net acres) are developed. The mineral rights on approximately 61 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 crown lands leased from the Province of Saskatchewan.

In 2013, our Conventional capital investment was $1,191 million and primarily focused on crude oil properties. This investment included drilling and facilities work in Weyburn, spending at Pelican Lake on the expansion of the polymer flood as well as drilling, completion and facilities work in our tight oil opportunities in Alberta.

Plans for 2014 include oil-focused capital investment to further develop our existing assets in Alberta and Saskatchewan. The spending will include additional drilling, including infill drilling at Pelican Lake, well optimizations, well recompletions and investment in our existing facility infrastructure.

The following table summarizes our landholdings at December 31, 2013:

Landholdings – Conventional	**Developed Acreage**		**Undeveloped Acreage**		**Total Acreage**		**Average Working**
(thousands of acres)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Interest**
Alberta							
Brooks North	571	569	8	8	579	577	100%
Suffield	917	906	142	141	1,059	1,047	99%
Langevin	737	697	245	228	982	925	94%
Pelican Lake	112	112	360	354	472	466	99%
Drumheller	406	392	76	74	482	466	97%
Wainwright	356	334	204	199	560	533	95%
Other	55	29	167	133	222	162	73%
Saskatchewan							
Weyburn	116	101	341	320	457	421	92%
Bakken	17	16	253	251	270	267	99%
Other	9	6	19	20	28	26	93%
Manitoba	4	4	263	263	267	267	100%
Total	3,300	3,166	2,078	1,991	5,378	5,157	96%

The following table summarizes 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)	2013	2012	2013	2012	2013	2012
Alberta						
Brooks North	3,183	2,866	205	225	37,350	40,366
Suffield	11,391	11,691	149	167	36,224	39,524
Langevin	8,754	7,719	101	109	25,587	25,886
Pelican Lake	24,254	22,552	-	-	24,254	22,552
Drumheller	4,537	3,653	47	54	12,370	12,653
Wainwright	4,668	4,417	3	3	5,168	4,917
Other	9	11	2	5	342	844
Saskatchewan						
Weyburn	16,361	16,278	-	-	16,361	16,278
Shaunavon (1)	2,095	4,411	-	-	2,095	4,411
Bakken	1,508	2,065	1	1	1,676	2,232
Other	15	4	-	-	15	4
Total	76,775	75,667	508	564	161,442	169,667

Note:
(1) In the third quarter of 2013, our Lower Shaunavon tight oil asset in southern Saskatchewan was sold.

The following table summarizes our interests in producing wells at December 31, 2013. These figures exclude wells which were capable of producing, but that were not producing, at December 31, 2013:

Producing Wells – Conventional	Producing Oil Wells		Producing Gas Wells		Total Producing Wells	
	Gross	Net	Gross	Net	Gross	Net
Alberta						
Brooks North	168	167	7,499	7,400	7,667	7,567
Suffield	795	795	10,645	10,627	11,440	11,422
Langevin	271	268	4,803	4,790	5,074	5,058
Pelican Lake	567	567	5	5	572	572
Drumheller	237	231	1,584	1,527	1,821	1,758
Wainwright	463	432	12	3	475	435
Other	7	1	20	19	27	20
Saskatchewan						
Weyburn	670	423	-	-	670	423
Bakken	34	23	-	-	34	23
Other	5	5	-	-	5	5
Total	3,217	2,912	24,568	24,371	27,785	27,283

Crude Oil Properties

We hold interests in multiple zones in the Suffield, Brooks North, Langevin, Drumheller, and Wainwright areas in Alberta with a mix of medium and heavy crude oil production. Development in these areas focuses on horizontal drilling targeting tight oil formations, infill drilling to enhance recovery in producing areas, optimization of existing wells to maximize production and other specialized oil recovery methods that increase our overall recovery factors in each field.

In the unitized portion of the Weyburn field in southeastern Saskatchewan, we have a 62 percent working interest. However, after taking into consideration a net royalty interest obligation to a third party, our economic interest is 50 percent. The Weyburn unit produces light to medium sour crude oil 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, 2013, approximately 92 percent of the approved CO_2 flood pattern development at the Weyburn unit was complete. Since the inception of the project, approximately 22 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, U.S. A new contract was executed in 2012 for the purchase of CO_2 from Saskatchewan Power Corporation providing an additional source of CO_2 beginning in 2014.

Using a patterned, horizontal well polymer flood, we produce heavy crude oil from the Cretaceous Wabiskaw formation at our Pelican Lake property, which is located within the Greater Pelican Region in northeastern Alberta. 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 major pipelines that transport crude oil from northern Alberta to crude oil markets.

In 2013, our capital was invested primarily in drilling and facilities work at Weyburn, infill drilling to progress the polymer flood at Pelican Lake, and drilling, completion and facilities work in our tight oil opportunities in Alberta.

The following table summarizes net oil wells drilled and daily average oil production figures for the periods indicated:

	Net Wells Drilled		Average Production (bbls/d) Light/Medium		Heavy	
Net Wells Drilled and Production	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Alberta						
Brooks North	21	52	3,034	2,707	-	-
Suffield	24	38	-	-	11,375	11,667
Langevin	36	44	8,625	7,551	-	-
Drumheller	23	33	3,970	3,051	-	-
Wainwright	39	57	40	58	4,616	4,348
Pelican Lake	49	76	-	-	24,254	22,552
Other	6	2	8	11	-	-
Saskatchewan						
Weyburn	14	6	16,229	16,277	-	-
Shaunavon (1)	-	36	2,095	4,411	-	-
Bakken	-	4	1,451	2,001	-	-
Other	-	4	15	4	-	-
Total	212	352	35,467	36,071	40,245	38,567

Note:
(1) In the third quarter of 2013, our Lower Shaunavon tight oil asset in southern Saskatchewan was sold.

Natural Gas Properties

We hold natural gas interests in multiple zones in the Suffield, Brooks North, Langevin and Drumheller areas in Alberta. Development in these areas focuses on recompletions and optimization of existing wells.

The following table summarizes net gas wells drilled and daily average gas production for the periods indicated:

	Net Wells Drilled		Average Production (MMcf/d)	
Net Wells Drilled and Production	**2013**	**2012**	**2013**	**2012**
Brooks North	-	-	205	225
Suffield	-	-	149	167
Langevin	-	-	101	109
Drumheller	-	-	47	54
Wainwright	-	-	3	3
Other	-	-	3	6
Total	-	-	508	564

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 Canadian Forces Base ("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.

Natural gas assets are an important component of our financial foundation, generating operating cash flow well in excess of their ongoing capital investment requirements. The natural gas business also acts as an economic hedge against price fluctuations because natural gas partially fuels the Company's oil sands and refining operations.

We plan to prudently manage declines in natural gas volumes, targeting a long-term production level that will match Cenovus's future anticipated internal usage at its oil sands and refining facilities.

Refining and Marketing

Refining

Through WRB we have a 50 percent ownership interest in both the Wood River and Borger Refineries located in Roxana, Illinois and Borger, Texas respectively. Phillips 66 is the operator and managing partner of WRB. WRB has a management committee, which is composed of three Cenovus representatives and three Phillips 66 representatives, with each company holding equal voting rights. In 2014, on a 100 percent basis, our refineries have a combined stated processing capacity of approximately 460,000 bbls/d of crude oil (2013 – 457,000 bbls/d), including heavy crude oil processing capability of up to 255,000 bbls/d.

Wood River Refinery

The Wood River Refinery 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 as well as coke and asphalt. The gasoline and diesel are transported via pipelines to markets in the upper U.S. Midwest. Other products are transported via pipeline, truck, barge and railcar to markets in the U.S. Midwest. Throughout 2013, the Wood River Refinery had stated processing capacity of 311,000 bbls/d. Since the start-up of the CORE project that was substantially completed in 2011, the Wood River Refinery has demonstrated the benefits of this project, including Canadian heavy crude oil processing capability of up to 220,000 bbls/d. In 2013, almost two-thirds of the crude oil processed at the Wood River Refinery consisted of Canadian heavy crude oil, including a significant proportion of high total acid number ("TAN") crudes.

For 2014, the Wood River Refinery's stated processing capacity is 314,000 bbls/d of crude oil. This figure is determined based on the guidelines for calculating maximum demonstrated rate, which is 95 percent of the highest average rate achieved over a continuous 30 day period.

Borger Refinery

The Borger Refinery processes mainly medium 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.

Throughout 2013 and for 2014, the Borger Refinery's stated processing capacity is approximately 146,000 bbls/d of crude oil, including approximately 35,000 bbls/d of heavy crude oil, and approximately 45,000 bbls/d of NGLs.

The following table summarizes the key operational results for our refineries in the periods indicated:

Refinery Operations [1]	**2013**	**2012**
Crude Oil Capacity (Mbbls/d)	457	452
Crude Oil Runs (Mbbls/d)	442	412
Heavy Oil	222	198
Light/Medium	220	214
Crude Utilization (%)	97	91
Refined Products (Mbbls/d)		
Gasoline	232	216
Distillates	144	138
Other	87	79
Total	463	433

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 also 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 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, 2013.

Crude Oil Marketing

This group manages the transportation and marketing of crude oil for our upstream operations. Cenovus's 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. Our portfolio of transportation commitments includes feeder pipelines from our production areas to the Edmonton and Hardisty trade centres and major pipeline alternatives to markets downstream of these hubs. Other transportation commitments are primarily related to the reliable supply of diluent, railcar transportation as well as tankage and terminalling of both crude oil blend and condensate volumes.

In 2013, in conjunction with the Company's priority to ensure future market access, we entered into various firm transportation commitments totaling over $11 billion, most of which are subject to regulatory approval. The Company's longer term target is to commit to transportation solutions for up to 50 percent of marketable production, including growing rail capacity by up to 10 percent of marketable production.

Natural Gas Marketing

We also manage the marketing of our natural gas, which is primarily sold to industrials, other producers and energy marketing companies. Prices received by us are based primarily upon prevailing index prices for natural gas. Prices are impacted by competing fuels 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").

Our reserves are primarily located in Alberta and Saskatchewan, Canada. We retained two independent qualified reserves evaluators ("IQREs"), McDaniel and Associates Consultants Ltd. ("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. McDaniel evaluated approximately 96 percent of our total proved reserves, located throughout Alberta and Saskatchewan, and GLJ evaluated approximately four percent of our total proved reserves, located at Weyburn. We also engaged McDaniel to evaluate 100 percent of our bitumen contingent and prospective resources.

The Reserves Committee of our Board of Directors ("Board"), composed of independent directors, 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 independently with Management and each IQRE to determine whether any restrictions affect the ability of the IQRE to report on the reserves data without reservation. In addition, the Reserves Committee reviews the reserves and resources data and the report of the IQRE and provides a recommendation regarding approval of the reserves and resources disclosure to the Board.

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 "Additional Notes to Reserves Data Tables", "Definitions" and "Pricing Assumptions" in conjunction with the disclosure. The reserves estimates 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 – Operational Risks – Uncertainty of Reserves and Future Net Revenue Estimates" in this AIF for additional information.

The reserves data and other oil and gas information contained in this AIF is dated February 11, 2014, with an effective date of December 31, 2013. McDaniel's preparation date of the information is January 13, 2014, and GLJ's preparation date is January 10, 2014.

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, costs associated with environmental regulations, the impact of any hedging activities or the liability associated with certain abandonment and all well, pipeline and facilities reclamation costs. Future net revenues have been presented on a before and after income tax basis.

We hold significant fee title rights which generate production for our account from third parties leasing those lands ("Royalty Interest Production"). At December 31, 2013, approximately 2.4 million acres throughout southeastern Alberta and southern Saskatchewan and Manitoba were leased out to third parties. In accordance with NI 51-101, only the After Royalties volumes presented herein include reserves associated with this Royalty Interest Production ("Royalty Interest Reserves").

Summary of Company Interest Oil and Gas Reserves at December 31, 2013
(Forecast Prices and Costs)

Before Royalties [1]

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	192	129	89	834
Developed Non-Producing	25	3	11	27
Undeveloped	1,629	47	15	4
Total Proved Reserves	1,846	179	115	865
Probable Reserves	683	140	50	300
Total Proved plus Probable Reserves	2,529	319	165	1,165

After Royalties [2]

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	149	108	78	846
Developed Non-Producing	18	3	8	27
Undeveloped	1,241	40	12	4
Total Proved Reserves	1,408	151	98	877
Probable Reserves	522	107	42	283
Total Proved plus Probable Reserves	1,930	258	140	1,160

Royalty Interest

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	-	1	6	42
Developed Non-Producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved Reserves	-	1	6	42
Probable Reserves	-	-	2	11
Total Proved plus Probable Reserves	-	1	8	53

Notes:
(1) Does not include Royalty Interest Reserves.
(2) Includes Royalty Interest Reserves.

Summary of Net Present Value of Future Net Revenue at December 31, 2013
(Forecast Prices and Costs)

Before Income Taxes

	Discounted at %/year ($ millions)					Unit Value Discounted at 10% [1]
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**$/BOE**
Proved Reserves						
Developed Producing	15,530	12,761	10,868	9,514	8,498	22.81
Developed Non-Producing	1,467	1,042	802	644	536	23.84
Undeveloped	48,111	22,625	11,899	6,710	3,915	9.20
Total Proved Reserves	65,108	36,428	23,569	16,868	12,949	13.07
Probable Reserves	28,265	13,055	6,916	4,079	2,599	9.63
Total Proved plus Probable Reserves	93,373	49,483	30,485	20,947	15,548	12.09

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

After Income Taxes (1)					
	Discounted at %/year ($ millions)				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Reserves					
Developed Producing	12,564	10,370	8,854	7,765	6,946
Developed Non-Producing	1,103	782	603	487	407
Undeveloped	36,916	17,043	8,842	4,920	2,827
Total Proved Reserves	50,583	28,195	18,299	13,172	10,180
Probable Reserves	21,448	9,785	5,105	2,966	1,864
Total Proved plus Probable Reserves	72,031	37,980	23,404	16,138	12,044

Note:
(1) Values are calculated by considering existing tax pools and tax circumstances for Cenovus and its subsidiaries in the consolidated evaluation of Cenovus's oil and gas properties, and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see our Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2013.

Total Future Net Revenue (undiscounted) at December 31, 2013 (Forecast Prices and Costs) ($ millions)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs (1)	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
Proved Reserves	169,590	37,328	48,065	17,795	1,294	65,108	14,525	50,583
Proved plus Probable Reserves	243,782	54,094	68,067	26,731	1,517	93,373	21,342	72,031

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, 2013 (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	16,758	11.90
	Heavy Oil	2,589	17.17
	Light & Medium Oil and NGLs	2,723	27.72
	Natural Gas	1,499	10.25
	Total	23,569	13.07
Proved plus Probable Reserves	Bitumen	20,760	10.76
	Heavy Oil	4,192	16.27
	Light & Medium Oil and NGLs	3,558	25.33
	Natural Gas	1,975	10.21
	Total	30,485	12.09

Additional Notes to Reserves Data Tables

- The estimates of future net revenue presented do not represent fair market value.
- Future net revenue from reserves excludes cash flows related to our risk management activities.
- For disclosure purposes, we have included NGLs with light and medium oil, and CBM gas with natural gas, as the reserves of each are not material relative to the other reported product types.
- Numbers presented may be rounded and tables may not add due to rounding.

Definitions

1. **After Royalties** means volumes after deduction of royalties and includes Royalty Interest Reserves.
2. **Before Royalties** means volumes before deduction of royalties and excludes Royalty Interest Reserves.
3. **Company Interest** means, in relation to production, reserves, resources and property, the interest (operating or non-operating) held by us.
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 our working interest.
6. **Reserves** are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology and specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

   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 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 as follows:
     - **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 (e.g., when compared 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 Reserves** means those reserves related to our royalty entitlement on lands to which we hold fee title and which have been leased to third parties, plus any reserves related to other royalty interests, such as overriding royalties, to which we are entitled.

8. **Royalty Interest Production** means the production related to our royalty entitlement on lands to which we hold fee title and which have been leased to third parties, plus any production related to other royalty interests, such as overriding royalties, to which we are entitled.

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, 2014 price forecast as referred to in the McDaniel & Associates Consultants Ltd. Summary of Price Forecasts dated January 1, 2014. For historical prices realized during 2013, see "Production History" in this AIF.

	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)**
2014	95.00	95.00	89.30	67.50	76.50	4.00	2.0	0.950
2015	95.00	96.50	90.70	70.40	79.60	4.25	2.0	0.950
2016	95.00	97.50	91.70	71.20	80.40	4.55	2.0	0.950
2017	95.00	98.00	92.10	71.50	80.90	4.75	2.0	0.950
2018	95.30	98.30	92.40	71.80	81.10	5.00	2.0	0.950
2019	96.60	99.60	93.60	72.70	82.20	5.25	2.0	0.950
2020	98.50	101.60	95.50	74.20	83.80	5.35	2.0	0.950
2021	100.50	103.60	97.40	75.60	85.50	5.45	2.0	0.950
2022	102.50	105.70	99.40	77.20	87.20	5.55	2.0	0.950
2023	104.60	107.90	101.40	78.80	89.00	5.65	2.0	0.950
2024	106.70	110.00	103.40	80.30	90.80	5.75	2.0	0.950
There-after	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.950

Future Development Costs

The following table outlines undiscounted development costs deducted in the estimation of future net revenue calculated utilizing forecast prices and costs for the years indicated:

Reserves Category ($ millions)	**2014**	**2015**	**2016**	**2017**	**2018**	**Remainder**	**Total**
Proved Reserves	1,502	1,115	1,172	754	1,107	12,145	17,795
Proved plus Probable Reserves	1,602	1,468	1,582	1,328	1,524	19,227	26,731

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 the necessary 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 Before Royalties reserves for bitumen, heavy oil, light and medium oil and NGLs, and natural gas for the year ended December 31, 2013, presented using forecast prices and costs. All reserves are located in Canada.

Company Interest Before Royalties
Reserves Reconciliation by Principal Product Type and Reserves Category
(Forecast Prices and Costs)

Proved	**Bitumen (MMbbls)**	**Heavy Oil (MMbbls)**	**Light & Medium Oil & NGLs (MMbbls)**	**Natural Gas & CBM (Bcf)**
December 31, 2012	1,717	184	115	955
Extensions and Improved Recovery	134	21	11	24
Discoveries	-	-	-	-
Technical Revisions	32	(12)	6	76
Economic Factors	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	(5)	-
Production [(1)]	(37)	(14)	(12)	(190)
December 31, 2013	1,846	179	115	865

Probable	**Bitumen (MMbbls)**	**Heavy Oil (MMbbls)**	**Light & Medium Oil & NGLs (MMbbls)**	**Natural Gas & CBM (Bcf)**
December 31, 2012	676	105	56	338
Extensions and Improved Recovery	28	55	-	5
Discoveries	78	-	-	-
Technical Revisions	(99)	(20)	(4)	(43)
Economic Factors	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	(2)	-
Production [(1)]	-	-	-	-
December 31, 2013	683	140	50	300

Proved plus Probable	**Bitumen (MMbbls)**	**Heavy Oil (MMbbls)**	**Light & Medium Oil & NGLs (MMbbls)**	**Natural Gas & CBM (Bcf)**
December 31, 2012	2,393	289	171	1,293
Extensions and Improved Recovery	162	76	11	29
Discoveries	78	-	-	-
Technical Revisions	(67)	(32)	2	33
Economic Factors	-	-	-	-
Acquisitions	-	-	-	-
Dispositions	-	-	(7)	-
Production [(1)]	(37)	(14)	(12)	(190)
December 31, 2013	2,529	319	165	1,165

Note:
(1) Production used for the reserves reconciliation differs from publicly reported production. In accordance with NI 51-101, Company Interest Before Royalties production used for the reserves reconciliation above includes our share of gas volumes provided to FCCL for steam generation, but does not include Royalty Interest Production.

Proved and proved plus probable bitumen reserves increased by approximately eight and six percent, respectively. Increases at Christina Lake were primarily a result of receiving approval to expand the development area and planned increases to future well density. Increases at Foster Creek were primarily a result of development area expansion.

Heavy oil proved reserves decreased by approximately three percent primarily as a result of production exceeding expanded polymer flood and infill drilling areas at Pelican Lake. Heavy oil probable reserves increased by approximately 33 percent also primarily based on expanding pad development using increased well density at Pelican Lake. Overall, heavy oil proved plus probable reserves increased by approximately 10 percent.

Light and medium oil and NGLs proved reserves remained unchanged, with production being offset by expanding waterflood and CO_2 flood areas and their successful performance at Weyburn. Light and medium oil and NGLs probable reserves decreased by approximately 11 percent primarily as a result of the conversion of probable reserves to proved reserves. Overall, light and medium oil and NGLs proved plus probable reserves decreased by approximately four percent, primarily as a result of additions being offset by production and the Lower Shaunavon disposition.

Natural gas proved reserves declined by approximately nine percent as extensions and technical revisions did not offset production. Probable natural gas reserves and proved plus probable natural gas reserves declined by approximately 11 percent and 10 percent, respectively.

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 50 years.

Company Interest Proved Undeveloped – Before Royalties

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light and Medium Oil and NGLs (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	1,108	1,008	60	45	50	27	300	36
2011	325	1,287	13	55	3	25	-	24
2012	284	1,532	20	61	3	22	-	6
2013	158	1,629	1	47	3	15	-	4

Company Interest Probable Undeveloped – Before Royalties

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light and Medium Oil and NGLs (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	804	506	43	37	28	21	54	30
2011	113	467	14	47	1	22	-	35
2012	182	646	9	42	5	24	-	16
2013	145	649	56	86	1	17	-	16

Development of Proved Undeveloped Reserves

Bitumen

At the end of 2013, we had proved undeveloped bitumen reserves of 1,629 million barrels Before Royalties, or approximately 88 percent of our total proved bitumen reserves. Of our 683 million barrels of probable bitumen reserves, 649 million barrels, or approximately 95 percent are undeveloped. The evaluation of these reserves anticipates they 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 well pairs 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's standard for sufficient drilling in the McMurray formation is a minimum of eight wells per section with 3D seismic, or 16 wells per section with no seismic. In other formations, such as Grand Rapids or Grosmont carbonates, there may be some variation in the standard. 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.

Recognition of probable reserves requires sufficient drilling of stratigraphic wells to establish reservoir suitability for SAGD. Reserves will be classified as probable if the number of wells drilled falls between the stratigraphic well requirements for proved reserves and for probable reserves, or if the reserves are not located within an approved development plan area. The IQRE's standard for probable reserves is a minimum of four stratigraphic wells per section. If 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 approximately 45 years, based on existing facilities. Production of the current proved developed portion is estimated to take about 10 years.

Oil

We have a significant medium oil CO_2 enhanced oil recovery ("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 proved undeveloped reserves is projected to continue for well over 40 years, with drilling of supplementary wells taking place over the next five years, and CO_2 flood advancement continuing many years beyond that. At Pelican Lake, investment in proved undeveloped reserves is projected to continue for 25 years, with a combination of infrastructure development, 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 these factors can be considered and potentially anticipated, certain judgments and assumptions are always required. As new information becomes available these areas are reviewed and revised accordingly. For a discussion of the risk factors and uncertainties affecting reserves data, see "Risk Factors – Operational Risks – Uncertainty of Reserves and Future Net Revenue Estimates".

Contingent and Prospective Resources

We retain McDaniel to evaluate and prepare reports on all of our contingent and prospective bitumen resources. 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. The assets currently producing from the McMurray-Wabiskaw formation at Foster Creek and Christina Lake are used as performance analogs for contingent and prospective resources estimation within these areas. Other regional analogs are used for contingent and prospective resources estimation in the Cretaceous Grand Rapids formation at the Grand Rapids property, in the Greater Pelican Region, in the McMurray formation at the Telephone Lake property in the Borealis Region and in the Clearwater formation in the Foster Creek Region. 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 vast majority of our bitumen resources will be recovered and produced using SAGD, with only a minor portion of our resources likely to be developed using cyclic steam stimulation ("CSS") established 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 our current contingent and prospective resources are associated with clastic or sandstone formations. We have also identified significant amounts of bitumen in the Grosmont carbonate formation for which we have extensive mineral rights. Pilot testing of the SAGD recovery process in carbonates is currently underway in the Grosmont carbonate formation several miles away from Cenovus's lands but commercial viability has yet to be established. Cenovus has commenced work on its own pilot for bitumen production from the Grosmont carbonate formation.

In addition to the reserve definitions provided in the preceding sections, the following terminology, consistent with the COGE Handbook and guidance from Canadian securities regulatory authorities, was used to prepare the disclosure that follows:

> **Contingent resources** are those quantities of bitumen 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. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The McDaniel estimates of contingent resources have not been adjusted for risk based on the chance of development.
>
> **Economic contingent resources** are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. Only those bitumen contingent resources based on established technology and determined to be economic using the same commodity price assumptions that were used for the 2013 reserves evaluation are disclosed in this AIF.
>
> **Contingencies,** which must be overcome to enable the reclassification of contingent resources as reserves, can be categorized as economic, non-technical and technical. The COGE Handbook identifies non-technical contingencies as legal, environmental, political and regulatory matters or a lack of markets. Technical contingencies include available

infrastructure and project justification. The outstanding contingencies applicable to our disclosed economic contingent resources do not include economic contingencies.

Our bitumen contingent resources are located in four general regions: Foster Creek, Christina Lake, Borealis, and the Greater Pelican Region. At Foster Creek and Christina Lake, we have economic contingent resources located outside the currently approved development project areas. Regulatory approval to expand the development project area is necessary to enable the reclassification of these economic contingent resources as reserves. The timing of these applications is dependent on the rate of development drilling, which ties to an orderly development plan that maximizes utilization of steam generation facilities and ultimately optimizes production, capital utilization and value.

In the Borealis Region, we submitted an application for a development project at the Telephone Lake property which, if approved, is expected to enable the reclassification of certain economic contingent resources to reserves. Other areas in the Borealis Region require additional results from delineation drilling and seismic activity to submit regulatory applications for development projects. Stratigraphic test well drilling and seismic activity are continuing in these areas to bring them to project readiness. Currently, sufficient pipeline capacity is also considered a contingency.

In the Greater Pelican Region, we submitted an application in the fourth quarter of 2011 for initial development project approval at the Grand Rapids property. We expect to receive regulatory approval in the first quarter of 2014. Pilot project work is underway to examine optimal development strategies.

Prospective resources are those quantities of bitumen 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 sub-classified 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 probability 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 included in the low estimate have the highest degree of certainty, a 90 percent probability, 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 included in the high estimate have a lower degree of certainty, a 10 percent probability, that the actual quantities recovered will equal or exceed the estimate.

The economic contingent resources were estimated for individual projects and then aggregated for disclosure purposes. The high and low estimate volumes are arithmetic sums of multiple estimates, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Because the results are aggregated for disclosure, the low estimate results disclosed may have a higher probability than the estimates for the individual projects, and the high estimate results disclosed may have a lower probability than the estimates for individual projects.

Bitumen Economic Contingent and Prospective Resources		
Company Interest Before Royalties, Billions of Barrels	**December 31, 2013**	December 31, 2012
Economic Contingent Resources (1)		
Low Estimate	7.0	7.1
Best Estimate	9.8	9.6
High Estimate	13.6	12.8
Prospective Resources (2)		
Low Estimate	4.5	5.0
Best Estimate	7.5	8.5
High Estimate	12.6	14.8

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.

Bitumen best estimate economic contingent resources increased 0.2 billion barrels or two percent compared to 2012. This increase is primarily a result of stratigraphic test well drilling successfully converting prospective resources to contingent resources, the net acquisition of contingent resources through a property exchange, offset by the reduction of recovery factors at Steepbank and portions of the Grand Rapids formation and the loss of contingent resources due to the cancellation of mineral rights by the Alberta government for future urban development. Refer to "Risk Factors – Environment & Regulatory Risks – Alberta's Land-Use Framework" for more information.

Bitumen best estimate prospective resources declined 1.0 billion barrels or approximately 11 percent compared to 2012, primarily due to stratigraphic drilling, dispositions and cancellation of mineral rights by the Alberta government.

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)**
December 31, 2012	2.393	9.6	8.5
Transfers between Categories			
Additions from other resource categories	0.113	0.4	(0.4)
Reductions to other resource categories	-	(0.1)	-
Additions and Revisions Net of Transfers	0.060	(0.3)	(0.3)
Net Acquisitions and Dispositions	-	0.2	(0.3)
Production	(0.037)	-	-
December 31, 2013	2.529	9.8	7.5

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.

We are systematically progressing the classification of our bitumen prospective resources to contingent resources and then to reserves, and ultimately to production. For example, the stratigraphic well drilling program in the Steepbank area moved some prospective resources to contingent resources. The overall reduction of prospective resources is the expected outcome of a successful stratigraphic well drilling program, which converts undiscovered resources to discovered resources.

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 continue to improve overall recovery from our bitumen assets as technology develops.

Other Oil and Gas Information

Oil and Gas Properties and Wells

The following tables summarize our interests in producing and non-producing wells, at December 31, 2013:

Producing Wells (1) (2)	**Oil**		**Gas**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta						
Oil Sands	338	171	299	299	637	470
Conventional	2,508	2,461	24,568	24,371	27,076	26,832
Total Alberta	2,846	2,632	24,867	24,670	27,713	27,302
Saskatchewan	709	451	-	-	709	451
Total	3,555	3,083	24,867	24,670	28,422	27,753

Notes:
(1) Cenovus also has varying royalty interests in 9,093 natural gas wells and 3,671 crude oil wells which are producing.
(2) Includes wells containing multiple completions as follows: 22,455 gross natural gas wells (22,287 net wells) and 1,127 gross crude oil wells (1,002 net wells).

Non-Producing Wells (1)	**Oil**		**Gas**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta						
Oil Sands	47	27	508	432	555	459
Conventional	830	794	768	742	1,598	1,536
Total Alberta	877	821	1,276	1,174	2,153	1,995
Saskatchewan	127	84	7	7	134	91
Total	1,004	905	1,283	1,181	2,287	2,086

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

Cenovus has no properties with attributed reserves which are capable of producing but which are not on production.

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**
2013:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	6	6	-	-	-	-	6	6	9	15	6
Total Canada	6	6	-	-	-	-	6	6	9	15	6
2012:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	8	7	-	-	-	-	8	7	20	28	7
Total Canada	8	7	-	-	-	-	8	7	20	28	7
2011:											
Oil Sands	-	-	-	-	-	-	-	-	-	-	-
Conventional	24	22	-	-	2	2	26	24	40	66	24
Total Canada	24	22	-	-	2	2	26	24	40	66	24

Development Wells Drilled											
	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2013:											
Oil Sands	91	46	-	-	-	-	91	46	3	94	46
Conventional	215	206	-	-	2	2	217	208	117	334	208
Total Canada	306	252	-	-	2	2	308	254	120	428	254
2012:											
Oil Sands	61	31	-	-	-	-	61	31	57	118	31
Conventional	349	345	-	-	1	1	350	346	129	479	346
Total Canada	410	376	-	-	1	1	411	377	186	597	377
2011:											
Oil Sands	40	20	3	3	-	-	43	23	87	130	23
Conventional	343	334	66	65	4	4	413	403	156	569	403
Total Canada	383	354	69	68	4	4	456	426	243	699	426

During the year ended December 31, 2013, Oil Sands drilled 339 gross stratigraphic test wells (210 net wells) and Conventional drilled 54 gross stratigraphic test wells (54 net wells).

During the year ended December 31, 2013, Oil Sands drilled 27 gross service wells (17 net wells) and Conventional drilled 80 gross service wells (75 net wells). SAGD well pairs are counted as a single producing well in the table above.

For all types of wells except stratigraphic test wells, the calculation of the number of wells is based on the number of surface locations. For stratigraphic test wells, the calculation is based on the number of bottomhole locations.

Interest in Material Properties

The following table summarizes our landholdings at December 31, 2013:

Landholdings	Developed		Undeveloped (1)		Total (2)	
(thousands of acres)	Gross	Net	Gross	Net	Gross	Net
Alberta:						
Oil Sands						
– Crown (3)	483	382	1,824	1,368	2,307	1,750
Conventional						
– Fee (4)	1,933	1,933	440	440	2,373	2,373
– Crown (3)	1,150	1,046	747	683	1,897	1,729
– Freehold (5)	71	60	15	14	86	74
Total Alberta	3,637	3,421	3,026	2,505	6,663	5,926
Saskatchewan:						
Oil Sands						
– Crown (3)	-	-	64	64	64	64
Conventional						
– Fee (4)	80	80	426	426	506	506
– Crown (3)	48	33	180	162	228	195
– Freehold (5)	14	10	7	3	21	13
Total Saskatchewan	142	123	677	655	819	778
Manitoba:						
Conventional – Fee (4)	4	4	263	263	267	267
Total Manitoba	4	4	263	263	267	267
Total	3,783	3,548	3,966	3,423	7,749	6,971

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 includes all freehold 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 4.0 million gross acres (3.4 million net acres) of properties to which no reserves have been specifically attributed. These properties are planned for current and future development in both our oil sands and conventional oil and gas operations. There are currently no work commitments on these properties.

We have rights to explore, develop, and exploit approximately 88,000 net acres that could potentially expire by December 31, 2014, 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.

Properties with no attributed reserves include crown lands where bitumen contingent and prospective resources have been identified, fee title holdings and crown lands where exploration activities to date have not identified potential reserves in commercial quantities. See "Risk Factors – Financial Risks – Commodity Price Volatility and Development and Operating Costs" and "Risk Factors – Operational Risks – Uncertainty of Reserves and Future Net Revenue Estimates and Uncertainty of Contingent and Prospective Resource Estimates" in this AIF for further discussion of economic and uncertainty factors relevant to our properties with no attributed reserves.

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 $7.5 billion (approximately $1.3 billion, discounted at 10 percent) at December 31, 2013, of which we expect to pay approximately $322 million in the next three financial years. We expect to incur these costs on approximately 35,185 net wells.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of our proved reserves, approximately $1.3 billion has been deducted in estimating the future net revenue, which only represents our downhole abandonment obligations for wells within reserves.

Tax Horizon

We expect to pay income tax in 2014.

Costs Incurred

($ millions)	**2013**
Acquisitions	
– Unproved	32
– Proved	-
Total acquisitions	32
Exploration costs	264
Development costs	2,763
Total costs incurred	3,059

Forward Contracts

We may use financial derivatives to manage our exposure to fluctuations in commodity prices, foreign exchange and interest rates. A description of such instruments is provided in the notes to our annual audited Consolidated Financial Statements for the year ended December 31, 2013.

Production Estimates

The following table summarizes the estimated 2014 average daily volume of Company Interest Before Royalties and Royalty Interest Production reflected in the reserves reports for all properties held on December 31, 2013 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 divestitures.

2014 Estimated Production Forecast Prices and Costs	**Proved**	**Proved plus Probable**
Bitumen (bbls/d) [1]	121,175	124,587
Light and Medium Oil (bbls/d)	41,964	43,935
Heavy Oil (bbls/d)	30,826	32,798
Natural Gas (MMcf/d)	431	450
Natural Gas Liquids (bbls/d)	735	819
Company Interest Before Royalties Production (BOE/d)	266,498	277,130
Royalty Interest Production (BOE/d)	6,450	6,795
Total Company Interest Before Royalties Plus Royalty Interest Production (BOE/d)	272,948	283,925

Note:
(1) Includes Foster Creek production of 56,375 bbls/d for Proved and 56,387 bbls/d for Proved plus Probable, and Christina Lake production of 64,800 bbls/d for Proved and 68,200 bbls/d for Proved plus Probable.

Production History

Average Before Royalties Daily Production Volumes – 2013	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands					
Foster Creek (Bitumen)	53,190	52,419	49,092	55,338	55,996
Christina Lake (Bitumen)	49,310	61,471	52,732	38,459	44,351
	102,500	113,890	101,824	93,797	100,347
Conventional Liquids					
Heavy Oil – Pelican Lake	24,254	24,528	24,826	23,959	23,687
Heavy Oil – Other	14,901	14,487	14,451	15,182	15,500
Light and Medium Oil	31,926	30,030	30,509	32,195	35,041
Natural Gas Liquids [1]	901	1,033	1,039	735	794
Total Crude Oil and Natural Gas Liquids	174,482	183,968	172,649	165,868	175,369
Natural Gas (MMcf/d)					
Oil Sands	21	21	23	22	18
Conventional	485	471	479	489	503
Total Natural Gas	506	492	502	511	521
Total (BOE/d)	258,815	265,968	256,316	251,035	262,202

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

Average Royalty Interest Daily Production Volumes – 2013	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Crude Oil and Natural Gas Liquids (bbls/d)					
Conventional Liquids					
Heavy Oil - Other	1,090	993	1,056	1,102	1,212
Light and Medium Oil	3,541	3,616	3,142	3,942	3,467
Natural Gas Liquids [1]	162	166	91	215	177
Total Crude Oil and Natural Gas Liquids	4,793	4,775	4,289	5,259	4,856
Natural Gas (MMcf/d)					
Conventional	23	22	21	25	24
Total (BOE/d)	8,626	8,442	7,789	9,426	8,856

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

Average Before Royalties Daily Production Volumes – 2012					
	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands					
Foster Creek (Bitumen)	57,833	59,059	63,245	51,740	57,214
Christina Lake (Bitumen)	31,903	41,808	32,380	28,577	24,733
	89,736	100,867	95,625	80,317	81,947
Conventional Liquids					
Heavy Oil – Pelican Lake	22,552	23,507	23,539	22,410	20,730
Heavy Oil – Other	14,862	15,073	14,398	14,559	15,418
Light and Medium Oil	32,115	32,482	32,121	32,213	31,641
Natural Gas Liquids (1)	835	805	827	799	912
Total Crude Oil and Natural Gas Liquids	160,100	172,734	166,510	150,298	150,648
Natural Gas (MMcf/d)					
Oil Sands	30	27	24	31	39
Conventional	538	514	532	538	566
Total Natural Gas	568	541	556	569	605
Total (BOE/d)	254,767	262,901	259,177	245,131	251,481

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

Average Royalty Interest Daily Production Volumes - 2012					
	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Conventional Liquids					
Heavy Oil – Other	1,153	1,170	1,094	1,144	1,206
Light and Medium Oil	3,956	3,552	3,574	3,936	4,770
Natural Gas Liquids (1)	194	190	172	188	226
Total Crude Oil and Natural Gas Liquids	5,303	4,912	4,840	5,268	6,202
Natural Gas (MMcf/d)					
Conventional	26	25	21	27	31
Total (BOE/d)	9,636	9,079	8,340	9,768	11,369

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

Average Before Royalties Daily Production Volumes – 2011					
	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids (bbls/d)					
Oil Sands					
Foster Creek (Bitumen)	54,868	55,045	56,322	50,373	57,744
Christina Lake (Bitumen)	11,665	19,531	10,067	7,880	9,084
	66,533	74,576	66,389	58,253	66,828
Conventional Liquids					
Heavy Oil – Pelican Lake	20,424	20,558	20,363	19,427	21,360
Heavy Oil – Other	14,397	14,275	14,191	14,038	15,096
Light and Medium Oil	26,513	29,011	26,470	23,361	27,190
Natural Gas Liquids (1)	935	915	897	934	994
Total Crude Oil and Natural Gas Liquids	128,802	139,335	128,310	116,013	131,468
Natural Gas (MMcf/d)					
Oil Sands	34	36	37	34	29
Conventional	599	599	599	598	596
Total Natural Gas	633	635	636	632	625
Total (BOE/d)	234,302	245,168	234,310	221,346	235,635

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

Average Royalty Interest Daily Production Volumes - 2011					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Crude Oil and Natural Gas Liquids (bbls/d)					
Conventional Liquids					
Heavy Oil – Other	1,260	1,237	1,114	1,340	1,351
Light and Medium Oil	4,011	3,519	3,929	4,256	4,349
Natural Gas Liquids [1]	166	182	143	153	187
Total Crude Oil and Natural Gas Liquids	5,437	4,938	5,186	5,749	5,887
Natural Gas (MMcf/d)					
Conventional	23	25	20	22	27
Total (BOE/d)	9,270	9,105	8,519	9,416	10,387

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

Per-Unit Results

The following tables summarize our per-unit results, as well as the impact of realized financial hedging, on a quarterly basis, before deduction of royalties, for the periods indicated:

Per-Unit Results – 2013					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Heavy Oil – Foster Creek ($/bbl) [1] [2]					
Price	66.30	59.39	87.49	68.17	52.60
Royalties	3.73	3.56	6.31	3.87	1.47
Transportation and blending	2.36	3.21	4.37	0.04	1.89
Operating	15.77	15.90	17.12	16.19	14.03
Netback	44.44	36.72	59.69	48.07	35.21
Heavy Oil – Christina Lake ($/bbl) [1] [2]					
Price	51.26	44.36	74.98	52.61	33.41
Royalties	3.25	3.22	5.06	2.71	1.69
Transportation and blending	3.55	3.29	3.16	4.45	3.67
Operating	12.47	10.57	11.46	16.83	12.93
Netback	31.99	27.28	55.30	28.62	15.12
Total Heavy Oil – Oil Sands ($/bbl) [1]					
Price	59.10	51.34	81.16	61.88	44.01
Royalties	3.50	3.37	5.68	3.40	1.57
Transportation and blending	2.93	3.25	3.76	1.82	2.69
Operating	14.19	13.04	14.26	16.45	13.53
Netback	38.48	31.68	57.46	40.21	26.22
Heavy Oil – Pelican Lake ($/bbl) [1]					
Price	70.09	64.52	88.08	72.32	54.30
Royalties	4.00	1.97	6.64	4.08	3.22
Transportation and blending	2.41	2.79	2.18	2.58	2.07
Operating	20.65	21.22	19.90	22.21	19.23
Netback	43.03	38.54	59.36	43.45	29.78
Total Heavy Oil – Conventional ($/bbl) [1]					
Price	70.31	64.55	87.50	71.73	57.42
Royalties	6.08	5.31	8.83	5.50	4.65
Transportation and blending	2.60	2.69	2.51	2.58	2.63
Operating	19.32	19.76	18.51	20.30	18.72
Production and mineral taxes	0.13	0.05	0.21	0.12	0.13
Netback	42.18	36.74	57.44	43.23	31.29
Total Heavy Oil ($/bbl) [1]					
Price	62.23	54.61	82.97	64.91	47.82
Royalties	4.22	3.85	6.58	4.05	2.45
Transportation and blending	2.84	3.11	3.40	2.06	2.67
Operating	15.62	14.70	15.47	17.63	15.01
Production and mineral taxes	0.04	0.01	0.06	0.04	0.04
Netback	39.51	32.94	57.46	41.13	27.65

Per-Unit Results – 2013					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Light and Medium Oil ($/bbl)					
Price	86.30	82.12	100.64	86.84	76.77
Royalties	8.28	6.58	11.01	8.61	7.05
Transportation and blending	4.35	5.15	4.58	4.37	3.39
Operating	16.23	17.26	15.06	16.32	16.26
Production and mineral taxes	2.30	1.26	2.80	2.64	2.46
Netback	55.14	51.87	67.19	54.90	47.61
Total Crude Oil ($/bbl)					
Price	67.05	59.41	86.41	69.75	54.02
Royalties	5.03	4.33	7.44	5.05	3.43
Transportation and blending	3.14	3.47	3.63	2.57	2.82
Operating	15.74	15.15	15.39	17.34	15.27
Production and mineral taxes	0.49	0.23	0.59	0.61	0.56
Netback	42.65	36.23	59.36	44.18	31.94
Natural Gas Liquids ($/bbl)					
Price	60.34	59.39	65.71	46.44	68.88
Royalties	1.13	1.14	1.92	1.17	0.12
Netback	59.21	58.25	63.79	45.27	68.76
Total Liquids ($/bbl)					
Price	67.01	59.41	86.28	69.61	54.10
Royalties	5.01	4.31	7.40	5.03	3.42
Transportation and blending	3.12	3.45	3.61	2.55	2.81
Operating	15.65	15.06	15.29	17.24	15.19
Production and mineral taxes	0.48	0.23	0.59	0.61	0.55
Netback	42.75	36.36	59.39	44.18	32.13
Total Natural Gas ($/Mcf)					
Price	3.20	3.21	2.83	3.50	3.25
Royalties	0.04	0.04	0.05	0.04	0.05
Transportation and blending	0.11	0.11	0.10	0.08	0.15
Operating	1.16	1.23	1.13	1.16	1.14
Production and mineral taxes	0.02	0.02	0.03	(0.01)	0.03
Netback	1.87	1.81	1.52	2.23	1.88
Total ($/BOE)					
Price	51.23	47.23	63.12	52.55	42.52
Royalties	3.44	3.07	5.02	3.35	2.38
Transportation and blending	2.31	2.60	2.60	1.82	2.17
Operating	12.79	12.73	12.44	13.64	12.39
Production and mineral taxes	0.36	0.19	0.45	0.38	0.42
Netback	32.33	28.64	42.61	33.36	25.16

Notes:

(1) Heavy oil price and transportation and blending costs exclude the costs of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the annual cost of condensate for 2013 is as follows: Foster Creek – $42.41/bbl; Christina Lake – $45.25/bbl; Heavy Oil – Oil Sands – $43.77/bbl; Pelican Lake – $15.59/bbl; Heavy Oil – Conventional – $14.60/bbl; and Total Heavy Oil – $35.63/bbl.

(2) Foster Creek and Christina Lake are bitumen properties.

Impact of Long-term Incentive Costs on Operating Costs – 2013	Year	Q4	Q3	Q2	Q1
Total ($/BOE)	0.12	0.06	0.23	0.07	0.10

Impact of Realized Financial Hedging – 2013	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	1.09	2.77	(2.02)	0.72	2.62
Natural Gas ($/Mcf)	0.32	0.36	0.38	0.18	0.39
Total ($/BOE)	1.37	2.58	(0.58)	0.84	2.52

Per-Unit Results – 2012					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Heavy Oil – Foster Creek ($/bbl) (1) (2)					
Price	64.55	59.93	63.95	63.83	70.71
Royalties	7.36	4.55	11.79	2.85	9.54
Transportation and blending	2.41	2.91	2.38	1.91	2.38
Operating	11.99	11.26	11.50	12.49	12.85
Netback	42.79	41.21	38.28	46.58	45.94

Per-Unit Results – 2012					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Heavy Oil – Christina Lake ($/bbl) (1) (2)					
Price	47.73	43.37	52.91	44.57	52.58
Royalties	2.72	2.32	2.61	2.90	3.37
Transportation and blending	3.79	3.00	4.00	4.12	4.51
Operating	12.95	11.42	13.59	12.52	15.33
Netback	28.27	26.63	32.71	25.03	29.37
Total Heavy Oil - Oil Sands ($/bbl) (1)					
Price	58.61	53.02	60.35	57.02	65.23
Royalties	5.72	3.62	8.80	2.87	7.68
Transportation and blending	2.90	2.95	2.91	2.69	3.02
Operating	12.33	11.33	12.17	12.52	13.60
Netback	37.66	35.12	36.47	38.94	40.93
Heavy Oil – Pelican Lake ($/bbl) (1)					
Price	69.23	64.37	66.75	66.42	78.50
Royalties	3.34	2.82	4.34	2.68	3.37
Transportation and blending	2.15	1.23	1.09	3.54	2.88
Operating	17.08	17.20	17.47	17.71	16.05
Netback	46.66	43.12	43.85	42.49	56.20
Total Heavy Oil - Conventional ($/bbl) (1)					
Price	69.76	64.52	67.25	66.95	79.37
Royalties	6.06	5.26	6.05	5.46	7.33
Transportation and blending	2.16	1.69	1.55	3.01	2.44
Operating	16.32	14.91	17.09	16.61	16.67
Production and mineral taxes	0.10	0.13	0.10	0.10	0.06
Netback	45.12	42.53	42.46	41.77	52.87
Total Heavy Oil ($/bbl) (1)					
Price	62.05	56.22	62.45	60.13	70.08
Royalties	5.83	4.07	7.96	3.68	7.56
Transportation and blending	2.67	2.60	2.50	2.79	2.82
Operating	13.56	12.33	13.66	13.80	14.65
Production and mineral taxes	0.03	0.04	0.03	0.03	0.02
Netback	39.96	37.18	38.30	39.83	45.03
Light and Medium Oil ($/bbl)					
Price	78.99	75.27	76.06	76.16	88.45
Royalties	8.09	6.92	7.53	7.98	9.94
Transportation and blending	2.65	2.39	2.36	3.02	2.83
Operating	15.51	15.63	16.27	14.76	15.36
Production and mineral taxes	2.44	2.51	2.35	2.34	2.57
Netback	50.30	47.82	47.55	48.06	57.75
Total Crude Oil ($/bbl)					
Price	65.76	60.10	65.37	63.91	74.22
Royalties	6.32	4.65	7.87	4.69	8.10
Transportation and blending	2.66	2.55	2.47	2.84	2.83
Operating	13.99	13.00	14.22	14.03	14.81
Production and mineral taxes	0.56	0.54	0.53	0.58	0.59
Netback	42.23	39.36	40.28	41.77	47.89
Natural Gas Liquids ($/bbl)					
Price	69.54	65.89	61.53	65.52	83.36
Royalties	1.42	1.52	1.55	1.13	1.45
Netback	68.12	64.37	59.98	64.39	81.91
Total Liquids ($/bbl)					
Price	65.79	60.13	65.35	63.92	74.28
Royalties	6.29	4.64	7.83	4.67	8.05
Transportation and blending	2.65	2.54	2.45	2.82	2.81
Operating	13.90	12.93	14.14	13.93	14.71
Production and mineral taxes	0.56	0.54	0.53	0.57	0.59
Netback	42.39	39.48	40.40	41.93	48.12

Per-Unit Results – 2012					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Total Natural Gas ($/Mcf)					
Price	2.42	2.97	2.30	1.92	2.50
Royalties	0.03	0.02	0.02	0.01	0.06
Transportation and blending	0.10	0.10	0.08	0.08	0.13
Operating	1.10	1.29	1.08	0.98	1.08
Production and mineral taxes	0.01	(0.01)	0.02	0.02	0.02
Netback	1.18	1.57	1.10	0.83	1.21
Total ($/BOE)					
Price	46.60	45.50	46.61	43.25	50.84
Royalties	4.00	3.08	5.02	2.84	5.00
Transportation and blending	1.88	1.86	1.74	1.90	2.00
Operating	11.18	11.12	11.35	10.75	11.46
Production and mineral taxes	0.38	0.33	0.38	0.40	0.40
Netback	29.16	29.11	28.12	27.36	31.98

Notes:

(1) Heavy oil price and transportation and blending costs exclude the costs of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the annual cost of condensate for 2012 is as follows: Foster Creek – $41.85/bbl; Christina Lake – $45.83/bbl; Heavy Oil – Oil Sands – $43.26/bbl; Pelican Lake – $15.55/bbl; Heavy Oil – Conventional – $14.66/bbl; and Total Heavy Oil – $34.44/bbl.

(2) Foster Creek and Christina Lake are bitumen properties.

Impact of Long-term Incentive Costs (Recovery) on Operating Costs – 2012	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Total ($/BOE)	0.16	0.05	0.32	(0.17)	0.42

Impact of Realized Financial Hedging – 2012	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
Liquids ($/bbl)	1.39	3.35	2.02	1.64	(1.67)
Natural Gas ($/Mcf)	1.14	0.89	1.24	1.39	1.03
Total ($/BOE)	3.42	4.05	3.98	4.27	1.44

Per-Unit Results – 2011					
	Year	**Q4**	**Q3**	**Q2**	**Q1**
Heavy Oil – Foster Creek ($/bbl) (1) (2)					
Price	67.38	75.96	62.68	72.23	59.50
Royalties	10.82	15.81	12.38	2.30	11.92
Transportation and blending	3.04	3.20	2.73	2.82	3.41
Operating	11.34	11.31	11.11	11.57	11.40
Netback	42.18	45.64	36.46	55.54	32.77
Heavy Oil – Christina Lake ($/bbl) (1) (2)					
Price	61.86	66.69	54.52	67.06	54.67
Royalties	3.03	2.97	2.87	3.98	2.44
Transportation and blending	3.53	2.98	4.54	3.51	3.69
Operating	20.20	17.96	23.01	23.41	19.09
Netback	35.10	42.78	24.10	36.16	29.45
Total Heavy Oil – Oil Sands ($/bbl) (1)					
Price	66.47	73.75	61.66	71.46	58.82
Royalties	9.55	12.75	11.20	2.53	10.59
Transportation and blending	3.12	3.15	2.95	2.92	3.45
Operating	12.79	12.90	12.60	13.24	12.48
Netback	41.01	44.95	34.91	52.77	32.30
Heavy Oil – Pelican Lake ($/bbl) (1)					
Price	73.07	88.67	66.76	78.26	64.66
Royalties	7.91	6.98	8.23	7.40	8.63
Transportation and blending	4.14	12.19	1.87	2.02	2.44
Operating	14.86	16.49	14.31	13.40	15.35
Netback	46.16	53.01	42.35	55.44	38.24

Per-Unit Results – 2011	Year	Q4	Q3	Q2	Q1
Total Heavy Oil – Conventional ($/bbl) (1)					
Price	73.57	85.06	67.26	78.36	66.59
Royalties	9.20	9.42	9.52	9.12	8.80
Transportation and blending	2.83	6.74	1.84	1.49	1.84
Operating	14.36	16.41	13.51	13.52	14.25
Production and mineral taxes	0.14	0.17	0.07	0.11	0.22
Netback	47.04	52.32	42.32	54.12	41.48
Total Heavy Oil ($/bbl) (1)					
Price	68.98	77.16	63.69	73.98	61.80
Royalties	9.42	11.74	10.59	4.93	9.91
Transportation and blending	3.02	4.23	2.55	2.40	2.83
Operating	13.35	13.96	12.93	13.34	13.16
Production and mineral taxes	0.05	0.05	0.03	0.04	0.08
Netback	43.14	47.18	37.59	53.27	35.82
Light and Medium Oil ($/bbl)					
Price	85.40	90.90	79.57	94.30	77.39
Royalties	11.54	12.12	10.74	12.82	10.58
Transportation and blending	2.00	1.99	1.90	2.22	1.92
Operating	14.38	15.12	14.37	12.96	14.86
Production and mineral taxes	2.27	2.63	2.40	2.77	1.32
Netback	55.21	59.04	50.16	63.53	48.71
Total Crude Oil ($/bbl)					
Price	72.80	80.49	67.37	78.71	65.32
Royalties	9.92	11.83	10.62	6.77	10.06
Transportation and blending	2.78	3.69	2.40	2.35	2.63
Operating	13.59	14.24	13.26	13.25	13.54
Production and mineral taxes	0.57	0.67	0.58	0.67	0.36
Netback	45.94	50.06	40.51	55.67	38.73
Natural Gas Liquids ($/bbl)					
Price	76.84	82.26	74.38	80.32	70.67
Royalties	1.34	1.51	1.06	1.87	0.93
Netback	75.50	80.75	73.32	78.45	69.74
Total Liquids ($/bbl)					
Price	72.84	80.50	67.43	78.72	65.37
Royalties	9.84	11.75	10.55	6.72	9.98
Transportation and blending	2.76	3.66	2.38	2.33	2.60
Operating	13.47	14.13	13.16	13.13	13.43
Production and mineral taxes	0.56	0.67	0.57	0.67	0.36
Netback	46.21	50.29	40.77	55.87	39.00
Total Natural Gas ($/Mcf)					
Price	3.65	3.35	3.72	3.71	3.82
Royalties	0.06	0.06	0.05	0.04	0.08
Transportation and blending	0.15	0.14	0.15	0.14	0.17
Operating	1.10	1.22	0.99	0.98	1.19
Production and mineral taxes	0.04	0.01	0.03	0.05	0.06
Netback	2.30	1.92	2.50	2.50	2.32
Total ($/BOE)					
Price	49.75	53.48	46.97	51.81	46.83
Royalties	5.55	6.65	5.91	3.64	5.85
Transportation and blending	1.91	2.39	1.70	1.61	1.92
Operating	10.35	11.09	9.88	9.69	10.68
Production and mineral taxes	0.41	0.40	0.39	0.49	0.36
Netback	31.53	32.95	29.09	36.38	28.02

Notes:

(1) Heavy oil price and transportation and blending costs exclude the costs of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the annual cost of condensate for 2011 is as follows: Foster Creek – $41.74/bbl; Christina Lake – $47.07/bbl; Heavy Oil – Oil Sands – $42.61/bbl; Pelican Lake – $16.32/bbl; Heavy Oil – Conventional – $14.69/bbl; and Total Heavy Oil – $32.76/bbl.

(2) Foster Creek and Christina Lake are bitumen properties.

Impact of Long-term Incentive Costs (Recovery) on Operating Costs – 2011	Year	Q4	Q3	Q2	Q1
Total ($/BOE)	0.17	0.33	(0.47)	(0.32)	1.11

Impact of Realized Financial Hedging - 2011	Year	Q4	Q3	Q2	Q1
Liquids ($/bbl)	(2.79)	(3.15)	0.75	(6.44)	(2.67)
Natural Gas ($/Mcf)	0.87	1.10	0.76	0.74	0.89
Total ($/BOE)	0.86	1.22	2.49	(1.25)	0.83

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 non-core assets, in order to increase our focus on our key assets within the long range business plan as well as generate proceeds to partially fund our capital investment. Early in the third quarter, we completed the sale of our Lower Shaunavon tight oil asset located in southern Saskatchewan for proceeds of approximately $240 million plus closing adjustments. Immediately prior to the disposition, Lower Shaunavon was producing an average of 3,592 bbls/d during the second quarter of 2013.

The following table summarizes our net capital investment for 2013 and 2012:

Net Capital Investment ($ millions)	**2013**	**2012**
Capital Investment		
Oil Sands		
Foster Creek	797	735
Christina Lake	688	593
Total	1,485	1,328
Other Oil Sands	398	365
	1,883	1,693
Conventional		
Pelican Lake	465	518
Other Conventional	726	848
	1,191	1,366
Refining and Marketing	107	118
Corporate	81	191
Capital Investment	3,262	3,368
Acquisitions	32	114
Divestitures	(283)	(76)
Net Acquisition and Divestiture Activity	(251)	38
Net Capital Investment	3,011	3,406

OTHER INFORMATION

Competitive Conditions

All aspects of the oil and gas industry are highly competitive. Refer to "Risk Factors – Operational Risks – 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 $15 to $65 per tonne of emissions applied across a range of regulatory policy options. A major benefit of applying a range of carbon prices at the strategic level is that it 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 – Environment & Regulatory Risks – Climate Change Regulations".

We also examine the impact of carbon regulation on our major projects, including our oil sands operations and our refining assets. We continue to closely monitor potential GHG legislation developments both in Canada and the U.S.

We expect to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2013, expenditures beyond normal compliance with environmental regulations were considered to be in the ordinary course of business. We do not anticipate material expenditures beyond amounts paid in respect of normal compliance with environmental regulations in 2014. Refer to "Risk Factors – Environment & Regulatory Risks – Environmental Regulations" for further information on environmental protection matters affecting Cenovus.

Corporate Responsibility Practice

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. Our CR Policy was developed through an award-winning process focused on engagement with employees, external stakeholders and industry experts. The CR 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. Our CR Policy is available on our website at cenovus.com.

Our CR Policy focuses on six commitment 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 annual CR report. Our annual CR report involves a limited assurance engagement with an independent auditor on a select number of quantitative indicators. This report 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 CR 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 strive to never compromise the health and safety of any individual in the conduct of our activities. We 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 CR 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.

The CR Policy was introduced in tandem with the Cenovus Operating Management System in 2011. The Cenovus Operating Management System is closely aligned with the CR Policy. Current steps that we have in place to ensure the successful integration of the CR Policy include: (i) a security program to regularly assess security threats to business operations and to manage the associated risks; (ii) CR performance metrics to track our progress; (iii) an energy efficiency program that focuses on reducing energy use at our operations, supports initiatives at the community level and provides incentives for employees to reduce energy use in their homes; (iv) an Investigations Practice and an Investigations Committee to review and resolve potential violations of Cenovus's policies or practices or other regulations; (v) an Integrity Helpline that provides an additional avenue for our stakeholders to raise their concerns; (vi) the CR website which allows people to write to Cenovus about non-financial issues of concern; (vii) related policies and practices such as an Alcohol and Drug Policy, a Code of Business Conduct & Ethics, an Aboriginal Business Engagement Framework, and an Expect Respect program concerning local community relations; and (viii) a requirement for acknowledgement and sign-off on key policies and practices by our Board and employees. Our Board approved the CR Policy on recommendation of the Safety, Environment and Responsibility Committee. The Board is also advised of significant policy contraventions and receives updates on trends, issues or events which could impact Cenovus.

In January 2014, Cenovus was included for the first time in the RobecoSAM 2014 Sustainability Yearbook with a Bronze Class distinction. RobecoSAM is a Swiss-based international investment specialist in sustainability investing that publishes the Dow Jones Sustainability Index (see below). Corporate Knights magazine also listed Cenovus to their Global 100 clean capitalism ranking for the second consecutive year. Corporate Knights also recognized Cenovus's leading CR performance in their inaugural Top 10 Energy Companies in the World listing, published in November 2013.

In October 2013, Cenovus was named to the Canada 200 Climate Disclosure Leadership Index, which recognizes companies for their open and transparent disclosure of greenhouse gas emissions, for the fourth consecutive year. This index, published by CDP (formerly known as the Carbon Disclosure Project), recognizes companies for their open and transparent disclosure of greenhouse gas emissions.

In September 2013, our leading CR practices were recognized internationally with the inclusion of Cenovus to the Dow Jones Sustainability World Index for the second consecutive year and to the Dow Jones Sustainability North America Index for the fourth consecutive year. The Dow Jones Sustainability Indexes track the financial performance of the leading companies worldwide regarding CR performance. In June 2013, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the second year in a row and for the third consecutive year by Corporate Knights magazine as one of the 2013 Best 50 Corporate Citizens in Canada. These external recognitions of our commitment to corporate responsibility reaffirm Cenovus's efforts to balance economic, governance, social and environmental performance.

Employees

The following table summarizes our full-time equivalent ("FTE") employees at December 31, 2013:

	FTE Employees
Oil Sands	1,385
Conventional	704
Refining and Marketing	69
Cenovus-wide	1,386
Total	3,544

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

Foreign Operations

We, and our reportable segments, are not dependent upon foreign operations outside North America. As a result, our exposure to risks and uncertainties in countries considered politically and economically unstable is limited. Any future operations 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 – Financial Risks – Foreign Exchange Rates" for information on foreign exchange rate matters affecting Cenovus.

DIRECTORS AND EXECUTIVE OFFICERS

Directors

The following individuals are directors of Cenovus.

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 a director of Enterprise Products Holdings, LLC, the successor general partner of Enterprise Products Partners L.P., a publicly traded midstream energy limited partnership; and Chairman of TETRA Technologies, Inc., a publicly traded energy services and chemicals company. Mr. Cunningham served as Chairman of Enterprise Products Holdings, LLC from November 2010 to February 2013; 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 August 2007 to November 2010; as a director of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners, L.P. from December 2005 to May 2010; as a director of LE GP, LLC, the general partner of Energy Transfer Equity, L.P., a publicly traded midstream energy limited partnership from December 2009 to November 2010; and as a director of Agrium Inc., a publicly traded agricultural chemicals company from December 1996 to April 2013. 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 of Canadian Imperial Bank of Commerce and a member of the North American Review Board of American Air Liquide Holdings, Inc., a publicly traded industrial gases service company. Mr. Daniel served as a director of Enbridge Inc., a publicly traded energy delivery company from April 2000 to October 2012. During his tenure with Enbridge, he also served as President & Chief Executive Officer from January 2001 to February 2012 and as Chief Executive Officer from February 2012 to October 2012. He is also a member of the Association of Professional Engineers and Geoscientists of Alberta.
Ian W. Delaney [2,4,5,7] Toronto, Ontario, Canada	2009	Mr. Delaney is Chairman of The Westaim Corporation, a publicly traded investment company and Dacha Strategic Metals Inc., a publicly traded investment company focused on the acquisition, storage and trading of strategic metals. Mr. Delaney served as a director of Sherritt International Corporation, a publicly traded diversified natural resource company that produces nickel, cobalt, thermal coal, oil and gas and electricity from October 1995 to May 2013. During his tenure with Sherritt, he also served as Chairman from November 1995 to May 2004, Executive Chairman from May 2004 to December 2008, Chairman and Chief Executive Officer from January 2009 to December 2011 and Chairman from January 2012 to May 2013. Mr. Delaney also served as Chairman of UrtheCast Corp. (formerly Longford Energy Inc.), a publicly traded video technology development company, from August 2012 to October 2013.

Name and Residence	Director Since [1]	Principal Occupation During the Past Five Years
Brian C. Ferguson [8] Calgary, Alberta, Canada	2009	Mr. Ferguson became President & Chief Executive Officer when Cenovus was formed on November 30, 2009. Mr. Ferguson is responsible for the overall leadership of Cenovus's strategic and operational performance. Prior to leading Cenovus, Mr. Ferguson was Executive Vice-President & Chief Financial Officer of Encana. His business experience includes a variety of areas in finance, business development, reserves, strategic planning, evaluations and communications. Mr. Ferguson is a Fellow of the Institute of Chartered Accountants of Alberta, a member of the Canadian Association of Petroleum Producers (CAPP) and participates on several CAPP committees, including the Oil Sands CEO Council, a member of the Canadian Institute of Chartered Accountants (CICA), a member of the Canadian Council of Chief Executives and Chair of the Calgary Police Foundation. He previously served as Chairman of CICA's Risk Oversight and Governance Board and on the board of CAPP, and is a former member of the Global Commerce Strategy Advisory Panel.
Michael A. Grandin [2,5,9] Calgary, Alberta, Canada	2009 (Chair)	Mr. Grandin is the Chair of our Board. He is also a director of BNS Split Corp. II, a publicly traded investment company; and HSBC Bank Canada. He was Chairman and Chief Executive Officer of Fording Canadian Coal Trust, a publicly traded mining trust, from February 2003 to October 2008 when it was acquired by Teck Cominco Limited. He was President of PanCanadian Energy Corporation from October 2001 to April 2002 when it merged with Alberta Energy Company Ltd. to form Encana. 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 was a director of Wajax Corporation, a publicly traded industrial parts and service company, from June 1995 to May 2012. She was also a member and past chair of an advisory group on the General Agreement on Tariffs and Trade (GATT) and the North America Free Trade Agreement (NAFTA) regarding international trade matters pertaining to energy, chemicals and plastics from 1986 to 2002. She is also a past director of the Bank of Canada and of the Canada Olympic Committee. Ms. Nielsen is a member of the Association of Professional Engineers and Geoscientists of Alberta and the Canadian Society of Exploration Geophysicists, and has been awarded the designation of Fellow of Geoscientists Canada (FGC).

Name and Residence	Director Since [1]	Principal Occupation During the Past Five Years
Charles M. Rampacek [5,6,7] Dallas, Texas, United States	2009	Mr. Rampacek is a director of Flowserve Corporation, a publicly traded manufacturer of industrial equipment; Pilko & Associates L.P., a private chemical and energy advisory company; and Energy Services Holdings, LLC, a private industrial services company that was formed in 2012 from the combination of Ardent Holdings, LLC and another company. Mr. Rampacek previously served as Chair of Ardent Holdings, LLC, from December 2008 to July 2012. Mr. Rampacek also served as a director of Enterprise Products Holdings, LLC, the sole general partner of Enterprise Products Partners, L.P., a publicly traded midstream energy limited partnership from November 2006 to September 2011. He 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 & 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 a director and Chief Executive Officer of Iskander Energy Corp., a private international oil and gas company; Chairman and President of Enviro Valve Inc., a private company manufacturing proprietary pressure relief valves; and a director of TVI Pacific Inc., a publicly traded international mining company. Mr. Thomson served as a director of Virgin Resources Limited, a private international oil and gas company from January 2005 to April 2013. Mr. Thomson is a member of the Association of Professional Engineers and Geoscientists of Alberta.

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 served as executive officers of Cenovus as at December 31, 2013.

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. In 2009, Mr. Ruste held the following positions with Encana: Executive Vice-President, Corporate Responsibility & Chief Risk Officer; and Executive Vice-President & Chief Risk Officer.
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). In 2009, Mr. Brannan held the following position with Encana: Executive Vice-President (President, Integrated Oil Division).
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. In 2009, Mr. Chhina held the following position with Encana: Vice-President, Upstream Operations, Integrated Oil Sands Division.
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. In 2009, Mr. Dyte held the following position with Encana: Vice-President, General Counsel & Corporate Secretary.
Sheila M. McIntosh Calgary, Alberta, Canada	Executive Vice-President, Environment & Corporate Affairs Ms. McIntosh became Executive Vice-President, Environment & Corporate Affairs on February 1, 2013. From November 2009 to January 2013, Ms. McIntosh was our Executive Vice-President, Communications & Stakeholder Relations. In 2009, Ms. McIntosh held the following position with Encana: Executive Vice-President, Corporate Communications.
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 and held that position until December 31, 2013. From November 2009 to November 2010, Mr. Swystun was our Executive Vice-President (President, Canadian Plains Division). In 2009, Mr. Swystun held the following position with Encana: Executive Vice-President (President, Canadian Plains Division).

Name and Residence	Office Held and Principal Occupation During the Past Five Years
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. In 2009, Mr. Walls held the following position with Encana: Executive Vice-President, Corporate Services.

As of December 31, 2013, all of our directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 1,086,121 Common Shares or approximately 0.14 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, none of our current directors or executive officers is, as at the date of this AIF, or has been, within 10 years prior to the date of this AIF, 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, as at the date of this AIF, or has been within 10 years prior to the date of this AIF, 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 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 10 years prior to the date of this AIF, 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.

To our knowledge, none of our directors or executive officers has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalty or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Mr. Delaney was a director of OPTI Canada Inc. ("OPTI") when it commenced proceedings for creditor protection under the Companies' Creditors Arrangement Act (Canada) ("CCAA") on July 13, 2011. Ernst & Young Inc. was appointed as monitor of OPTI. On November 28, 2011, OPTI announced that it had closed a transaction whereby a subsidiary of CNOOC Limited acquired all of the outstanding securities of OPTI pursuant to a plan of arrangement under the CCAA and the Canada Business Corporations Act.

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 (U.S.). 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 AIF.

Composition of the Audit Committee

The Audit Committee consists of three members, each of whom is independent and financially literate in accordance with National Instrument 52-110 *Audit Committees* ("NI 52-110"). The education and experience of each of the members of the Audit Committee relevant to the performance of the responsibilities as an Audit Committee member 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 a past Chief Executive Officer and director of Enbridge Inc., a publicly traded energy delivery company. He is also a past director and member of the audit committee of Enerflex Systems Income Fund, a compression systems manufacturer and 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 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 a past director and served 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 in the years ended December 31, 2013 and 2012:

($ thousands)	**2013**	**2012**
Audit Fees (1)	2,460	2,598
Audit-Related Fees (2)	288	198
Tax Fees (3)	374	414
All Other Fees	57	43
Total	3,179	3,253

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. The services provided in this category included audit-related services in relation to our debt shelf prospectuses, systems development and controls testing.

(3) *Tax Fees* consist of fees for tax compliance, tax advice and tax planning. The services provided in this category primarily included support of scientific research and experimental development claims for Cenovus and FCCL.

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, 2013, there were approximately 756.0 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 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 assets in the event of any liquidation, dissolution or winding up 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 such class, as a return of capital in the event of liquidation, dissolution or winding up or any other distribution of assets among shareholders for the purpose of winding up, 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 was amended and reconfirmed at the 2012 annual meeting of shareholders and must be reconfirmed by our shareholders at every third annual shareholder meeting.

Dividend Reinvestment Plan

We have 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. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years, and are fully exercisable after three years. Options granted prior to February 17, 2010 expire after five years while options granted on or after February 17, 2010 expire after seven years. Each option granted prior to February 24, 2011 has an associated tandem stock appreciation right which gives the option holder 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. Options granted on or after February 24, 2011 have associated net settlement rights. In lieu of exercising the option, the net settlement right grants the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of the Common Shares at the time of exercise over the exercise price of 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 at December 31, 2013:

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

Credit ratings are intended to provide an independent measure of the credit quality of an issue of securities. The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the securities nor do the ratings comment on market price or suitability for a particular investor. A rating may not remain in effect for any given period of time and, at any time, 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 10 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 10 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 10 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 but overall strength is not as favourable as higher rating categories. Cenovus may be vulnerable to future events but qualifying negative factors are considered manageable.

During the last two years, we have made payments to S&P, Moody's and DBRS related to the rating of our debt. Additionally, we have purchased products and services from S&P and Moody's.

DIVIDENDS

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

The Board has approved a 10 percent increase in the first quarter dividend to $0.2662 per share payable on March 31, 2014 to holders of Common Shares of record as of March 14, 2014. Readers should also refer to risk factors "Risk Factors – Financial Risks – Ability to Pay Dividends" for additional information.

We paid the following dividends over the last three years:

Dividends Paid ($ per share)	**Year**	**Q4**	**Q3**	**Q2**	**Q1**
2013	0.968	0.242	0.242	0.242	0.242
2012	0.880	0.220	0.220	0.220	0.220
2011	0.800	0.200	0.200	0.200	0.200

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 2013:

2013	**TSX**				**NYSE**			
	Share Price Trading Range				Share Price Trading Range			
	High	Low	Close	Share Volume	High	Low	Close	Share Volume
	($ per share)			(thousands)	(US$ per share)			(thousands)
January	34.13	32.60	33.11	30,439	34.50	32.89	33.24	16,217
February	33.76	31.32	33.39	27,727	33.84	31.11	32.31	20,069
March	33.16	31.09	31.46	42,818	32.48	30.58	30.99	17,611
April	32.08	28.32	30.15	54,598	31.58	27.57	29.94	27,644
May	31.51	29.25	31.04	32,100	30.85	29.06	29.93	25,883
June	31.47	28.67	30.00	37,841	30.42	27.25	28.52	23,487
July	32.77	29.88	30.42	50,346	31.60	28.38	29.60	23,707
August	30.89	28.98	30.18	37,623	29.88	28.00	28.74	27,665
September	31.62	30.17	30.74	27,821	30.54	28.77	29.85	15,933
October	31.36	29.98	30.98	31,033	30.34	28.79	29.72	18,409
November	31.25	29.98	30.93	25,675	29.80	28.56	29.21	20,076
December	31.69	29.33	30.40	26,899	29.79	27.60	28.65	24,108

RISK FACTORS

Our operations are exposed to a number of risks, some that impact the oil and gas industry as a whole and others that are unique to our operations. We have identified risks in four main categories: financial, operational, environment & regulatory, and reputation. The impact of any risk or a combination of risks in these four categories may adversely affect our business, reputation, financial condition, results of operations and cash flow, which may reduce or restrict our ability to pay a dividend to our shareholders and may materially affect the market price of our securities.

Our approach to risk management includes compliance with our Board approved Enterprise Risk Management Policy and the related enterprise risk management framework and program. It includes an annual review of our principal and emerging risks, an analysis of the severity and likelihood of each principal risk, consideration of our current mitigation and an evaluation if additional mitigation or treatment of the risk is required. In addition, we continuously monitor our risk profile as well as industry best practices.

Financial Risks

Financial risks include, but are not limited to: fluctuations in commodity prices; royalty regimes and tax laws; volatile financial and credit markets; development and operating costs; availability of credit and access to sufficient liquidity; fluctuations in foreign exchange and interest rates; risks related to our hedging activities; and risks related to our ability to pay a dividend to shareholders. Changes in global economic conditions could impact a number of factors including, but not limited to, pace of our growth, financial strength of our counterparties, access to capital and cost of borrowing.

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 supply of and demand for crude oil; global economic conditions; the actions of the Organization of Petroleum Exporting Countries; government regulation; political stability; the ability to transport crude to markets; 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: global supply and demand for refined products; market competitiveness; weather; and industry planned and unplanned refinery maintenance. 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 U.S. dollars, are stated in Canadian dollars.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium oil, heavy oil (in particular the light/heavy differential) and bitumen and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions; refining demand; the availability and cost of diluent used to blend and transport product; and the quality of the oil produced, all of which are beyond our control.

The financial performance of our refining operations is impacted by the relationship, or margin, between refined product prices and the prices of 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; crude oil costs; and 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 may have a negative impact on our business.

Fluctuations in the price of commodities, associated price differentials and refining margins may impact the value of our assets, our ability to maintain our business and to fund growth projects including, but not limited to, the continued development of our oil sands properties. Prolonged periods of commodity price volatility may also negatively impact our ability to meet guidance targets and meet all of our financial obligations as they come due. Any substantial or extended decline in these commodity prices may result in a delay or cancellation of existing or future drilling, development or construction programs, curtailment in production, unutilized long-term transportation commitments and/or low utilization levels at our refineries.

We conduct an annual assessment of the carrying value of our assets in accordance with International Financial Reporting Standards. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying value of our assets may be subject to impairment.

Development and Operating Costs

Our financial performance is significantly affected by the cost of developing and operating our assets. Development and operating costs are affected by a number of factors including, but not limited to: inflationary price pressure; scheduling delays; failure to maintain quality construction and manufacturing standards; and supply chain disruptions, including access to skilled labour. Electricity, water, diluent, chemicals, supplies, reclamation, abandonment and labour costs are examples of operating costs that are susceptible to significant fluctuation.

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. We also use derivative instruments in various operational markets to optimize our supply or production chain. We may also utilize derivative instruments when considered appropriate, to help mitigate the potential impact of changes in interest rates and foreign exchange rates.

The use of such hedging activities exposes us to risks which may cause significant loss. These risks include, but are not limited to: changes in the price of the hedge instrument that are not reflected in the price of the products we sell; failure by a counterparty to perform an obligation; human error or deficiency in our systems or controls; and the unenforceability of our contracts.

Additionally, the consequences of hedging to protect against downside price risk 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.

Exposure to Counterparties

In the normal course of business we enter into contractual relationships with suppliers, partners and other counterparties in the energy industry and other industries for the provision and sale of goods and services. If such counterparties do not fulfill their contractual obligations, we may suffer financial losses, may have to delay our development plans or may have to forego other opportunities which may materially impact our financial condition or operational results.

Credit, Liquidity and Availability of Future Financing

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. 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 on acceptable terms and conditions. An inability to access capital could affect our ability to make future capital expenditures and to meet all of our financial obligations as they come due. Our ability to obtain additional capital is dependent on, among other things, interest in investments in the energy industry in general and interest in our securities in particular.

As at December 31, 2013, Cenovus had US$4.75 billion in debt outstanding with no principal payments due until October 2019 (US$1.3 billion). We have a $3.0 billion committed credit facility, with a maturity of November 30, 2017, of which the entire amount was available at December 31, 2013, to meet operating and capital requirements. Going forward, an inability to access the credit markets, a sustained downturn in the prices of crude oil or refined products or the continued downturn in the price of natural gas or significant unanticipated expenses related to development and maintenance of our existing properties could negatively impact our liquidity, our credit ratings and our ability to access additional sources of capital. We are also required to comply with various financial and operating covenants under our credit facilities and the indentures governing our debt securities. We routinely review the covenants and may make changes to our development plans, dividend policy, or may take alternative actions 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, and/or if repayment is required before maturity, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired.

Foreign Exchange Rates

Fluctuations in foreign exchange rates may 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 as well as our Consolidated Financial Statements are denominated in Canadian dollars. Cenovus also holds substantial amounts of U.S. dollar debt. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of our oil, natural gas and refined products. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar creates uncertainty and impacts our capital expenditures and expenses.

Interest Rates

We may be exposed to fluctuations in interest rates as a result of the use of floating rate securities. An increase in interest rates could increase our net interest expense and negatively impact our financial results. Additionally, we are exposed to interest rates upon the refinancing of maturing long-term debt and anticipated future financing needs at prevailing interest rates.

Ability to Pay Dividends

The payment of dividends is at the discretion of our Board. All dividends will be reviewed by the Board and may be increased, reduced or suspended from time to time. Our ability to pay dividends and the actual amount of such dividends is dependent upon, among other things, our financial performance, our debt covenants and obligations, our ability to meet our financial obligations as they come due, our working capital requirements, our future tax obligations, our future capital requirements and the risk factors set forth in this AIF.

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 general risks affecting the oil and gas industry. Our operational risks include, but are not limited to: operational and safety considerations; pipeline transportation and interruptions; phased growth execution; uncertainty of reserves and resources estimates; reservoir performance and technical challenges; partner risks; competition; technology; third-party claims; land claims; key personnel; and information systems.

Health and Safety

The operation of our properties is subject to hazards of finding, recovering, transporting and processing hydrocarbons, including but not limited to: blowouts; fires; explosions; gaseous leaks; migration of harmful substances; oil spills; corrosion; and acts of vandalism and terrorism. Any of these hazards can interrupt operations, impact our reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology systems, related data and control systems, and cause environmental damage that may include polluting water, land or air.

Transportation Capacity and Pipeline Interruptions

Our production is transported through various pipelines and our refineries are reliant on various pipelines to receive feedstock. Disruptions in, or restricted availability of pipeline service, could adversely affect our crude oil and natural gas sales, projected production growth, refining operations and our cash flow. Interruptions or restrictions 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 and restrictions 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 extra long-term take-away capacity will be made by applicable third party pipeline providers or that the application will receive the required regulatory approval. 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. There is also no certainty that crude-by-rail transportation and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on the pipeline system. In addition, our crude-by-rail shipments may be impacted by service delays, inclement weather or derailment and could adversely impact our crude oil sales volumes or the price received for our product. Our product or railcars may be involved in a derailment or incident that results in legal liability or reputational harm. In addition, if new regulation is introduced, including but not limited to the potential amendment of the safety standards for tank cars used to transport crude oil, it could adversely affect our ability to ship crude oil by rail or the economics associated with rail transportation. Finally, planned or unplanned shutdowns or closures of our refinery customers may limit our ability to deliver product with negative implications on sales and cash from operating activities.

Operational Considerations

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 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 failure or transportation disruptions; weather; 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.

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 royalty payments and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities, 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 current estimates and such variances may 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 condition, 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 similar 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. Actual results may vary significantly from these estimates and such variances could be material. For additional information on resources and their associated contingencies, see "Contingent and Prospective Resources" in this AIF.

Project 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; our ability to source or complete strategic transactions; 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.

Partner Risks

Some of our assets are not operated by us or are held in partnership with others. Therefore, our results of operations may be affected by the actions of third-party operators or partners.

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 held in a partnership with Phillips 66 and operated by Phillips 66. The success of our refining operations is dependent on the ability of Phillips 66 to successfully operate this business and maintain the refining assets. We rely on the judgment and operating expertise of Phillips 66 in respect of the operation of such refining assets and we also rely on Phillips 66 to provide us with information on the status of such refining assets and related results of operations.

ConocoPhillips or Phillips 66, as unrelated third parties, 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 each respective partner, while certain operational decisions may be made by the operator of the applicable assets. While Cenovus and its partners 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, our ability to obtain or maintain necessary licenses or approvals or affect the timing of undertaking various activities.

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 or 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 which may decrease the market price of crude oil and increase our input costs for skilled labour and materials.

Technology

Current SAGD technologies for the recovery of bitumen are energy intensive, requiring significant consumption of natural gas 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. 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 which may affect our business. In particular, aboriginal groups have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal groups have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the Regional Municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including certain lands in Christina Lake. Such claims, if successful, could have an adverse effect on operations in the affected areas. No certainty exists that any lands currently unaffected by claims brought by aboriginal groups will remain unaffected by future claims.

Personnel

Our success is dependent upon our management and the quality of our personnel. Failure to retain current personnel or to attract and retain new personnel with the necessary skills and competencies 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 certain business critical information systems could result in operational difficulties, damage or loss of data, productivity losses or result in unauthorized knowledge and use of information.

Environment & 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, but not limited to: land tenure; permitting of production projects; royalties; taxes (including income taxes); government fees; production rates; environmental protection controls; protection of certain species or lands; provincial and federal land use designations; 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.

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 royalty rate that we are charged on our oil sands production is 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 may have a negative impact 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. The potential for changes in the royalty and mineral tax regimes applicable in the provinces we operate creates uncertainty relating to the ability 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, other laws or government incentive programs may in the future be changed or interpreted in a manner that adversely affects us and our shareholders. Tax authorities having jurisdiction over us or our shareholders may disagree with the manner in which we calculate our tax liabilities or could change their administrative practices to our detriment or the detriment of our shareholders.

Environmental Regulations

All phases of crude oil, natural gas and refining operations are subject to environmental regulation pursuant to a variety of Canadian and U.S. 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 regulations impose, 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 in the environment. They also impose 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 and the imposition of environmental protection orders. Although it is not expected that the costs of complying with environmental regulation 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 environmental regulations or the modification of existing environmental regulations affecting the crude oil and natural gas industry generally could reduce demand for crude oil and natural gas and increase our costs.

Climate Change Regulations

The Canadian federal government, various provincial governments and U.S. federal and state governments have announced intentions to regulate GHG emissions and other air pollutants (collectively, "regulations"). Some of these regulations are in effect while others remain in various phases of review, discussion or implementation in the U.S. and Canada. Uncertainties exist relating to the timing and effects of these 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 or regulation is enacted and applies to our business in any jurisdiction in which we operate or conduct business, may include, but are not limited to: increased compliance costs; permitting delays; substantial costs to generate or purchase emission credits or allowances adding costs to the products we produce; and reduced demand for crude oil and certain refined products. Emission allowances or offset credits may not be available for acquisition 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 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 climate change regulations will not be significant to us.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs or additional regulations 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.

Low Carbon Fuel Standards

Existing and proposed environmental legislation in certain U.S. states, Canadian provinces and in the European Union, regulating carbon fuel standards could result in increased costs and reduced revenue. The potential regulation may negatively affect the marketing of our bitumen, crude oil or refined products, and require us to purchase emissions credits in order to affect sales in such jurisdictions.

The state of California has implemented climate change regulation in the form of a Low Carbon Fuel Standard that requires the reduction of life cycle carbon emissions from transportation fuels. As an oil sands producer, Cenovus is not directly regulated and is not expected to have a compliance obligation. Refiners in California will be required to comply with the legislation. A number of studies produced on the subject, including one that was conducted by an organization that advised on the legislation, suggest a wide range of carbon intensity values for oil sands crudes. We believe that we are well positioned within the sector given our historically low steam to oil ratio.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that impose stringent and costly requirements. Of specific note is the Energy Independence & Security Act of 2007 ("EISA 2007") that established energy management goals and requirements. Pursuant to EISA 2007, among other things, the Environmental Protection Agency issued the Renewable Fuel Standard program that mandates the total volume of renewable transportation fuel sold or introduced in the U.S. and require refiners to blend renewable fuels such as ethanol and advanced biofuels with their gasoline. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. To the extent refineries do not blend renewable fuels into their finished products, they must purchase credits, referred to as Renewable Identification Numbers ("RINs"), in the open market. A RIN is a number assigned to each gallon of renewable fuel produced or imported into the U.S., and were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

Our refineries do not blend renewable fuels into the motor fuel products they produce and, consequently, we are obligated to purchase RINs in the open market, where prices fluctuate. In the future, the regulations could change the volume of renewable fuels required to be blended with refined products, creating volatility in the price for RINs or an insufficient number of RINs being available in order to meet the requirements. Our financial condition, results of operations, and cash flow may be materially adversely impacted as a result.

Alberta's Land-Use Framework

Alberta's Land-Use Framework has been implemented under the Alberta Land Stewardship Act ("ALSA") which 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. In some cases, ALSA amends or extinguishes 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 has approved its Lower Athabasca Regional Plan ("LARP"), which was issued under the ALSA. The LARP identifies management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. In 2013, we received compensation of $20 million, including interest, from the Government of Alberta related to some of our non-core Oil Sands mineral rights that were cancelled. The cancelled mineral rights had no direct impact on our business plan, our current operations at Foster Creek and Christina Lake, or on any of our filed applications. Uncertainty exists with respect to the impact to future development applications in the areas covered by the LARP, including the potential for development restrictions and mineral rights cancellation.

The Government of Alberta recently announced its South Saskatchewan Regional Plan ("SSRP"), the second and similar regional plan to be developed under the ALSA. This plan applies to Cenovus's conventional oil and gas operations in Southern Alberta. Public consultations are currently in progress and the SSRP is expected to be implemented starting in 2015. To date, the SSRP is not expected to materially impact Cenovus's existing conventional oil and gas operations, but no assurance can be given that future expansion of these operations will not be affected.

Species at Risk Act

The federal legislation, *Species at Risk Act,* and provincial counterparts regarding threatened or endangered species may limit the pace and the amount of development in areas identified as critical habitat for species of concern (e.g. woodland caribou). Recent litigation against the federal government in relation to the *Species at Risk Act* has raised issues associated with the protection of species at risk and their critical habitat both federally and on a provincial level. In Alberta, the Alberta Caribou Action and Range Planning Project has been established to develop range plans and action plans with a view to achieving the maintenance and recovery of Alberta's 15 caribou populations. The federal and/or provincial implementation of measures to protect species at risk such as woodland caribou and their critical habitat in areas of Cenovus's current or future operations may limit our pace and amount of development and, in some cases, may result in an inability to further develop or continue to develop or operate in affected areas.

Alberta's Regulatory Enhancement Project

A comprehensive, multi-stakeholder review of Alberta's regulatory system, the Regulatory Enhancement Project, was initiated by the Government of Alberta in March 2010 with the intention of creating an effective regulatory system that contributes to Alberta's overall competitiveness while protecting the environment, ensuring public safety and conservation of resources. As part of the implementation of the resulting recommendations, on October 24, 2012, the Government of Alberta introduced Bill 2, the Responsible Energy Development Act. With the intention to streamline and reduce costs of regulations of upstream energy resource activities, a single provincial regulator was introduced in June 2013, the AER, and is expected to take-over responsibilities from Alberta Environment and Sustainable Resource Development by March 2014. The AER has also assumed the regulatory functions of the Energy Resources Conservation Board with respect to oil, gas, oil sands and coal development.

During the transition period to the new single regulator, regulatory applications and proceedings have been delayed, which may negatively impact our development plans.

Alberta Environment and Sustainable Resource Development Water Licences

We currently utilize fresh water in certain operations, which is obtained under licenses from Alberta Environment and Sustainable Resource Development to provide, for example, domestic and utility water at our SAGD facilities and for our bitumen delineation programs. 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.

Alberta Wetlands Policy

In September 2013, the Government of Alberta approved a new wetlands policy to be implemented in 2015. This new policy is not expected to affect our existing operations in Foster Creek, Christina Lake and Narrows Lake, where our ten year wetlands mitigation and monitoring plans were recently approved under the existing wetlands policy. However, new project developments and phase expansions may be affected by this new policy in 2015.

Under the new policy, wetlands will be ranked by significance, with new projects in high-ranking wetlands areas having to either avoid the area entirely or offset the disturbance by reclaiming another high-ranking wetlands area. As the methodology for ranking wetlands is still under development, we are unable to predict the total impact of the new policy on any planned future developments.

Reputation Risks

We rely on our reputation to build and maintain positive relationships with our stakeholders, to recruit and retain staff, and to be a credible, trusted company. Any actions we take that cause negative public opinion have the potential to negatively impact our reputation which may adversely affect our share price, our development plan and our ability to continue operations. The increasing use of social media has especially heightened the need for reputational risk management.

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 that much of the focus is on bitumen mining operations and not in-situ production, public concerns about oil sands generally and GHG emissions and water and land use practices in oil sands developments specifically 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

Arrangement Related Risk

We have certain post-Arrangement indemnification and other obligations under each of the arrangement agreement (the "Arrangement Agreement") and the separation and transition agreement (the "Separation Agreement"), both of which are among Encana, 7050372 and Subco, dated October 20, 2009 and November 30, 2009 respectively, entered in connection with the Arrangement. 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.

A discussion of additional risks, should they arise after the date of this AIF, 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 most recent Management's Discussion and Analysis, available at www.sedar.com, www.sec.gov and cenovus.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

During the year ended December 31, 2013, there were 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.

During the year ended December 31, 2013, there were no 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 or companies, in each case, as at the date of this AIF, 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, 2013, 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 – Other Risk Factors – Arrangement Related Risk".

INTERESTS OF EXPERTS

Our independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditor's report dated February 12, 2014 in respect of our Consolidated Financial Statements which comprise the Consolidated Balance Sheets as at December 31, 2013, December 31, 2012 and January 1, 2012 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for the years ended December 31, 2013, 2012, and 2011 and Cenovus's internal control over financial reporting as at December 31, 2013. 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.

Information relating to reserves and resources in this AIF 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:
Computershare Investor Services Inc.
8th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
Canada

In the United States:
Computershare Trust Company NA
250 Royall St.
Canton, MA 02021
U.S.

Tel: 1-866-332-8898 Website: www.investorcentre.com/cenovus

ADDITIONAL INFORMATION

Additional information relating to Cenovus is available on SEDAR at www.sedar.com, and EDGAR at www.sec.gov. Additional financial information is contained in our audited Consolidated Financial Statements and MD&A for the year ended December 31, 2013. Additional disclosure, including directors' and officers' remuneration, principal holders of our securities, securities authorized for issuance under our equity-based compensation plans and our statement of corporate governance practices, is included in our management proxy circular for our most recent annual meeting of shareholders.

Disclosure regarding the contribution of each reportable segment to revenues and earnings can be found in our audited Consolidated Financial Statements and MD&A for the year ended December 31, 2013, which disclosure is incorporated by reference into this AIF.

As a Canadian corporation listed on the NYSE, we are not required to comply with most of the NYSE's corporate governance standards, and instead may comply with Canadian corporate governance practices. However, we are required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. Except as summarized on our website at cenovus.com, we are in compliance with the NYSE corporate governance standards in all significant respects.

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. The information contained in this AIF is dated as at December 31, 2013 unless otherwise indicated. Numbers presented are rounded to the nearest whole number and tables may not add due to rounding.

Unless otherwise indicated, all financial information included in this AIF has been prepared in accordance with International Financial Reporting Standards, which are also generally accepted accounting principles for publicly accountable enterprises in Canada.

ABBREVIATIONS AND CONVERSIONS

Oil and Natural Gas Liquids

bbl	barrel
bbls/d	barrels per day
Mbbls/d	thousand barrels per day
MMbbls	million barrels
NGLs	natural gas liquids
BOE	barrel of oil equivalent
BOE/d	barrels of oil equivalent per day
WTI	West Texas Intermediate
TM	Trademark of Cenovus Energy Inc.

Natural Gas

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 AIF, certain natural gas volumes have been converted to BOE on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of six Mcf to one bbl 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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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, 2013.

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 January 13, 2014	Canada	28,345
GLJ Petroleum Consultants Ltd.	Cenovus Energy Inc. Corporate Evaluation Janaury 10, 2014	Canada	2,140
			30,485

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. Welch
McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

(signed) Keith Braaten
GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 11, 2014

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, 2013, 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 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) Ivor M. Ruste
Executive Vice-President &
Chief Financial Officer

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

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

February 12, 2014

APPENDIX C

AUDIT COMMITTEE MANDATE

I. PURPOSE

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

The Committee's primary duties and responsibilities are to:

- Oversee and monitor the effectiveness and integrity of the Corporation's accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting compliance.
- Oversee audits of the Corporation's financial statements.
- Review and evaluate the Corporation's risk management framework and related processes including the supporting guidelines and practice documents.
- 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.
- Oversee and monitor the qualifications, independence and performance of the Corporation's external auditors and internal auditing group.
- Provide an avenue of communication among the external auditors, management, the internal auditing group, 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

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 ("CSA") 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 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, if any, 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 Chair shall be a non-voting member of the Committee. See "Quorum" for further details.

Appointment of Committee 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.

Vacancies

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

Chair

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

If 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 Chair presiding at any meeting of the Committee shall not have a casting vote.

The items pertaining to the Chair 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.

Secretary

The Committee shall appoint a Secretary who need not be a member of the Committee. The Secretary shall keep minutes of the meetings of the Committee.

Meetings

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

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

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.

Attendance at Meetings

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.

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

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 Chair or by a majority of the members of the Committee.

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 if the Committee deems it appropriate to do so. Review the summary of the Committee's composition and responsibilities in the Corporation's annual report, annual information form or other public disclosure documentation.

Review the 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 and Annual Information Form filed with the CSA and 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 shall include:

    (a) The annual financial statements and related notes 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) The use of off-balance sheet financing including management's risk assessment and adequacy of disclosure.

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

    (e) Any significant changes required in the external auditors' audit plan.

    (f) 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) 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.

Quarterly Financial Statements

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

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

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

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

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 CSA or SEC or news releases related thereto, and consider whether the information is consistent with the information contained in the financial statements of the Corporation or any subsidiary with public securities.

Internal Control Environment

5. Receive and review from management, the external auditors and the internal auditors 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 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.

8. 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.

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

Risk Oversight

10. Review and evaluate the Corporation's risk management framework and related processes including the supporting guidelines and practice documents.

Other Review Items

11. 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.

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

13. 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.

14. Review legal and regulatory matters, including correspondence with and reports received from regulators and government agencies, that may have a material impact on the interim or annual financial statements and related corporate compliance policies and programs. Members from the Legal and Tax groups should be at the meeting in person to deliver their respective reports.

15. 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.

16. Ensure that the Corporation's presentation of reserves has been reviewed with the Reserves Committee of the Board.

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

18. Review (a) 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 and (b) a summary of any significant investigations regarding such matters.

19. Meet on a periodic basis separately with management.

External Auditors

20. 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.

21. 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 Chair of the Committee or by a majority of the members of the Committee.

22. 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 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.

23. 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.

24. 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.

25. 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.

26. Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 22 through 25, 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 to the Board its conclusions in this respect.

27. Review 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.

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

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

30. 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 Group and Independence

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

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

33. Confirm and assure, annually, the independence of the internal audit group and the external auditors.

Approval of Audit and Non-Audit Services

34. 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 CSA and SEC legislation and regulations, which services are approved by the Committee prior to the completion of the audit).

35. 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.

36. If the pre-approvals contemplated in paragraphs 34 and 35 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.

37. 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 34 through 36. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

38. Establish policies and procedures for the pre-approvals described in paragraphs 34 and 35 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 to management of the Committee's responsibilities under the Exchange Act or applicable CSA and SEC legislation and regulations.

Other Matters

39. Review and concur in the appointment, replacement, reassignment, or dismissal of the Chief Financial Officer.

40. Upon a majority vote of the Committee outside resources may be engaged where and if deemed advisable.

41. Report Committee actions to the Board of Directors with such recommendations as the Committee may deem appropriate.

42. 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.

43. Determine the appropriate funding for payment by the Corporation (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.

44. Obtain assurance from the external auditors that no disclosure to the Committee is required pursuant to the provisions of the Exchange Act regarding the discovery of illegal acts by the external auditors.

45. Review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Board for approval.

46. Consider for implementation any recommendations of the Nominating and Corporate Governance Committee of the Board with respect to the Committee's effectiveness, structure, processes or mandate.

47. Perform such other functions as required by law, the Corporation's by-laws or the Board of Directors.

48. Consider any other matters referred to it by the Board of Directors.

cenovus ENERGY

500 Centre Street SE
PO Box 766
Calgary, AB T2P 0M5

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2013

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated February 12, 2014, should be read in conjunction with our December 31, 2013 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 12, 2014, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A, while the Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended its approval by the Board, which occurred on February 12, 2014. Additional information about Cenovus, including our quarterly and annual reports and the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

This MD&A and the Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated and have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Production volumes are presented on a before royalties basis.

Non-GAAP Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the Financial Results or Liquidity and Capital Resources sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On December 31, 2013, we had a market capitalization of approximately $23 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S."). Our 2013 average crude oil and NGLs (collectively, "crude oil") production was in excess of 179,000 barrels per day and our average natural gas production was 529 MMcf per day. Our refinery operations processed an average of 442,000 gross barrels per day of crude oil feedstock into an average of 463,000 gross barrels per day of refined product.

Our Strategy

Our strategy is to create long-term value through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on continually building our net asset value and paying a strong and sustainable dividend.

Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:

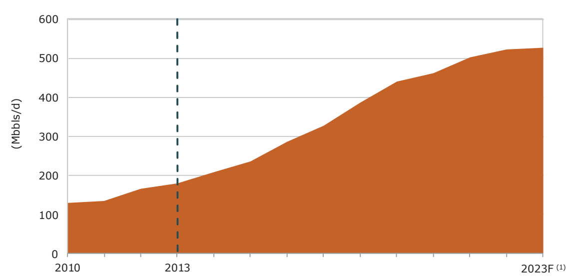
- Oil sands for growth;
- Conventional crude oil for near-term cash flow and diversification of our revenue stream;
- Natural gas for the fuel we use at our oil sands and refining facilities and for the cash flow it provides to help fund our capital spending programs; and
- Refining to help reduce the impact of commodity price fluctuations.

To achieve our expected production targets noted below, we anticipate our total annual capital investment to average between $3.0 and $3.7 billion for the next decade. This capital investment is expected to be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations as well as prudent use of our balance sheet capacity. We continue to focus on executing our 10-year business plan in a predictable and reliable way, leveraging the strong foundation we have built to date.

Oil Production

We plan to increase our net oil sands bitumen production to approximately 435,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 525,000 barrels per day by the end of 2023. We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek, Christina Lake, Narrows Lake, Telephone Lake, Pelican Lake and our conventional tight oil opportunities. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 300-450 gross stratigraphic test wells each year for the next five years.

Total Crude Oil Production, net to Cenovus



(1) Expected net production.

Oil Sands

Our operations include the following steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta:

	2013 Ownership Interest (percent)	2013 Net Production Volumes (bbls/d)	2013 Gross Production Volumes (bbls/d)	Current Expected Gross Production Capacity (bbls/d)
Existing Projects				
Foster Creek	50	53,190	106,380	310,000
Christina Lake	50	49,310	98,620	310,000
Narrows Lake	50	-	-	130,000
Emerging Projects				
Telephone Lake	100	-	-	300,000
Grand Rapids	100	-	-	180,000

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and jointly owned with ConocoPhillips, an unrelated U.S. public company. They are located in the Athabasca region of northeastern Alberta.

Foster Creek is producing from phases A through E. Expansion work is underway at phases F, G and H with added production capacity from phase F expected in the third quarter of 2014 and phases G and H in 2015 and 2016, respectively. In the first quarter of 2013, we submitted a joint application and environmental impact assessment ("EIA") for Foster Creek phase J, a 50,000 barrel per day phase. We anticipate receiving regulatory approval in the first quarter of 2015.

Christina Lake is producing from phases A through E. Our phase E expansion commenced steam injection in June 2013 and first production was achieved in July 2013. Expansion work is currently underway for phase F, including cogeneration, and phase G, with added production capacity expected in 2016 and 2017, respectively. In the first quarter of 2013, we submitted an EIA for Christina Lake phase H, a 50,000 barrel per day phase. We anticipate receiving regulatory approval in the fourth quarter of 2014.

For our Narrows Lake property, we received regulatory approval in May 2012 for phases A, B and C, and final partner approval for phase A, a 45,000 barrel per day phase, in December 2012. Construction of the phase A plant commenced in August 2013 and we anticipate first production in 2017.

Two of our emerging projects are Telephone Lake and Grand Rapids. At our Telephone Lake project located within the Borealis region, we commenced a dewatering pilot in the fourth quarter of 2012 and we completed the pilot in October 2013. We successfully displaced water with compressed air, displacing approximately 70 percent of below-ground top water. In December 2011, we submitted a revised joint application and EIA due to an increase in the Telephone Lake project development area. We anticipate receiving regulatory approval in the second quarter of 2014. At our Grand Rapids project located within the Greater Pelican region, a SAGD pilot project is underway. We anticipate receiving regulatory approval in the first quarter of 2014 for a 180,000 barrel per day commercial SAGD operation.

Conventional

Crude oil production from our Conventional business segment continues to generate predictable near-term cash flows. This production provides diversification to our revenue stream and enables further development of our oil sands assets. Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations and provides cash flows to help fund our growth opportunities.

	2013	
($ millions)	Crude Oil [1]	Natural Gas
Operating Cash Flow [2]	1,388	415
Capital Investment	1,169	22
Operating Cash Flow net of Related Capital Investment	219	393

(1) Includes NGLs.
(2) Non-GAAP measure defined in this MD&A.

We have established conventional crude oil and natural gas producing assets and developing tight oil assets in Alberta. We also inject carbon dioxide to enhance oil recovery at our Weyburn operations in Saskatchewan. Located in the Athabasca region of northeastern Alberta is our wholly owned Pelican Lake property. This property produces conventional heavy oil using polymer flood technology.

Refining and Marketing

Our operations include two refineries located in Illinois and Texas that are jointly owned with and operated by Phillips 66, an unrelated U.S. public company.

	2013 Ownership Interest (percent)	2013 Gross Nameplate Capacity (Mbbls/d)
Wood River [1]	50	311
Borger	50	146

(1) Effective January 1, 2014, Wood River has a nameplate capacity of 314,000 barrels per day.

Our refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with North American commodity price movements. This segment also includes our marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

($ millions)	2013
Operating Cash Flow [1]	1,143
Capital Investment	107
Operating Cash Flow net of Related Capital Investment	1,036

(1) Non-GAAP measure defined in this MD&A.

Technology and Environment

Both technology development, including research activities, and the environment are playing increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing our own technology with the goals of increasing recoveries from our reservoirs, while reducing the amount of water, natural gas and electricity consumed in our operations, and minimizing our environmental disturbance. The Cenovus culture fosters the pursuit of new ideas and new approaches, potentially reducing costs. We have a track record of developing innovative solutions that unlock challenging crude oil resources and builds on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Dividend

Our disciplined approach to capital allocation includes continuing to pay a strong and sustainable dividend as part of delivering total shareholder return. We paid dividends of $0.968 per share in 2013, a 10 percent increase from 2012 (2012 – $0.88 per share; 2011 – $0.80 per share).

Net Asset Value

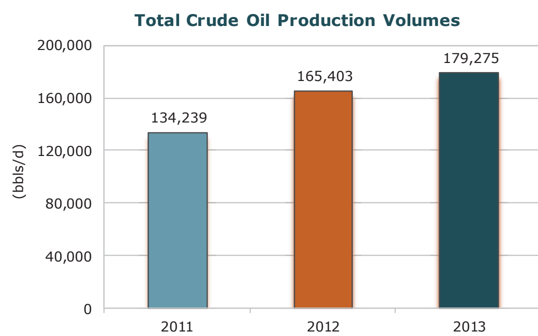
We measure our success in a number of ways with a key measure being growth in net asset value. In 2013, our net asset value was positively impacted by our overall operational and financial performance offset by the impact of changing commodity prices. We continue to believe that our goal of doubling December 2009 net asset value by the end of 2015 is achievable.

2013 OPERATING AND FINANCIAL HIGHLIGHTS

2013 continued to reflect the strength of our integrated approach. Overall, the integration of our business and growing crude oil production helped to reduce the impact of commodity price fluctuations. We completed our planned capital programs, submitted regulatory applications for expansions at Foster Creek and Christina Lake and increased our rail shipping capacity.

Operational Results

Total crude oil production averaged 179,275 barrels per day, an increase of eight percent from 2012.



Crude oil production from our Oil Sands segment averaged 102,500 barrels per day, an increase of 14 percent, primarily driven by increased production at Christina Lake. Average production at Christina Lake was 49,310 barrels per day, a 55 percent increase, as phase D reached full capacity and phase E, our tenth expansion phase at Cenovus, started to produce in July 2013. Phase E increases nameplate capacity to 138,000 gross barrels per day. The phase E ramp-up is proceeding similar to the ramp-up of phases C and D, which reached nameplate capacity within six to nine months of first production.

Foster Creek production averaged 53,190 barrels per day, a decrease of eight percent, resulting from a number of production matters that are discussed in the Reportable Segments section under Oil Sands.

Our Conventional crude oil production averaged 76,775 barrels per day, an increase of one percent, due to strong horizontal well performance from our current drilling program in southern Alberta and higher Pelican Lake production, offset by decreased production due to the sale of our Lower Shaunavon asset in July 2013, and expected natural declines. Pelican Lake production averaged 24,254 barrels per day, an increase of eight percent resulting from additional infill wells coming on-stream throughout 2012 and 2013, as well as an increased response from the polymer flood program.

Our proved bitumen reserves increased eight percent to over 1.8 billion barrels and our economic bitumen best estimate contingent resources increased two percent to 9.8 billion barrels, highlighting our strong resource base. Additional information about our resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

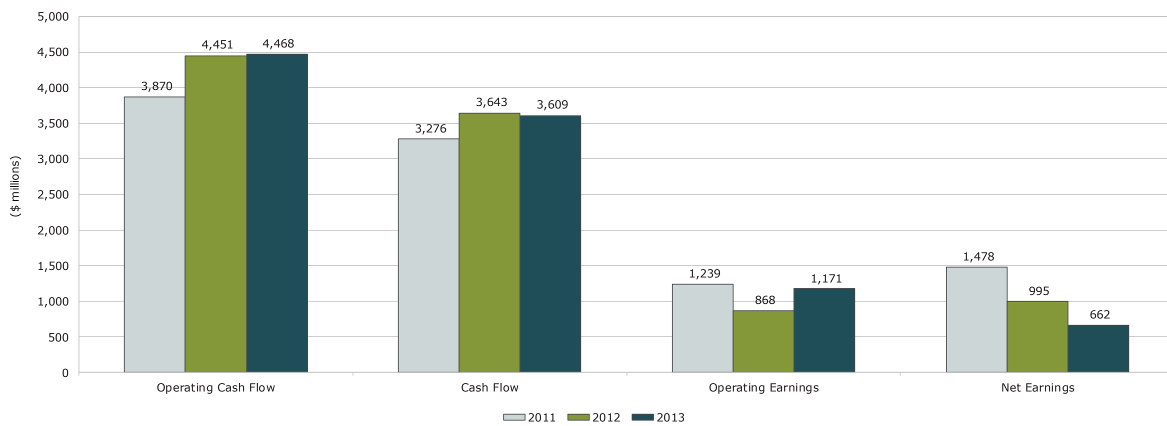
Our refining operations processed an average of 442,000 (2012 – 412,000) gross barrels per day of crude oil, of which 222,000 gross barrels per day was heavy crude oil (2012 – 198,000). We produced 463,000 gross barrels per day of refined products, an increase of about 30,000 gross barrels per day or seven percent, as refined product output last year was impacted by planned turnarounds at both refineries.

Other significant operational results in 2013 compared with 2012 include:

- Receiving regulatory approval for an optimization program for Christina Lake phases C, D and E which is expected to add up to 22,000 barrels per day of gross capacity in 2015;
- Completing our first major planned turnaround at Christina Lake;
- The closing of the Lower Shaunavon asset divestiture for proceeds of approximately $240 million;
- Managing our natural gas production, which declined 11 percent to an average of 529 MMcf per day due to expected natural declines; and
- Increasing our access to new sales markets by increasing our rail shipping capacity to 10,000 barrels per day by the end of 2013.

Financial Results

Operating Cash Flow(1), Cash Flow, Operating Earnings and Net Earnings



(1) For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.

Our integrated approach has resulted in consistent and predictable financial results. Operating Cash Flow and Cash Flow remained relatively flat in 2013 as compared to 2012.

Financial highlights for 2013 compared with 2012 include:

Revenues

Revenues of $18,657 million, increasing $1,815 million or 11 percent as a result of:

- Refining and Marketing revenues rising $1,350 million primarily due to higher refinery output, partially offset by declines in refined product prices. Revenues from third-party sales of crude oil were higher as a result of a rise in purchased crude oil volumes and higher crude oil and condensate pricing;
- Crude oil sales volumes increasing eight percent;
- Our average crude oil and natural gas sales prices (excluding financial hedging) rising two percent to $67.01 per barrel and 32 percent to $3.20 per Mcf, respectively; and
- A rise in condensate volumes and prices used in blending.

These increases to revenues were partially offset by declines in natural gas production volumes.

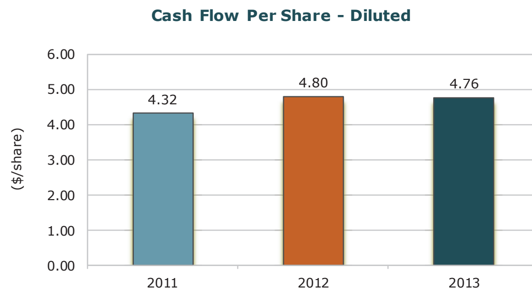
Operating Cash Flow

In 2013, Operating Cash Flow was $4,468 million, an increase of $17 million. Upstream Operating Cash Flow increased $147 million, or five percent, to $3,325 million due to higher crude oil production volumes at Christina Lake and rising crude oil and natural gas sales prices, partially offset by lower realized risk management gains, increasing operating costs and declines in natural gas production volumes. Crude oil sales prices increased two percent primarily due to the rise in West Texas Intermediate ("WTI"), which averaged US$98.05 per barrel (2012 – US$94.15 per barrel) and the weakening of the Canadian dollar, despite the average decline in Western Canadian Select ("WCS") of US$0.27 per barrel.

These increases were partially offset by Operating Cash Flow from our Refining and Marketing segment decreasing $130 million to $1,143 million primarily due to lower market crack spreads and higher costs associated with Renewable Identification Numbers ("RINs"), partially offset by an improved feedstock cost advantage attributed to processing a higher proportion of heavy crude oil at a discounted price and an increase in refined product output. The Chicago and Midwest Combined 3-2-1 ("Group 3") market crack spreads decreased by approximately US$6 per barrel and US$8 per barrel, respectively. The discount of WCS relative to WTI continues to benefit our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

Cash Flow

Cash Flow decreased one percent to $3,609 million, remaining relatively flat as a result of consistent Operating Cash Flow in 2013 as compared to 2012, reflecting the strength of our integrated approach. Declines in Cash Flow were primarily due to higher pre-exploration expense, finance costs, excluding the unwinding of the discount on decommissioning liabilities, and general and administrative expenses, excluding non-cash long-term incentive costs. Decreases in cash tax compared to 2012 partially offset the decline in Cash Flow.



Operating Earnings

In addition to changes in Cash Flow discussed above, Operating Earnings increased $303 million, or 35 percent, to $1,171 million due to no goodwill impairment in 2013 compared to a goodwill impairment of $393 million recorded in 2012 and a decrease in deferred tax expense of $111 million, not including tax on unrealized risk management (gains) losses and non-operating unrealized foreign exchange (gains) losses. Higher Operating Earnings were partially offset by increased depreciation, depletion and amortization ("DD&A") as a result of higher production and higher DD&A rates.

Net Earnings

In addition to changes in Operating Earnings discussed above, Net Earnings decreased $333 million or 33 percent, to $662 million, primarily due to:

- After-tax unrealized risk management losses of $310 million compared with gains of $43 million in 2012;
- Realized foreign exchange losses of $146 million, after-tax, as a result of a decision made by our partner to pay the remaining principal on the Partnership Contribution Receivable (described further in the Financial Results section of this MD&A); and
- After-tax non-operating unrealized foreign exchange losses of $52 million compared with gains of $84 million in 2012.

Capital Investment

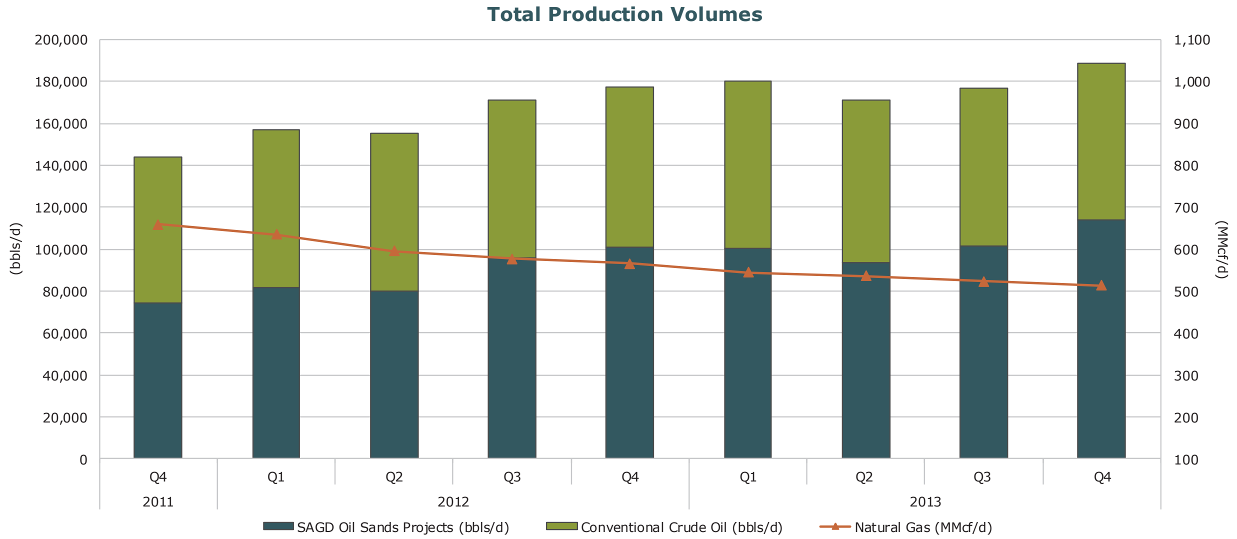
Capital investment was $3,262 million, decreasing three percent, primarily due to reduced capital investment in our Conventional segment, as a result of discontinued spending related to our Lower Shaunavon asset and declines in spending at Pelican Lake, and lower spending on corporate assets. Within our Oil Sands operations, there was a decrease in capital investment at Telephone Lake, as spending decreased with completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012. In 2013, spending related to the operation of the dewatering pilot, which was completed in the fourth quarter of 2013.

Declines in capital investment were partially offset by increases at Christina Lake and Foster Creek, with continued focus on the development of our expansion phases, and at Narrows Lake, with construction commencing on phase A in 2013.

Dividend

We paid dividends of $0.968 per share (2012 – $0.88 per share), an increase of 10 percent over 2012. This demonstrates our commitment to pay a strong and sustainable dividend as part of delivering total shareholder return.

OPERATING RESULTS



In 2013, the operating and reportable segments changed from those presented in prior periods to match Cenovus's new operating structure. Our Pelican Lake property is now being managed within our Conventional segment. All prior period results have been restated.

Crude Oil Production Volumes

(barrels per day)	**2013**	**Percent Change**	2012	Percent Change	2011
Oil Sands					
Foster Creek	**53,190**	**(8)%**	57,833	5%	54,868
Christina Lake	**49,310**	**55%**	31,903	173%	11,665
	102,500	**14%**	89,736	35%	66,533
Conventional					
Pelican Lake	**24,254**	**8%**	22,552	10%	20,424
Other Heavy Oil	**15,991**	**- %**	16,015	2%	15,657
Light & Medium Oil	**35,467**	**(2)%**	36,071	18%	30,524
NGLs [(1)]	**1,063**	**3%**	1,029	(7)%	1,101
	76,775	**1%**	75,667	12%	67,706
Total Crude Oil Production	**179,275**	**8%**	165,403	23%	134,239

(1) NGLs include condensate volumes.

In 2013, our crude oil production increased eight percent driven by higher production at Christina Lake as a result of phase D reaching full capacity in the first quarter of 2013 and phase E achieving first production in July 2013.

Foster Creek production decreased eight percent from 2012. In the fourth quarter of 2012, with production levels exceeding the nameplate capacity of our plant, we made a decision to defer some routine workover activity until 2013. That deferral of maintenance resulted in a backlog in the number of wells requiring workovers causing an unanticipated negative impact on our 2013 production volumes. See the Reportable Segments section of this MD&A for more detail.

Our crude oil production from the Conventional segment increased slightly due to better horizontal well performance from our current drilling program in southern Alberta and higher production from Pelican Lake partially offset by the divestiture of our Lower Shaunavon asset and expected natural declines. Pelican Lake production was higher in 2013 with additional infill wells coming on-stream throughout 2012 and 2013 and an increased response from our polymer flood program. In 2013, Lower Shaunavon, which was sold in early July, produced an annual average of 2,095 barrels per day (2012 – 4,411 barrels per day).

Natural Gas Production Volumes

(MMcf per day)	2013	2012	2011
Conventional	**508**	564	622
Oil Sands	**21**	30	34
	529	594	656

Spending on natural gas activities continues to be managed in response to the low natural gas price environment. We continue to focus on high rate of return projects and direct capital investment to our crude oil properties.

Operating Netbacks

	Crude Oil [1] ($/bbl)			**Natural Gas** ($/Mcf)		
	2013	2012	2011	**2013**	2012	2011
Price [2]	**67.01**	65.79	72.84	**3.20**	2.42	3.65
Royalties	**5.01**	6.29	9.84	**0.04**	0.03	0.06
Transportation and Blending [2]	**3.12**	2.65	2.76	**0.11**	0.10	0.15
Operating Expenses	**15.65**	13.90	13.47	**1.16**	1.10	1.10
Production and Mineral Taxes	**0.48**	0.56	0.56	**0.02**	0.01	0.04
Netback Excluding Realized Risk Management	**42.75**	42.39	46.21	**1.87**	1.18	2.30
Realized Risk Management Gain (Loss)	**1.09**	1.39	(2.79)	**0.32**	1.14	0.87
Netback Including Realized Risk Management	**43.84**	43.78	43.42	**2.19**	2.32	3.17

(1) *Includes NGLs.*
(2) *The crude oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate was $28.33 per barrel (2012 – $26.72 per barrel; 2011 – $24.91 per barrel).*

In 2013, our average crude oil netback, excluding realized risk management gains and losses, increased $0.36 per barrel from 2012, remaining relatively flat, primarily due to higher sales prices and lower royalties, partially offset by increased operating and transportation and blending costs. The rise in sales price is consistent with the increase in the average WTI price for 2013 and the weakening of the Canadian dollar.

Our average natural gas netback, excluding realized risk management gains and losses, increased $0.69 per Mcf predominantly due to higher sales prices, partially offset by higher per-unit operating costs as a result of the decline in production volumes.

Refining [1]

	2013	Percent Change	2012	Percent Change	2011
Crude Oil Runs (Mbbls/d)	**442**	**7%**	412	3%	401
Heavy Crude Oil	**222**	**12%**	198	57%	126
Refined Product (Mbbls/d)	**463**	**7%**	433	3%	419
Crude Utilization (percent)	**97**	**6%**	91	2%	89

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

In 2012, both of our refineries underwent planned turnarounds resulting in an increase to crude oil runs, refined product output and crude utilization in 2013. In addition, the heavy crude oil processed increased 12 percent, reflecting our ability to process a greater proportion of heavy crude oil feedstock and the optimization of our total crude input slate.

Further information on the changes in our production volumes, items included in our operating netbacks and refining statistics can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management section of this MD&A and in the notes to the Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates (1)

	Q4 2013	2013	2012	2011
Crude Oil Prices (US$/bbl)				
Brent				
Average	**109.35**	**108.70**	111.68	110.91
End of Period	**110.80**	**110.80**	111.11	107.38
WTI				
Average	**97.61**	**98.05**	94.15	95.11
End of Period	**98.42**	**98.42**	91.82	98.83
Average Differential Brent-WTI	**11.74**	**10.65**	17.53	15.80
WCS				
Average	**65.41**	**72.85**	73.12	77.96
End of Period	**74.80**	**74.80**	59.16	84.37
Average Differential WTI-WCS	**32.20**	**25.20**	21.03	17.15
Condensate (C5 @ Edmonton) Average	**94.37**	**101.77**	100.88	105.34
Average Differential WTI-Condensate (Premium)/Discount	**3.24**	**(3.72)**	(6.73)	(10.23)
Refining Margin 3-2-1 Average Crack Spreads (US$/bbl)				
Chicago	**12.29**	**21.77**	27.76	24.55
Group 3	**10.66**	**20.80**	28.56	25.26
Natural Gas Average Prices				
AECO (C$/Mcf)	**3.15**	**3.17**	2.41	3.67
NYMEX (US$/Mcf)	**3.60**	**3.65**	2.79	4.04
Basis Differential NYMEX-AECO (US$/Mcf)	**0.59**	**0.58**	0.38	0.31
Foreign Exchange Rates (US$/C$1)				
Average	**0.953**	**0.971**	1.001	1.012

(1) *These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the operating netbacks table in the Operating Results section of this MD&A.*

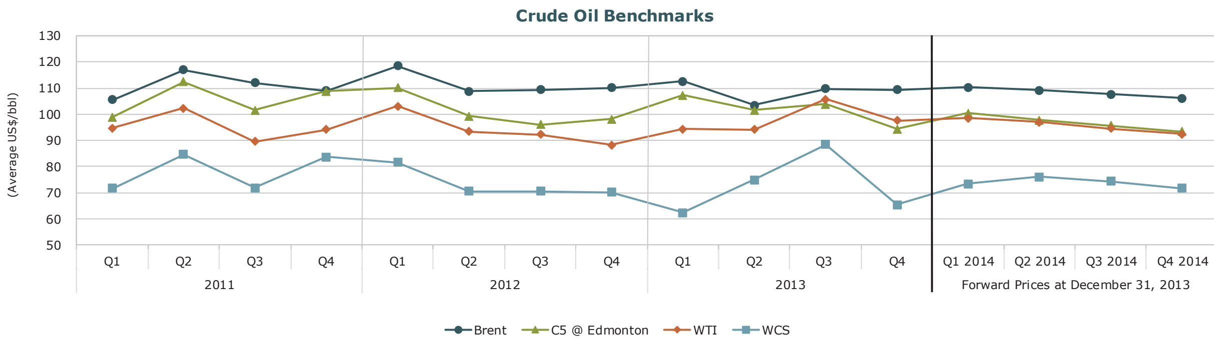
Crude Oil Benchmarks

The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of changes in inland refined product prices. In 2013, the average price of Brent crude oil declined by US$2.98 per barrel due to continued strong growth in North American crude oil supply partially offset by an increase in global crude oil demand and ongoing supply disruptions in various countries.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average discount between WTI and Brent narrowed in 2013 by US$6.88 per barrel as new pipeline infrastructure from the Cushing, Oklahoma area to the U.S. Gulf Coast relieved congestion that had developed recently due to the rapid growth in U.S. inland supply.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WTI-WCS average differential widened by US$4.17 per barrel due to continued growth in Canadian crude oil production and delays in the approval and construction of new pipeline capacity to U.S. markets.

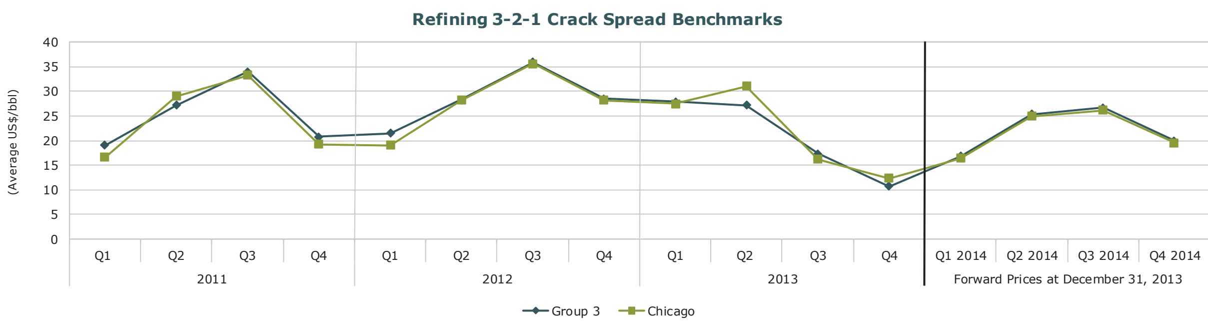
Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from approximately 10 percent to 33 percent. As the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices are driven by Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton. Condensate prices increased in 2013 by US$0.89 per barrel to US$101.77 per barrel due to increased demand for diluent by oil sands producers. During the fourth quarter of 2013, condensate prices decreased by US$3.77 per barrel from the same period last year due to an increase in condensate transportation capacity and growing condensate supply in the Gulf Coast. In the second half of 2013, condensate traded at a discount to WTI for the first time since the third quarter of 2010 due to the reductions in pipeline congestion causing WTI prices to increase more than condensate prices.



Refining 3-2-1 Crack Spread Benchmarks

The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and valued on a last in, first out accounting basis. Average market crack spreads in the U.S. inland Chicago and Group 3 markets fell in 2013 compared to 2012 primarily due to the strengthening of WTI prices as inland congestion issues were addressed.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, and feedstock costs which are based on a first in, first out accounting basis.



Other Benchmarks

Average natural gas prices increased in 2013 due to a slowing in the pace of supply growth and colder temperatures during the winter heating seasons.

A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on all of our revenues as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a weakened Canadian dollar improves our reported results, although a weaker Canadian dollar also increases our current period's reported refining capital investment. In 2013, the Canadian dollar weakened by $0.03 relative to the U.S. dollar due to interest rates rising faster in the U.S. compared with Canada as the U.S. economy improved, overall weaker commodity prices and concerns regarding the ability of anticipated increases in crude oil supply to access markets. The weakening of the Canadian dollar by three percent in 2013 as compared to 2012 had a positive impact of approximately $560 million on our revenues.

FINANCIAL RESULTS

Selected Consolidated Financial Results

The following key performance indicators are discussed in more detail within this section.

($ millions, except per share amounts)	**2013**	**Percent Change**	2012	Percent Change	2011
Revenues	**18,657**	**11%**	16,842	7%	15,696
Operating Cash Flow (1) (2)	**4,468**	**- %**	4,451	15%	3,870
Cash Flow (1)	**3,609**	**(1)%**	3,643	11%	3,276
Per Share – Diluted	**4.76**	**(1)%**	4.80	11%	4.32
Operating Earnings (1) (3)	**1,171**	**35%**	868	(30)%	1,239
Per Share – Diluted (3)	**1.55**	**36%**	1.14	(30)%	1.64
Net Earnings (3)	**662**	**(33)%**	995	(33)%	1,478
Per Share – Basic (3)	**0.88**	**(33)%**	1.32	(33)%	1.96
Per Share – Diluted (3)	**0.87**	**(34)%**	1.31	(33)%	1.95
Total Assets	**25,224**	**4%**	24,216	9%	22,194
Total Long-Term Financial Liabilities (4)	**6,113**	**- %**	6,128	13%	5,411
Capital Investment (5)	**3,262**	**(3)%**	3,368	24%	2,723
Cash Dividends	**732**	**10%**	665	10%	603
Per Share	**0.968**	**10%**	0.88	10%	0.80

(1) Non-GAAP measure and defined in this MD&A.
(2) For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.
(3) We restated prior periods as a result of adoption of new accounting standards. See Critical Accounting Judgments, Estimates and Accounting Policies within this MD&A for more detail.
(4) Includes Long-Term Debt, Partnership Contribution Payable, Risk Management Liability and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(5) Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.

Revenues

During 2013, revenues increased $1,815 million or 11 percent compared with 2012.

($ millions)	**2013 vs. 2012**	2012 vs. 2011
Revenues, Comparative Year	**16,842**	15,696
Increase (Decrease) due to:		
Oil Sands	**610**	739
Conventional	**177**	(100)
Refining and Marketing	**1,350**	731
Corporate and Eliminations	**(322)**	(224)
Revenues, End of Year	**18,657**	16,842

In 2013, upstream revenues rose $787 million, an increase of 14 percent, due to increased blended crude oil sales volumes, rising crude oil, condensate and natural gas sales prices and reduced royalties, partially offset by a decline in natural gas production.

Revenues generated by the Refining and Marketing segment in 2013 increased 12 percent as higher refined product output and a weakening of the Canadian dollar was partially offset by declines in refined product prices. Revenues from third-party sales, undertaken to provide operational flexibility, were higher as a result of a rise in purchased crude oil volumes and higher crude oil and condensate pricing.

Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices.

Revenues increased in 2012 compared with 2011 as a result of higher blended crude oil sales volumes in our upstream operations and higher refined product output and prices. Increases in revenues were partially offset by declines in the average crude oil and natural gas sales price.

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

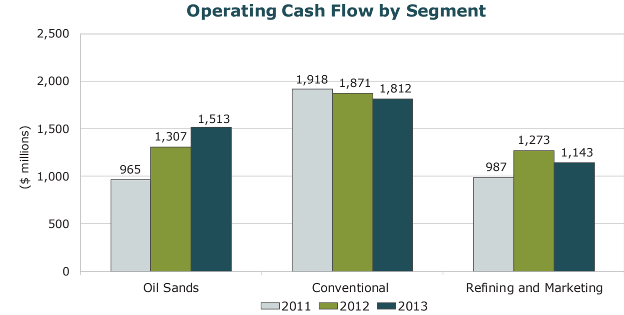
Operating Cash Flow

Operating Cash Flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between years. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Cash Flow.

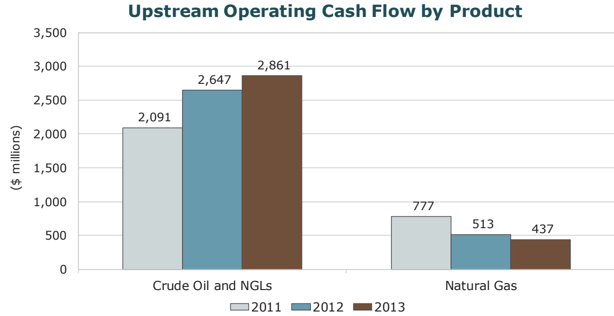
($ millions)	**2013**	2012	2011
Revenues	**19,262**	17,125	15,755
(Add) Deduct:			
Purchased Product	**11,004**	9,506	9,149
Transportation and Blending	**2,074**	1,798	1,369
Operating Expenses [1]	**1,803**	1,669	1,399
Production and Mineral Taxes	**35**	37	36
Realized (Gain) Loss on Risk Management Activities	**(122)**	(336)	(68)
Operating Cash Flow	**4,468**	4,451	3,870

(1) *For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.*

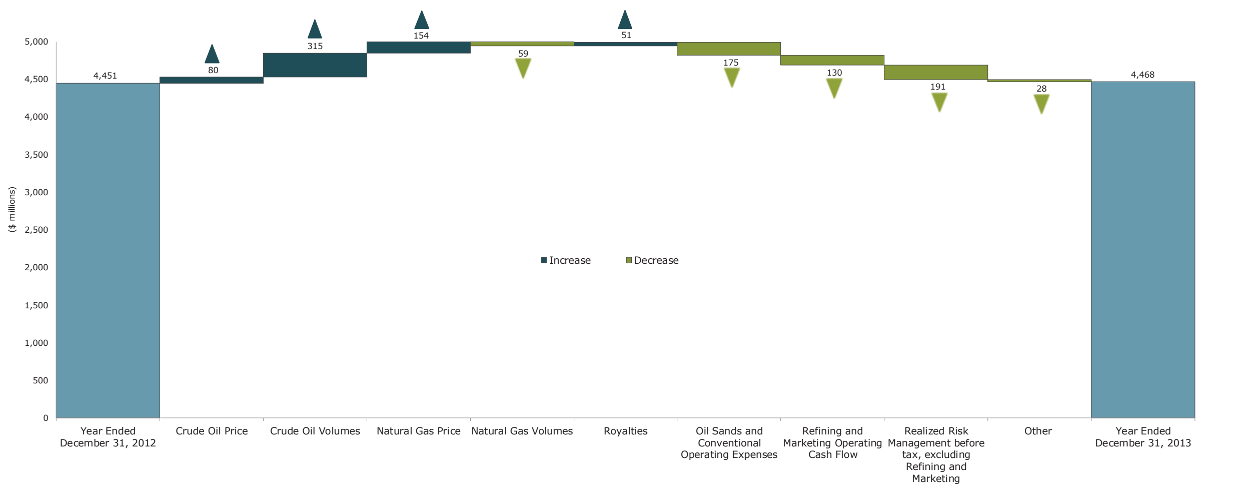
Operating Cash Flow by Segment



Upstream Operating Cash Flow by Product



Operating Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012



Total Operating Cash Flow in 2013 was $4,468 million, relatively unchanged from 2012. As highlighted in the above graph our Operating Cash Flow increased $17 million compared with 2012 primarily due to:

- An increase in our crude oil sales volumes by eight percent; and
- A 32 percent increase in our average natural gas sales price to $3.20 per Mcf and a two percent increase in our average crude oil sales price to $67.01 per barrel.

The increases were partially offset by:

- Realized risk management gains before tax, excluding Refining and Marketing, of $141 million compared with gains of $332 million in 2012;
- An increase in crude oil operating expenses of $184 million, partially due to higher crude oil production. On a per barrel basis, crude oil operating costs increased by $1.75 to $15.65 per barrel; and

- A decline in Operating Cash Flow from Refining and Marketing of $130 million primarily due to the decline in market crack spreads and an increase of $121 million in costs associated with RINs, partially offset by the benefit of processing a higher proportion of heavy crude oil feedstock at a discounted price and an increase in refined product output.

Additional details explaining the changes in Operating Cash Flow can be found in the Reportable Segments section of this MD&A.

Cash Flow

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

($ millions)	**2013**	2012	2011
Cash From Operating Activities	**3,539**	3,420	3,273
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(120)**	(113)	(82)
Net Change in Non-Cash Working Capital	**50**	(110)	79
Cash Flow	**3,609**	3,643	3,276

Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012

In 2013, Cash Flow decreased $34 million as a result of relatively flat Operating Cash Flow year-over-year, reflecting the strength of our integrated approach. Other changes in Cash Flow included:

- Pre-exploration expense of $64 million;
- An increase in finance costs primarily due to a US$32 million premium paid on the early redemption of the US$800 million of senior unsecured notes that were due in September 2014; and
- Higher general and administrative costs, excluding non-cash long-term incentive costs, due to higher rent and staffing costs.

The decreases in our Cash Flow were partially offset by lower current tax of $121 million primarily due to $68 million of withholding tax on a U.S. dividend in 2012, adjustments related to a change in legislation, the finalization of our 2012 tax filings and lower taxable U.S. earnings in the current year.

Operating Earnings

Operating Earnings is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings is defined as Net Earnings excluding after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management gains (losses) on derivative instruments, after-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, after-tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt, the effect of changes in statutory income tax rates and the after-tax realized foreign exchange loss on the early receipt of the Partnership Contribution Receivable described below.

On December 17, 2013, our partner exercised its right under the FCCL Partnership Agreement to early retire the remaining principal of the Partnership Contribution Receivable in the amount of US$1.4 billion, net to Cenovus. This resulted in the crystallization of realized foreign exchange losses of $146 million, after-tax, from a weakened Canadian dollar as compared to January 2, 2007, when the note was originally issued. This realized foreign exchange loss has been excluded from the calculation of Operating Earnings as it is not reflective of our ongoing operations.

($ millions)	**2013**	2012	2011
Net Earnings	**662**	995	1,478
Add (Deduct):			
Unrealized Risk Management (Gain) Loss, after-tax (1) (3)	**310**	(43)	(134)
Non-Operating Unrealized Foreign Exchange (Gain) Loss, after-tax (2) (3)	**52**	(84)	(14)
Realized Foreign Exchange Loss on Early Receipt of the Partnership Contribution Receivable, after-tax (3)	**146**	-	-
(Gain) Loss on Divestiture of Assets, after-tax	**1**	-	(91)
Operating Earnings	**1,171**	868	1,239

(1) The after-tax unrealized risk management (gains) losses include the reversal of unrealized (gains) losses recognized in prior periods.

(2) Includes after-tax unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange (gains) losses on settlement of intercompany transactions and deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

(3) The tax benefit of losses are recognized only to the extent that we have capital gains.

In 2013, with consistent Operating Cash Flow, Operating Earnings were $1,171 million, an increase of $303 million, primarily related to there being no goodwill impairment recorded in 2013. In 2012, we recorded a goodwill impairment of $393 million in our Conventional segment.

In addition, Operating Earnings increased due to:

- A decrease in deferred income tax expense of $111 million, not including income tax on unrealized risk management gains and non-operating unrealized foreign exchange losses, as a result of a decrease in income from our refining operations.

Partially offset by:

- Increased DD&A of $248 million as a result of higher production and increased DD&A rates. DD&A also includes an impairment loss of $57 million related to our Lower Shaunavon asset which was recorded in the second quarter of 2013.

Net Earnings

($ millions)	2013 vs. 2012	2012 vs. 2011
Net Earnings, Comparative Year	**995**	1,478
Increase (Decrease) due to:		
Operating Cash Flow (1)	**17**	581
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss), after-tax	**(353)**	(91)
Unrealized Foreign Exchange Gain (Loss)	**(110)**	28
Gain (Loss) on Divestiture of Assets	**(1)**	(107)
Expenses (2)	**(217)**	(57)
Depreciation, Depletion and Amortization	**(248)**	(290)
Goodwill Impairment	**393**	(393)
Exploration Expense	**(46)**	(68)
Income Taxes, Excluding Income Taxes on Unrealized Risk Management Gain (Loss)	**232**	(86)
Net Earnings, End of Year	**662**	995

(1) Non-GAAP measure defined in this MD&A.
(2) Includes general and administrative, research costs, finance costs, interest income, realized foreign exchange (gains) losses, after-tax, other (income) loss, net and Corporate and Eliminations operating expenses.

In addition to the changes discussed above in the Cash Flow and Operating Earnings sections, our Net Earnings decreased 33 percent in 2013 primarily due to after-tax unrealized risk management losses of $310 million compared with gains of $43 million in 2012, a realized foreign exchange loss of $146 million, after-tax, related to the receipt of the remaining principal on the Partnership Contribution Receivable as discussed above, and after-tax non-operating unrealized foreign exchange losses of $52 million compared with gains of $84 million in 2012 as a result of a weaker Canadian dollar in 2013.

Net Earnings decreased during 2012, compared with 2011, primarily due to a goodwill impairment in our Conventional segment and an increase in DD&A. Decreases were partially offset by higher upstream Operating Cash Flow, largely due to increased crude oil production volumes and higher upstream realized risk management gains before tax, and an increase in Operating Cash Flow from Refining and Marketing.

Net Capital Investment

($ millions)	2013	2012	2011
Oil Sands	**1,883**	1,693	1,098
Conventional	**1,191**	1,366	1,105
Refining and Marketing	**107**	118	393
Corporate and Eliminations	**81**	191	127
Capital Investment	**3,262**	3,368	2,723
Acquisitions	**32**	114	71
Divestitures	**(283)**	(76)	(173)
Net Capital Investment (1)	**3,011**	3,406	2,621

(1) Includes expenditures on PP&E and E&E.

Oil Sands capital investment in 2013 focused primarily on the development of the expansion phases at Foster Creek and Christina Lake and development of phase A at Narrows Lake. Capital investment includes the drilling of 339 gross stratigraphic test wells.

Conventional capital investment in 2013 was composed primarily of spending at Pelican Lake on the expansion of the polymer flood and drilling, completion, recompletion programs, and work on facilities at our other Conventional properties. Spending on natural gas activities continues to be managed in response to the low natural gas price environment.

Our capital investment in 2013 in the Refining and Marketing segment focused on capital maintenance and projects improving refinery reliability and safety.

Capital also includes spending on technology development, which plays an integral role in our business. Having an integrated innovation and technology development strategy is vital to our ability to maintain our track record of being a low cost producer, minimize our environmental footprint, and execute our projects with excellence. Our teams look for ways to improve existing operations and evaluate new ideas to enhance the recovery techniques we use to access crude oil and natural gas, and improve our refining processes. In 2013, our capital investment included $129 million on technology development activities. We expensed $24 million related to research activities.

Capital investment in our Corporate and Eliminations segment decreased as costs related to tenant improvements and information technology were lower due to the move into our new office space in the first quarter of 2013.

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

Acquisitions and Divestitures

In 2013, our primary acquisition was for undeveloped land adjacent to our Telephone Lake property.

Divestitures in 2013 included the sale of our Lower Shaunavon asset in July 2013 for proceeds of approximately $240 million plus closing adjustments, undeveloped land in northern Alberta and the cancellation of some of our non-core Oil Sands mineral rights covered under the Lower Athabasca Regional Plan ("LARP") resulting in compensation of $20 million, including interest. The cancelled mineral rights had no direct impact on our business plan, on our current operations at Foster Creek and Christina Lake, or any of our filed applications. Refer to the Risk Management section of this MD&A for more details on the LARP.

Capital Investment Decisions

Our disciplined approach to capital allocation includes prioritizing our uses of cash flow in the following manner:

- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third, for growth or discretionary capital, which is the capital spending for projects beyond our committed capital projects.

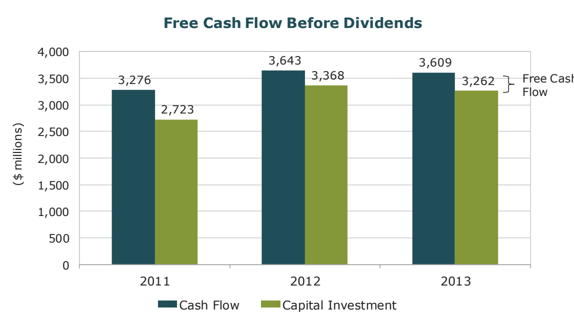
This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which allow us to be financially resilient in times of lower cash flow.

($ millions)	2013	2012	2011
Cash Flow (1)	**3,609**	3,643	3,276
Capital Investment (Committed and Growth)	**3,262**	3,368	2,723
Free Cash Flow (2)	**347**	275	553
Dividends Paid	**732**	665	603
	(385)	(390)	(50)

(1) *Non-GAAP measure defined in this MD&A.*
(2) *Free Cash Flow is a non-GAAP measure defined as Cash Flow less capital investment.*

While cash flow from our crude oil, natural gas and refining operations is expected to fund a significant portion of our cash requirements, a portion may be required to be funded through financing activities and management of our asset portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion.

Approximately two-thirds of our planned 2014 capital investment is committed capital, which is used to progress approved expansions at Christina Lake, Foster Creek and Narrows Lake and support existing business operations. The remaining one-third is discretionary capital for activities that include further developing our tight oil opportunities, advancing future oil sands expansions through the regulatory process and investment in technology development.



REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

Conventional, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake. This segment also includes the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.

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 Phillips 66, an unrelated U.S. public company. 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.

This graphic is for illustration purposes only. Land as at December 31, 2013.

Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, research costs 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 have been changed from those presented in prior periods to match Cenovus's new operating structure. Our Pelican Lake property is now being managed within our Conventional segment. All prior periods have been restated to reflect this presentation. As a result, for the years ended December 31, 2012 and 2011, Operating Cash Flow of $418 million and $305 million, respectively, was reclassified from Oil Sands to Conventional. In addition to the restatement required due to changes in operating segments, research activities previously included in operating expense have been reclassified to conform to the presentation adopted in 2013.

Revenues by Reportable Segment

($ millions)	**2013**	2012	2011
Oil Sands	**3,780**	3,170	2,431
Conventional	**2,776**	2,599	2,699
Refining and Marketing	**12,706**	11,356	10,625
Corporate and Eliminations	**(605)**	(283)	(59)
	18,657	16,842	15,696

OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects. We have several emerging projects in the early stages of assessment, including Telephone Lake and Grand Rapids. The Oil Sands segment also includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant factors that impacted our Oil Sands segment in 2013 compared with 2012 include:

- Christina Lake production increasing 55 percent, to an average of 49,310 barrels per day. Phase D reached full production capacity in 2013 and phase E, our tenth expansion phase at Cenovus, started up in July 2013;
- Completing our first major planned turnaround at Christina Lake resulting in 11 days of full production outage;
- Receiving regulatory approval for an optimization program for Christina Lake phases C, D and E, which is expected to add up to 22,000 barrels per day of gross capacity in 2015;
- Filing joint applications and EIAs for Foster Creek phase J and Christina Lake phase H; and
- Foster Creek production averaging 53,190 barrels per day, a decrease of eight percent, resulting from a number of production matters discussed below.

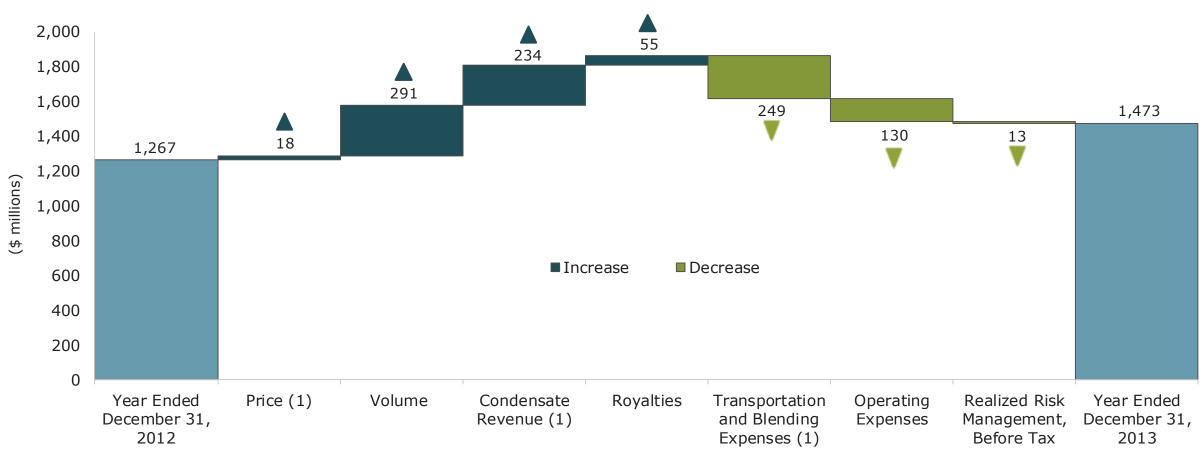
Oil Sands – Crude Oil

Financial Results

($ millions)	**2013**	2012	2011
Gross Sales	**3,850**	3,307	2,585
Less: Royalties	**131**	186	226
Revenues	**3,719**	3,121	2,359
Expenses			
Transportation and Blending	**1,748**	1,499	1,084
Operating	**531**	401	303
(Gain) Loss on Risk Management	**(33)**	(46)	67
Operating Cash Flow	**1,473**	1,267	905
Capital Investment	**1,878**	1,685	1,084
Operating Cash Flow net of Related Capital Investment	**(405)**	(418)	(179)

Capital investment in excess of Operating Cash Flow is funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments.

Operating Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012



(1) *Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.*

Revenues

Pricing

In 2013, our average crude oil sales price was $59.10 per barrel, one percent higher than in 2012, primarily due to the weakening of the Canadian dollar, partially offset by a higher proportion of our sales volumes coming from Christina Lake. In 2013, 42,664 barrels per day of Christina Lake production was sold as Christina Dilbit Blend ("CDB") (2012 – 23,220 barrels per day), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production

(barrels per day)	2013	Percent Change	2012	Percent Change	2011
Foster Creek	**53,190**	**(8)%**	57,833	5%	54,868
Christina Lake	**49,310**	**55%**	31,903	173%	11,665
	102,500	**14%**	89,736	35%	66,533

In 2013, Foster Creek production averaged 53,190 barrels per day, an eight percent decrease from 2012. In the fourth quarter of 2012, with production levels exceeding the nameplate capacity of our plant, we made a decision to defer some routine well maintenance until 2013. That deferral of maintenance resulted in a backlog in the number of wells requiring workovers causing an unanticipated negative impact on our 2013 production volumes. In 2013, we were able to complete the majority of our backlog in well work and had time to analyze the data and more fully assess how we are operating the initial phases of Foster Creek.

Based on this new information, we have made two key observations on the way we operate Foster Creek. First, our wells require more preventative maintenance and improved instrumentation which will allow for increased data collection and monitoring capability and we have improved our liner design, which we expect will improve reliability. The second key observation relates to the evolution of common steam chambers in the initial phases of the project and our need to focus on optimizing the formation of common steam chambers across the field rather than on a well or pad basis. As common steam chambers form, we require different reservoir management processes, which we are assessing. In the near-term, we expect to see a higher steam to oil ratio ("SOR") and corresponding reduction in production levels. As we advised in the fourth quarter, we expect to operate Foster Creek phases A through E at a production level of between 100,000 to 110,000 barrels per day in the near-term. Fourth quarter 2013 production was in-line with this expectation. Over the long term, we remain confident in the overall magnitude of the resource and the plant deliverability at a SOR consistent with the plant design. As we continue to learn more about operating a SAGD project with one common steam chamber, and build out the remaining phases, we will look to further optimize both the SOR and plant upgrades for the entire facility.

Christina Lake production increased as a result of phase D reaching full capacity, approximately six months after production began in the third quarter of 2012, and phase E production continuing to ramp up as expected after first production in July 2013.

Condensate

The heavy oil and bitumen produced by Cenovus requires the blending of condensate to reduce their viscosity to transport them to market. Revenues include the value of condensate sold as heavy oil blend. The overall value of condensate used in blending increased as a result of higher condensate volumes required for blending and condensate prices increasing two percent, consistent with the increase in the benchmark price.

Royalties

Royalty calculations for our Oil Sands projects differ between properties and are based on government prescribed pre and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price.

Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent) to the gross revenues from the project. Gross revenues are a function of sales volumes and realized prices.

Royalties at Foster Creek, a post-payout project, are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent). Net profits are a function of sales volumes, realized prices and allowed operating and capital costs.

Royalties decreased $55 million during 2013 primarily at Foster Creek related to lower sales volumes, increased annual capital expenditures and higher operating expenses. These changes resulted in a royalty calculation for 2013 based on gross revenues.

Effective Royalty Rates

(percent)	2013	2012	2011
Foster Creek	**5.8**	11.8	16.8
Christina Lake	**6.8**	6.2	5.2

Expenses

Transportation and Blending

Transportation and blending costs rose $249 million or 17 percent. Blending costs rose as discussed in the Revenues section. Transportation charges were $15 million higher due to production increases and higher sales into the U.S. market which attract higher tariffs, partially offset by volumes shipped on the Trans Mountain pipeline system, on which we have a long-term commitment for firm service since February 2012, resulting in lower transportation charges for our net share.

Operating

Primary drivers of our operating costs in 2013 were workforce, fuel costs, workover activities, and repairs and maintenance. In total, operating costs increased $130 million or $1.86 per barrel.

Per-unit Operating Costs

($/bbl)	**2013**	**Percent Change**	2012	Percent Change	2011
Foster Creek	**15.77**	**32%**	11.99	6%	11.34
Christina Lake	**12.47**	**(4)%**	12.95	(36)%	20.20

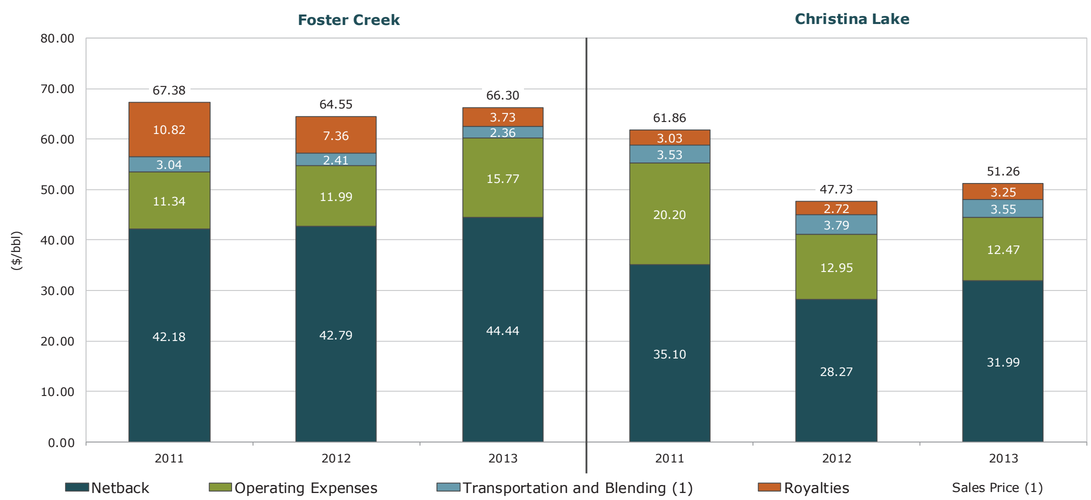
Declining production volumes at Foster Creek contributed to an overall rise in operating costs of $3.78 per barrel. The increase of $55 million was due to:

- Workover activities, as we completed the majority of our backlog in well work as previously discussed;
- Higher fuel prices, consistent with the rising benchmark AECO natural gas price and higher fuel consumption as a result of a higher SOR; and
- Higher workforce costs as we hired additional field staff in advance of the start-up of the phase F expansion expected in the third quarter of 2014.

Christina Lake operating costs decreased $0.48 on a per barrel basis as a result of higher production volumes. The increase of $75 million was due to:

- Increasing fuel usage, as a result of rising production, and higher fuel prices consistent with the benchmark AECO natural gas price;
- Higher costs associated with workforce and fluid, waste handling and trucking costs related to increased production;
- Additional repairs and maintenance costs mainly related to the planned turnaround in the second quarter of 2013; and
- Higher chemical costs due to higher production volumes associated with phase D reaching full capacity early in 2013 and phase E starting up in July, and higher prices.

Operating Netbacks



(1) *The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate in 2013 was $42.41 per barrel (2012 – $41.85 per barrel; 2011 – $41.74 per barrel) for Foster Creek; and $45.25 per barrel (2012 – $45.83 per barrel; 2011 – $47.07 per barrel) for Christina Lake.*

Risk Management

Risk management activities resulted in realized gains of $33 million (2012 – gains of $46 million), consistent with our 2013 contract prices exceeding average benchmark prices in 2013.

Oil Sands – Natural Gas

Oil Sands includes our 100 percent owned natural gas operation in Athabasca. Our natural gas production decreased to 21 MMcf per day in 2013 (2012 – 30 MMcf per day) as the result of anticipated natural declines. The internal use of our natural gas production at Foster Creek increased slightly in 2013. Operating Cash Flow was $22 million in 2013 (2012 – $31 million), a 29 percent decrease, primarily due to lower realized gains on risk management, partially offset by decreased operating costs.

Oil Sands – Capital Investment

($ millions)	**2013**	2012	2011
Foster Creek	**797**	735	429
Christina Lake	**688**	593	481
	1,485	1,328	910
Narrows Lake	**152**	44	19
Telephone Lake	**93**	138	61
Grand Rapids	**39**	65	31
Other (1)	**114**	118	77
Capital Investment (2)	**1,883**	1,693	1,098

(1) Includes new resource plays and Athabasca natural gas.
(2) Includes expenditures on PP&E and E&E assets.

Existing Projects

2013 capital investment at Foster Creek focused on expansion of phases F, G and H, drilling of sustaining wells, operational improvement projects and infrastructure. Spending also includes the drilling of 112 gross stratigraphic test wells (2012 – 141 gross wells). In 2013, investment increased due to phase H procurement, offsite fabrication and pilings, and phases F and G well pad drilling, construction and pipeline development, partially offset by a reduction in phase F procurement.

2013 Christina Lake capital investment focused on expansion of phases E, F and G, the phase C, D and E optimization program, drilling of sustaining wells, operational improvement projects and infrastructure. Capital investment also included the drilling of 74 gross stratigraphic test wells (2012 – 98 gross wells). In 2013, investment increased primarily due to phase F plant construction, procurement and engineering, and phase E well pad construction and drilling of well pairs, partially offset by lower spending on phase E plant construction, engineering and procurement. In addition, spending commenced for engineering and procurement for the phase C, D and E optimization program which received regulatory approval in 2013.

In 2013, capital investment increased at Narrows Lake due to phase A engineering and procurement, commencement of plant construction in August 2013 and infrastructure costs. Capital investment also included the drilling of 26 gross stratigraphic test wells (2012 – 42 gross wells).

Emerging Projects

At Telephone Lake, our 2013 capital investment was primarily focused on the dewatering pilot. The pilot commenced in the fourth quarter of 2012 and was completed in the fourth quarter of 2013 with the removal and reinjection of water and monitoring of results. We have successfully displaced water with compressed air, displacing approximately 70 percent of below-ground top water. The displaced water was not potable and therefore not suitable for human or other consumption. Capital investment decreased in 2013 with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012. Capital investment also included the drilling of 28 stratigraphic test wells (2012 – 29 wells).

Capital investment at Grand Rapids decreased in 2013 due to drilling fewer stratigraphic test wells (2013 – three wells; 2012 – 62 wells). Steam injection started on the second pilot well pair in the third quarter of 2012 and first production was achieved in February 2013. The pilot experienced facility constraints that impacted the production from both well pairs in the first half of 2013. A facility turnaround was performed in the third quarter of 2013 that mitigated these constraints. The purpose of the pilot is to test reservoir performance.

Drilling Activity

The stratigraphic test wells drilled at Foster Creek, Christina Lake and Narrows Lake were to help identify well pad locations for the expansion phases under construction, add contingent resources and increase well density per section for future expansion phases. Other stratigraphic test wells were drilled to continue gathering data on the quality of our projects and to support regulatory applications for project approval.

To minimize the impact on local infrastructure, the drilling of stratigraphic test wells is primarily completed in the winter months, typically between the end of the fourth quarter and the end of the first quarter. Since 2012, we have been developing the SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. This rig does not require roads for many of its locations and reduces the water, drill cuttings and surface pad size compared with traditional drilling methods. Our first prototype rig has now drilled 42 wells and we are currently constructing a second rig.

The 0.2 billion barrel increase to our economic bitumen best estimate contingent resources resulted from the success of our 2013 stratigraphic test well program converting prospective resources to contingent resources, a net acquisition of contingent resources through a property exchange, offset by the reduction of recovery factors at Steepbank and portions of the Grand Rapids formation and the loss of contingent resources due to the cancellation of mineral rights by the Alberta government for future urban development. Additional information about our resources, including definitions and year end results, is included in the Oil and Gas Reserves and Resources section of this MD&A.

Drilling Activity

	Gross Stratigraphic Test Wells			Gross Production Wells [(1)] [(2)]		
	2013	2012	2011	**2013**	2012	2011
Foster Creek	**112**	141	118	**56**	28	21
Christina Lake	**74**	98	93	**35**	32	19
	186	239	211	**91**	60	40
Narrows Lake	**26**	42	47	**-**	-	-
Telephone Lake	**28**	29	40	**-**	-	-
Grand Rapids	**3**	62	59	**-**	1	-
Other	**96**	96	66	**-**	-	3
	339	468	423	**91**	61	43

(1) Includes wells drilled using our Wedge Well™ technology.
(2) SAGD well pairs are counted as a single producing well.

Future Capital Investment

Expansion work at phases F, G and H at Foster Creek is proceeding as planned. We expect phases F, G and H to each ramp-up to their initial design capacity of 30,000 barrels per day. Once those phases are complete, we anticipate moving ahead with optimization work to lower the SOR, increase production and improve plant efficiency. Total gross production capacity for these phases, including optimization work, is expected to reach 125,000 barrels per day. Production from phase F is expected to start in the third quarter of 2014 with production ramp-up to design capacity expected to take twelve to eighteen months. Production start-up from phases G and H is expected in 2015 and 2016, respectively. We submitted a joint application and EIA to regulators in February 2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first quarter of 2015. Upon completion and optimization of production from phases F, G and H, and after ramp-up to initial design capacity of phase J, we believe further optimization opportunities exist to increase total overall plant capacity to over 300,000 barrels per day. Foster Creek capital investment for 2014 is forecast to be between $680 million and $760 million and is primarily focused on expansion phases, sustaining wells, operational improvement projects and infrastructure.

At Christina Lake, phase E development spending for the completion of drilling and well pad and facility construction is expected to continue to the end of 2014. The ramp-up of production from phase E is proceeding as expected with total gross production capacity expected to reach nameplate capacity of 138,000 gross barrels per day in the first quarter of 2014. The phase E ramp-up, similar to the ramp-up of phases C and D, is expected to reach nameplate capacity within six to nine months of first production. Expansion work on phases F, including cogeneration, and G is continuing as planned and we expect to add gross production capacity of 50,000 barrels per day from each phase in 2016 and 2017, respectively. In the third quarter of 2013, we received regulatory approval for the optimization program for Christina Lake phases C, D and E, which is expected to add up to 22,000 barrels per day of gross capacity in 2015. We submitted a joint application and EIA to regulators in March 2013 for the phase H expansion, a 50,000 barrel per day phase for which we expect to receive regulatory approval in the fourth quarter of 2014. Christina Lake capital investment in 2014 is forecast to be between $750 million and $820 million and is primarily focused on expansion phases F and G, the phase C, D and E optimization program, and drilling and facilities work for wedge wells and sustaining wells.

In 2012, we received regulatory approval for Narrows Lake phases A, B and C, and final partner approval for phase A. We are continuing with site construction, engineering and procurement and construction of the phase A plant, which started in the third quarter of 2013. The first phase of the project is anticipated to have a production capacity of 45,000 gross barrels per day, with first oil expected in 2017. Narrows Lake capital investment is forecast to be between $210 million and $230 million in 2014 and is primarily focused on plant construction, procurement and offsite fabrication for the phase A expansion and infrastructure for a construction camp and control room.

Additional capital investment of approximately $140 million to $160 million in 2014 is expected for our emerging SAGD projects and is primarily focused on drilling stratigraphic test wells, front end engineering at Telephone Lake and costs related to the pilot projects at Telephone Lake and Grand Rapids. At Telephone Lake we are advancing the regulatory application for the project and anticipate receiving approval in the second quarter of 2014. The first phase of the project is anticipated to have a production capacity of 90,000 barrels per day. At Grand Rapids we anticipate receiving regulatory approval in the first quarter of 2014 for a 180,000 barrel per day commercial SAGD operation.

DD&A

In 2013, Oil Sands DD&A increased $107 million to $446 million (2012 – $339 million; 2011 – $246 million) due to higher DD&A rates for both of our properties due to higher future development costs associated with total proved reserves and additional sales volumes at Christina Lake, partially offset by lower sales volumes at Foster Creek.

CONVENTIONAL

Our Conventional operations include predictable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a carbon dioxide enhanced oil recovery project in Weyburn and developing tight oil assets in Alberta. This segment also includes the heavy oil assets at Pelican Lake. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced. Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. The cash flow generated in our Conventional operations helps to fund our future growth opportunities in our Oil Sands segment.

Significant factors that impacted our Conventional segment in 2013 compared with 2012 include:

- Crude oil production averaging 76,775 barrels per day, increasing one percent primarily due to successful horizontal well performance in southern Alberta associated with our current drilling program and higher production at Pelican Lake, partially offset by the sale of our Lower Shaunavon asset and expected natural declines; and
- Generating Operating Cash Flow net of capital investment of $621 million, an increase of 23 percent.

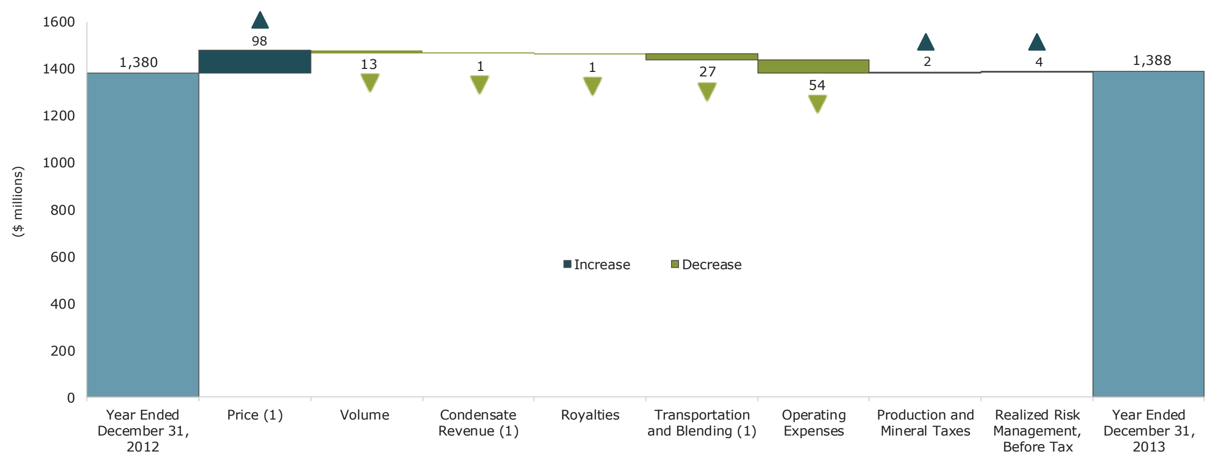
Conventional – Crude Oil

Financial Results

($ millions)	2013	2012	2011
Gross Sales	**2,373**	2,289	2,124
Less: Royalties	**196**	195	249
Revenues	**2,177**	2,094	1,875
Expenses			
Transportation and Blending	**305**	278	249
Operating	**495**	441	350
Production and Mineral Taxes	**32**	34	27
(Gain) Loss on Risk Management	**(43)**	(39)	63
Operating Cash Flow (1)	**1,388**	1,380	1,186
Capital Investment	**1,169**	1,323	1,003
Operating Cash Flow net of Related Capital Investment	**219**	57	183

(1) Non-GAAP measure defined in this MD&A.

Operating Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012



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

Revenues

Pricing

Our average crude oil sales price in 2013 increased five percent to $77.62 per barrel, consistent with the change in crude oil benchmark prices.

Production

(barrels per day)	2013	Percent Change	2012	Percent Change	2011
Pelican Lake	**24,254**	**8%**	22,552	10%	20,424
Other Heavy Oil	**15,991**	**-%**	16,015	2%	15,657
Light and Medium Oil	**35,467**	**(2)%**	36,071	18%	30,524
NGLs	**1,063**	**3%**	1,029	(7)%	1,101
	76,775	**1%**	75,667	12%	67,706

Our crude oil production increased one percent due to strong horizontal well performance in southern Alberta from our current drilling program and higher production at Pelican Lake as a result of additional infill wells coming on stream throughout 2012 and 2013, partially offset by reduced production from the sale of our Lower Shaunavon asset in July 2013 and expected natural declines. In 2013, Lower Shaunavon produced an annual average of 2,095 barrels per day (2012 – 4,411 barrels per day).

Condensate

Revenues include the value of condensate sold as heavy oil blend. The overall value of condensate decreased due to lower condensate prices, partially offset by an increase in the volumes used in blending.

Royalties

Royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project therefore royalties are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent). Net profits are a function of sales volumes, realized prices and allowed operating and capital costs.

Royalties increased $1 million primarily due to increased royalties at Pelican Lake as a result of declines in capital investment, an increase in sales volumes and higher prices. Increases in royalties at Pelican Lake were partially offset by lower royalties in our other heavy oil properties due to decreased production volumes.

In 2013, the effective royalty rate at Pelican Lake was 5.9 percent (2012 – 5.0 percent). The effective crude oil royalty rate for our other Conventional properties was 11.0 percent (2012 – 11.8 percent). Our other crude oil producing assets are located primarily on crown or fee land. Production from fee lands results in mineral tax recorded within production and mineral taxes.

Expenses

Transportation and Blending

Transportation and blending costs increased $27 million. Transportation costs rose $28 million largely due to the higher cost associated with transporting our light and medium crude oil production by rail. In 2013, we sold approximately 6,150 barrels per day of crude oil that was transported by rail to Canada's East Coast and the U.S. (2012 – 2,600 barrels per day). The overall cost of condensate used in blending decreased as discussed in the Revenues section.

Operating

Primary drivers of our operating costs in 2013 were workover activities, workforce costs, electricity, repairs and maintenance and chemical consumption.

Operating costs at Pelican Lake increased $3.57 per barrel to $20.65 per barrel. The total dollar increase of $33 million was associated with:

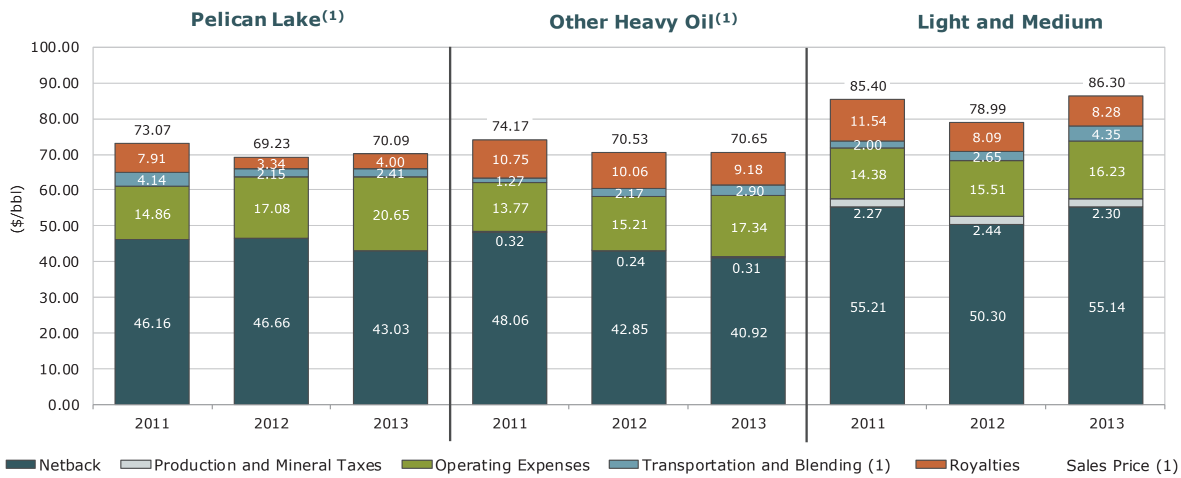
- Higher polymer chemical consumption related to the expansion of the polymer flood program;
- Increased workover and repairs and maintenance activities related to equipment failure; and
- Routine maintenance, and electricity costs from higher market rates and increased consumption.

Operating costs for our other Conventional crude oil properties increased $1.12 per barrel to $16.24 per barrel. The total dollar increase of $21 million was primarily due to:

- Increased workforce costs and increased workover activities associated with high-return well optimizations that helped mitigate production declines; and
- Rising electricity costs from higher market rates.

The cost increases in our other Conventional crude oil operating costs were partially offset by declines in repairs and maintenance due to the sale of Lower Shaunavon and a reduction in road and lease maintenance.

Operating Netbacks



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate for Pelican Lake was $15.59 per barrel in 2013 (2012 – $15.55 per barrel; 2011 – $16.32 per barrel) and for our other heavy oil properties was $13.12 per barrel in 2013 (2012 – $13.35 per barrel; 2011 – $12.73 per barrel).

Risk Management

Risk management activities in 2013 resulted in realized gains of $43 million (2012 – gains of $39 million), consistent with our contract prices exceeding the average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	**2013**	2012	2011
Gross Sales	**594**	498	825
Less: Royalties	**8**	6	12
Revenues	**586**	492	813
Expenses			
Transportation and Blending	**20**	19	34
Operating	**209**	217	240
Production and Mineral Taxes	**3**	3	9
(Gain) Loss on Risk Management	**(61)**	(229)	(195)
Operating Cash Flow (1)	**415**	482	725
Capital Investment	**22**	43	102
Operating Cash Flow net of Related Capital Investment	**393**	439	623

(1) Non-GAAP measure defined in this MD&A.

Operating Cash Flow from natural gas net of capital investment decreased $46 million due to lower Operating Cash Flow partially offset by a $21 million reduction in capital investment. Operating Cash Flow from natural gas continues to help fund our growth opportunities in our Oil Sands segment.

Revenues

Pricing

Our average natural gas sales price increased $0.78 per Mcf to $3.20 per Mcf, consistent with the rise in the benchmark AECO natural gas price.

Production

Production decreased 10 percent to 508 MMcf per day primarily due to expected natural declines.

Royalties

Royalties increased slightly as a result of higher prices, despite declines in production. The average royalty rate in 2013 was 1.4 percent (2012 – 1.3 percent). Most of our natural gas production is located on fee land. Production from fee lands results in mineral tax recorded within production and mineral taxes.

Expenses

Transportation

Transportation costs increased as higher pipeline rates were partially offset by lower production volumes.

Operating

Primary drivers of our operating expenses in 2013 were property taxes and lease costs, workforce costs and repairs and maintenance. Operating expenses decreased $8 million in 2013 primarily related to a decrease in workforce and repairs and maintenance expenses as a result of a reduction in our natural gas production.

Risk Management

Risk management activities resulted in realized gains in 2013 of $61 million (2012 – gains of $229 million), consistent with our contract prices exceeding the average benchmark price.

Conventional – Capital Investment (1)

($ millions)	**2013**	2012	2011
Pelican Lake	**465**	518	317
Other Crude Oil	**704**	805	686
Natural Gas	**22**	43	102
	1,191	1,366	1,105

(1) *Includes expenditures on PP&E and E&E assets.*

Capital investment in 2013 was composed primarily of spending at Pelican Lake on infill drilling, facilities and maintenance capital associated with the expansion of the polymer flood, and drilling, completion, recompletion programs, and work on our facilities at our other Conventional crude oil assets. Spending on natural gas activities continues to be managed in response to the low natural gas price environment.

Capital investment declined in 2013 primarily due to discontinued spending related to our Lower Shaunavon asset and declines related to Pelican Lake as the rate at which we are expanding the polymer flood slowed to better match our production growth.

In early 2013, we launched a public sales process to divest our Lower Shaunavon asset and certain of our Bakken properties in Saskatchewan. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. In June 2013, we entered into a purchase and sale agreement with an unrelated third party to sell our Lower Shaunavon asset. The sale was completed in July 2013 for proceeds of approximately $240 million plus closing adjustments.

Management decided to discontinue the Bakken sales process until market conditions improve. While discussions with prospective purchasers have occurred, an offer that meets Management's expectations has not been received. As a result of the decision, as at December 31, 2013 the assets and associated decommissioning liabilities were reclassified from held for sale to PP&E and decommissioning liabilities at their carrying amounts. Depletion, calculated on a per-unit of production basis, was recorded in the fourth quarter of 2013. The carrying value continues to be less than the estimated recoverable amount.

Future Capital Investment

In 2014, Pelican Lake capital investment is forecast to be between $230 million and $250 million with spending mainly focused on infill drilling, pipeline construction and maintenance capital for the polymer flood. The reduction in capital investment from 2013 is due to our decision to align spending with the more moderate production ramp-up associated with the initial results of the polymer flood program.

Capital investment in other Conventional crude oil is forecast to be between $540 million and $590 million which will be focused on tight oil development and drilling and facilities work.

Conventional Drilling Activity

(net wells, unless otherwise stated)	**2013**	2012	2011
Crude Oil	**212**	352	356
Natural Gas	**-**	-	65
Recompletions	**751**	977	1,122
Gross Stratigraphic Test Wells	**54**	19	68

Crude oil wells drilled reflect the continued development of our Conventional properties. Well recompletions are mostly related to lower-risk Alberta coal bed methane development that continues to deliver acceptable rates of return. Drilling of stratigraphic test wells increased in 2013 in order to further assess our tight oil plays in Alberta.

DD&A, Goodwill Impairment, Exploration Expense

DD&A

In 2013, Conventional DD&A increased $122 million to $1,170 million (2012 – $1,048 million; 2011 – $879 million) as a result of an increase in the average DD&A rates due to lower proved reserves, in addition to an impairment loss of $57 million related to our Lower Shaunavon asset which was sold in July 2013.

Goodwill Impairment

In 2012, we recognized $393 million of goodwill impairment associated with our Suffield cash-generating unit ("CGU"). The Suffield CGU, including the allocated goodwill, exceeded its fair value less costs of disposal resulting in an impairment that was attributed to goodwill. The impairment resulted primarily due to a decline in natural gas and crude oil prices and increased operating costs. In addition, we had minimal levels of capital spending for natural gas such that production exceeded reserve replacement in the area. There was no goodwill impairment in 2013.

Exploration Expense

In 2013, we recorded total exploration expense of $114 million (2012 – $68 million).

As part of our business plan, we look for opportunities to enhance our portfolio in areas where we may apply our core competencies in crude oil development. Costs incurred prior to obtaining the legal right to explore (pre-exploration) are expensed. As a result of our evaluation of crude oil exploration opportunities, $64 million of pre-exploration expense was recorded in 2013.

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability have been established are capitalized as E&E assets. If a field, area or project is determined not to be technically feasible and commercially viable and we decide not to continue the exploration activity, the unrecoverable costs are charged to exploration expense.

In 2013, $50 million (2012 – $68 million) of previously capitalized E&E costs, related to certain conventional tight oil exploration assets, were deemed not to be commercially viable and technically feasible and were recognized as exploration expense.

REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. Our Refining and Marketing segment allows us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated strategy provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to our refineries. The Refining and Marketing segment's results are affected by changes in the U.S./Canadian dollar exchange rate.

Significant factors related to our Refining and Marketing segment in 2013 compared with 2012 include:

- Processing 442,000 barrels per day of crude oil, including 222,000 barrels per day of heavy crude oil, resulting in 463,000 barrels per day of refined product output, an increase of seven percent, and a six percent increase in crude utilization. Refined product output last year was reduced due to planned turnarounds at both refineries; and
- Operating Cash Flow decreasing 10 percent to $1,143 million primarily due to declines in market crack spreads and higher costs associated with RINs, partially offset by an improved feedstock cost advantage and increases in refined product output.

Refinery Operations [1]

	2013	2012	2011
Crude Oil Capacity [2] (Mbbls/d)	**457**	452	452
Crude Oil Runs (Mbbls/d)	**442**	412	401
Heavy Crude Oil	**222**	198	126
Light/Medium	**220**	214	275
Crude Utilization (percent)	**97**	91	89
Refined Products (Mbbls/d)	**463**	433	419
Gasoline	**232**	216	207
Distillate	**144**	138	132
Other	**87**	79	80

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity increased effective January 1, 2014 to 460,000 gross barrels per day.

On a 100 percent basis, our refineries had capacity of approximately 457,000 gross barrels per day of crude oil, excluding NGLs, and 45,000 gross barrels per day of NGLs, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our ability to economically integrate our heavy crude oil production.

In 2013, crude oil runs increased seven percent and heavy crude oil runs increased 12 percent. Total refined product output increased by seven percent with the relative proportion of gasoline, distillate and other refined products remaining relatively the same. Planned turnarounds in 2012 reduced output.

Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity. Due to our ability to process heavy crude oil, a feedstock cost advantage is created by processing less expensive heavy crude oil. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate being optimized at each refinery to maximize economic benefit.

Financial Results

($ millions)	2013	2012	2011
Revenues	**12,706**	11,356	10,625
Purchased Product	**11,004**	9,506	9,149
Gross Margin	**1,702**	1,850	1,476
Expenses			
Operating [(1)]	**540**	581	475
(Gain) Loss on Risk Management	**19**	(4)	14
Operating Cash Flow [(2)]	**1,143**	1,273	987
Capital Investment	**107**	118	393
Operating Cash Flow net of Related Capital Investment	**1,036**	1,155	594

(1) We reclassified expenditures related to research activities from operating expenses to research costs.
(2) Non-GAAP measure defined in this MD&A.

Gross Margin

The gross margin for the Refining and Marketing segment declined $148 million or eight percent as a result of the decline in market crack spreads, consistent with the narrowing of the Brent-WTI differential and higher costs associated with RINs. The decline was partially offset by an improved feedstock cost advantage resulting from processing a higher proportion of discounted heavy crude oil as well as the widening of the WTI-WCS differential and an increase in refined product output.

As part of the U.S. Environmental Protection Agency's ("EPA") Renewable Fuel Standards, refineries in the U.S. are obligated to blend renewable fuels, such as ethanol, into petroleum-based motor fuel products at rates determined by the EPA. To the extent they do not, refineries must purchase credits, referred to as RINs, in the open market. RINs are a number assigned to each gallon of renewable fuel produced or imported into the U.S., and were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

We are obligated to purchase RINs in the open market as our refineries do not blend renewable fuels into gasoline and diesel products. In 2013, our RINs cost was $153 million, an increase of $121 million reflecting the $0.55 per barrel increase in the ethanol RINs price, as a result of the change in the EPA's mandated blending quotas for 2013. Despite the recent increase in costs associated with RINs, these costs remain a minor component of our total refinery feedstock costs.

Operating Expense

Primary drivers of operating costs in 2013 were labour, maintenance, utilities and supplies. Operating costs were lower by $41 million or seven percent as 2012 planned maintenance activities resulted in higher costs.

Operating Cash Flow

Operating Cash Flow from the Refining and Marketing segment declined $130 million or 10 percent from 2012 primarily due to the decrease in gross margin, partially offset by lower operating costs.

Refining and Marketing – Capital Investment

($ millions)	2013	2012	2011
Wood River Refinery	**64**	54	346
Borger Refinery	**42**	64	45
Marketing	**1**	-	2
	107	118	393

Capital expenditures in 2013 focused on capital maintenance and refinery reliability and safety projects. In 2012, capital investment was reduced by Illinois tax credits of $14 million related to capital expenditures incurred at the Wood River Refinery in prior periods.

In 2014, we expect to invest between $150 million and $160 million mainly related to routine safety initiatives, meeting new low sulphur (Tier III) gasoline requirements and additional capital investments expected to enhance returns at the Wood River Refinery. We also expect to sanction a debottlenecking project at the Wood River Refinery in the first quarter of 2014.

DD&A

In 2013, Refining and Marketing DD&A decreased $8 million to $138 million (2012 – $146 million; 2011 – $130 million) primarily due to the change in foreign exchange rates.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and the unrealized mark-to-market gains and losses on the long-term power purchase contract. In 2013, our risk management activities resulted in $415 million of unrealized losses, before tax (2012 – $57 million of unrealized gains, before tax). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing activities and research costs.

($ millions)	**2013**	2012	2011
General and Administrative	**349**	350	295
Finance Costs	**529**	455	447
Interest Income	**(96)**	(109)	(124)
Foreign Exchange (Gain) Loss, net	**208**	(20)	26
Research Costs	**24**	15	8
(Gain) Loss on Divestiture of Assets	**1**	-	(107)
Other (Income) Loss, net	**2**	(5)	4
	1,017	686	549

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2013 were workforce, office rent and information technology costs. General and administrative expenses decreased $1 million, remaining relatively flat from 2012, primarily due to lower long-term incentive costs partially offset by rent increases and higher staffing costs.

Research Costs

Both technology development, including research activities, and the environment are playing increasingly larger roles in all aspects of our business.

In 2013, we reclassified 2012 and 2011 research costs from operating expenses in our Consolidated Statements of Earnings and Comprehensive Income to conform with current presentation. There were no changes to Net Earnings as a result. Research costs increased $9 million in 2013 compared with 2012, as a result of our increased focus on research activities which provide important information on how we will manage our operations.

Finance Costs

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. In 2013, finance costs were $74 million higher than in 2012 due to a full year of interest incurred on our senior unsecured notes issued in August 2012 and a US$32 million premium paid on the early redemption of the US$800 million of senior unsecured notes that were due in September 2014. Increases were partially offset by lower interest incurred on the Partnership Contribution Payable as the balance continues to be repaid. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for 2013 was 5.2 percent (2012 – 5.3 percent).

Interest Income

Interest income includes interest earned on our short-term investments and U.S. dollar denominated Partnership Contribution Receivable. In 2013, interest income decreased by $13 million consistent with lower interest earned on the Partnership Contribution Receivable as the balance was collected over the course of the year.

Foreign Exchange

($ millions)	**2013**	2012	2011
Unrealized Foreign Exchange (Gain) Loss	**40**	(70)	(42)
Realized Foreign Exchange (Gain) Loss	**168**	50	68
	208	(20)	26

The majority of unrealized foreign exchange losses stem from translation of our U.S. dollar denominated debt as a result of a weaker Canadian dollar at December 31, 2013, offset by the reversal of the previously recognized unrealized losses on the U.S. dollar Partnership Contribution Receivable.

Realized losses resulted primarily from the receipt of the remaining principal of the Partnership Contribution Receivable on December 17, 2013, partially offset by a realized foreign exchange gain of $33 million recorded on the early redemption of the US$800 million senior unsecured notes that were to mature September 2014.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. DD&A for 2013 was $79 million (2012 – $52 million; 2011 – $40 million) an increase of $27 million, due to the depreciation of our new office space leaseholds starting in October 2012.

Income Tax Expense

($ millions)	2013	2012	2011
Current Tax			
Canada	143	188	150
U.S.	45	121	4
Total Current Tax	188	309	154
Deferred Tax	244	474	575
	432	783	729

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

($ millions, except percent amounts)	2013	2012	2011
Earnings Before Income Tax	1,094	1,778	2,207
Canadian Statutory Rate	25.2%	25.2%	26.7%
Expected Income Tax	276	448	589
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	109	146	82
Non-deductible Stock-based Compensation	10	10	18
Multi-jurisdictional Financing	(22)	(27)	(50)
Foreign Exchange Gain (Loss), not Included in Net Earnings	19	14	(9)
Non-taxable Capital (Gains) Losses	31	(7)	(8)
Derecognition (Recognition) of Capital Losses	15	(22)	26
Adjustments Arising From Prior Year Tax Filings	(13)	33	31
Withholding Tax on Foreign Dividends	-	68	-
Goodwill Impairment	-	99	-
Other	7	21	50
Total Tax	432	783	729
Effective Tax Rate	39.5%	44.0%	33.0%

The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation. In 2013, current taxes decreased $121 million primarily due to $68 million of withholding tax on a U.S. dividend in 2012, adjustments related to a change in legislation of $24 million, the finalization of our 2012 tax filings, and lower taxable U.S. earnings in the current year. The decrease in deferred tax is primarily due to unrealized risk management losses compared to gains in 2012 and lower earnings before tax from U.S. sources resulting in lower utilization of tax loss pools compared to 2012.

Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it reflects higher U.S. tax rates, permanent differences, adjustments for changes in tax rates and other tax legislation, variations in the estimate of reserves and differences between the provision and the actual amounts subsequently reported on the tax returns.

The decrease in our effective tax rate in 2013 when compared to 2012 is primarily due to the non-deductible charge for a goodwill impairment and the U.S. withholding tax in 2012, partially offset by non-deductible foreign exchange losses, derecognition of capital losses and a significant increase in 2013 in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction.

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

QUARTERLY RESULTS

($ millions, except per share amounts or where otherwise indicated)	Q4 2013	Q3 2013	Q2 2013	Q1 2013	Q4 2012	Q3 2012	Q2 2012	Q1 2012	Q4 2011
Production Volumes									
Crude Oil (bbls/d)	**188,743**	**176,938**	**171,127**	**180,225**	177,646	171,350	155,566	156,850	144,273
Natural Gas (MMcf/d)	**514**	**523**	**536**	**545**	566	577	596	636	660
Revenues	**4,747**	**5,075**	**4,516**	**4,319**	3,724	4,340	4,214	4,564	4,329
Operating Cash Flow (1) (2)	**976**	**1,153**	**1,125**	**1,214**	966	1,314	1,081	1,090	1,021
Cash Flow (1)	**835**	**932**	**871**	**971**	697	1,117	925	904	851
Per Share – Diluted	**1.10**	**1.23**	**1.15**	**1.28**	0.92	1.47	1.22	1.19	1.12
Operating Earnings (Loss) (1) (3)	**212**	**313**	**255**	**391**	(188)	432	284	340	332
Per Share – Diluted (3)	**0.28**	**0.41**	**0.34**	**0.52**	(0.25)	0.57	0.37	0.45	0.44
Net Earnings (Loss) (3)	**(58)**	**370**	**179**	**171**	(117)	289	397	426	266
Per Share – Basic (3)	**(0.08)**	**0.49**	**0.24**	**0.23**	(0.15)	0.38	0.53	0.56	0.35
Per Share – Diluted (3)	**(0.08)**	**0.49**	**0.24**	**0.23**	(0.15)	0.38	0.52	0.56	0.35
Capital Investment (4)	**898**	**743**	**706**	**915**	978	830	660	900	903
Cash Dividends	**183**	**182**	**183**	**184**	167	166	166	166	151
Per Share	**0.242**	**0.242**	**0.242**	**0.242**	0.22	0.22	0.22	0.22	0.20

(1) Non-GAAP measures defined in this MD&A.
(2) For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.
(3) We restated prior periods as a result of adoption of new accounting standards. See Critical Accounting Judgments, Estimates and Accounting Policies within this MD&A for more details.
(4) Includes expenditures on PP&E and E&E assets.

Our quarterly results over the last eight quarters were impacted primarily by rising crude oil production volumes and fluctuations in commodity prices.

Fourth Quarter 2013 Results as Compared to the Fourth Quarter 2012

Total crude oil production rose six percent, with the most significant increase at Christina Lake (rising 47 percent). Crude oil sales prices decreased one percent, consistent with the widening of the average WTI-WCS differential in the fourth quarter of 2013 to US$32.20 per barrel compared with US$18.11 per barrel for the same period last year.

Natural gas production in the fourth quarter of 2013 was 514 MMcf per day, a decrease of nine percent, mainly due to expected declines in production from limited capital investment.

Our refining operations processed an average of 447,000 (2012 – 311,000) gross barrels per day of crude oil, of which 221,000 gross barrels per day was heavy crude oil (2012 – 155,000). We produced 469,000 gross barrels per day of refined products, an increase of about 139,000 gross barrels per day or 42 percent, as refined product output in the fourth quarter of 2012 was impacted by planned turnarounds at both refineries.

Operating Cash Flow

Operating Cash Flow increased $10 million, or one percent, remaining relatively flat compared with 2012. Refining and Marketing Operating Cash Flow of $151 million increased 23 percent primarily due to an improved feedstock cost advantage and higher refined product output, partially offset by sharp declines in market crack spreads and increased costs associated with RINs. Upstream Operating Cash Flow of $825 million declined two percent primarily due to higher crude oil operating costs, an increase of $2.13 per barrel, realized risk management gains before tax of $67 million compared with gains of $102 million in 2012 and lower natural gas production volumes, partially offset by rising crude oil production.

Cash Flow

While Operating Cash Flow was relatively unchanged from 2012, our Cash Flow increased $138 million in the fourth quarter of 2013 primarily due to a decrease in current tax expense of $122 million mainly related to $68 million of withholding tax incurred on the payment of a U.S. dividend in 2012 and a difference in the recognition of Canadian partnership income for tax purposes.

Operating Earnings (Loss)

In addition to changes impacting Cash Flow, Operating Earnings increased $400 million in the fourth quarter of 2013 as compared to the same period in 2012. The increase was primarily due to a goodwill impairment of $393 million recorded in 2012 in our Conventional segment. Increases in Operating Earnings were partially offset by rising DD&A, as a result of higher production and higher DD&A rates, and an increase in deferred tax expense, excluding tax on unrealized risk management (gains) losses and non-operating unrealized foreign exchange (gains) losses, due to the reversal of Canadian temporary differences from increased earnings in Canada.

Net Earnings (Loss)

In the fourth quarter of 2013, our net loss was $58 million, compared to a net loss of $117 million in the same period last year. Our net loss decreased $59 million as a result of the increase in Operating Earnings discussed above, partially offset by unrealized risk management losses, after-tax, of $163 million compared with gains of $87 million in the fourth quarter of 2012 and a realized foreign exchange loss of $146 million, after-tax, related to the receipt of the remaining principal on the Partnership Contribution Receivable.

Capital Investment

Capital investment in the fourth quarter of 2013 was $898 million, a decrease of $80 million from the same period in 2012 due to declines in spending primarily in our Conventional segment. The fourth quarter was focused on the development of our expansion phases at Foster Creek and Christina Lake, and construction on phase A of Narrows Lake.

OIL AND GAS RESERVES AND RESOURCES

We retain independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of our bitumen, heavy oil, light and medium oil, NGLs, natural gas and CBM reserves and 100 percent of our bitumen contingent and prospective resources. Our AIF contains additional information with respect to the evaluation and reporting of our reserves and resources in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

Highlights in 2013 compared with 2012 include:

- Proved bitumen reserves increased eight percent and proved plus probable bitumen reserves increased six percent.
  - Christina Lake added proved reserves of 82 million barrels while proved plus probable reserves increased by 28 million barrels. Increases at Christina Lake were as a result of receiving approval to expand the development area and planned increases to future well density. Foster Creek added proved reserves of 67 million barrels and proved plus probable reserves of 16 million barrels. Increases at Foster Creek were a result of development area expansion. Increases were also due to well downspacing at Christina Lake and Narrows Lake.
- Heavy oil proved reserves decreased three percent and proved plus probable heavy oil reserves increased 10 percent. These changes were as a result of revised Pelican Lake development plans to drill more infill wells and expand polymer flood areas using increased well density.
- Light and medium crude oil and NGLs proved reserves remained unchanged and proved plus probable reserves decreased by four percent, as a result of additions being offset by production and the Lower Shaunavon divestiture.
- Natural gas proved reserves declined nine percent and proved plus probable reserves decreased 10 percent as additions and improved performance at Brooks North were more than offset by production.
- Bitumen best estimate economic contingent resources increased 0.2 billion barrels or two percent while bitumen best estimate prospective resources declined 1.0 billion barrels or 12 percent. Factors impacting the results include:
  - Stratigraphic test well drilling successfully converting prospective resources to contingent resources;
  - A property exchange resulting in the net acquisition of contingent resources and the net divestiture of prospective resources;
  - The reduction of recovery factors at Steepbank and portions of the Grand Rapids formation; and
  - The loss of contingent and prospective resources due to the cancellation of mineral rights by the Alberta government for future urban development.

The reserves and resources data that follows is presented as at December 31, 2013 using McDaniel & Associates Consultants Ltd. ("McDaniel's") January 1, 2014 forecast prices and costs. Comparative information as at December 31, 2012 uses McDaniel's January 1, 2013 forecast prices and costs. We hold significant fee title rights which generate production for Cenovus from third parties leasing those lands. The before royalty volumes, as follows, do not include reserves associated with this production.

Reserves

As at December 31, 2013	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
Before Royalties	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Proved	**1,846**	1,717	**179**	184	**115**	115	**865**	955
Probable	**683**	676	**140**	105	**50**	56	**300**	338
Proved plus Probable	**2,529**	2,393	**319**	289	**165**	171	**1,165**	1,293

Reconciliation of Proved Reserves

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2012	**1,717**	**184**	**115**	**955**
Extensions and Improved Recovery	**134**	**21**	**11**	**24**
Discoveries	**-**	**-**	**-**	**-**
Technical Revisions	**32**	**(12)**	**6**	**76**
Economic Factors	**-**	**-**	**-**	**-**
Acquisitions	**-**	**-**	**-**	**-**
Dispositions	**-**	**-**	**(5)**	**-**
Production	**(37)**	**(14)**	**(12)**	**(190)**
December 31, 2013	**1,846**	**179**	**115**	**865**
Year Over Year Change	**129**	**(5)**	**-**	**(90)**
	8%	**(3)%**	**0%**	**(9)%**

Reconciliation of Probable Reserves

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2012	**676**	**105**	**56**	**338**
Extensions and Improved Recovery	**28**	**55**	**-**	**5**
Discoveries	**78**	**-**	**-**	**-**
Technical Revisions	**(99)**	**(20)**	**(4)**	**(43)**
Economic Factors	**-**	**-**	**-**	**-**
Acquisitions	**-**	**-**	**-**	**-**
Dispositions	**-**	**-**	**(2)**	**-**
Production	**-**	**-**	**-**	**-**
December 31, 2013	**683**	**140**	**50**	**300**
Year Over Year Change	**7**	**35**	**(6)**	**(38)**
	1%	**33%**	**(11)%**	**(11)%**

Economic Contingent Resources and Prospective Resources

As at December 31 (billions of barrels, before royalties)	Bitumen 2013	2012
Economic Contingent Resources [1]		
Best Estimate	**9.8**	9.6
Prospective Resources [1][2]		
Best Estimate	**7.5**	8.5

(1) See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and best estimates. 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.

Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates and related disclosure is contained in our AIF for the year ended December 31, 2013.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2013	2012	2011
Net Cash From (Used In)			
Operating Activities	**3,539**	3,420	3,273
Investing Activities	**(1,519)**	(3,336)	(2,530)
Net Cash Provided (Used) Before Financing Activities	**2,020**	84	743
Financing Activities	**(726)**	592	(558)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(2)**	(11)	10
Increase in Cash and Cash Equivalents	**1,292**	665	195

At December 31, 2013, we had cash and cash equivalents of $2.5 billion, no amounts were drawn on our committed credit facility and no commercial paper was outstanding.

Operating Activities

Cash from operating activities was $119 million higher in 2013 mainly due to the change in non-cash working capital, partially offset by the decrease in Cash Flow as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities and assets and liabilities held for sale, working capital was $1,957 million at December 31, 2013 compared with $1,043 million at December 31, 2012. We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

In 2013, cash used in investing activities was $1,519 million, a $1,817 million decrease from 2012. The reduction was predominately due to the receipt of the remaining principal of the Partnership Contribution Receivable in December 2013. In addition, proceeds of $258 million on the sale of our Lower Shaunavon asset and other minor assets increased cash from investing activities.

Financing Activities

Our disciplined approach to capital investment decisions means that we prioritize our use of cash flow first to committed capital investment, then to paying a meaningful dividend and finally to growth capital. In 2013, we paid a dividend of $0.968 per share (2012 – $0.88 per share). Total dividend payments in 2013 were $732 million (2012 – $665 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities in 2013 increased $1,318 million from 2012 primarily as a result of the issuance and repayment of debt. On August 15, 2013, we completed a public offering in the U.S. in aggregate of US$800 million senior unsecured notes under our U.S. base shelf prospectus. The notes were issued in two tranches, US$450 million of senior unsecured notes with a coupon rate of 3.8 percent due September 15, 2023 and US$350 million of senior unsecured notes with a coupon rate of 5.2 percent due September 15, 2043. The net proceeds of the offering were used to partially fund the early redemption of our US$800 million senior unsecured notes due September 2014. The offering allowed us to secure favorable interest rates, eliminate our 2014 re-financing risk and extend the weighted average term to maturity of our long-term debt.

In 2012, we completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US$1.25 billion under our U.S. base shelf prospectus. We issued US$500 million of senior unsecured notes with a coupon rate of 3.00 percent due August 15, 2022 and US$750 million of senior unsecured notes with a coupon rate of 4.45 percent due September 15, 2042. The net proceeds were used for general corporate purposes, including repayment of commercial paper indebtedness.

Our long-term debt at December 31, 2013, was $4,997 million with no principal payments due until October 2019 (US$1.3 billion). The $318 million increase in long-term debt from December 31, 2012 was due to fluctuations in foreign exchange rates.

As at December 31, 2013, we are in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

We expect cash flow from our crude oil, natural gas and refining operations to fund a significant portion of our cash requirements over the next decade. Any potential shortfalls may be required to be funded through financing activities or management of our asset portfolio. The following sources of liquidity are available as at December 31, 2013.

($ millions)	Amount	Term
Cash and Cash Equivalents	**2,452**	**Not applicable**
Committed Credit Facility	**3,000**	**November 2017**
Canadian Base Shelf Prospectus (1)	**1,500**	**June 2014**
U.S. Base Shelf Prospectus (1)	**US$1,200**	**July 2014**

(1) Availability is subject to market conditions.

Our cash and cash equivalents balance at December 31, 2013 includes US$1.4 billion related to the December 17, 2013 receipt of the remaining principal of the Partnership Contribution Receivable.

Committed Credit Facility

In September 2013, we renegotiated our existing $3.0 billion committed credit facility, extending the maturity date from November 30, 2016 to November 30, 2017.

We also have a commercial paper program which, together with our committed credit facility, is used to manage our short-term cash requirements. We reserve capacity under our committed credit facility for amounts of outstanding commercial paper. As of December 31, 2013, no amounts were drawn on our committed credit facility and there was no commercial paper outstanding.

Canadian Base Shelf Prospectus

On May 24, 2012, we filed a Canadian base shelf prospectus for unsecured medium-term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issuance of medium-term notes in Canadian dollars or other foreign currencies from time to time, in one or more offerings, with availability subject to market conditions. Terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. The Canadian base shelf prospectus expires in June 2014. It is our intention to file a new Canadian shelf prospectus prior to the maturity of the existing Canadian shelf prospectus.

As at December 31, 2013, no medium-term notes were issued under this Canadian shelf prospectus.

U.S. Base Shelf Prospectus

On May 9, 2013, we amended our U.S. base shelf prospectus for senior unsecured notes to increase the total capacity from US$2.0 billion to US$3.25 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time, in one or more offerings, with availability subject to market conditions. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. The U.S. base shelf prospectus expires in July 2014. It is our intention to file a new U.S. shelf prospectus prior to the maturity of the existing U.S. shelf prospectus.

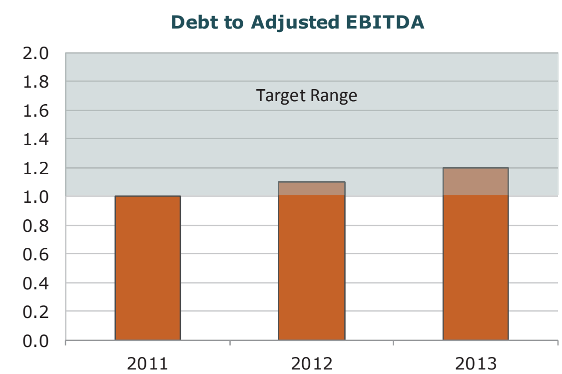
As at December 31, 2013, US$1.2 billion remains available under our U.S. base shelf prospectus, the availability of which is dependent on market conditions.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

	2013	2012	2011
Debt to Capitalization	**33%**	32%	27%
Debt to Adjusted EBITDA (times)	**1.2x**	1.1x	1.0x

We continue to have long-term targets for a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. At December 31, 2013, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges.



Debt to Capitalization is calculated as follows:

As at December 31,	**2013**	2012	2011
Debt	**4,997**	4,679	3,527
Shareholders' Equity	**9,946**	9,782	9,384
Capitalization	**14,943**	14,461	12,911
Debt to Capitalization	**33%**	32%	27%

The following is a reconciliation of Adjusted EBITDA and the calculation of Debt to Adjusted EBITDA:

As at December 31,	**2013**	2012	2011
Debt	**4,997**	4,679	3,527
Net Earnings	**662**	995	1,478
Add (Deduct):			
Finance Costs	**529**	455	447
Interest Income	**(96)**	(109)	(124)
Income Tax Expense	**432**	783	729
DD&A	**1,833**	1,585	1,295
Goodwill Impairment	**-**	393	-
E&E Impairment	**50**	68	-
Unrealized (Gain) Loss on Risk Management	**415**	(57)	(180)
Foreign Exchange (Gain) Loss, net	**208**	(20)	26
(Gain) Loss on Divestiture of Assets	**1**	-	(107)
Other (Income) Loss, net	**2**	(5)	4
Adjusted EBITDA	**4,036**	4,088	3,568
Debt to Adjusted EBITDA	**1.2x**	1.1x	1.0x

Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

Outstanding Share Data and Stock-Based Compensation Plans

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. At December 31, 2013, no preferred shares were outstanding.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of Cenovus.

In addition to its Stock Option Plan, Cenovus has a performance share unit ("PSU") plan and two deferred share unit ("DSU") plans. PSUs are whole share units which entitle the holder to receive upon vesting either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. Refer to note 28 of the Consolidated Financial Statements for more details.

Total Outstanding Common Shares and Stock-Based Compensation Plans

As at December 31, 2013	**Units** (thousands)
Common Shares	**756,046**
Stock Options	
NSRs	**26,315**
TSARs	**7,086**
Cenovus Replacement TSARs	**1,479**
Encana Replacement TSARs	**3,904**
Other Stock-Based Compensation Plans	
PSUs	**5,785**
DSUs	**1,192**

Contractual Obligations and Commitments

The below contractual obligations have been grouped as operating, investing and financing, relating to the type of cash outflow that will arise:

	Expected Payment Date						
($ millions)	2014	2015	2016	2017	2018	Thereafter	Total
Operating							
Pipeline Transportation [1]	377	554	647	807	1,284	17,512	21,181
Operating Leases (Building Leases)	119	119	117	118	159	2,950	3,582
Product Purchases	98	20	7	-	-	-	125
Other Long-term Commitments	50	40	21	17	12	116	256
Interest on Long-term Debt	271	268	268	268	268	3,682	5,025
Interest on Partnership Contribution Payable	82	55	26	2	-	-	165
Decommissioning Liabilities	104	105	113	117	116	6,916	7,471
Total Operating	1,101	1,161	1,199	1,329	1,839	31,176	37,805
Investing							
Capital Commitments	52	36	30	9	21	27	175
Partnership Contribution Payable	438	465	494	128	-	-	1,525
Total Investing	490	501	524	137	21	27	1,700
Financing							
Long-term Debt (principal only)	-	-	-	-	-	5,052	5,052
Total Financing	-	-	-	-	-	5,052	5,052
Total Payments [2]	1,591	1,662	1,723	1,466	1,860	36,255	44,557
Fixed Price Product Sales	52	54	56	3	-	-	165

(1) Certain transportation commitments included are subject to regulatory approval.
(2) Contracts on behalf of the FCCL Partnership ("FCCL") and WRB Refining LP ("WRB") are reflected at our 50 percent interest.

As operator of Foster Creek, Christina Lake and Narrows Lake, Cenovus is responsible for the field operations, marketing and transportation of 100 percent of the production from these assets. Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements, debt, future building leases, marketing agreements and capital commitments. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information, see the notes to the Consolidated Financial Statements.

In 2013, Cenovus entered into various firm transportation agreements totaling approximately $11 billion. These agreements, most of which are subject to regulatory approval, are for terms up to 20 years, subsequent to the date of commencement, and will help align our future transportation requirements with our anticipated production growth. We also entered into rail related commitments that increased our rail shipping capacity to approximately 10,000 barrels per day by the end of 2013. We anticipate increasing our rail shipping capacity for crude oil to approximately 30,000 barrels per day by the end of 2014, subject to favourable market conditions.

As at December 31, 2013, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 33 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 37 Bcf of natural gas, at a weighted average price of $4.43 per Mcf.

In the normal course of business, we also lease office space for personnel who support field operations and for corporate purposes.

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims. There are no individually or collectively significant claims.

Related Party Transactions

Cenovus did not enter into any related party transactions during the year ended December 31, 2013 or 2012. For a summary of key Management compensation refer to the notes to the Consolidated Financial Statements.

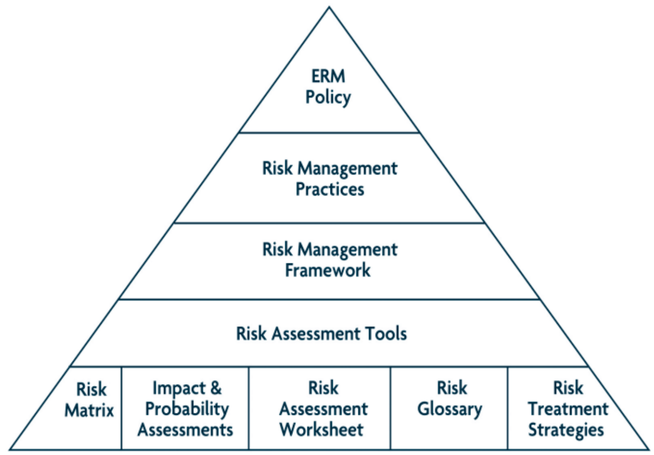
RISK MANAGEMENT

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. We manage risk to our risk appetite that is determined by Management and confirmed by the Board.

Risk Governance

Through our Enterprise Risk Management ("ERM") program, we have established a systematic process for identifying, measuring, prioritizing and managing risk across Cenovus.

The ERM Policy, approved by our Board, outlines our risk management principles and expectations as well as the roles and responsibilities of all staff. Building on the ERM Policy, we have established Risk Management Practices, a Risk Management Framework and Risk Assessment Tools. Our Risk Management Framework contains the key attributes recommended by the International Standards Organization ("ISO") in their *ISO 31000 – Risk Management Principles and Guidelines*. The results of our ERM program are documented in an Annual Risk Report presented to the Board as well as through quarterly updates.



Risk Assessment

All risks are assessed for their potential impact on the achievement of Cenovus's strategic objectives as well as their likelihood of occurring. Risks are analyzed through the use of a Risk Matrix and other standardized assessment tools.

Using the Risk Matrix, each risk is classified on a continuum ranging from "Low" to "Extreme". Risks are first evaluated on an inherent basis, without considering the presence of controls or mitigating measures. Risks are then re-evaluated based on their residual risk ranking, reflecting the exposure that remains after mitigation and control measures are considered.

Management determines if additional risk treatment is required based on the residual risk ranking. There are prescribed actions for elevating these exposures to the right decision makers.

Risk Management Roles and Responsibilities

The roles and responsibilities of the various participants of our ERM Program are:

Board:

- Oversees the implementation of the ERM program by Management and provides oversight for risk management activities; and
- The Audit Committee of the Board reviews our Risk Management Framework and related processes on an annual basis to ensure processes remain current and relevant.

Senior Management:

- Confirms our corporate risk appetite with the Board. The executive team is interviewed annually and collaborative workshops are held with Senior Vice-Presidents and Vice-Presidents to support the development of the Annual Risk Report.

The Financial & Enterprise Risk Team reports to the Executive Vice-President & Chief Financial Officer and is responsible for managing our ERM program and the related risk reporting.

Principal and Strategic Risks

Cenovus's operations, financial condition and in some cases our reputation, may be impacted by principal and strategic risks. Cenovus defines principal risks as those risks that when measured in terms of likelihood and impact, may adversely affect the achievement of our strategic or major business objectives. Strategic risk is the risk of loss resulting from the inability to adequately plan or implement an appropriate business strategy, or to adapt to changes in the external business, political or regulatory environment.

Principal and strategic risks are categorized into:

- Financial risks, which includes commodity price risk and liquidity risk;
- Operational risks such as risks related to safety, the environment, transportation restrictions, project execution and reserves replacement; and
- Regulatory risks from the regulatory approval process and changes to or introduction of environmental regulations.

A description of the risk factors and uncertainties affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2013.

The following explains how some of the material principal and strategic risks impact our business:

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. From time to time, Management may enter into contracts to mitigate risk associated with fluctuations in commodity prices, interest rates and foreign exchange rates. These contracts may prevent Cenovus from fully realizing the benefit of price or rate increases or decreases above or below those established by these contracts. We have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of fixed and floating rate debt. Credit is managed through our credit policy which is approved by the Audit Committee of the Board.

Commodity Price Risk

Fluctuations in commodity prices create volatility in our financial performance. Commodity prices are impacted by a number of factors including global and regional supply and demand, transportation constraints, weather conditions and availability of alternative fuels, all of which are beyond our control and can result in a high degree of price volatility.

Changes in commodity prices will affect the revenues generated by the sale of our crude oil, NGLs, natural gas production from our Oil Sands and Conventional segments and sale of refined products from our refining operations. Our financial performance is also affected by price differentials since our upstream production differs in quality and location from underlying benchmark commodity prices quoted on financial exchanges.

We anticipate commodity prices and refining margins will continue to be volatile over the next few years. If crude oil and natural gas prices decline significantly and remained at low levels for an extended period of time, the carrying value of our assets may be subject to impairment, future capital programs could be delayed or cancelled and production could be curtailed, among other impacts. However, lower commodity prices would reduce the cost of natural gas and crude oil feedstock used in our refining operations.

We manage our commodity price exposure through a combination of activities including integration, financial hedges and physical contracts. Our business model partially mitigates our exposure to light/heavy differentials and refinery margins through our upstream and downstream integration. In addition, our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations.

We further reduce our exposure to commodity price risk through the use of various financial instruments and select physical contracts. These transactions protect a portion of the budgeted cash flow and ensure funds are available for capital projects. These activities are reviewed and approved by the Market Risk Management Committee which is composed of the President & Chief Executive Officer, Executive Vice-President & Chief Financial Officer and one other Executive Vice-President. These activities are governed through our Market Risk Mitigation Policy, which contains prescribed hedging protocols and limits. In 2013, we partially mitigated our exposure to the following:

- Crude oil commodity price risk on our crude oil sales with fixed price commodity swaps;
- Natural gas commodity price risk on our natural gas sales with fixed price swaps;
- Widening location or quality differentials for crude oil and natural gas with fixed price differential swaps and futures; and
- Electricity consumption costs through a derivative power contract.

For further details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3 and 32 to the Consolidated Financial Statements. The financial impact is summarized below:

Financial Impact of Risk Management Activities

	2013			2012		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(71)**	**343**	**272**	(81)	(247)	(328)
Natural Gas	**(63)**	**69**	**6**	(247)	176	(71)
Refining	**18**	**-**	**18**	(7)	(1)	(8)
Power	**(6)**	**3**	**(3)**	(1)	15	14
(Gain) Loss on Risk Management	**(122)**	**415**	**293**	(336)	(57)	(393)
Income Tax Expense (Recovery)	**29**	**(105)**	**(76)**	86	14	100
(Gain) Loss on Risk Management, after-tax	**(93)**	**310**	**217**	(250)	(43)	(293)

In 2013, management of commodity price risk resulted in realized gains on crude oil and natural gas financial instruments, consistent with our contract prices exceeding the average benchmark price. We recognized unrealized losses as a result of the increase in forward commodity prices compared with prices at the end of the prior year and changes in prices for transactions executed during the year, as well as the realization of settled positions, partially offset by the widening of forward light/heavy differentials.

Financial instruments undertaken within our refining segment by the operator, Phillips 66, are primarily for purchased product. Details of contract volumes and prices can be found in the notes to the Consolidated Financial Statements.

For our risk management activities, we take an integrated view of our exposure across the upstream and refining businesses. We entered into Brent crude oil hedges using fixed-price swap contracts to reduce our commodity price risk on a portion of our expected 2014 production.

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. Fluctuations in commodity prices could have resulted in unrealized gains (losses) for the year impacting earnings before income tax on open risk management positions as at December 31, 2013 as follows:

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl applied to Brent, WTI and Condensate hedges	(200)	200
Crude Oil Differential Price	± US$5 per bbl applied to differential hedges tied to production	31	(31)
Power Commodity Price	± $25 per MWHr applied to power hedge	19	(19)

Liquidity Risk

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. In depressed economic times or due to unforeseen events, Cenovus's liquidity risk could become heightened. If we were unable to meet our financial obligations as they became due this would have a material adverse effect on our financial condition, results of operations, cash flows and reputation.

We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under our shelf prospectuses. At December 31, 2013, we had cash and cash equivalents of $2.5 billion, no amounts were drawn on our committed credit facility and no commercial paper was outstanding. In addition, we had $1.5 billion in unused capacity under our Canadian base shelf prospectus and US$1.2 billion in unused capacity under our U.S. base shelf prospectus, the availability of which are dependent on market conditions.

We believe that our current liquidity position is sufficient to protect us in the near-term from unforeseen economic events that could create further volatility in cash flow.

Operational Risk

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that could impact the achievement of our objectives.

Safety Risk

Crude oil and natural gas development, production and refining are, by their nature, high risk activities that may cause personal injury or loss of life. The inability to operate safely has the potential to have a material adverse impact on Cenovus's reputation, financial condition, results of operations and cash flow.

We are committed to safety in our operations. We take an active role with our refining partner in ensuring safety is the first priority. Our safety policies and standards comply with government regulations and industry standards. To partially mitigate safety risk, we have a system of standards, practices and procedures called the Cenovus Operations Management System to identify, assess and control safety, security and environmental risk across our operations. Cenovus endeavors to engage contractors who share the same commitment to safety. We use a third-party online safety prequalification system as well as safety performance data to assist in selecting our contractors. Prevention of occupational diseases and illnesses is also an integral part of our health and safety focus. We take a risk-based approach to systematically identify, evaluate, and manage health hazards of all workers at our sites.

The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies for approval by our Board and oversees compliance with government laws and regulations.

Transportation Restrictions

Our ability to efficiently access end markets may be affected by insufficient transportation capacity for our production. Transportation restrictions can negatively impact financial performance by way of higher transportation costs, wider price differentials, lower realized prices at specific locations or for specific grades and in extreme situations, production curtailment. While this risk may impact our natural gas production, it has the greatest potential to impact our crude oil production, which could negatively affect our financial position, results of operations and cash flows within our Oil Sands and Conventional segments.

To help mitigate these risks, we employ a diversified sales strategy which includes utilizing multiple transportation options, including pipeline, railcar, and cargo. In addition to the firm transportation commitments we have made to date, we continue to evaluate our options and may make further commitments to new and expanding transportation infrastructure to enable access to additional markets for our production.

We anticipate transportation constraints will continue in the near term. The Keystone XL project, the Northern Gateway Pipeline project and the Energy East Pipeline project, if approved, are expected to benefit heavy oil producers by improving access to refineries with capacity to process heavy crude oil as well as creating an option to ship crude oil offshore. Currently, the Keystone XL project will connect Alberta's oil sands with refineries in the U.S. Gulf Coast, the Northern Gateway Pipeline project will connect Alberta's oil sands to Canada's West Coast, allowing for transportation to new markets such as Asia, and the Energy East Pipeline project will carry crude oil from Alberta and Saskatchewan to refineries and marine terminals in eastern Canada. Other industry options are being developed and we are actively participating in those developments.

Capital Project Execution and Operating Risk

There are risks associated with the execution and operations of our upstream and refining projects. Over the next 10 years, we will be required to concurrently manage multiple projects. Successful project execution will be highly dependent upon the weather, price escalations, availability of skilled labour, key components or other scarce resources and general economic conditions, any of which could have a material adverse effect on Cenovus.

We are also mindful of the need to maintain financial resiliency and control our costs. Our capital programs are scalable in most cases, and if necessary, there are areas where we could defer spending in response to reduced cash flows from operations or liquidity challenges. When making operating and investing decisions, capital allocation is focused on strategic fit, mitigation of risk and optimization of project returns. Our capital approval process requires projects to be presented on a fully risked basis which considers potential construction, commercial, operational and/or regulatory risk exposures. We apply a manufacturing-like approach to our phased oil sands development projects to help manage project quality, scheduling and control costs, including utilizing a templated phase design, in-house project management, construction management and commissioning/start-up teams, and Cenovus's own modular yard for fabrication of pipe rack and equipment modules.

Operational risks affect our ability to continue operations in the ordinary course of business. Our operations are subject to risks generally affecting the oil and gas and refining industries. Our operational risks include, but are not limited to safety considerations, environmental challenges, transportation capacity and interruptions, uncertainty of reserves and resources estimates, reservoir performance and technical challenges, phased execution of oil sands projects and partner risks. We attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations.

Reserves Replacement Risk

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. Our financial position, results of operations and cash flows are highly dependent upon successfully producing from current reserves and acquiring, discovering or developing additional reserves.

To mitigate the risk associated with replacing reserves we evaluate projects on a fully risked basis, including geological risk and engineering risk, and consider information provided by our stratigraphic well program. In addition, our asset teams undertake a project look-back process, whereby each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include technical and operational issues that impacted the project's results. Mitigation plans are developed for the issues that had a negative impact on results and are incorporated into the current year's plan.

To date our ability to find, acquire and develop additional crude oil and natural gas reserves has been in line with our 10 year business plan. See the Oil and Gas Reserves and Resources section of this MD&A for further details of our proved and probable reserves and economic bitumen contingent and prospective resources at December 31, 2013.

Environmental Risk

Developing and operating our projects is subject to hazards of recovering, transporting and processing hydrocarbons which can cause damage to the environment. We take our responsibility for the environment very seriously. To manage these risks, we strive to use, recycle and dispose of water safely, manage air emissions, limit our physical footprint and minimize our impact on habitat, including wildlife. Working with our stakeholders, we identify the unique needs of the different areas where we operate. Employees, contractors and third-party service providers have the necessary skills and appropriate training needed to comply with regulations and be responsible environmental stewards. Our environmental impact is measured using the Cenovus Operations Management System to monitor, manage and accurately report our activities.

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 incident and remediation/reclamation programs have been put in place and utilized to restore the environment.

Regulatory Risk

Regulatory risk is the risk of loss or lost opportunity resulting from the introduction of, or changes in, regulatory requirements or the failure to secure regulatory approval for a crude oil or natural gas development project. The implementation of new regulations or the modification of existing regulations could impact our existing and planned projects as well as impose a cost of compliance, adversely impacting our financial condition, results of operations and cash flows.

Environmental Regulation Risk

The complexities of changes in environmental regulation make it difficult to predict the potential future impact to Cenovus. We anticipate that future capital expenditures and operating expenses could continue to increase as a result of the implementation of new environmental regulations. However, we expect that the cost of meeting new environmental and climate change regulations will not be so high as to cause a material disadvantage to our competitive position. Non-compliance with environmental regulations could also have an adverse impact on Cenovus's reputation.

Further discussion on specific areas that currently have, and are reasonably likely to have, an impact on Cenovus's operations is below.

Water Use Impacts

To operate our SAGD facilities we rely on water, which is obtained under licenses from Alberta Environment and Sustainable Resource Development. Currently, we are not required to pay for the water we use under these licenses. If a change to the requirements under these licenses reduces the amount of water available for our use, our production could decline or operating costs could increase, both of which may have a material adverse effect on our business and financial performance. 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.

Greenhouse Gases & Air Pollutants

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants. A number of legislative and regulatory measures to address GHG emission reductions are in various phases of review, discussion or implementation in Canada and the U.S.

If comprehensive GHG regulation is enacted in any jurisdiction in which we operate, adverse impacts to our business may include, among other things, increased compliance costs, loss of markets, permitting delays, substantial costs to generate or purchase emission credits or allowances, all of which may increase operating costs and reduce demand for crude oil, natural gas and certain refined products. Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

Our approach to emissions management is demonstrated by our industry leadership focusing on energy efficiency, developing oil sands technology to reduce GHG emissions and carbon dioxide sequestration. Cenovus was recognized for leadership in GHG emissions reporting by being included in the 2013 Carbon Disclosure Leadership Index for Canada. We incorporate the potential costs of carbon, ranging from $15-$65 per tonne of CO_2, into future planning which guides the capital allocation process. We intend to continue using scenario planning to anticipate the future impact of regulations, reduce our emissions intensity and improve our energy efficiency.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that may impose costly requirements. In 2007, the EPA issued the Renewable Fuel Standard program that mandates the total volume of renewable transportation fuel sold or introduced in the U.S. and requires refiners to blend renewable fuels, such as ethanol and advanced biofuels, with their gasoline. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. To the extent refineries do not, they must purchase credits, referred to as RINs, in the open market. RINs are a number assigned to each gallon of renewable fuel produced or imported into the U.S., and were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

Our refineries do not blend renewable fuels into the motor fuel products we produce and consequently we are obligated to purchase RINs. In the future, the existing regulations could change the volume of renewable fuels required to be blended with refined products. This could create volatility in the price for RINs or an insufficient number of RINs being available in order to meet the requirements. Our financial conditions, results of operations, and cash flow could be materially adversely impacted.

Land Use, Habitat and Biodiversity

Alberta's Land-Use Framework has been implemented under the Alberta Land Stewardship Act ("ALSA") which 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. In some cases, ALSA amends or extinguishes 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 approved its LARP, issued under the ALSA.

The LARP identifies management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. In 2013, we received compensation of $20 million, including interest, from the Government of Alberta related to some of our non-core Oil Sands mineral rights that were cancelled. The cancelled mineral rights had no direct impact on our business plan, our current operations at Foster Creek and Christina Lake, or on any of our filed applications. Uncertainty exists with respect to future development applications in the areas covered by the LARP, including the potential for development restrictions and mineral rights cancellation.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

We are required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recognized in our Consolidated Financial Statements.

Joint Arrangements

Cenovus holds a 50 percent ownership interest in two jointly controlled entities, FCCL and WRB. The classification of these joint arrangements as either a joint operation or a joint venture requires judgment. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements are classified as joint operations and our share of the assets, liabilities, revenues and expenses are recognized in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, we considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnership. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third-party borrowings.

- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and as such are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Exploration and Evaluation Assets

The application of our accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating costs, as well as estimated economically recoverable reserves are considered. If it is determined that an E&E asset is not technically feasible or commercially viable and Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

Identification of CGUs

Our upstream and refining assets are grouped into CGUs. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of Cenovus's upstream, refining and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Reserves

There are a number of inherent uncertainties associated with estimating reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would have a significant impact on the impairment test and DD&A expense of Cenovus's crude oil and natural gas assets in the Oil Sands and Conventional segments. Cenovus's crude oil and natural gas reserves are evaluated and reported to Cenovus by IQREs.

Impairment of Assets

PP&E, E&E assets and goodwill are assessed for impairment at least annually and when circumstances suggest that the carrying amount may exceed the recoverable amount. Assets are tested for impairment at the CGU level. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. For our upstream assets, these estimates include future commodity prices, expected production volumes, quantity of reserves and discount rates, as well as future development and operating costs. Recoverable amounts for Cenovus's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating costs, transportation capacity and supply and demand conditions. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

For impairment testing purposes, goodwill has been allocated to each of the CGUs to which it relates.

At December 31, 2013, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal. Key assumptions in the determination of cash flows from reserves include reserves as estimated by Cenovus's IQREs, crude oil and natural gas prices and the discount rate.

Crude Oil and Natural Gas Prices

The future prices used to determine cash flows from crude oil and natural gas reserves are:

	2014	2015	2016	2017	2018	Average Annual % Change to 2024
WTI (US$/barrel)	95.00	95.00	95.00	95.00	95.30	1.9%
AECO ($/Mcf)	4.00	4.25	4.55	4.75	5.00	2.4%

Discount Rate

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent, which is common industry practice, and used by our IQREs in preparing their reserves reports. Based on the individual characteristics of the asset, other economic and operating factors are also considered, which may increase or decrease the implied discount rate. Changes in the economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recognized for the future decommissioning and restoration of our upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recognized to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

Changes in Accounting Policies

We adopted the following new standards and amendments to standards:

Joint Arrangements, Consolidation, Associates and Disclosures

Effective January 1, 2013, we adopted, as required, IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10"), IFRS 11, "*Joint Arrangements*" ("IFRS 11"), IFRS 12, "*Disclosure of Interests in Other Entities*" ("IFRS 12") as well as the amendments to International Accounting Standard ("IAS") 28, "*Investments in Associates and Joint Ventures*" ("IAS 28").

IFRS 10 revised the definition of control to include three elements: (1) power over an investee; (2) exposure to variable returns from its involvement with the investee and (3) the ability to use its power to affect returns from the investee. Cenovus reviewed its consolidation methodology and determined that the adoption of IFRS 10 did not result in a change in the consolidation status of its subsidiaries and investees.

Under IFRS 11, a joint arrangement is classified as either a joint operation or a joint venture depending on the rights and obligations of the parties to the arrangement. Under a joint operation, parties have rights to the assets and obligations for the liabilities of the arrangement and account for their share of assets, liabilities, revenues and expenses. Under a joint venture, parties have the rights to the net assets of the arrangement and account for the arrangement as an investment using the equity method. Cenovus performed a comprehensive review of its interest in other entities and identified two individually significant interests, FCCL and WRB, for which it shares joint control. Cenovus reviewed these joint arrangements considering their structure, the legal form of the separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of our accounting policy under IFRS 11 requires judgment in determining the classification of these joint arrangements. A discussion of the judgments used in our assessment of joint arrangements can be found in the Consolidated Financial Statements. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements are classified as joint operations. There has been no impact on the recognized assets, liabilities and comprehensive income of Cenovus with the application of IFRS 11.

IFRS 12 requires disclosures relating to an entity's interest in subsidiaries, joint arrangements, associates and unconsolidated structured entities. IAS 28 was amended to conform to the changes made in IFRS 10 and IFRS 11. The adoption of IFRS 12 and IAS 28 did not result in any changes to disclosures.

Employee Benefits

Effective January 1, 2013, we adopted, as required, IAS 19, "*Employee Benefits*", as amended in June 2011 ("IAS 19R"). We applied the standard retrospectively and in accordance with the transitional provisions. The opening Consolidated Balance Sheet of the earliest comparative period presented (January 1, 2012) was restated.

IAS 19R requires the recognition of changes in defined benefit pension obligations and plan assets when they occur, eliminating the 'corridor' approach previously permitted and accelerating the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are recognized immediately through other comprehensive income ("OCI"). In addition, we replaced interest costs on the defined benefit obligation and the expected return on plan assets with a net interest cost based on the net defined benefit asset or liability measured by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period. Interest expense and interest income on net post-employment benefit liabilities and assets continue to be recognized in Net Earnings.

Furthermore, termination benefits must be recognized at the earlier of when the entity can no longer withdraw an offer of termination benefits or recognizes any restructuring costs.

The effect on the Consolidated Balance Sheets of IAS 19R was:

As at January 1, 2012	Net Defined Benefit Liability (1)	Deferred Income Taxes	Shareholders' Equity
Balance as Previously Reported	16	2,101	9,406
Effect of Adoption of IAS 19R	30	(8)	(22)
Restated Balance	46	2,093	9,384

(1) *Composed of the defined benefit pension and other post-employment benefit plans ("OPEB") plans, which are included in other liabilities on the Consolidated Balance Sheets of the Consolidated Financial Statements.*

As at December 31, 2012	Net Defined Benefit Liability (1)	Deferred Income Taxes	Shareholders' Equity
Balance as Previously Reported	28	2,568	9,806
Effect of Adoption of IAS 19R	32	(8)	(24)
Restated Balance	60	2,560	9,782

(1) *Composed of the defined benefit pension and OPEB plans, which are included in other liabilities on the Consolidated Balance Sheets of the Consolidated Financial Statements.*

The effect on the Consolidated Statements of Earnings and Comprehensive Income of IAS 19R was:

	Year Ended December 31, 2012	Year Ended December 31, 2011
Decrease in General and Administrative Expense	2	-
Increase in Net Earnings for the Year	2	-
Remeasurement of Defined Benefit and OPEB Liabilities	(4)	(12)
(Decrease) in Comprehensive Income for the Period	(2)	(12)

The change in accounting policy did not have a material impact on the Consolidated Financial Statements including Net Earnings per Share.

Details about our pension and OPEB plans are disclosed in the Consolidated Financial Statements.

Fair Value Measurement

Effective January 1, 2013, we adopted, as required, IFRS 13, "*Fair Value Measurement*" ("IFRS 13") and applied the standard prospectively as required by the transitional provisions. The standard provides a consistent definition of fair value and introduces consistent requirements for disclosures related to fair value measurement. There has been no change to Cenovus's methodology for determining the fair value for its financial assets and liabilities and, as such, the adoption of IFRS 13 did not result in any measurement adjustments as at January 1, 2013. The disclosures related to fair value measurement can be found in Note 32 to the Consolidated Financial Statements.

Presentation of Items in Other Comprehensive Income

Effective January 1, 2013, we applied the amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1"), as amended in June 2011. The amendment requires items within OCI to be grouped into two categories: (1) items that will not be subsequently reclassified to profit or loss or (2) items that may be subsequently reclassified to profit or loss when specific conditions are met. The amendment has been applied retrospectively and, as such, the presentation of items in OCI has been modified. The application of the amendment to IAS 1 did not result in any adjustments to OCI or comprehensive income.

Disclosure of Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2013, we complied with the amended disclosure requirements, regarding offsetting financial assets and financial liabilities, found in IFRS 7, "*Financial Instruments: Disclosures*" issued in December 2011. The additional disclosures can be found in the Consolidated Financial Statements. The application of the amendment had no impact on the Consolidated Statements of Earnings and Comprehensive Income or the Consolidated Balance Sheets of the Consolidated Financial Statements.

Disclosures of Recoverable Amounts of Non-Financial Assets

In May 2013, the IASB issued an amendment to IAS 36, "*Impairment of Assets*". The amendment removes certain disclosures of the recoverable amount of a CGU. The amendment is effective retrospectively for annual periods beginning on or after January 1, 2014. As allowed by the standard, we have early adopted the amendment in the current period. Refer to the notes to the Consolidated Financial Statements for the amended disclosures.

Future Accounting Pronouncements

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning on or after January 1, 2014 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2013. The standards and interpretations applicable to Cenovus are as follows and will be adopted on their respective effective dates:

Financial Instruments

The IASB intends to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39") with IFRS 9, "*Financial Instruments*" ("IFRS 9"). IFRS 9 will be published in three phases, of which two phases have been published.

Phases one and two address accounting for financial assets and financial liabilities, and hedge accounting, respectively. The third phase will address impairment of financial instruments.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than Net Earnings, unless this creates an accounting mismatch.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. We do not currently apply hedge accounting.

A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of the two completed phases is permitted only if adopted in their entirety at the beginning of a fiscal period. We are currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IAS 32, "*Financial Instruments: Presentation*" ("IAS 32"), to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. The amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, requiring retrospective application. IAS 32 will not have a significant impact on the Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, has assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2013. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2013.

The effectiveness of our ICFR was audited by PricewaterhouseCoopers LLP, an independent firm of chartered accountants, as stated in their Independent Auditor's Report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2013.

There have been no changes to ICFR during the year ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

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

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

Our CR policy focuses on six commitment 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 annual CR report.

The CR 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. We 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 CR 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.

We continue to review our CR reporting process, performance indicators and controls to ensure they align with our stakeholder expectations, our operations and our strategy. The CR report 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.

We published our 2012 CR report in July 2013, which highlighted our investments in innovation and research, local and Aboriginal spending in our operating areas, advancements made in minimizing our environmental impacts, long-term agreements signed with Aboriginal communities, and our involvement with and investments in charities and non-profit organizations. Our CR policy and CR report are available on our website at cenovus.com.

In January 2014, Cenovus was included for the first time in the RobecoSAM 2014 Sustainability Yearbook with a Bronze Class distinction. RobecoSAM is a Swiss-based specialist in international sustainability investment that publishes the Dow Jones Sustainability Index (see below). Corporate Knights magazine also named Cenovus to their 2014 Global 100 clean capitalism ranking for the second consecutive year, as announced during the World Economic Forum in Davos, Switzerland in January. Corporate Knights also recognized Cenovus's leading CR performance in their inaugural Top 10 Energy Companies in the World listing, published in November 2013.

In October 2013, we were named to the Canada 200 Climate Disclosure Leadership Index for the fourth consecutive year. This index, published by CDP (formerly known as the Carbon Disclosure Project), recognizes companies for their open and transparent disclosure of greenhouse gas emissions. In September 2013, our leading CR practices were recognized internationally with the inclusion of Cenovus to the Dow Jones Sustainability World Index for the second consecutive year. We were also named to the Dow Jones Sustainability North America Index for the fourth consecutive year. In June 2013, Cenovus was named one of the Top 50 Socially Responsible

Corporations in Canada by Maclean's magazine and Sustainalytics for the second year in a row and for the third consecutive year by Corporate Knights magazine as one of the 2013 Best 50 Corporate Citizens in Canada.

These external recognitions of our commitment to corporate responsibility reaffirm Cenovus's efforts to balance economic, governance, social and environmental performance.

OUTLOOK

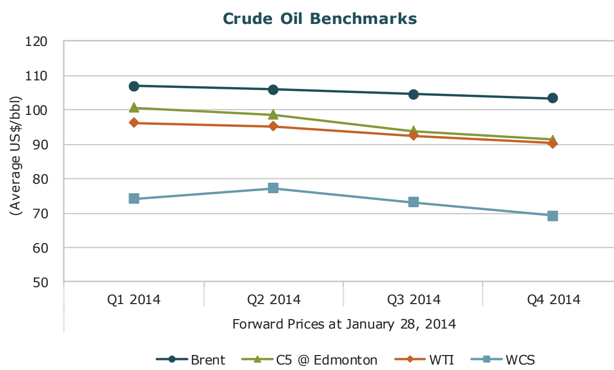
We continue to move forward on our 10-year business plan targeting net oil sands bitumen production of approximately 435,000 barrels per day and net crude oil production, including our conventional oil operations, of approximately 525,000 barrels per day by the end of 2023. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Telephone Lake and Grand Rapids. We will continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach. This approach will be enabled by technology, innovation and continued respect for the health and safety of our employees and contractors, with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

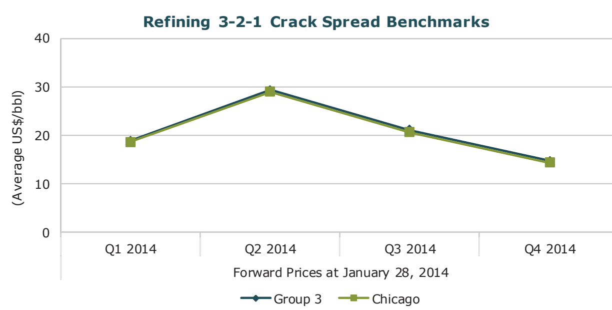
The following outlook commentary herein is focused on the next twelve months.

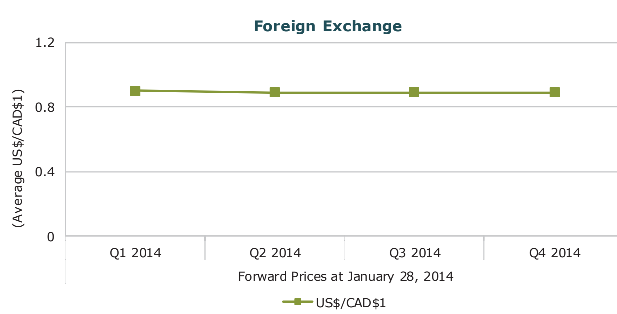
Commodity Prices Underlying our Financial Results

Our pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will continue to be tied to global economic growth, the pace of North American supply growth and production interruptions. Indicators suggest a continued gradual improvement in demand growth from both U.S. and Asian markets. North American supply growth is expected to continue at a strong, but moderating pace. Global supply disruptions are difficult to predict, however, we believe political instability, which is the root cause of supply outages, is unlikely to be resolved quickly. The overall expectation is for a modest decline in Brent crude oil prices in 2014 compared with 2013;
- The Brent-WTI differential is expected to narrow from 2013 as new pipeline capacity from Cushing to the Gulf Coast reduces inland congestion, partially offset by increased discounts of Gulf Coast crude oil prices relative to Brent crude oil prices as growing tight oil supply reduces the need for imports;
- We expect 2014 WTI-WCS price differentials to remain near 2013 levels as growing inland supply will approximate growth in pipeline and rail shipping capacity;
- Average Refining crack spreads in 2014 are expected to strengthen compared with 2013, mostly due to declines in WTI prices relative to Brent prices;
- Natural gas prices are expected to strengthen compared with 2013 as the pace of demand growth increases and storage inventories are reduced by late-2013 cold weather, partially offset by rising supply growth as new infrastructure is added to high-growth areas; and
- Based on forward prices, the Canadian dollar has weakened approximately seven percent from US$0.953/C$1 in the fourth quarter to a forward average of about US$0.890/C$1 for 2014. The weakening of the Canadian dollar has a positive impact on our revenues and Operating Cash Flow.



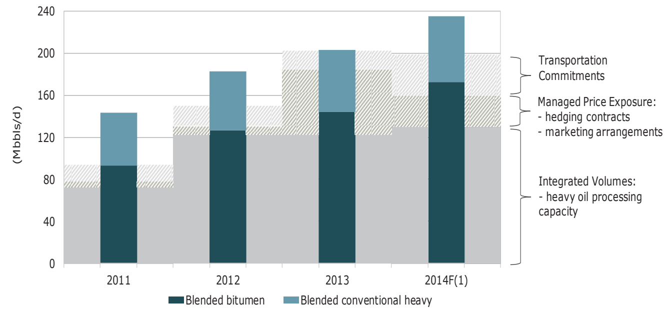




While we expect to see volatility in crude prices, we mitigate our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity able to process Canadian heavy crudes. From a value perspective, our refining business is able to capture value from both the WTI-WCS differential for Canadian crude and the Brent-WTI differential from the sale of refined products;
- Financial hedge transactions – protecting our upstream crude prices from downside risk by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – protecting our upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Transportation commitments – supporting transportation projects that move crude oil from our production areas to consuming markets and also to tidewater markets.

Protection Against Canadian Congestion



(1) Expected gross production capacity.

Key Priorities for 2014

Our key priorities for 2014 remain unchanged from 2013.

Market Access

We are focused on near and mid-term strategies to broaden market access for our crude oil production. This will allow us to build on our successful marketing and transportation strategy and broaden the portfolio of market opportunities for our growing production. We anticipate increasing our rail shipping capacity for crude oil to approximately 30,000 barrels per day by the end of 2014, subject to favourable market conditions, by supporting industry transportation projects as well as new and expanded market development initiatives for our crude oil. During 2013, we entered into approximately $11 billion of new pipeline commitments (most of which include amounts for projects awaiting regulatory approval) to align our future transportation requirements with our anticipated growth.

Attacking Cost Structures

We continue to take aim at cost structures across the organization to maintain our track record of cost efficiency. We must ensure that, over the long term, we maintain an efficient and sustainable cost structure and take advantage of our business model. For example, we are actively identifying opportunities in supply chain management to further reduce capital and operating costs.

Other Key Challenges

We will need to effectively manage our business to support our development plans, including securing timely regulatory and partner approvals, complying with environmental regulations and managing competitive pressures within our industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section of this MD&A.

ADVISORY

Forward-Looking Information

This document 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 document is identified by words such as "anticipate", "believe", "expect", "plan", "forecast" or "F", "target", "project", "could", "focus", "goal", "outlook", "potential", "may", "strategy" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related milestones and schedules, projected future value or net asset value, projections for 2014 and future years, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, expected reserves and contingent and prospective resources, broadening market access, improving cost structures, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology, including to reduce our environmental impact 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 disclosed in our current guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our 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; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; 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.

2014 guidance is based on an average diluted number of shares outstanding of approximately 757 million. It assumes: Brent US$105.00/bbl, WTI of US$102.00/bbl; Western Canada Select of US$76.00/bbl; NYMEX of US$4.00/MMBtu; AECO of $3.30/GJ; Chicago 3-2-1 crack spread of US$13.50/bbl; exchange rate of $0.98 US$/C$. For the period 2015 to 2023, assumptions include: Brent US$105.00-US$110.00; WTI of US$100.00-US$106.00/bbl; Western Canada Select of C$81.00-C$91.00/bbl; NYMEX of US$4.25-US$4.75/MMBtu; AECO of C$3.70-C$4.31/GJ; Chicago 3-2-1 crack spread of US$12.00-US$13.00; exchange rate of $1.00 US$/C$; and average diluted number of shares outstanding of approximately 782 million.

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 the success of our hedging strategies; the accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationships with our partners 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 producing, transporting or refining of crude oil into petroleum and chemical products; 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, including sufficient crude-by-rail or other alternate transportation; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our AIF or Form 40-F for the year ended December 31, 2013, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

Oil and Gas Information

The estimates of reserves, bitumen contingent resources and prospective resources estimates were prepared effective December 31, 2013 by our IQREs in accordance with the Canadian Oil and Gas Evaluation Handbook and NI 51-101.

Contingent resources are those quantities of bitumen 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. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The estimate of contingent resources has not been adjusted for risk based on the chance of development.

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 2013 reserves evaluation, which comply with NI 51-101 requirements.

Prospective resources are those quantities of bitumen 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 sub-classified 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 probability that the actual quantities recovered will equal or exceed the estimate. The contingent resources were estimated for individual projects and then aggregated for disclosure purposes.

Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates, is contained in our AIF and Form 40-F for the year ended December 31, 2013, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

ABBREVIATIONS

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

Crude Oil		**Natural Gas**	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Bcf	billion cubic feet
MMbbls	million barrels	MMBtu	million British thermal units
		GJ	Gigajoule
		CBM	Coal Bed Methane
TM	Trademark of Cenovus Energy Inc.		

Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2013

(Canadian Dollars)

Report of Management

Management's Responsibility for the Consolidated Financial Statements

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect Management's best judgments.

The Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee which is made up of three independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation and the United States *Sarbanes – Oxley Act of 2002* and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets with Management and the independent auditors on at least a quarterly basis to review and approve interim Consolidated Financial Statements and Management's Discussion and Analysis prior to their public release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

Management's Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the design and effectiveness of internal control over financial reporting as at December 31, 2013. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework (1992) to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that internal control over financial reporting was effective as at December 31, 2013.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2013, as stated in their Auditor's Report dated February 12, 2014. PricewaterhouseCoopers LLP has provided such opinions.

(signed)

Brian C. Ferguson
President &
Chief Executive Officer
Cenovus Energy Inc.

(signed)

Ivor M. Ruste
Executive Vice-President &
Chief Financial Officer
Cenovus Energy Inc.

February 12, 2014

Independent Auditor’s Report

To the Shareholders of Cenovus Energy Inc.

We have completed an integrated audit of Cenovus Energy Inc.’s 2013, 2012 and 2011 Consolidated Financial Statements and its internal control over financial reporting as at December 31, 2013. Our opinions, based on our audits, are presented below.

Report on the Consolidated Financial Statements

We have audited the accompanying Consolidated Financial Statements of Cenovus Energy Inc., which comprise the Consolidated Balance Sheets as at December 31, 2013, December 31, 2012 and January 1, 2012 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders’ Equity and Cash Flows for each of the three years ended December 31, 2013, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management’s Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor’s Responsibility

Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company’s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the Consolidated Financial Statements.

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the financial position of Cenovus Energy Inc. as at December 31, 2013, December 31, 2012 and January 1, 2012 and its financial performance and cash flows for each of the three years in the period ended December 31, 2013 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matter

As discussed in Note 4 to the Consolidated Financial Statements, Cenovus Energy Inc. changed its method of accounting for employee benefits.

Report on Internal Control over Financial Reporting

We have also audited Cenovus Energy Inc.’s internal control over financial reporting as at December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992), issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”).

Management’s Responsibility for Internal Control over Financial Reporting

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Report of Management.

Auditor’s Responsibility

Our responsibility is to express an opinion on Cenovus Energy Inc.’s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on Cenovus Energy Inc.'s internal control over financial reporting.

Definition of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Inherent Limitations

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Opinion

In our opinion, Cenovus Energy Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2013 based on criteria established in Internal Control – Integrated Framework (1992), issued by COSO.

(signed)

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta, Canada

February 12, 2014

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

For the years ended December 31,
($ millions, except per share amounts)

	Notes	2013	2012	2011
			(Note 4)	(Note 4)
Revenues	1			
Gross Sales		**18,993**	17,229	16,185
Less: Royalties		**336**	387	489
		18,657	16,842	15,696
Expenses	1			
Purchased Product		**10,399**	9,223	9,090
Transportation and Blending		**2,074**	1,798	1,369
Operating		**1,798**	1,667	1,398
Production and Mineral Taxes		**35**	37	36
(Gain) Loss on Risk Management	32	**293**	(393)	(248)
Depreciation, Depletion and Amortization	17,18	**1,833**	1,585	1,295
Goodwill Impairment	20	**-**	393	-
Exploration Expense		**114**	68	-
General and Administrative		**349**	350	295
Finance Costs	6	**529**	455	447
Interest Income	7	**(96)**	(109)	(124)
Foreign Exchange (Gain) Loss, Net	8	**208**	(20)	26
Research Costs		**24**	15	8
(Gain) Loss on Divestiture of Assets	18	**1**	-	(107)
Other (Income) Loss, Net		**2**	(5)	4
Earnings Before Income Tax		**1,094**	1,778	2,207
Income Tax Expense	9	**432**	783	729
Net Earnings		**662**	995	1,478
Other Comprehensive Income (Loss), Net of Tax				
Items That Will Not be Reclassified to Profit or Loss:				
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**14**	(4)	(12)
Items That May be Subsequently Reclassified to Profit or Loss:				
Change in Value of Available for Sale Financial Assets		**10**	-	-
Foreign Currency Translation Adjustment		**117**	(24)	48
Total Other Comprehensive Income (Loss), Net of Tax		**141**	(28)	36
Comprehensive Income		**803**	967	1,514
Net Earnings Per Common Share	10			
Basic		**$0.88**	$1.32	$1.96
Diluted		**$0.87**	$1.31	$1.95

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at
($ millions)

	Notes	**December 31, 2013**	December 31, 2012 (Note 4)	January 1, 2012 (Note 4)
Assets				
Current Assets				
Cash and Cash Equivalents	11	**2,452**	1,160	495
Accounts Receivable and Accrued Revenues	12	**1,874**	1,464	1,405
Income Tax Receivable		**15**	-	-
Current Portion of Partnership Contribution Receivable	13	**-**	384	372
Inventories	14	**1,259**	1,288	1,291
Risk Management	32	**10**	283	232
Assets Held for Sale	15	**-**	-	116
Current Assets		**5,610**	4,579	3,911
Exploration and Evaluation Assets	1,16	**1,473**	1,285	880
Property, Plant and Equipment, Net	1,17	**17,334**	16,152	14,324
Partnership Contribution Receivable	13	**-**	1,398	1,822
Risk Management	32	**-**	5	52
Income Tax Receivable		**-**	-	29
Other Assets	19	**68**	58	44
Goodwill	1,20	**739**	739	1,132
Total Assets		**25,224**	24,216	22,194
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts Payable and Accrued Liabilities	21	**2,937**	2,650	2,579
Income Tax Payable		**268**	217	329
Current Portion of Partnership Contribution Payable	13	**438**	386	372
Risk Management	32	**136**	17	54
Liabilities Related to Assets Held for Sale	15	**-**	-	54
Current Liabilities		**3,779**	3,270	3,388
Long-Term Debt	22	**4,997**	4,679	3,527
Partnership Contribution Payable	13	**1,087**	1,426	1,853
Risk Management	32	**3**	1	14
Decommissioning Liabilities	23	**2,370**	2,315	1,777
Other Liabilities	24	**180**	183	158
Deferred Income Taxes	9	**2,862**	2,560	2,093
Total Liabilities		**15,278**	14,434	12,810
Shareholders' Equity		**9,946**	9,782	9,384
Total Liabilities and Shareholders' Equity		**25,224**	24,216	22,194
Commitments and Contingencies	35			

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board of Directors

(signed)

Michael A. Grandin
Director
Cenovus Energy Inc.

(signed)

Colin Taylor
Director
Cenovus Energy Inc.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions)

	Share Capital	Paid in Surplus	Retained Earnings	AOCI [1]	Total
	(Note 26)	(Note 26)		(Note 27)	
Balance as at January 1, 2011, as Previously Reported	3,716	4,083	525	71	8,395
Cumulative Effective of Change in Accounting Policy (Note 4)	-	-	-	(10)	(10)
Balance as at January 1, 2011, Restated	3,716	4,083	525	61	8,385
Net Earnings	-	-	1,478	-	1,478
Other Comprehensive Income (Loss)	-	-	-	36	36
Total Comprehensive Income (Loss)	-	-	1,478	36	1,514
Common Shares Issued Under Option Plans	64	-	-	-	64
Stock-Based Compensation Expense	-	24	-	-	24
Dividends on Common Shares	-	-	(603)	-	(603)
Balance as at December 31, 2011	3,780	4,107	1,400	97	9,384
Net Earnings	-	-	995	-	995
Other Comprehensive Income (Loss)	-	-	-	(28)	(28)
Total Comprehensive Income (Loss)	-	-	995	(28)	967
Common Shares Issued Under Option Plans	49	-	-	-	49
Stock-Based Compensation Expense	-	47	-	-	47
Dividends on Common Shares	-	-	(665)	-	(665)
Balance as at December 31, 2012	3,829	4,154	1,730	69	9,782
Net Earnings	-	-	662	-	662
Other Comprehensive Income (Loss)	-	-	-	141	141
Total Comprehensive Income (Loss)	-	-	662	141	803
Common Shares Issued Under Option Plans	31	-	-	-	31
Common Shares Cancelled	(3)	3	-	-	-
Stock-Based Compensation Expense	-	62	-	-	62
Dividends on Common Shares	-	-	(732)	-	(732)
Balance as at December 31, 2013	**3,857**	**4,219**	**1,660**	**210**	**9,946**

(1) Accumulated Other Comprehensive Income (Loss).

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,
($ millions)

	Notes	2013	2012	2011
Operating Activities				
Net Earnings		**662**	995	1,478
Depreciation, Depletion and Amortization		**1,833**	1,585	1,295
Goodwill Impairment		**-**	393	-
Exploration Expense		**50**	68	-
Deferred Income Taxes	9	**244**	474	575
Cash Tax on Divestiture of Assets		**-**	-	13
Unrealized (Gain) Loss on Risk Management	32	**415**	(57)	(180)
Unrealized Foreign Exchange (Gain) Loss	8	**40**	(70)	(42)
(Gain) Loss on Divestiture of Assets		**1**	-	(107)
Unwinding of Discount on Decommissioning Liabilities	6,23	**97**	86	75
Other		**267**	169	169
		3,609	3,643	3,276
Net Change in Other Assets and Liabilities		**(120)**	(113)	(82)
Net Change in Non-Cash Working Capital		**50**	(110)	79
Cash From Operating Activities		**3,539**	3,420	3,273
Investing Activities				
Capital Expenditures – Exploration and Evaluation Assets	16	**(331)**	(654)	(527)
Capital Expenditures – Property, Plant and Equipment	17	**(2,938)**	(2,795)	(2,265)
Proceeds From Divestiture of Assets		**258**	76	173
Cash Tax on Divestiture of Assets		**-**	-	(13)
Net Change in Investments and Other	13	**1,486**	(13)	(28)
Net Change in Non-Cash Working Capital		**6**	50	130
Cash (Used in) Investing Activities		**(1,519)**	(3,336)	(2,530)
Net Cash Provided (Used) before Financing Activities		**2,020**	84	743
Financing Activities				
Net Issuance (Repayment) of Short-Term Borrowings		**(8)**	3	(9)
Issuance of U.S. Unsecured Notes	22	**814**	1,219	-
Repayment of U.S. Unsecured Notes	22	**(825)**	-	-
Proceeds on Issuance of Common Shares		**28**	37	48
Dividends Paid on Common Shares	10	**(732)**	(665)	(603)
Other		**(3)**	(2)	6
Cash From (Used in) Financing Activities		**(726)**	592	(558)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(2)**	(11)	10
Increase (Decrease) in Cash and Cash Equivalents		**1,292**	665	195
Cash and Cash Equivalents, Beginning of Year		**1,160**	495	300
Cash and Cash Equivalents, End of Year		**2,452**	1,160	495
Supplementary Cash Flow Information	34			

See accompanying Notes to Consolidated Financial Statements.

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. and its subsidiaries, (together "Cenovus" or the "Company") are in the business of the development, production and marketing of crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S.").

Cenovus began independent operations on December 1, 2009, as a result of the plan of arrangement ("Arrangement") involving Encana Corporation ("Encana") whereby Encana was split into two independent energy companies, one a natural gas company, Encana, and the other an oil company, Cenovus. In connection with the Arrangement, Encana common shareholders received one share in each of the new Encana and Cenovus in exchange for each Encana share held.

Cenovus was incorporated under the *Canada Business Corporations Act* and its shares are publicly traded on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at 2600, 500 Centre Street S.E., Calgary, Alberta, Canada, T2G 1A6. Information on the Company's basis of preparation for these Consolidated Financial Statements is found in Note 2.

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by Cenovus's chief operating decision makers. The Company evaluates the financial performance of its operating segments primarily based on operating cash flow. The Company's reportable segments are:

- **Oil Sands,** which includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional,** which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake. This segment also includes the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.
- **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 Phillips 66, an unrelated U.S. public company. 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 and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, research costs 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 have been changed from those presented in prior periods to match Cenovus's new operating structure. All prior periods have been restated to reflect this presentation. As a result, for the years ended December 31, 2012 and 2011, segment income of $275 million and $204 million, respectively, was reclassified from Oil Sands to Conventional. In addition to the restatement required due to changes in operating segments, research activities previously included in operating expense have been reclassified to conform to the presentation adopted for the year ended December 31, 2013.

The following tabular financial information presents the segmented information first by segment, then by product and geographic location.

A) Results of Operations – Segment and Operational Information

	Oil Sands			Conventional			Refining and Marketing		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**3,912**	3,356	2,659	**2,980**	2,800	2,960	**12,706**	11,356	10,625
Less: Royalties	**132**	186	228	**204**	201	261	**-**	-	-
	3,780	3,170	2,431	**2,776**	2,599	2,699	**12,706**	11,356	10,625
Expenses									
Purchased Product	**-**	-	-	**-**	-	-	**11,004**	9,506	9,149
Transportation and Blending	**1,749**	1,501	1,086	**325**	297	283	**-**	-	-
Operating	**555**	426	330	**708**	662	594	**540**	581	475
Production and Mineral Taxes	**-**	-	-	**35**	37	36	**-**	-	-
(Gain) Loss on Risk Management	**(37)**	(64)	50	**(104)**	(268)	(132)	**19**	(4)	14
Operating Cash Flow	**1,513**	1,307	965	**1,812**	1,871	1,918	**1,143**	1,273	987
Depreciation, Depletion and Amortization	**446**	339	246	**1,170**	1,048	879	**138**	146	130
Goodwill Impairment	**-**	-	-	**-**	393	-	**-**	-	-
Exploration Expense	**-**	-	-	**114**	68	-	**-**	-	-
Segment Income (Loss)	**1,067**	968	719	**528**	362	1,039	**1,005**	1,127	857

	Corporate and Eliminations			Consolidated		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Revenues						
Gross Sales	**(605)**	(283)	(59)	**18,993**	17,229	16,185
Less: Royalties	**-**	-	-	**336**	387	489
	(605)	(283)	(59)	**18,657**	16,842	15,696
Expenses						
Purchased Product	**(605)**	(283)	(59)	**10,399**	9,223	9,090
Transportation and Blending	**-**	-	-	**2,074**	1,798	1,369
Operating	**(5)**	(2)	(1)	**1,798**	1,667	1,398
Production and Mineral Taxes	**-**	-	-	**35**	37	36
(Gain) Loss on Risk Management	**415**	(57)	(180)	**293**	(393)	(248)
	(410)	59	181	**4,058**	4,510	4,051
Depreciation, Depletion and Amortization	**79**	52	40	**1,833**	1,585	1,295
Goodwill Impairment	**-**	-	-	**-**	393	-
Exploration Expense	**-**	-	-	**114**	68	-
Segment Income (Loss)	**(489)**	7	141	**2,111**	2,464	2,756
General and Administrative	**349**	350	295	**349**	350	295
Finance Costs	**529**	455	447	**529**	455	447
Interest Income	**(96)**	(109)	(124)	**(96)**	(109)	(124)
Foreign Exchange (Gain) Loss, Net	**208**	(20)	26	**208**	(20)	26
Research Costs	**24**	15	8	**24**	15	8
(Gain) Loss on Divestiture of Assets	**1**	-	(107)	**1**	-	(107)
Other (Income) Loss, Net	**2**	(5)	4	**2**	(5)	4
	1,017	686	549	**1,017**	686	549
Earnings Before Income Tax				**1,094**	1,778	2,207
Income Tax Expense				**432**	783	729
Net Earnings				**662**	995	1,478

B) Financial Results by Upstream Product

	Crude Oil [1]								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**3,850**	3,307	2,585	**2,373**	2,289	2,124	**6,223**	5,596	4,709
Less: Royalties	**131**	186	226	**196**	195	249	**327**	381	475
	3,719	3,121	2,359	**2,177**	2,094	1,875	**5,896**	5,215	4,234
Expenses									
Transportation and Blending	**1,748**	1,499	1,084	**305**	278	249	**2,053**	1,777	1,333
Operating	**531**	401	303	**495**	441	350	**1,026**	842	653
Production and Mineral Taxes	**-**	-	-	**32**	34	27	**32**	34	27
(Gain) Loss on Risk Management	**(33)**	(46)	67	**(43)**	(39)	63	**(76)**	(85)	130
Operating Cash Flow	**1,473**	1,267	905	**1,388**	1,380	1,186	**2,861**	2,647	2,091

(1) Includes NGLs.

	Natural Gas								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**38**	38	63	**594**	498	825	**632**	536	888
Less: Royalties	**1**	-	2	**8**	6	12	**9**	6	14
	37	38	61	**586**	492	813	**623**	530	874
Expenses									
Transportation and Blending	**1**	2	2	**20**	19	34	**21**	21	36
Operating	**18**	23	24	**209**	217	240	**227**	240	264
Production and Mineral Taxes	**-**	-	-	**3**	3	9	**3**	3	9
(Gain) Loss on Risk Management	**(4)**	(18)	(17)	**(61)**	(229)	(195)	**(65)**	(247)	(212)
Operating Cash Flow	**22**	31	52	**415**	482	725	**437**	513	777

	Other								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**24**	11	11	**13**	13	11	**37**	24	22
Less: Royalties	**-**	-	-	**-**	-	-	**-**	-	-
	24	11	11	**13**	13	11	**37**	24	22
Expenses									
Transportation and Blending	**-**	-	-	**-**	-	-	**-**	-	-
Operating	**6**	2	3	**4**	4	4	**10**	6	7
Production and Mineral Taxes	**-**	-	-	**-**	-	-	**-**	-	-
(Gain) Loss on Risk Management	**-**	-	-	**-**	-	-	**-**	-	-
Operating Cash Flow	**18**	9	8	**9**	9	7	**27**	18	15

	Total Upstream								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**3,912**	3,356	2,659	**2,980**	2,800	2,960	**6,892**	6,156	5,619
Less: Royalties	**132**	186	228	**204**	201	261	**336**	387	489
	3,780	3,170	2,431	**2,776**	2,599	2,699	**6,556**	5,769	5,130
Expenses									
Transportation and Blending	**1,749**	1,501	1,086	**325**	297	283	**2,074**	1,798	1,369
Operating	**555**	426	330	**708**	662	594	**1,263**	1,088	924
Production and Mineral Taxes	**-**	-	-	**35**	37	36	**35**	37	36
(Gain) Loss on Risk Management	**(37)**	(64)	50	**(104)**	(268)	(132)	**(141)**	(332)	(82)
Operating Cash Flow	**1,513**	1,307	965	**1,812**	1,871	1,918	**3,325**	3,178	2,883

C) Geographic Information

For the years ended December 31,	Canada			United States			Consolidated		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**8,943**	8,069	7,513	**10,050**	9,160	8,672	**18,993**	17,229	16,185
Less: Royalties	**336**	387	489	**-**	-	-	**336**	387	489
	8,607	7,682	7,024	**10,050**	9,160	8,672	**18,657**	16,842	15,696
Expenses									
Purchased Product	**2,022**	1,884	1,867	**8,377**	7,339	7,223	**10,399**	9,223	9,090
Transportation and Blending	**2,074**	1,798	1,369	**-**	-	-	**2,074**	1,798	1,369
Operating	**1,276**	1,108	944	**522**	559	454	**1,798**	1,667	1,398
Production and Mineral Taxes	**35**	37	36	**-**	-	-	**35**	37	36
(Gain) Loss on Risk Management	**275**	(385)	(255)	**18**	(8)	7	**293**	(393)	(248)
	2,925	3,240	3,063	**1,133**	1,270	988	**4,058**	4,510	4,051
Depreciation, Depletion and Amortization	**1,695**	1,439	1,165	**138**	146	130	**1,833**	1,585	1,295
Goodwill Impairment	**-**	393	-	**-**	-	-	**-**	393	-
Exploration Expense	**114**	68	-	**-**	-	-	**114**	68	-
Segment Income (Loss)	**1,116**	1,340	1,898	**995**	1,124	858	**2,111**	2,464	2,756

The Oil Sands and Conventional segments operate in Canada. Both of Cenovus's refining facilities are located and carry on business in the U.S. The marketing of Cenovus's crude oil and natural gas produced in Canada, as well as the third-party purchases and sales of product, is undertaken in Canada. Physical product sales that settle in the U.S. are considered to be export sales undertaken by a Canadian business. The Corporate and Eliminations segment is attributed to Canada, with the exception of the unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

Export Sales

Sales of crude oil, natural gas and NGLs produced or purchased in Canada that have been delivered to customers outside of Canada were $926 million (2012 – $671 million; 2011 – $700 million).

Major Customers

In connection with the marketing and sale of Cenovus's own and purchased crude oil, natural gas and refined products for the year ended December 31, 2013, Cenovus had three customers (2012 – three; 2011 – two) that individually accounted for more than 10 percent of its consolidated gross sales. Sales to these customers, recognized as major international energy companies with investment grade credit ratings, were approximately $7,032 million, $2,711 million and $1,799 million, respectively (2012 – $3,928 million, $3,300 million, and $2,839 million; 2011 – $7,324 million and $2,683 million).

D) Joint Operations

A significant portion of the operating cash flows from the Oil Sands and Refining and Marketing segments are derived through jointly controlled entities, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), respectively. These joint arrangements, in which Cenovus has a 50 percent ownership interest, are classified as joint operations and, as such, Cenovus recognizes its share of the assets, liabilities, revenues and expenses.

FCCL, which is involved in the development and production of crude oil in Canada, is jointly controlled with ConocoPhillips and operated by Cenovus. WRB has two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products. WRB is jointly controlled with and operated by Phillips 66. Cenovus's share of operating cash flow from FCCL and WRB for the year ended December 31, 2013 was $1,383 million and $1,144 million, respectively (2012 – $1,188 million and $1,274 million; 2011 – $967 million and $981 million).

E) Exploration and Evaluation Assets, Property, Plant and Equipment, Goodwill and Total Assets

By Segment

	E&E (1)			PP&E (2)		
As at	**December 31, 2013**	December 31, 2012	January 1, 2012	**December 31, 2013**	December 31, 2012	January 1, 2012
Oil Sands	**1,313**	1,064	699	**7,401**	6,041	4,897
Conventional	**160**	221	181	**6,291**	6,652	5,995
Refining and Marketing	**-**	-	-	**3,269**	3,088	3,200
Corporate and Eliminations	**-**	-	-	**373**	371	232
Consolidated	**1,473**	1,285	880	**17,334**	16,152	14,324

	Goodwill			Total Assets		
As at	**December 31, 2013**	December 31, 2012	January 1, 2012	**December 31, 2013**	December 31, 2012	January 1, 2012
Oil Sands	**242**	242	242	**9,549**	9,658	8,578
Conventional	**497**	497	890	**7,235**	7,618	7,512
Refining and Marketing	**-**	-	-	**5,491**	5,018	4,927
Corporate and Eliminations	**-**	-	-	**2,949**	1,922	1,177
Consolidated	**739**	739	1,132	**25,224**	24,216	22,194

(1) Exploration and evaluation ("E&E") assets.
(2) Property, plant and equipment ("PP&E").

By Geographic Region

	E&E			PP&E		
As at	**December 31, 2013**	December 31, 2012	January 1, 2012	**December 31, 2013**	December 31, 2012	January 1, 2012
Canada	**1,473**	1,285	880	**14,066**	13,065	11,124
United States	**-**	-	-	**3,268**	3,087	3,200
Consolidated	**1,473**	1,285	880	**17,334**	16,152	14,324

	Goodwill			Total Assets		
As at	**December 31, 2013**	December 31, 2012	January 1, 2012	**December 31, 2013**	December 31, 2012	January 1, 2012
Canada	**739**	739	1,132	**20,548**	19,744	17,536
United States	**-**	-	-	**4,676**	4,472	4,658
Consolidated	**739**	739	1,132	**25,224**	24,216	22,194

F) Capital Expenditures (1)

For the years ended December 31,	**2013**	2012	2011
Capital			
Oil Sands	**1,883**	1,693	1,098
Conventional	**1,191**	1,366	1,105
Refining and Marketing	**107**	118	393
Corporate	**81**	191	127
	3,262	3,368	2,723
Acquisition Capital			
Oil Sands (2)	**27**	69	40
Conventional	**5**	45	29
Corporate	**-**	-	2
	3,294	3,482	2,794

(1) Includes expenditures on PP&E and E&E assets.
(2) 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

These Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). These Consolidated Financial Statements have been prepared in compliance with IFRS.

These Consolidated Financial Statements have been prepared on a historical cost basis, except as detailed in the Company's accounting policies disclosed in Note 3.

These Consolidated Financial Statements of Cenovus were approved by the Board of Directors on February 12, 2014.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries. Subsidiaries are entities over which the Company has the power to govern their financial and operating policies. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is a loss of control. All intercompany transactions, balances and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company recognizes its share of assets, liabilities, revenues and expenses of a joint operation. Joint ventures arise when the Company has rights to the net assets of the arrangement. Joint ventures are accounted for under the equity method.

B) Foreign Currency Translation

Functional and Presentation Currency

The Company's presentation currency is Canadian dollars. The accounts of the Company's foreign operations that have a functional currency different from the Company's presentation currency are translated into the Company's presentation currency at period end exchange rates for assets and liabilities and at the average rate over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in other comprehensive income ("OCI") as cumulative translation adjustments.

When the Company disposes of an entire interest in a foreign operation or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in OCI related to the foreign operation are recognized in net earnings. When the Company disposes of part of an interest in a foreign operation that continues to be a subsidiary, a proportionate amount of gains and losses accumulated in OCI is allocated between controlling and non-controlling interests.

Transactions and Balances

Transactions in foreign currencies are translated to the respective functional currencies at exchange rates in effect at the dates of the transactions. Monetary assets and liabilities of Cenovus that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period end date. Any gains or losses are recorded in the Consolidated Statements of Earnings and Comprehensive Income.

C) Revenue and Interest Income Recognition

Sales of Product

Revenues associated with the sales of Cenovus's crude oil, natural gas, NGLs and petroleum and refined products are recognized when the significant risks and rewards of ownership have been transferred to the customer, the sales price and costs can be measured reliably and it is probable that the economic benefits will flow to the Company. This is generally met when title passes from the Company to its customer. Revenues from crude oil and natural gas production represent the Company's share, net of royalty payments to governments and other mineral interest owners.

Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided as agent are recorded as the services are provided.

Interest Income

Interest income is recognized as the interest accrues using the effective interest method.

D) Transportation and Blending

The costs associated with the transportation of crude oil, natural gas and NGLs, including the cost of diluent used in blending, are recognized when the product is sold.

E) Production and Mineral Taxes

Costs paid to non-mineral interest owners based on production of crude oil, natural gas and NGLs are recognized when the product is sold.

F) Exploration Expense

Costs incurred prior to obtaining the legal right to explore (pre-exploration costs) are expensed in the period in which they are incurred as exploration expense.

Costs incurred after the legal right to explore is obtained, are initially capitalized. If it is determined that the field/project/area is not technically feasible and commercially viable and if the Company decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense.

G) Employee Benefit Plans

The Company provides employees with a pension plan that includes either a defined contribution or defined benefit component and an other post-employment benefit plan (“OPEB”).

Pension expense for the defined contribution pension is recorded as the benefits are earned.

The cost of the defined benefit pension and OPEB plans are actuarially determined using the projected unit credit method. The amount recognized in other liabilities on the Consolidated Balance Sheets for the defined benefit pension and OPEB plans is the present value of the defined benefit obligation less the fair value of plan assets. Any surplus resulting from this calculation is limited to the present value of any economic benefits available in the form of refunds from the plans or reductions in future contributions to the plans.

Changes in the defined benefit obligation from service costs, net interest and remeasurements are recognized as follows:

- Service costs, including current service costs, past service costs, gains and losses on curtailments and settlements, are recognized in net earnings.
- Net interest is calculated by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability measured. Interest expense and interest income on net post-employment benefit liabilities and assets are recognized in net earnings.
- Remeasurements, composed of actuarial gains and losses, the effect of changes to the asset ceiling (excluding interest) and the return on plan assets (excluding interest income), are charged or credited to equity in OCI in the period in which they arise. Remeasurements are not reclassified to net earnings in subsequent periods.

Pension costs are recorded in operating and general and administrative expenses, as well as PP&E and E&E assets, corresponding to where the associated salaries of the employees rendering the service are recorded.

H) Income Taxes

Income taxes comprise current and deferred taxes. Current and deferred income taxes are provided for on a non-discounted basis at amounts expected to be paid using the tax rates and laws that have been enacted or substantively enacted at the Consolidated Balance Sheet date.

Cenovus follows the liability method of accounting for income taxes, where deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs, except when it relates to items charged or credited directly to equity or OCI, in which case the deferred income tax is also recorded in equity or OCI, respectively.

Deferred income tax is provided on temporary differences arising from investments in subsidiaries except in the case where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future.

Deferred income tax assets are recognized only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized.

Deferred income tax assets and liabilities are only offset where they arise within the same entity and tax jurisdiction.

Deferred income tax assets and liabilities are presented as non-current.

I) Net Earnings per Share Amounts

Basic net earnings per common share is computed by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share is calculated giving effect to the potential dilution that would occur if stock options or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price. For those contracts that may be settled in cash or in shares at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

J) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less.

K) Inventories

Product inventories are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis. The cost of inventory includes all costs incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if circumstances which caused it no longer exist and the inventory is still on hand.

L) Assets (Disposal Group) Held for Sale

Non-current assets or disposal groups are classified as held for sale when their carrying amount will be principally recovered through a sales transaction rather than through continued use and a sales transaction is highly probable. Assets held for sale are recorded at the lower of carrying value and fair value less costs of disposal.

M) Exploration and Evaluation Assets

Costs incurred after the legal right to explore an area has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as E&E assets. These costs include license acquisition, geological and geophysical, drilling, sampling, decommissioning and other directly attributable internal costs. E&E assets are not depreciated and are carried forward until technical feasibility and commercial viability of the field/project/area is established or the assets are determined to be impaired.

Once technical feasibility and commercial viability have been established for a field/project/area, the carrying value of the E&E assets associated with that field/area/project is tested for impairment. The carrying value, net of any impairment loss, is then reclassified as PP&E.

E&E costs are subject to regular technical, commercial and Management review to confirm the continued intent to develop the resources. If a field/project/area is determined not to be technically feasible and commercially viable, and Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense in the period in which the determination occurs.

Any gains or losses from the divestiture of E&E assets are recognized in net earnings.

N) Property, Plant and Equipment

Development and Production Assets

Development and production assets are stated at cost less accumulated depreciation, depletion, amortization ("DD&A") and net impairment losses. Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of the crude oil and natural gas properties, as well as any E&E expenditures incurred in finding commercial reserves of crude oil or natural gas transferred from E&E assets. Capitalized costs include directly attributable internal costs, decommissioning liabilities, and, for qualifying assets, borrowing costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves.

Costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using estimated future prices and costs. For the purpose of this calculation, natural gas is converted to crude oil on an energy equivalent basis. Costs subject to depletion include estimated future costs to be incurred in developing proved reserves.

Exchanges of development and production assets are measured at fair value unless the transaction lacks commercial substance or the fair value of neither the asset received, nor the asset given up, can be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

Any gains or losses from the divestiture of development and production assets are recognized in net earnings.

Other Upstream Assets

Other upstream assets include pipelines and information technology assets used to support the upstream business. These assets are depreciated on a straight-line basis over their useful lives of three to 35 years.

Refining Assets

The refining assets are stated at cost less accumulated depreciation and net impairment losses.

The initial acquisition costs of refining PP&E are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use, the associated decommissioning costs and, for qualifying assets, borrowing costs. Maintenance and repairs are expensed as incurred.

Capitalized costs are not subject to depreciation until the asset is available for use, after which they are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The major components are depreciated as follows:

Land Improvements and Buildings	25 to 40 years
Office Equipment and Vehicles	3 to 20 years
Refining Equipment	5 to 35 years

The residual value, method of amortization and the useful life of each component are reviewed annually and adjusted on a prospective basis, if appropriate.

Other Assets

Costs associated with office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 25 years. The residual value, method of amortization and the useful lives of the assets are reviewed annually and adjusted on a prospective basis, if appropriate. Assets under construction are not subject to depreciation until they are available for use. Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

O) Impairment

Non-Financial Assets

PP&E and E&E assets are assessed for impairment at least annually or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. The recoverable amount is determined as the greater of an asset's or cash-generating unit's ("CGU") value-in-use ("VIU") and fair value less costs of disposal ("FVLCOD"). VIU is estimated as the discounted present value of the future cash flows expected to arise from the continuing use of a CGU or an asset. FVLCOD is based on the discounted after-tax cash flows of reserves and resources using forecast prices and costs as estimated by Cenovus's independent qualified reserves evaluators and an evaluation of comparable asset transactions.

The impairment test is performed at the CGU for development and production assets and other upstream assets. E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. Corporate assets are allocated to the CGUs to which they contribute to the future cash flows. For refining assets, the impairment test is performed at each refinery independently.

Impairment losses on PP&E are recognized in the Consolidated Statements of Earnings and Comprehensive Income as additional DD&A and are separately disclosed. An impairment of E&E assets is recognized as exploration expense in the Consolidated Statements of Earnings and Comprehensive Income.

Goodwill is assessed for impairment at least annually. To assess impairment, the recoverable amount of the CGU to which the goodwill relates is compared to the carrying amount. If the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized. An impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU. Goodwill impairments are not reversed.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

Financial Assets

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is objective evidence of impairment, the loss event has an impact on future cash flow and the loss can be reliably estimated.

Evidence of impairment may include default or delinquency by a debtor or indicators that the debtor may enter bankruptcy. For equity securities, a significant or prolonged decline in the fair value of the security below cost is evidence that the assets are impaired.

An impairment loss on a financial asset carried at amortized cost is calculated as the difference between the amortized cost and the present value of the future cash flows discounted at the asset's original effective interest rate. The carrying amount of the asset is reduced through the use of an allowance account. Impairment losses on financial assets carried at amortized cost are reversed through net earnings in subsequent periods if the amount of the loss decreases.

P) Borrowing Costs

Borrowing costs are expensed as incurred unless there is a qualifying asset. Borrowing costs directly associated with the acquisition, construction or production of a qualifying asset are capitalized when a substantial period of time is required to make the asset ready for its intended use. Capitalization of borrowing costs ceases when the asset is in the location and condition necessary for its intended use.

Q) Leases

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term.

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases within PP&E.

R) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and any non-controlling interest are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net earnings.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

S) Provisions

General

A provision is recognized if, as a result of a past event, the Company has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. Where applicable, provisions are determined by discounting the expected future cash flows at a pre-tax credit-adjusted rate that reflects the current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance cost in the Consolidated Statements of Earnings and Comprehensive Income.

Decommissioning Liabilities

Decommissioning liabilities include those legal or constructive obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing facilities and refining facilities. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a credit-adjusted risk-free rate. A corresponding asset equal to the initial estimate of the liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to expected timing or future decommissioning costs are recognized as a change in the decommissioning liability and the related long-lived asset. The amount capitalized in PP&E is depreciated over the useful life of the related asset. Increases in the decommissioning liabilities resulting from the passage of time are recognized as a finance cost in the Consolidated Statements of Earnings and Comprehensive Income.

Actual expenditures incurred are charged against the accumulated liability.

T) Share Capital

Common shares are classified as equity. Transaction costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any income taxes.

U) Stock-Based Compensation

Cenovus has a number of cash and stock-based compensation plans which include stock options with associated net settlement rights ("NSRs"), stock options with associated tandem stock appreciation rights ("TSARs"), performance share units ("PSUs") and deferred share units ("DSUs").

Net Settlement Rights

NSRs are accounted for as equity instruments, which are measured at fair value on the grant date using the Black-Scholes-Merton valuation model and are not revalued at each reporting date. The fair value is recognized as compensation costs over the vesting period, with a corresponding increase recorded as paid in surplus in Shareholders' Equity. On exercise, the cash consideration received by the Company and the associated paid in surplus are recorded as share capital.

Tandem Stock Appreciation Rights

TSARs are accounted for as liability instruments, which are measured at fair value at each period end using the Black-Scholes-Merton valuation model. The fair value is recognized as compensation costs over the vesting period. When options are settled for cash, the liability is reduced by the cash settlement paid. When options are settled for common shares, the cash consideration received by the Company and the previously recorded liability associated with the option are recorded as share capital.

Performance and Deferred Share Units

PSUs and DSUs are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as compensation costs over the vesting period. Fluctuations in the fair values are recognized as compensation costs in the period they occur.

V) Financial Instruments

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership. A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, this exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability. The difference in the carrying amounts of the liabilities is recognized in the Consolidated Statements of Earnings and Comprehensive Income.

Financial instruments are classified as either "fair value through profit and loss", "loans and receivables", "held-to-maturity investments", "available for sale financial assets" or "financial liabilities measured at amortized cost". The Company determines the classification of its financial assets at initial recognition. Financial instruments are initially measured at fair value except in the case of "financial liabilities measured at amortized cost", which are initially measured at fair value net of directly attributable transaction costs.

The Company's consolidated financial assets include cash and cash equivalents, accounts receivable and accrued revenues, partner loans receivable, the Partnership Contribution Receivable, risk management assets and long-term receivables. The Company's financial liabilities include accounts payable and accrued liabilities, partner loans payable, the Partnership Contribution Payable, derivative financial instruments, short-term borrowings and long-term debt.

Fair Value through Profit or Loss

Financial assets and financial liabilities at "fair value through profit or loss" are either "held-for-trading" or have been "designated at fair value through profit or loss". In both cases, the financial assets and financial liabilities are measured at fair value with changes in fair value recognized in net earnings.

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the Consolidated Balance Sheets as either an asset or liability with changes in fair value recognized in net earnings as a (gain) loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Derivative financial instruments are not used for speculative purposes. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Loans and Receivables

"Loans and receivables" are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. "Loans and receivables" comprise cash and cash equivalents, accounts receivable and accrued revenues, partner loans receivable, the Partnership Contribution Receivable and long-term receivables. Gains and losses on "loans and receivables" are recognized in net earnings when the "loans and receivables" are derecognized or impaired.

Held to Maturity Investments

"Held-to-maturity investments" are measured at amortized cost using the effective interest method of amortization.

Available for Sale Financial Assets

"Available for sale financial assets" are measured at fair value, with changes in the fair value recognized in OCI. When an active market is non-existent, fair value is determined using valuation techniques. When fair value cannot be reliably measured, such assets are carried at cost.

Financial Liabilities Measured at Amortized Cost

These financial liabilities are measured at amortized cost at the settlement date using the effective interest method of amortization. Financial liabilities measured at amortized cost comprise accounts payable and accrued liabilities, partner loans payable, the Partnership Contribution Payable, short-term borrowings and long-term debt. Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt or as a prepayment and amortized using the effective interest method.

W) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2013.

X) Recent Accounting Pronouncements

New Standards and Interpretations not yet Adopted

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning on or after January 1, 2014 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2013. The standards and interpretations applicable to the Company are as follows and will be adopted on their respective effective dates:

Financial Instruments

The IASB intends to replace International Accounting Standard 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39") with IFRS 9, "*Financial Instruments*" ("IFRS 9"). IFRS 9 will be published in three phases, of which two phases have been published.

Phases one and two address accounting for financial assets and financial liabilities, and hedge accounting, respectively. The third phase will address impairment of financial instruments.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. Cenovus does not currently apply hedge accounting.

A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of the two completed phases is permitted only if adopted in their entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IAS 32, *"Financial Instruments: Presentation"* ("IAS 32"), to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. The amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, requiring retrospective application. IAS 32 will not have a significant impact on the Consolidated Financial Statements.

4. CHANGE IN ACCOUNTING POLICIES

New and Amended Standards Adopted

The Company adopted the following new standards and amendments to standards:

Joint Arrangements, Consolidation, Associates and Disclosures

Effective January 1, 2013, the Company adopted, as required, IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10"), IFRS 11, "*Joint Arrangements*" ("IFRS 11"), IFRS 12, "*Disclosure of Interests in Other Entities*" ("IFRS 12") as well as the amendments to IAS 28, "*Investments in Associates and Joint Ventures*" ("IAS 28").

IFRS 10 revised the definition of control to include three elements: (1) power over an investee; (2) exposure to variable returns from its involvement with the investee and (3) the ability to use its power to affect returns from the investee. Cenovus reviewed its consolidation methodology and determined that the adoption of IFRS 10 did not result in a change in the consolidation status of its subsidiaries and investees.

Under IFRS 11, a joint arrangement is classified as either a joint operation or a joint venture depending on the rights and obligations of the parties to the arrangement. Under a joint operation, parties have rights to the assets and obligations for the liabilities of the arrangement and account for their share of assets, liabilities, revenues and expenses. Under a joint venture, parties have the rights to the net assets of the arrangement and account for the arrangement as an investment using the equity method. Cenovus performed a comprehensive review of its interest in other entities and identified two individually significant interests, FCCL and WRB, for which it shares joint control. Cenovus reviewed these joint arrangements considering their structure, the legal form of the separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of the Company's accounting policy under IFRS 11 requires judgment in determining the classification of these joint arrangements. A discussion of the judgments used in the Company's assessment of its joint arrangements can be found in Note 5. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements are classified as joint operations. There has been no impact on the recognized assets, liabilities and comprehensive income of the Company with the application of IFRS 11.

IFRS 12 requires disclosures relating to an entity's interest in subsidiaries, joint arrangements, associates and unconsolidated structured entities. IAS 28 was amended to conform to the changes made in IFRS 10 and IFRS 11. The adoption of IFRS 12 and IAS 28 did not result in any changes to disclosures.

Employee Benefits

Effective January 1, 2013, the Company adopted, as required, IAS 19, "*Employee Benefits*", as amended in June 2011 ("IAS 19R"). The Company applied the standard retrospectively and in accordance with the transitional provisions. The opening Consolidated Balance Sheet of the earliest comparative period presented (January 1, 2012) was restated.

IAS 19R requires the recognition of changes in defined benefit pension obligations and plan assets when they occur, eliminating the 'corridor' approach previously permitted and accelerating the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are recognized immediately through OCI. In addition, the Company replaced interest costs on the defined benefit obligation and the expected return on plan assets with a net interest cost based on the net defined benefit asset or liability measured by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period. Interest expense and interest income on net post-employment benefit liabilities and assets continue to be recognized in net earnings.

Furthermore, termination benefits must be recognized at the earlier of when the entity can no longer withdraw an offer of termination benefits or recognizes any restructuring costs.

The effect on the Consolidated Balance Sheets of IAS 19R was:

As at January 1, 2012	Net Defined Benefit Liability [1]	Deferred Income Taxes	Shareholders' Equity
Balance as Previously Reported	16	2,101	9,406
Effect of Adoption of IAS 19R	30	(8)	(22)
Restated Balance	46	2,093	9,384

(1) Composed of the defined benefit pension and OPEB plans, which are included in other liabilities on the Consolidated Balance Sheets.

As at December 31, 2012	Net Defined Benefit Liability [1]	Deferred Income Taxes	Shareholders' Equity
Balance as Previously Reported	28	2,568	9,806
Effect of Adoption of IAS 19R	32	(8)	(24)
Restated Balance	60	2,560	9,782

(1) Composed of the defined benefit pension and OPEB plans, which are included in other liabilities on the Consolidated Balance Sheets.

The effect on the Consolidated Statements of Earnings and Comprehensive Income of IAS 19R was:

	Year Ended December 31, 2012	Year Ended December 31, 2011
Decrease in General and Administrative Expense	2	-
Increase in Net Earnings for the Year	2	-
Remeasurement of Defined Benefit and OPEB Liabilities	(4)	(12)
(Decrease) in Comprehensive Income for the Year	(2)	(12)

The change in accounting policy did not have a material impact on the Consolidated Financial Statements including net earnings per share.

Details about the Company's pension and OPEB plans are disclosed in Note 25.

Fair Value Measurement

Effective January 1, 2013, the Company adopted, as required, IFRS 13, "*Fair Value Measurement*" ("IFRS 13") and applied the standard prospectively as required by the transitional provisions. The standard provides a consistent definition of fair value and introduces consistent requirements for disclosures related to fair value measurement. There has been no change to Cenovus's methodology for determining the fair value for its financial assets and liabilities and, as such, the adoption of IFRS 13 did not result in any measurement adjustments as at January 1, 2013. The disclosures related to fair value measurement can be found in Note 32.

Presentation of Items in Other Comprehensive Income

Effective January 1, 2013, the Company applied the amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1"), as amended in June 2011. The amendment requires items within OCI to be grouped into two categories: (1) items that will not be subsequently reclassified to profit or loss or (2) items that may be subsequently reclassified to profit or loss when specific conditions are met. The amendment has been applied retrospectively and, as such, the presentation of items in OCI has been modified. The application of the amendment to IAS 1 did not result in any adjustments to OCI.

Disclosure of Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2013, the Company complied with the amended disclosure requirements, regarding offsetting financial assets and financial liabilities, found in IFRS 7, "*Financial Instruments: Disclosures*" issued in December 2011. The additional disclosures can be found in Note 32. The application of the amendment had no impact on the Consolidated Statements of Earnings and Comprehensive Income or the Consolidated Balance Sheets.

Disclosures of Recoverable Amounts of Non-Financial Assets

In May 2013, the IASB issued an amendment to IAS 36, "*Impairment of Assets*". The amendment removes certain disclosures of the recoverable amount of a CGU. The amendment is effective retrospectively for annual periods beginning on or after January 1, 2014. As allowed by the standard, the Company early adopted the amendment in the current period. Refer to Note 20 for the amended disclosures.

5. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in accordance with IFRS requires that Management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

A) Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recognized in the Company's Consolidated Financial Statements.

Joint Arrangements

Cenovus holds a 50 percent ownership interest in two jointly controlled entities, FCCL and WRB. The classification of these joint arrangements as either a joint operation or a joint venture requires judgment. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements are classified as joint operations and the Company's share of the assets, liabilities, revenues and expenses are recognized in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, the Company considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnership. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third-party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.

- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and as such are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Exploration and Evaluation Assets

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating costs, as well as estimated economically recoverable reserves are considered. If it is determined that an E&E asset is not technically feasible and commercially viable and Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

Identification of CGUs

The Company's upstream and refining assets are grouped into CGUs. CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company's upstream, refining and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses.

B) Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Reserves

There are a number of inherent uncertainties associated with estimating reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would have a significant impact on the impairment test and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands and Conventional segments. The Company's crude oil and natural gas reserves are evaluated and reported to the Company by independent qualified reserves evaluators.

Impairment of Assets

PP&E, E&E assets and goodwill are assessed for impairment at least annually and when circumstances suggest that the carrying amount may exceed the recoverable amount. Assets are tested for impairment at the CGU level. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. For the Company's upstream assets, these estimates include future commodity prices, expected production volumes, quantity of reserves and discount rates, as well as future development and operating costs. Recoverable amounts for the Company's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating costs, transportation capacity and supply and demand conditions. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

For impairment testing purposes, goodwill has been allocated to each of the CGUs to which it relates.

At December 31, 2013, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal. Key assumptions in the determination of cash flows from reserves include reserves as estimated by Cenovus's independent qualified reserves evaluators, crude oil and natural gas prices and the discount rate.

Crude Oil and Natural Gas Prices

The future prices used to determine cash flows from crude oil and natural gas reserves are:

	2014	2015	2016	2017	2018	Average Annual % Change to 2024
WTI (US$/barrel)	95.00	95.00	95.00	95.00	95.30	1.9%
AECO ($/Mcf)	4.00	4.25	4.55	4.75	5.00	2.4%

Discount Rate

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent, which is common industry practice, and used by Cenovus's independent qualified reserves evaluators in preparing their reserves reports. Based on the individual characteristics of the asset, other economic and operating factors are also considered, which may increase or decrease the implied discount rate. Changes in the economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recognized for the future decommissioning and restoration of the Company's upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recognized to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

6. FINANCE COSTS

For the years ended December 31,	**2013**	2012	2011
Interest Expense – Short-Term Borrowings and Long-Term Debt	**271**	230	213
Premium on Redemption of Long-Term Debt (Note 22)	**33**	-	-
Interest Expense – Partnership Contribution Payable (Note 13)	**98**	118	138
Unwinding of Discount on Decommissioning Liabilities (Note 23)	**97**	86	75
Other	**30**	21	21
	529	455	447

7. INTEREST INCOME

For the years ended December 31,	**2013**	2012	2011
Interest Income – Partnership Contribution Receivable (Note 13)	**(82)**	(102)	(120)
Other	**(14)**	(7)	(4)
	(96)	(109)	(124)

8. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	**2013**	2012	2011
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued from Canada	**357**	(69)	78
U.S. Dollar Partnership Contribution Receivable Issued from Canada	**(305)**	(15)	(107)
Other	**(12)**	14	(13)
Unrealized Foreign Exchange (Gain) Loss	**40**	(70)	(42)
Realized Foreign Exchange (Gain) Loss	**168**	50	68
	208	(20)	26

9. INCOME TAXES

The provision for income taxes is:

For the years ended December 31,	**2013**	2012	2011
Current Tax			
Canada	**143**	188	150
United States (1)	**45**	121	4
Total Current Tax	**188**	309	154
Deferred Tax	**244**	474	575
	432	783	729

(1) 2012 includes $68 million of withholding tax on a U.S. dividend.

The following table reconciles income taxes calculated at the Canadian statutory rate with recorded income taxes:

For the years ended December 31,	**2013**	2012	2011
Earnings Before Income Tax	**1,094**	1,778	2,207
Canadian Statutory Rate	**25.2%**	25.2%	26.7%
Expected Income Tax	**276**	448	589
Effect of Taxes Resulting from:			
Foreign Tax Rate Differential	**109**	146	82
Non-Deductible Stock-Based Compensation	**10**	10	18
Multi-Jurisdictional Financing	**(22)**	(27)	(50)
Foreign Exchange Gains (Losses) not Included in Net Earnings	**19**	14	(9)
Non-Taxable Capital (Gains) Losses	**31**	(7)	(8)
Derecognition (Recognition) of Capital Losses	**15**	(22)	26
Adjustments Arising from Prior Year Tax Filings	**(13)**	33	31
Withholding Tax on Foreign Dividend	**-**	68	-
Goodwill Impairment	**-**	99	-
Other	**7**	21	50
Total Tax	**432**	783	729
Effective Tax Rate	**39.5%**	44.0%	33.0%

The Canadian statutory tax rate remained unchanged at 25.2 percent for 2013. The Canadian statutory tax rate decreased to 25.2 percent in 2012 and 26.7 percent in 2011 as a result of tax legislation enacted in 2007. The U.S. statutory tax rate of 38.5 percent also remained unchanged for 2013. The U.S. statutory tax rate increased to 38.5 percent in 2012 from 37.5 percent in 2011 as a result of the allocation of taxable income to U.S. states.

The analysis of deferred income tax liabilities and deferred income tax assets is:

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Net Deferred Income Tax Liabilities			
Deferred Tax Liabilities to be Settled Within 12 Months	**75**	140	117
Deferred Tax Liabilities to be Settled After More Than 12 Months	**2,787**	2,420	1,976
	2,862	2,560	2,093

For the purposes of the preceding table, deferred income tax liabilities are shown net of offsetting deferred income tax assets where these occur in the same entity and jurisdiction. The deferred income tax liabilities to be settled within 12 months represents Management's estimate of the timing of the reversal of temporary differences and does not correlate to the current income tax expense of the subsequent year.

The movement in deferred income tax liabilities and assets, without taking into consideration the offsetting of balances within the same tax jurisdiction, is:

Deferred Income Tax Liabilities	Property, Plant and Equipment	Timing of Partnership Items	Net Foreign Exchange Gains	Risk Management	Other	Total
As at January 1, 2011	1,651	125	127	55	55	2,013
Charged/(Credited) to Earnings	725	38	(15)	16	75	839
Charged/(Credited) to OCI	-	-	-	-	-	-
Foreign Exchange Adjustments	18	-	-	-	2	20
As at January 1, 2012	2,394	163	112	71	132	2,872
Charged/(Credited) to Earnings	418	(104)	(85)	2	(32)	199
Charged/(Credited) to OCI	-	-	-	-	-	-
Foreign Exchange Adjustments	(17)	-	-	-	(1)	(18)
As at December 31, 2012	2,795	59	27	73	99	3,053
Charged/(Credited) to Earnings	145	29	(27)	(71)	49	125
Charged/(Credited) to OCI	-	-	-	-	-	-
Foreign Exchange Adjustments	60	-	-	-	4	64
As at December 31, 2013	**3,000**	**88**	**-**	**2**	**152**	**3,242**

Deferred Income Tax Assets	Unused Tax Losses	Risk Management	Other	Total
As at January 1, 2011	(281)	(45)	(173)	(499)
Charged/(Credited) to Earnings	(270)	29	(21)	(262)
Charged/(Credited) to OCI	-	-	(5)	(5)
Foreign Exchange Adjustments	(13)	-	-	(13)
As at January 1, 2012	(564)	(16)	(199)	(779)
Charged/(Credited) to Earnings	244	11	20	275
Charged/(Credited) to OCI	-	-	-	-
Foreign Exchange Adjustments	11	-	-	11
As at December 31, 2012	(309)	(5)	(179)	(493)
Charged/(Credited) to Earnings	218	(30)	(69)	119
Charged/(Credited) to OCI	-	-	7	7
Foreign Exchange Adjustments	(13)	-	-	(13)
As at December 31, 2013	**(104)**	**(35)**	**(241)**	**(380)**

Net Deferred Income Tax Liabilities	Total
Net Deferred Income Tax Liabilities as at January 1, 2011	1,514
Charged/(Credited) to Earnings	577
Charged/(Credited) to OCI	(5)
Foreign Exchange Adjustments	7
Net Deferred Income Tax Liabilities as at January 1, 2012	2,093
Charged/(Credited) to Earnings	474
Charged/(Credited) to OCI	-
Foreign Exchange Adjustments	(7)
Net Deferred Income Tax Liabilities as at December 31, 2012	2,560
Charged/(Credited) to Earnings	244
Charged/(Credited) to OCI	7
Foreign Exchange Adjustments	51
Net Deferred Income Tax Liabilities as at December 31, 2013	**2,862**

The allocation of deferred income tax expense is composed of:

As at December 31,	2013	2012	2011
Credited/(Charged) to Net Deferred Income Tax Liabilities	244	474	577
Credited/(Charged) to Liabilities Related to Assets Held for Sale	-	-	(2)
Deferred Income Tax Expense	**244**	474	575

No tax liability has been recognized in respect of temporary differences associated with investments in subsidiaries. As no taxes are expected to be paid in respect of these differences related to Canadian subsidiaries, the amounts have not been determined. There are no taxable temporary differences associated with investments in non-Canadian subsidiaries.

The approximate amounts of tax pools available are:

As at December 31,	2013	2012
Canada	5,425	4,895
United States	1,083	1,607
	6,508	6,502

At December 31, 2013, the above tax pools included $5 million (2012 – $13 million; 2011 – $78 million) of Canadian non-capital losses and $238 million (2012 – $791 million; 2011 – $1,479 million) of U.S. federal net operating losses. These losses expire no earlier than 2029.

Also included in the December 31, 2013 tax pools are Canadian net capital losses totaling $561 million (2012 – $512 million; 2011 – $759 million), which are available for carry forward to reduce future capital gains. Of these losses, $561 million are unrecognized as a deferred income tax asset at December 31, 2013 (2012 – $406 million; 2011 – $286 million). Recognition is dependent on the level of future capital gains.

10. PER SHARE AMOUNTS

A) Net Earnings Per Share

For the years ended December 31, ($ millions, except earnings per share)	2013	2012	2011
Net Earnings – Basic and Diluted	662	995	1,478
Weighted Average Number of Shares – Basic	755.9	755.6	754.0
Dilutive Effect of Cenovus TSARs	1.6	2.9	3.7
Dilutive Effect of NSRs	-	-	-
Weighted Average Number of Shares – Diluted	757.5	758.5	757.7
Net Earnings Per Share – Basic	$0.88	$1.32	$1.96
Net Earnings Per Share – Diluted	$0.87	$1.31	$1.95

B) Dividends Per Share

The dividends paid in 2013 were $732 million or $0.968 per share, (2012 – $665 million, $0.88 per share; 2011 – $603 million, $0.80 per share). The Cenovus Board of Directors declared a first quarter 2014 dividend of $0.2662 per share, payable on March 31, 2014, to common shareholders of record as of March 14, 2014.

11. CASH AND CASH EQUIVALENTS

As at	December 31, 2013	December 31, 2012	January 1, 2012
Cash	363	339	232
Short-Term Investments	2,089	821	263
	2,452	1,160	495

12. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Accruals	**1,589**	1,184	1,016
Partner Advances	**153**	87	191
Prepaids and Deposits	**55**	45	34
Joint Operations Receivables	**26**	30	30
Interest	**-**	23	28
Other	**51**	95	106
	1,874	1,464	1,405

13. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

Cenovus has two significant joint operations, FCCL and WRB (Note 1). Through its interests in these joint operations, Cenovus's Consolidated Balance Sheets include a Partnership Contribution Receivable and Payable, which arose when Cenovus became a 50 percent partner of an integrated North American oil business. The integrated business consists of an upstream entity, FCCL, and a refining entity, WRB. On formation of the upstream entity Cenovus contributed assets, primarily Foster Creek and Christina Lake properties, with a fair value of US$7.5 billion and a note receivable of an equal amount was contributed by the partner ("Partnership Contribution Receivable"). For the refining entity, the partner contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of US$7.5 billion and Cenovus contributed a note payable of an equal amount ("Partnership Contribution Payable").

Partnership Contribution Receivable

On December 17, 2013, Cenovus, through its interest in FCCL, received US$1.4 billion, representing the remaining principal and interest due under the Partnership Contribution Receivable.

Partnership Contribution Payable

This note payable is denominated in US dollars and bears interest at a rate of 6.0 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term Partnership Contribution Payable amounts recognized in the Consolidated Balance Sheets represent Cenovus's 50 percent share of this promissory note, net of payments to date.

Mandatory Payments – Partnership Contribution Payable

	2014	2015	2016	2017	Thereafter	**Total**
US$	412	438	464	120	-	**1,434**
C$ equivalent	438	465	494	128	-	**1,525**

14. INVENTORIES

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Product			
Refining and Marketing	**1,047**	1,056	1,079
Oil Sands	**156**	192	162
Conventional	**17**	11	25
Parts and Supplies	**39**	29	25
	1,259	1,288	1,291

During the year ended December 31, 2013, approximately $13,895 million of produced and purchased inventory was recognized as an expense (2012 – $12,363 million; 2011 – $11,568 million). Inventory costs include purchased product, the cost of condensate blended with heavy oil and related operating costs.

In the third quarter, Cenovus recorded a $28 million write-down of its product inventory as a result of a decline in refined product prices. Product turnover and the subsequent improvement in commodity prices have resulted in the $28 million being reversed in the fourth quarter.

15. ASSETS AND LIABILITIES HELD FOR SALE

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Assets Held for Sale			
Property, Plant and Equipment	**-**	-	116
Liabilities Related to Assets Held for Sale			
Decommissioning Liabilities	**-**	-	54
Deferred Income Taxes	**-**	-	-
	-	-	54

In the first quarter of 2013, Management decided to launch a public sales process to divest certain of its Bakken properties in Saskatchewan. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. At that time, the assets were recorded at the lesser of fair value less costs of disposal and their carrying amount, and depletion ceased. These assets and the related liabilities are reported in the Conventional segment.

Management decided to discontinue the Bakken sales process until market conditions improve. While discussions with prospective purchasers have occurred, an offer that meets Management's expectations has not been received for the Bakken assets. As a result of this decision, as at December 31, 2013, the assets and associated decommissioning liabilities were reclassified from held for sale to PP&E and decommissioning liabilities, at their carrying amounts. Depletion, calculated on a per-unit of production basis, was recorded in the fourth quarter. The carrying value continues to be less than the estimated recoverable amount; therefore, no impairment was recognized.

16. EXPLORATION AND EVALUATION ASSETS

COST	
As at January 1, 2012	880
Additions [(1)]	687
Transfers to PP&E (Note 17)	(218)
Exploration Expense	(68)
Divestitures	(11)
Change in Decommissioning Liabilities	15
As at December 31, 2012	1,285
Additions	331
Transfers to PP&E (Note 17)	(95)
Exploration Expense	(50)
Divestitures	(17)
Change in Decommissioning Liabilities	19
As at December 31, 2013	**1,473**

(1) 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.

E&E assets consist of the Company's evaluation projects which are pending determination of technical feasibility and commercial viability. All of the Company's E&E assets are located within Canada.

Additions to E&E assets for the year ended December 31, 2013 include $60 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2012 – $37 million; December 31, 2011 – $15 million). Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized during the year ended December 31, 2013 (year ended December 31, 2012 and 2011 – $nil).

For the year ended December 31, 2013, $95 million of E&E assets were transferred to PP&E – development and production assets, following the determination of technical feasibility and commercial viability of the projects (year ended December 31, 2012 – $218 million; December 31, 2011 – $356 million).

Impairment

The impairment of E&E assets and any subsequent reversal of such impairment losses are recognized in exploration expense in the Consolidated Statements of Earnings and Comprehensive Income. For the year ended December 31, 2013, $50 million of previously capitalized E&E costs related to certain tight oil exploration assets within the Conventional segment were deemed not to be technically feasible and commercially viable and were recognized as exploration expense (2012 – $68 million; 2011 – $nil).

17. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other [(1)]	Total
COST					
As at January 1, 2012	23,858	194	3,425	576	28,053
Additions	2,442	44	118	191	2,795
Transfers from E&E Assets (Note 16)	218	-	-	-	218
Transfers and Reclassifications	-	-	(55)	-	(55)
Change in Decommissioning Liabilities	484	-	(16)	-	468
Exchange Rate Movements	1	-	(73)	-	(72)
As at December 31, 2012	27,003	238	3,399	767	31,407
Additions	2,702	48	106	82	2,938
Transfers from E&E Assets (Note 16)	95	-	-	-	95
Transfers and Reclassifications	(450)	-	(88)	-	(538)
Change in Decommissioning Liabilities	40	-	(1)	-	39
Exchange Rate Movements	-	-	238	-	238
As at December 31, 2013	**29,390**	**286**	**3,654**	**849**	**34,179**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at January 1, 2012	13,021	139	225	344	13,729
Depreciation, Depletion and Amortization	1,368	19	146	52	1,585
Transfers and Reclassifications	-	-	(55)	-	(55)
Impairment Losses	-	-	-	-	-
Exchange Rate Movements	1	-	(5)	-	(4)
As at December 31, 2012	14,390	158	311	396	15,255
Depreciation, Depletion and Amortization	1,522	35	138	79	1,774
Transfers and Reclassifications	(123)	-	(88)	-	(211)
Impairment Losses	2	-	-	-	2
Exchange Rate Movements	-	-	25	-	25
As at December 31, 2013	**15,791**	**193**	**386**	**475**	**16,845**
CARRYING VALUE					
As at January 1, 2012	10,837	55	3,200	232	14,324
As at December 31, 2012	12,613	80	3,088	371	16,152
As at December 31, 2013	**13,599**	**93**	**3,268**	**374**	**17,334**

(1) Includes office furniture, fixtures, leasehold improvements, information technology and aircraft.

Additions to development and production assets include internal costs directly related to the development and construction of crude oil and natural gas properties of $204 million (2012 – $161 million; 2011 – $125 million). All of the Company's development and production assets are located within Canada. Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized in 2013 (2012 and 2011 – $nil).

PP&E includes the following amounts in respect of assets under construction and are not subject to DD&A:

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Development and Production	**225**	71	-
Refining Equipment	**97**	13	125
Other	**-**	-	112
	322	84	237

Impairment

The impairment of PP&E and any subsequent reversal of such impairment losses are recognized in DD&A in the Consolidated Statements of Earnings and Comprehensive Income.

DD&A expense includes impairment losses as follows:

For the years ended December 31,	**2013**	2012	2011
Development and Production	**2**	-	2
Refining Equipment	**-**	-	45
	2	-	47

There were no impairment reversals of PP&E in 2013. The impairment losses for the year ended December 31, 2011 were related to a catalytic cracking unit at the Wood River Refinery, which will not be used in future operations, and an impairment on non-core natural gas assets that were reclassified as held for sale.

18. DIVESTITURES

In July 2013, the Company completed the sale of the Lower Shaunavon asset to an unrelated third party for proceeds of approximately $240 million plus closing adjustments. In the second quarter of 2013, an impairment loss of $57 million was recorded as additional DD&A on the transaction. A loss of $2 million was recorded on the sale in the third quarter. Other divestitures in 2013 include undeveloped land in northern Alberta, cancellation of some of the Company's non-core Oil Sands mineral rights under the Lower Athabasca Regional Plan and a third party land exchange.

In January 2012, the Company completed the sale of non-core natural gas assets located in northern Alberta. A loss of $2 million was recorded on the sale. These assets and the related liabilities were reported in the Conventional segment.

In 2011, the Company disposed of non-core crude oil and natural gas properties and marine terminal facilities recognizing an after-tax gain of $91 million in the Consolidated Statement of Earnings and Comprehensive Income.

19. OTHER ASSETS

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Equity Investments	**32**	14	6
Long-Term Receivables	**11**	22	18
Prepaids	**7**	8	8
Other	**18**	14	12
	68	58	44

20. GOODWILL

As at December 31,	2013	2012
Carrying Value, Beginning of Year	**739**	1,132
Impairment	**-**	(393)
Carrying Value, End of Year	**739**	739

There were no additions to goodwill during 2013 or 2012.

Impairment Test for CGUs Containing Goodwill

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. All of the Company's goodwill arose in 2002 upon the formation of the predecessor corporation. The carrying amount of goodwill allocated to the Company's exploration and production CGUs was:

As at	December 31, 2013	December 31, 2012	January 1, 2012
Primrose (Foster Creek)	**242**	242	242
Northern Alberta	**497**	497	497
Suffield	**-**	-	393
	739	739	1,132

At December 31, 2012, the Company determined that the carrying amount of the Suffield CGU exceeded its fair value less costs of disposal and the full amount of the impairment was attributed to goodwill. An impairment loss of $393 million was recorded as goodwill impairment on the Consolidated Statement of Earnings and Comprehensive Income. The Suffield property resides on the Canadian Forces Base in southeast Alberta and the operating results are included in the Conventional segment. Future cash flows for the area declined due to lower natural gas and crude oil prices and increased operating costs. In addition, minimal levels of capital spending for natural gas resulted in production exceeding reserves replacement in the area. With lower future cash flows and decreasing volumes, the carrying amount of the Suffield CGU exceeded its fair value.

The recoverable amount was determined using fair value less costs of disposal. A calculation based on discounted after-tax cash flows of proved and probable reserves using forecast prices and costs as estimated by Cenovus's independent qualified reserves evaluators was completed. To assess reasonableness, an evaluation of fair value based on comparable asset transactions was also completed. As at December 31, 2012, the recoverable amount of the Suffield CGU was $1,130 million.

There were no impairments of goodwill in 2013 and 2011.

21. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at	December 31, 2013	December 31, 2012	January 1, 2012
Accruals	**2,317**	2,053	1,855
Partner Advances	**233**	87	191
Trade	**102**	133	148
Employee Long-Term Incentives	**116**	196	209
Interest	**82**	82	72
Other	**87**	99	104
	2,937	2,650	2,579

22. LONG-TERM DEBT

As at		**December 31, 2013**	December 31, 2012	January 1, 2012
Revolving Term Debt [1]	A	**-**	-	-
U.S. Dollar Denominated Unsecured Notes	B	**5,052**	4,726	3,559
Total Debt Principal	C	**5,052**	4,726	3,559
Debt Discounts and Transaction Costs	D	**(55)**	(47)	(32)
		4,997	4,679	3,527

(1) *Revolving term debt may include bankers' acceptances, LIBOR loans, prime rate loans and U.S. base rate loans.*

The weighted average interest rate on outstanding debt for the year ended December 31, 2013 was 5.2 percent (2012 – 5.3 percent; 2011 – 5.5 percent).

A) Revolving Term Debt

At December 31, 2013, Cenovus had in place a committed credit facility in the amount of $3.0 billion or the equivalent amount in U.S. dollars. The committed credit facility was renegotiated in September 2013 to extend the maturity date to November 30, 2017. The maturity date is extendable from time to time, for a period of up to four years at the option of Cenovus and upon agreement from the lenders. Borrowings are available by way of Bankers' Acceptances, LIBOR based loans, prime rate loans or U.S. base rate loans. At December 31, 2013, there were no amounts drawn on Cenovus's committed bank credit facility (December 31, 2012 – $nil; January 1, 2012 – $nil).

B) Unsecured Notes

Unsecured notes are composed of:

As at	US$ Principal Amount	**December 31, 2013**	December 31, 2012	January 1, 2012
4.50% due September 15, 2014	800	**-**	796	814
5.70% due October 15, 2019	1,300	**1,382**	1,293	1,322
3.00% due August 15, 2022	500	**532**	498	-
3.80% due September 15, 2023	450	**479**	-	-
6.75% due November 15, 2039	1,400	**1,489**	1,393	1,423
4.45% due September 15, 2042	750	**798**	746	-
5.20% due September 15, 2043	350	**372**	-	-
		5,052	4,726	3,559

Cenovus has in place a Canadian base shelf prospectus for unsecured medium-term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issuance of medium-term notes in Canadian dollars or other foreign currencies, from time to time, in one or more offerings. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at December 31, 2013, no medium-term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.

On May 9, 2013, Cenovus amended its U.S. base shelf prospectus for unsecured notes to increase the total capacity from US$2.0 billion to US$3.25 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies, from time to time, in one or more offerings. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at December 31, 2013, US$1.2 billion remains under this U.S. base shelf prospectus. The U.S. shelf prospectus expires in July 2014.

On August 15, 2013, Cenovus completed a public offering in the U.S. of senior unsecured notes of US$450 million, with a coupon rate of 3.80 percent, due September 15, 2023 and US$350 million of senior unsecured notes with a coupon rate of 5.20 percent, due September 15, 2043, for an aggregate principal amount of US$800 million. The net proceeds from the offering were used to partially fund the early redemption of Cenovus's US$800 million senior unsecured notes due September 15, 2014. A premium of US$32 million was paid on the early redemption of these notes and was recorded as finance costs.

As at December 31, 2013, the Company is in compliance with all of the terms of its debt agreements.

C) Mandatory Debt Payments

	US$ Principal Amount	C$ Principal Amount	**Total C$ Equivalent**
2014	-	-	**-**
2015	-	-	**-**
2016	-	-	**-**
2017	-	-	**-**
2018	-	-	**-**
Thereafter	4,750	-	**5,052**
	4,750	-	**5,052**

D) Debt Discounts and Transaction Costs

Long-term debt transaction costs and discounts associated with the unsecured notes are recorded within long-term debt and are amortized using the effective interest rate method. Transaction costs associated with the revolving term debt are recorded as a prepayment and are amortized over the remaining term of the committed credit facility. During 2013, additional transaction costs of $15 million were recorded (2012 – $19 million).

23. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the expected future costs associated with the retirement of upstream crude oil and natural gas assets and refining facilities. The aggregate carrying amount of the obligation is:

As at December 31,	**2013**	2012
Decommissioning Liabilities, Beginning of Year	**2,315**	1,777
Liabilities Incurred	**45**	99
Liabilities Settled	**(76)**	(66)
Transfers and Reclassifications	**(26)**	3
Change in Estimated Future Cash Flows	**414**	144
Change in Discount Rate	**(401)**	273
Unwinding of Discount on Decommissioning Liabilities	**97**	86
Foreign Currency Translation	**2**	(1)
Decommissioning Liabilities, End of Year	**2,370**	2,315

The undiscounted amount of estimated future cash flows required to settle the obligation is $7,471 million (December 31, 2012 – $6,865 million; January 1, 2012 – $6,541 million), which has been discounted using a credit-adjusted risk-free rate of 5.2 percent (December 31, 2012 – 4.2 percent; January 1, 2012 – 4.8 percent). Most of these obligations are not expected to be paid for several years, or decades, and are expected to be funded from general resources at that time. Revisions in estimated future cash flows resulted from accelerated timing of forecast abandonment and reclamation spending, and higher cost estimates.

Sensitivities

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

	2013		2012	
As at December 31,	**Credit-Adjusted Risk-Free Rate**	**Inflation Rate**	Credit-Adjusted Risk-Free Rate	Inflation Rate
One Percent Increase	**(345)**	**472**	(408)	572
One Percent Decrease	**461**	**(357)**	565	(418)

24. OTHER LIABILITIES

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Deferred Revenues	**25**	31	35
Employee Long-Term Incentives	**67**	64	55
Pension and OPEB (Note 25)	**51**	60	46
Other	**37**	28	22
	180	183	158

25. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension that includes either a defined contribution or defined benefit component and OPEB. Most of the employees participate in the defined contribution pension. Starting in 2012, employees who meet certain criteria may move from the current defined contribution component to a defined benefit component for their future service.

The defined benefit pension provides pension benefits at retirement based on years of service and final average earnings. Future enrollment is limited to eligible employees who meet certain criteria. The Company's OPEB provides certain retired employees with health care and dental benefits until age 65 and life insurance benefits.

The Company is required to file an actuarial valuation of its registered defined benefit pension with the provincial regulator at least every three years. The most recently filed valuation was dated June 30, 2012 and the next required actuarial valuation will be as at December 31, 2014.

A) Defined Benefit and OPEB Plan Obligation and Funded Status

Information related to defined benefit pension and OPEB plans, based on actuarial estimations, is:

	Pension Benefits		**OPEB**	
As at December 31,	**2013**	2012	**2013**	2012
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**134**	84	**20**	19
Current Service Costs	**17**	10	**2**	2
Interest Costs [(1)]	**6**	4	**1**	1
Benefits Paid	**(5)**	(2)	**-**	-
Plan Participant Contributions	**2**	1	**-**	-
Plan Conversion	**-**	30	**-**	-
Remeasurements:				
(Gains) Losses from Experience Adjustments	**1**	3	**-**	1
(Gains) Losses from Changes in Demographic Assumptions	**12**	-	**(1)**	(1)
(Gains) Losses from Changes in Financial Assumptions	**(19)**	4	**(4)**	(2)
Defined Benefit Obligation, End of Year	**148**	134	**18**	20
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**94**	57	**-**	-
Employer Contributions	**15**	22	**-**	-
Plan Participant Contributions	**2**	1	**-**	-
Benefits Paid	**(5)**	(2)	**-**	-
Interest Income [(1)]	**2**	3	**-**	-
Asset Transfer From Plan Conversion	**-**	12	**-**	-
Remeasurements:				
Return on Plan Assets (Excluding Interest Income)	**7**	1	**-**	-
Fair Value of Plan Assets, End of Year	**115**	94	**-**	-
Pension and Other Post-Employment Benefit (Liability) [(2)]	**(33)**	(40)	**(18)**	(20)

(1) Based on the discount rate of the defined benefit obligation at the beginning of the year.
(2) Pension and OPEB liabilities are included in other liabilities on the Consolidated Balance Sheets.

The weighted average duration of the defined benefit pension and OPEB obligations are 16 years and 12 years, respectively.

B) Pension and OPEB Costs

Pension and OPEB costs are:

For the years ended December 31,	Pension Benefits 2013	Pension Benefits 2012	Pension Benefits 2011	OPEB 2013	OPEB 2012	OPEB 2011
Defined Benefit Plan Cost:						
Current Service Costs	**17**	10	3	**2**	2	2
Past Service Costs [1]	**-**	18	-	**-**	-	-
Net Interest Costs	**4**	1	1	**1**	1	1
Remeasurements:						
Return on Plan Assets (Excluding Interest Income)	**(7)**	(1)	4	**-**	-	-
(Gains) Losses from Experience Adjustments	**1**	3	(1)	**-**	1	-
(Gains) Losses from Changes in Demographic Assumptions	**12**	-	-	**(1)**	(1)	-
(Gains) Losses from Changes in Financial Assumptions	**(19)**	4	12	**(4)**	(2)	2
Defined Benefit Plan Cost (Gain)	**8**	35	19	**(2)**	1	5
Defined Contribution Plan Cost	**27**	25	22	**-**	-	-
Total Plan Cost	**35**	60	41	**(2)**	1	5

(1) Past service costs for eligible employees meeting certain criteria who elected to convert from the defined contribution pension to defined benefit pension.

Pension costs are recorded in operating and general and administrative expenses, and PP&E and E&E assets, corresponding to where the associated salaries and wages of the employees rendering the service are recorded.

C) Investment Objectives and Fair Value of Plan Assets

The objective of the asset allocation is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment and credit rating categories.

The allocation of assets between the various types of investment funds is monitored monthly and is re-balanced as necessary. The asset allocation structure targets an investment of 65 to 70 percent in equity securities, 30 percent in debt instruments and the remainder invested in real estate and other.

The Company does not use derivative instruments to manage the risks of its plan assets. There has been no change in the process used by the Company to manage these risks from prior periods.

The fair value of the plan assets is:

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Equity Securities			
Equity Funds and Balanced Funds	**67**	52	30
Other	**8**	3	-
Bond Funds	**25**	24	17
Non-Invested Assets	**12**	11	7
Real Estate	**3**	4	3
	115	94	57

Fair value of equity securities and bond funds are based on the trading price of the underlying funds. The fair value of the non-invested assets is the discounted value of the expected future payments. The fair value of real estate is determined by accredited real estate appraisers.

Equity securities do not include any direct investments in Cenovus shares.

D) Funding

The defined benefit pension is funded in accordance with federal and provincial government pension legislation, where applicable. Contributions are made to trust funds administered by an independent trustee. The Company's contributions to the defined benefit pension plan are based on the most recent actuarial valuation as at June 30, 2012, and direction by the Management Pension Committee and Human Resources and Compensation Committee of the Board of Directors.

Employees participating in the defined benefit pension are required to contribute four percent of their pensionable earnings, up to an annual maximum, and the Company provides the balance of the funding necessary to ensure benefits will be fully provided for at retirement. The expected employer contributions for the year ended December 31, 2014 are $15 million for the defined benefit pension plan and $nil for the OPEB. The OPEB is funded on an as required basis.

E) Actuarial Assumptions and Sensitivities

Actuarial Assumptions

The principal weighted average actuarial assumptions used to determine benefit obligations and expenses are as follows:

	Pension Benefits			OPEB		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Discount Rate	**4.75%**	4.00%	4.25%	**4.75%**	4.00%	4.25%
Future Salary Growth Rate	**4.39%**	4.39%	3.99%	**5.65%**	5.77%	5.77%
Average Longevity (Years)	**88.5**	86.1	86.1	**88.5**	86.1	86.1
Health Care Cost Trend Rate	**N/A**	N/A	N/A	**7.00%**	8.00%	10.00%

The discount rates are determined with reference to market yields on high quality corporate debt instruments of similar duration to the benefit obligations at the end of the reporting period.

Sensitivities

The sensitivity of the defined benefit and OPEB obligation to changes in relevant actuarial assumptions at December 31, 2013 is shown below.

	One Percentage Point Increase	One Percentage Point Decrease
Discount Rate	**(23)**	**29**
Future Salary Growth Rate	**4**	**(4)**
Health Care Cost Trend Rate	**1**	**(1)**
Future Mortality Rate (Years)	**3**	**(3)**

The above sensitivity analysis is based on a change in an assumption while holding all other assumptions constant; however, the changes in some assumptions may be correlated. The same methodologies have been used to calculate the sensitivity of the defined benefit obligation to significant actuarial assumptions as have been applied when calculating the defined benefit pension liability recognized on the consolidated balance sheets.

F) Risks

Through its defined benefit pension and OPEB plans, the Company is exposed to actuarial risks, such as longevity risk, interest rate risk, investment risk and salary risk.

Longevity Risk

The present value of the defined benefit plan obligation is calculated by reference to the best estimate of the mortality of plan participants both during and after their employment. An increase in the life expectancy of participants will increase the defined benefit plan obligation.

Interest Rate Risk

A decrease in corporate bond yields will increase the defined benefit plan obligation, although this will be partially offset by an increase in the return on debt holdings.

Investment Risk

The present value of the defined benefit plan obligation is calculated using a discount rate determined by reference to high quality corporate bond yields. If the return on plan assets is below this rate, a plan deficit will result. Due to the long-term nature of the plan liabilities, a higher portion of the plan assets are invested in equity securities than in debt instruments and real estate.

Salary Risk

The present value of the defined benefit plan obligation is calculated by reference to the future salaries of plan participants. As such, an increase in the salary of the plan participants will increase the defined benefit obligation.

26. SHARE CAPITAL

A) Authorized

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

B) Issued and Outstanding

	2013		2012	
As at December 31,	**Number of Common Shares (thousands)**	**Amount**	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**755,843**	**3,829**	754,499	3,780
Common Shares Issued under Stock Option Plans	**970**	**31**	1,344	49
Common Shares Cancelled	**(767)**	**(3)**	-	-
Outstanding, End of Year	**756,046**	**3,857**	755,843	3,829

During the year ended December 31, 2013, the Company cancelled 767,327 common shares. The common shares were held in reserve for un-exchanged shares of Alberta Energy Company Ltd., pursuant to the merger of Alberta Energy Company Ltd. and PanCanadian Energy Corporation in 2002 ("AEC Merger"), in which Encana was formed. Due to the Arrangement, common shares of the Company were held in reserve until the tenth anniversary of the AEC Merger.

There were no preferred shares outstanding as at December 31, 2013 (2012 – nil).

As at December 31, 2013, there were 24 million (2012 – 28 million) common shares available for future issuance under stock option plans.

The Company has a dividend reinvestment plan ("DRIP"). Under the DRIP, holders of common shares may reinvest all or a portion of the cash dividends payable on their common shares in additional common shares. At the discretion of the Company, the additional common shares may be issued from treasury or purchased on the market.

C) Paid in Surplus

Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana under the Arrangement into two independent energy companies, Encana and Cenovus. In addition, paid in surplus includes compensation expense related to the Company's NSRs discussed in Note 28A.

	Pre-Arrangement Earnings	**Stock-Based Compensation**	**Total**
As at January 1, 2012	4,083	24	4,107
Stock-Based Compensation Expense	-	47	47
As at December 31, 2012	4,083	71	4,154
Stock-Based Compensation Expense	-	62	62
Common Shares Cancelled	3	-	3
As at December 31, 2013	**4,086**	**133**	**4,219**

27. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Investments	Total
As at January 1, 2012	(22)	119	-	97
Other Comprehensive Income (Loss), Before Tax	(4)	(24)	-	(28)
Income Tax	-	-	-	-
As at December 31, 2012	(26)	95	-	69
Other Comprehensive Income (Loss), Before Tax	18	117	13	148
Income Tax	(4)	-	(3)	(7)
As at December 31, 2013	**(12)**	**212**	**10**	**210**

28. STOCK-BASED COMPENSATION PLANS

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of the Company. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options granted prior to February 17, 2010 expire after five years while options granted on or after February 17, 2010 expire after seven years.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 have associated tandem stock appreciation rights. In lieu of exercising the options, the tandem stock appreciation rights give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

Options issued by the Company on or after February 24, 2011 have associated net settlement rights. The net settlement rights, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

The tandem stock appreciation rights and net settlement rights vest and expire under the same terms and conditions as the underlying options. For the purpose of this financial statement note, options with associated tandem stock appreciation rights are referred to as "TSARs" and options with associated net settlement rights are referred to as "NSRs".

In addition, certain of the TSARs are performance based ("performance TSARs"). All performance TSARs have vested, and, as such, terms and conditions are consistent with TSARs, which were not performance based.

In accordance with the Arrangement described in Note 1, each Cenovus and Encana employee exchanged their original Encana TSAR for one Cenovus replacement TSAR and one Encana replacement TSAR. The terms and conditions of the Cenovus and Encana replacement TSARs are similar to the terms and conditions of the original Encana TSAR. The original exercise price of the Encana TSAR was apportioned to the Cenovus and Encana replacement TSARs based on the one day volume weighted average trading price of Cenovus's common share price relative to that of Encana's common share price on the TSX on December 2, 2009. Cenovus TSARs and Cenovus replacement TSARs are measured against the Cenovus common share price while Encana replacement TSARs are measured against the Encana common share price. The Cenovus replacement TSARs have similar vesting provisions as outlined above for the Employee Stock Option Plan. The original Encana performance TSARs were also exchanged under the same terms as the original Encana TSARs.

As at December 31, 2013	Issued	Term (Years)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	Closing Share Price ($)	Number of Units Outstanding (thousands)
NSRs	On or After February 24, 2011	**7**	**5.46**	**35.26**	**30.40**	**26,315**
TSARs	Prior to February 17, 2010	**5**	**0.15**	**26.28**	**30.40**	**2,483**
TSARs	On or After February 17, 2010	**7**	**3.20**	**26.71**	**30.40**	**4,603**
Encana Replacement TSARs held by Cenovus Employees	Prior to December 1, 2009	**5**	**0.12**	**29.06**	**19.18**	**3,904**
Cenovus Replacement TSARs held by Encana Employees	Prior to December 1, 2009	**5**	**0.12**	**26.28**	**30.40**	**1,479**

Unless otherwise indicated, all references to TSARs collectively refer to both the Cenovus issued TSARs and Cenovus replacement TSARs.

NSRs

The weighted average unit fair value of NSRs granted during the year ended December 31, 2013 was $6.10 before considering forfeitures, which are considered in determining total cost for the period. The fair value of each NSR was estimated on its grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.49%**
Expected Dividend Yield	**2.65%**
Expected Volatility (1)	**27.62%**
Expected Life (Years)	**4.55**

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The following tables summarize information related to the NSRs as at December 31, 2013:

As at December 31, 2013	**Number of NSRs** (thousands)	**Weighted Average Exercise Price** ($)
Outstanding, Beginning of Year	**15,074**	**37.52**
Granted	**12,078**	**32.50**
Exercised for Common Shares	**-**	**31.85**
Forfeited	**(837)**	**36.26**
Outstanding, End of Year	**26,315**	**35.26**
Exercisable, End of Year	**5,966**	**37.37**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $33.11.

	Outstanding NSRs		
As at December 31, 2013 Range of Exercise Price ($)	**Number of NSRs** (thousands)	**Weighted Average Remaining Contractual Life** (Years)	**Weighted Average Exercise Price** ($)
25.00 to 29.99	**271**	**6.49**	**29.64**
30.00 to 34.99	**13,407**	**6.07**	**32.61**
35.00 to 39.99	**12,637**	**4.78**	**38.18**
	26,315	**5.46**	**35.26**

	Exercisable NSRs	
As at December 31, 2013 Range of Exercise Price ($)	**Number of NSRs** (thousands)	**Weighted Average Exercise Price** ($)
30.00 to 34.99	**726**	**32.92**
35.00 to 39.99	**5,240**	**37.99**
	5,966	**37.37**

TSARs Held by Cenovus Employees

The Company has recorded a liability of $33 million at December 31, 2013 (December 31, 2012 – $64 million; January 1, 2012 – $90 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.91%**
Expected Dividend Yield	**3.05%**
Expected Volatility [1]	**26.43%**
Cenovus's Common Share Price	**$30.40**

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested TSARs held by Cenovus employees at December 31, 2013 was $27 million (2012 – $45 million).

The following tables summarize information related to the TSARs held by Cenovus employees as at December 31, 2013:

As at December 31, 2013	**Number of TSARs** (thousands)	**Weighted Average Exercise Price** ($)
Outstanding, Beginning of Year	**11,251**	**28.13**
Exercised for Cash Payment	**(1,840)**	**29.70**
Exercised as Options for Common Shares	**(955)**	**29.07**
Forfeited	**(67)**	**28.62**
Expired	**(1,303)**	**33.77**
Outstanding, End of Year	**7,086**	**26.56**
Exercisable, End of Year	**7,037**	**26.51**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $32.60.

As at December 31, 2013 Range of Exercise Price ($)	Outstanding TSARs **Number of TSARs** (thousands)	 **Weighted Average Remaining Contractual Life** (Years)	 **Weighted Average Exercise Price** ($)
20.00 to 29.99	**6,910**	**2.08**	**26.40**
30.00 to 39.99	**176**	**3.90**	**32.71**
	7,086	**2.13**	**26.56**

As at December 31, 2013 Range of Exercise Price ($)	Exercisable TSARs **Number of TSARs** (thousands)	 **Weighted Average Exercise Price** ($)
20.00 to 29.99	**6,910**	**26.40**
30.00 to 39.99	**127**	**32.42**
	7,037	**26.51**

The closing price of Cenovus's common shares on the TSX as at December 31, 2013 was $30.40.

Encana Replacement TSARs Held by Cenovus Employees

Cenovus is required to reimburse Encana for cash payments made by Encana to Cenovus employees when a Cenovus employee exercises an Encana replacement TSAR for cash. No further Encana Replacement TSARs will be granted to Cenovus employees.

The Company has recorded a liability of $nil at December 31, 2013 (December 31, 2012 – $1 million; January 1, 2012 – $1 million) in the Consolidated Balance Sheets based on the fair value of each Encana replacement TSAR held by Cenovus employees. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.91%**
Expected Dividend Yield	**3.63%**
Expected Volatility [1]	**30.27%**
Encana's Common Share Price	**$19.18**

(1) Expected volatility has been based on the historical volatility of Encana's publicly traded shares.

The intrinsic value of vested Encana replacement TSARs held by Cenovus employees at December 31, 2013 was $nil (2012 – $nil).

The following tables summarize information related to the Encana replacement TSARs held by Cenovus employees as at December 31, 2013:

As at December 31, 2013	Number of TSARs (thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	7,722	32.66
Forfeited	(187)	30.07
Expired	(3,631)	36.66
Outstanding, End of Year	3,904	29.06
Exercisable, End of Year	3,904	29.06

	Outstanding & Exercisable TSARs		
As at December 31, 2013 Range of Exercise Price ($)	Number of TSARs (thousands)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	3,874	0.12	29.04
30.00 to 39.99	30	0.73	31.53
	3,904	0.12	29.06

The closing price of Encana common shares on the TSX as at December 31, 2013 was $19.18.

Cenovus Replacement TSARs Held by Encana Employees

Encana is required to reimburse Cenovus for cash payments made by Cenovus to Encana employees when these employees exercise a Cenovus replacement TSAR for cash. No compensation expense is recognized and no further Cenovus replacement TSARs will be granted to Encana employees.

The Company has recorded a liability of $6 million at December 31, 2013 (December 31, 2012 – $35 million; January 1, 2012 – $83 million) in the Consolidated Balance Sheets based on the fair value of each Cenovus replacement TSAR held by Encana employees, with an offsetting account receivable from Encana. Fair value was estimated at the period end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.91%**
Expected Dividend Yield	**3.05%**
Expected Volatility [1]	**26.43%**
Cenovus's Common Share Price	**$30.40**

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested Cenovus replacement TSARs held by Encana employees at December 31, 2013 was $6 million (2012 – $22 million).

The following tables summarize the information related to the Cenovus replacement TSARs held by Encana employees as at December 31, 2013:

As at December 31, 2013	Number of TSARs (thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	5,229	29.29
Exercised for Cash Payment	(2,351)	28.75
Exercised as Options for Common Shares	(15)	29.54
Forfeited	(27)	28.74
Expired	(1,357)	33.51
Outstanding, End of Year	1,479	26.28
Exercisable, End of Year	1,479	26.28

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $32.42.

	Outstanding & Exercisable TSARs		
As at December 31, 2013 Range of Exercise Price ($)	Number of TSARs (thousands)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	1,479	0.12	26.28

The closing price of Cenovus's common shares on the TSX as at December 31, 2013 was $30.40.

B) PSUs

Cenovus has granted PSUs to certain employees under its Performance Share Unit Plan for Employees. PSUs are whole share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. For a portion of PSUs, the number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three. All PSUs are eligible to vest based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $103 million at December 31, 2013 (December 31, 2012 – $124 million; January 1, 2012 – $55 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus common shares at December 31, 2013. The intrinsic value of vested PSUs was $nil at December 31, 2013 and 2012 as PSUs are paid out upon vesting.

The following table summarizes the information related to the PSUs held by Cenovus employees:

As at December 31, 2013	PSUs (thousands)
Outstanding, Beginning of Year	5,258
Granted	2,552
Vested and Paid Out	(2,008)
Cancelled	(194)
Units in Lieu of Dividends	177
Outstanding, End of Year	5,785

C) DSUs

Under two Deferred Share Unit Plans, Cenovus directors, officers and employees may receive DSUs, which are equivalent in value to a common share of the Company. Employees have the option to convert either zero, 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of $36 million at December 31, 2013 (December 31, 2012 – $36 million; January 1, 2012 – $35 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus common shares at December 31, 2013. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees:

As at December 31, 2013	DSUs (thousands)
Outstanding, Beginning of Year	**1,084**
Granted to Directors	**65**
Granted from Annual Bonus Awards	**8**
Units in Lieu of Dividends	**36**
Redeemed	**(1)**
Outstanding, End of Year	**1,192**

D) Total Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating and general and administrative expenses in the Consolidated Statements of Earnings and Comprehensive Income:

For the years ended December 31,	2013	2012	2011
NSRs	**35**	27	16
TSARs Held by Cenovus Employees	**(16)**	(1)	24
Encana Replacement TSARs Held by Cenovus Employees	**-**	-	(8)
PSUs	**32**	46	27
DSUs	**-**	3	4
Total Stock-Based Compensation Expense (Recovery)	**51**	75	63

29. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	2013	2012	2011
Salaries, Bonuses and Other Short-Term Employee Benefits	**494**	441	399
Defined Contribution Pension Plan	**17**	14	13
Defined Benefit Pension Plan and OPEB	**15**	20	4
Stock-Based Compensation (Note 28)	**51**	75	63
	577	550	479

30. RELATED PARTY TRANSACTIONS

Key Management Compensation

Key management includes Directors (executive and non-executive), Executive Officers, Senior Vice-Presidents and Vice-Presidents. The compensation paid or payable to key management is:

For the years ended December 31,	2013	2012	2011
Salaries, Director Fees and Short-Term Benefits	**31**	27	25
Post-Employment Benefits	**4**	7	3
Other Long-Term Benefits	**-**	-	-
Stock-Based Compensation	**24**	35	35
	59	69	63

Post-employment benefits represent the present value of future pension benefits earned during the year. Stock-based compensation includes the costs recognized during the year associated with stock options, NSRs, TSARs, PSUs and DSUs.

31. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt is defined as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes and DD&A ("Adjusted EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength.

Cenovus continues to target a Debt to Capitalization ratio of between 30 and 40 percent over the long-term.

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Long-Term Debt	**4,997**	4,679	3,527
Shareholders' Equity	**9,946**	9,782	9,384
Capitalization	**14,943**	14,461	12,911
Debt to Capitalization	**33%**	32%	27%

Cenovus continues to target a Debt to Adjusted EBITDA of between 1.0 and 2.0 times over the long-term.

As at December 31,	**2013**	2012	2011
Debt	**4,997**	4,679	3,527
Net Earnings	**662**	995	1,478
Add (Deduct):			
Finance Costs	**529**	455	447
Interest Income	**(96)**	(109)	(124)
Income Tax Expense	**432**	783	729
Depreciation, Depletion and Amortization	**1,833**	1,585	1,295
Goodwill Impairment	**-**	393	-
E&E Impairment	**50**	68	-
Unrealized (Gain) Loss on Risk Management	**415**	(57)	(180)
Foreign Exchange (Gain) Loss, Net	**208**	(20)	26
(Gain) Loss on Divestiture of Assets	**1**	-	(107)
Other (Income) Loss, Net	**2**	(5)	4
Adjusted EBITDA	**4,036**	4,088	3,568
Debt to Adjusted EBITDA	**1.2x**	1.1x	1.0x

It is Cenovus's intention to maintain investment grade credit ratings to help ensure it has continuous access to capital and the financial flexibility to fund its capital programs, meet its financial obligations and finance potential acquisitions. Cenovus will maintain a high level of capital discipline and manage its capital structure to ensure sufficient liquidity through all stages of the economic cycle. To manage its capital structure, Cenovus may adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facilities or repay existing debt.

At December 31, 2013, Cenovus is in compliance with all of the terms of its debt agreements.

32. FINANCIAL INSTRUMENTS

Cenovus's consolidated financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, Partnership Contribution Receivable and Payable, partner loans, risk management assets and liabilities, long-term receivables, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments.

A) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of those instruments.

The fair values of the Partnership Contribution Receivable and Payable, partner loans and long-term receivables approximate their carrying amount due to the specific non-tradeable nature of these instruments.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on period end trading prices of long-term borrowings on the secondary market (Level 2). As at December 31, 2013, the carrying value of Cenovus's long-term debt was $4,997 million and the fair value was $5,388 million (December 31, 2012 carrying value – $4,679 million, fair value – $5,582 million).

Available for sale financial assets comprise private equity investments. These assets are carried at fair value on the Consolidated Balance Sheets in other assets. Fair value is determined based on recent private placement transactions (Level 3) when available. When fair value cannot be reliably measured, these assets are carried at cost. A reconciliation of changes in the fair value of available for sale financial assets is below.

As at December 31,	**2013**	2012
Fair Value, Beginning of Year	**14**	6
Acquisition of Investments	**5**	8
Change in Fair Value [(1)]	**13**	-
Fair Value, End of Year	**32**	14

(1) Unrealized gains and losses on available for sale financial assets are recorded in Other Comprehensive Income.

B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil, natural gas and power purchase contracts. Crude oil and natural gas contracts are recorded at their estimated fair value based on the difference between the contracted price and the period end forward price for the same commodity, using quoted market prices or the period end forward price for the same commodity extrapolated to the end of the term of the contract (Level 2). The fair value of power purchase contracts are calculated internally based on observable and unobservable inputs such as forward power prices in less active markets (Level 3). The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness. The forward prices used in the determination of the fair value of the power purchase contracts at December 31, 2013 range from $44.75 to $66.00 per Megawatt Hour.

Summary of Unrealized Risk Management Positions

	December 31, 2013			December 31, 2012			January 1, 2012		
	Risk Management			Risk Management			Risk Management		
As at	**Asset**	**Liability**	**Net**	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices									
Crude Oil	**10**	**136**	**(126)**	221	16	205	22	65	(43)
Natural Gas	**-**	**-**	**-**	66	1	65	247	3	244
Power	**-**	**3**	**(3)**	1	1	-	15	-	15
Total Fair Value	**10**	**139**	**(129)**	288	18	270	284	68	216

The following table presents the Company's fair value hierarchy for risk management assets and liabilities carried at fair value.

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Prices Sourced from Observable Data or Market Corroboration (Level 2)	**(126)**	270	216
Prices Determined from Unobservable Inputs (Level 3)	**(3)**	-	-
	(129)	270	216

Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data. Prices determined from unobservable inputs refers to the fair value of contracts valued using data that is both unobservable and significant to the overall fair value measurement.

The following table provides a reconciliation of changes in the fair value of our risk management assets and liabilities:

	2013	2012
Fair Value of Contracts, Beginning of Year	**270**	216
Fair Value of Contracts Realized During the Year	**(122)**	(336)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**(293)**	393
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**16**	(3)
Fair Value of Contracts, End of Year	**(129)**	270

Financial assets and liabilities are only offset if Cenovus has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. Cenovus offsets risk management assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same. No additional unrealized risk management positions are subject to an enforceable master netting arrangement or similar agreement that are not otherwise offset.

The following table provides a summary of the Company's offsetting risk management positions:

	December 31, 2013			December 31, 2012		
	Risk Management			Risk Management		
As at	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	**16**	**145**	**(129)**	306	36	270
Amount Offset	**(6)**	**(6)**	**-**	(18)	(18)	-
Net Amount per Consolidated Financial Statements	**10**	**139**	**(129)**	288	18	270

	January 1, 2012		
	Risk Management		
As at	Asset	Liability	Net
Recognized Risk Management Positions			
Gross Amount	307	91	216
Amount Offset	(23)	(23)	-
Net Amount per Consolidated Financial Statements	284	68	216

The derivative liabilities do not have credit risk-related contingent features. Due to credit practices that limit transactions according to counterparties' credit quality, the change in fair value through profit or loss attributable to changes in the credit risk of financial liabilities is immaterial.

Cenovus pledges cash collateral with respect to certain of these risk management contracts, which is not offset against the related financial liability. The amount of cash collateral required will vary daily over the life of these risk management contracts as commodity prices change. Additional cash collateral is required if, on a net basis, risk management payables exceed risk management receivables on a particular day. As at December 31, 2013, $10 million (December 31, 2012 – $12 million; January 1, 2012 – $12 million) was pledged as collateral, of which $5 million (December 31, 2012 – $12 million; January 1, 2012 – $4 million) could have been withdrawn.

C) Earnings Impact of Realized and Unrealized (Gains) Losses from Risk Management Positions

For the years ended December 31,	2013	2012	2011
Realized (Gain) Loss [1]	**(122)**	(336)	(68)
Unrealized (Gain) Loss [2]	**415**	(57)	(180)
(Gain) Loss on Risk Management	**293**	(393)	(248)

(1) Realized gains and losses on risk management are recorded in the operating segment to which the derivative instrument relates.
(2) Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.

33. RISK MANAGEMENT

The Company is exposed to financial risks, including market risk related to commodity prices, foreign exchange rates, interest rates as well as credit risk and liquidity risk.

A) Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is not to use derivative instruments for speculative purposes.

Crude Oil – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its crude oil sales and condensate supply used for blending. Cenovus has entered into a limited number of swaps and futures to help protect against widening light/heavy crude oil price differentials.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the NYMEX price. To help protect against widening natural gas price differentials in various production areas, Cenovus has entered into a limited number of swaps to manage the price differentials between these production areas and various sales points.

Power – The Company has in place a Canadian dollar denominated derivative contract, which commenced January 1, 2007 for a period of 11 years, to manage a portion of its electricity consumption costs.

Net Fair Value of Commodity Price Positions at December 31, 2013

As at December 31, 2013	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	30,000 bbls/d	2014	US$102.04/bbl	**(73)**
Brent Fixed Price	20,000 bbls/d	2014	$107.06/bbl	**(64)**
WCS Differential [1]	15,900 bbls/d	2014	US$(20.39)/bbl	**10**
Other Financial Positions [2]				**1**
Crude Oil Fair Value Position				**(126)**
Power Purchase Contracts				
Power Fair Value Position				**(3)**

(1) Cenovus entered into fixed price swaps to protect against widening light/heavy price differentials for heavy crudes.
(2) Other financial positions are part of ongoing operations to market the Company's production.

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices, with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices on the Company's open risk management positions as at December 31 could have resulted in unrealized gains (losses) impacting earnings before income tax for the year ended December 31 as follows:

Risk Management Positions in Place as at December 31, 2013

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	**(200)**	**200**
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges tied to Production	**31**	**(31)**
Natural Gas Commodity Price	± $1 per mcf Applied to NYMEX Natural Gas Hedges	**-**	**-**
Natural Gas Basis Price	± $0.10 per mcf Applied to Natural Gas Basis Hedges	**-**	**-**
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	**19**	**(19)**

Risk Management Positions in Place as at December 31, 2012

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	(156)	156
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges tied to Production	111	(111)
Natural Gas Commodity Price	± $1 per mcf Applied to NYMEX and AECO Hedges	(55)	55
Natural Gas Basis Price	± $0.10 per mcf Applied to Natural Gas Basis Hedges	1	(1)
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	19	(19)

B) Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollars can have a significant effect on reported results.

As disclosed in Note 8, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada and the translation of the U.S. dollar Partnership Contribution Receivable issued from Canada. At December 31, 2013, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (2012 – US$4,750 million; 2011 – US$3,500 million) and US$nil related to the U.S. dollar Partnership Contribution Receivable (2012 – US$1,791 million; 2011 – US$2,157 million). In respect of these financial instruments, the impact of a $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a change to foreign exchange (gain) loss as follows:

For the years ended December 31,	**2013**	2012	2011
$0.01 Increase in Foreign Exchange Rate	**48**	30	13
$0.01 Decrease in Foreign Exchange Rate	**(48)**	(30)	(13)

C) Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt.

At December 31, 2013, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (2012 – $nil; 2011 – $nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

D) Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of credit policies approved by the Audit Committee of the Board of Directors governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Agreements are entered into with major financial institutions with investment grade credit ratings and with large commercial counterparties, most of which have investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. At December 31, 2013 and 2012, substantially all of the Company's accounts receivable were current. As at December 31, 2013, 94 percent (2012 – 87 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties. Cenovus's exposure to its counterparties is within credit policy tolerances.

At December 31, 2013, Cenovus had four counterparties (2012 – two counterparties) whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, Partnership Contribution Receivable, partner loans receivable, and long-term receivables is the total carrying value.

E) Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit. As disclosed in Note 31, over the long term, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position. It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under its shelf prospectuses. At December 31, 2013, Cenovus had $3.0 billion available on its committed credit facility. In addition, Cenovus had in place a Canadian debt shelf prospectus for $1.5 billion and unused capacity of US$1.2 billion under a U.S. debt shelf prospectus, the availability of which are dependent on market conditions.

Undiscounted cash outflows relating to financial liabilities are:

2013	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	2,937	-	-	-	**2,937**
Risk Management Liabilities [1]	136	3	-	-	**139**
Long-Term Debt [2]	271	537	537	8,732	**10,077**
Partnership Contribution Payable [2]	520	1,040	130	-	**1,690**
Other [2]	-	6	2	4	**12**

2012	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	2,650	-	-	-	2,650
Risk Management Liabilities [1]	17	1	-	-	18
Long-Term Debt [2]	254	1,263	432	7,051	9,000
Partnership Contribution Payable [2]	486	972	609	-	2,067
Other [2]	-	9	4	4	17

(1) Risk management liabilities subject to master netting agreements.
(2) Principal and interest, including current portion.

34. SUPPLEMENTARY CASH FLOW INFORMATION

For the years ended December 31,	**2013**	2012	2011
Interest Paid	**409**	342	357
Interest Received	**119**	113	128
Income Taxes Paid	**133**	304	-

35. COMMITMENTS AND CONTINGENCIES

A) Commitments

As part of normal operations, the Company has committed to certain amounts over the next five years and thereafter as follows:

2013	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Pipeline Transportation [1]	377	554	647	807	1,284	17,512	**21,181**
Operating Leases (Building Leases)	119	119	117	118	159	2,950	**3,582**
Product Purchases	98	20	7	-	-	-	**125**
Capital Commitments	52	36	30	9	21	27	**175**
Other Long-Term Commitments	50	40	21	17	12	116	**256**
Total Payments [2]	696	769	822	951	1,476	20,605	**25,319**
Fixed Price Product Sales	52	54	56	3	-	-	**165**

2012	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Pipeline Transportation [1]	145	209	378	403	675	8,130	9,940
Operating Leases (Building Leases)	109	106	112	110	104	1,602	2,143
Product Purchases	81	18	18	6	-	-	123
Capital Commitments	320	54	61	53	6	2	496
Other Long-Term Commitments	33	25	18	7	6	10	99
Total Payments [2]	688	412	587	579	791	9,744	12,801
Fixed Price Product Sales	50	52	54	55	3	-	214

(1) Certain transportation commitments included are subject to regulatory approval.
(2) Contracts undertaken on behalf of the FCCL and WRB are reflected at Cenovus's 50 percent interest.

At December 31, 2013, there were outstanding letters of credit aggregating $78 million issued as security for performance under certain contracts (2012 – $36 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 33.

B) Contingencies

Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims. There are no individually or collectively significant claims.

Decommissioning Liabilities

Cenovus is responsible for the retirement of long-lived assets at the end of their useful lives. Cenovus has recognized a liability of $2,370 million, based on current legislation and estimated costs, related to its crude oil and natural gas properties, refining facilities and midstream facilities. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Income Tax Matters

The tax regulations and legislation and interpretations thereof in the various jurisdictions in which Cenovus operates are continually changing. As a result, there are usually a number of tax matters under review. Management believes that the provision for taxes is adequate.

Cenovus Energy Inc.

Supplementary Information – Oil and Gas Activities (unaudited)

For the Year Ended December 31, 2013

(Canadian Dollars)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES TOPIC 932 "EXTRACTIVE ACTIVITIES – OIL AND GAS" (unaudited)

The following select disclosures of Cenovus Energy Inc.'s ("Cenovus" or the "Company") reserves and other oil and gas information have been prepared in accordance with United States ("U.S.") Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil & Gas" and the U.S. disclosure requirements of the Securities and Exchange Commission ("SEC").

All amounts pertaining to Cenovus's audited Consolidated Financial Statements are prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). Unless otherwise noted, all amounts are in millions of Canadian dollars.

RESERVES DATA

The SEC Modernization of Oil and Gas Reporting final rules require that proved reserves be estimated using existing economic conditions (constant pricing). Cenovus's results have been calculated using the average of the first-day-of-the-month prices for the prior 12 month period. This same 12 month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause Cenovus's share of future production from Canadian reserves to be materially different from that presented.

The reserves estimates included in this supplemental information 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; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities, 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, royalty payments, taxes and development and operating expenditures with respect to our reserves may vary from current estimates and such variances may 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.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume royalty rates in existence at the time the estimates were made.

Subsequent to December 31, 2013 no major discovery or other favourable or unfavourable event is believed to have caused a material change in the proved or proved developed reserves as of that date.

OIL AND GAS RESERVE INFORMATION

All of Cenovus's reserves are located in Canada, primarily within the provinces of Alberta and Saskatchewan.

Net Proved Reserves (Cenovus Share After Royalties)(1)(2)(3)
Average Fiscal-Year Prices

	Bitumen (millions of barrels)	Crude Oil and Natural Gas Liquids (millions of barrels)	Natural Gas (billions of cubic feet)
2012			
Beginning of year	1,109	240	1,119
Revisions and improved recovery	44	13	(144)
Extensions and discoveries	211	27	29
Purchase of reserves in place	-	-	1
Sale of reserves in place	-	-	(40)
Production	(30)	(25)	(209)
End of year	1,334	255	756
Developed	144	185	756
Undeveloped	1,190	70	-
Total	1,334	255	756
2013			
Beginning of year	1,334	255	756
Revisions and improved recovery	53	(2)	214
Extensions and discoveries	103	29	21
Purchase of reserves in place	-	-	-
Sale of reserves in place	-	(5)	-
Production	(35)	(26)	(196)
End of year	1,455	251	795
Developed	169	199	791
Undeveloped	1,286	52	4
Total	1,455	251	795

Notes:

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

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

(3) Natural gas liquids reserves are individually insignificant and have been included with crude oil reserves.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

In calculating the standardized measure of discounted future net cash flows, the average of the first-day-of-the-month prices for the prior 12 month period and cost assumptions were applied to Cenovus's annual future production from proved reserves to determine cash inflows. Future production and development costs do not include any cost inflation and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by independent qualified reserves evaluators in relation to the reserves they respectively evaluated, and adjusted to the extent provided by contractual arrangements such as price risk management activities, in existence at year end and to account for asset retirement obligations and future income taxes.

Cenovus cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of the Cenovus's oil and gas properties, nor the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to Cenovus's enhancing the netback price of the Company's proprietary production.

Computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves were based on the following average of the first-day-of-the-month benchmark prices for the 12 month period before the end of the year:

	Crude Oil			**Natural Gas**	
	WTI[1] Cushing Oklahoma (US$/bbl)	WCS[2] (C$/bbl)	Edmonton Par (C$/bbl)	Henry Hub Louisiana (US$/MMBtu)	AECO[3] (C$/MMBtu)
2013	96.70	74.04	92.16	3.67	3.14
2012	94.71	73.26	87.11	2.76	2.35

Notes:
(1) WTI is an abbreviation for West Texas Intermediate.
(2) WCS is an abbreviation for Western Canadian Select.
(3) AECO is an abbreviation for Alberta Energy Company Operations.

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

($ millions)	2013	2012
Future cash inflows	96,160	92,383
Less future:		
Production costs	34,161	29,356
Development costs	14,242	12,705
Asset retirement obligation payments	900	842
Income taxes	10,654	11,410
Future net cash flows	36,203	38,070
Less 10 percent annual discount for estimated timing of cash flows	22,211	23,381
Discounted future net cash flows	13,992	14,689

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

($ millions)	2013	2012
Balance, beginning of year	14,689	15,454
Changes resulting from:		
Sales of oil and gas produced during the period	(3,325)	(3,169)
Discoveries and extensions, net of related costs	1,341	2,668
Purchases of proved reserves in place	-	7
Sales of proved reserves in place	(46)	(85)
Net change in prices and production costs	(2,592)	(1,911)
Revisions to quantity estimates	852	431
Accretion of discount	1,911	2,002
Previously estimated development costs incurred net of change in future development costs	643	(1,055)
Other	198	207
Net change in income taxes	321	140
Balance, end of year	13,992	14,689

Results of Operations

($millions)	2013	2012
Oil and gas sales to external customers, net of royalties, transportation and blending and realized risk management	4,018	4,020
Intersegment sales	605	283
	4,623	4,303
Less:		
Operating costs, production and mineral taxes, and accretion of decommissioning liabilities(1)	1,393	1,209
Depreciation, depletion and amortization	1,616	1,387
Goodwill impairment	-	393
Exploration expense	114	68
Operating income	1,500	1,246
Income taxes	394	413
Results of operations	1,106	833

(1) Certain research activities previously included in operating costs have been reclassified for the year ended December 31, 2012 to conform to the presentation adopted in 2013.

Capitalized Costs

($millions)	2013	2012
Proved oil and gas properties	29,676	27,241
Unproved oil and gas properties (1)	1,473	1,285
Total capital cost	31,149	28,526
Accumulated depreciation, depletion and amortization	15,984	14,548
Net capitalized costs	15,165	13,978

(1) Unproved oil and gas properties include exploration and evaluation assets for which no proved reserves have been recognized.

Costs Incurred

($millions)	2013	2012
Acquisitions		
- Unproved	32	90
- Proved	-	24
Total acquisitions	32	114
Exploration costs	264	424
Development costs	2,763	2,589
Total costs incurred	3,059	3,127

ADDITIONAL DISCLOSURE

Certifications and Disclosure Regarding Controls and Procedures.

(a) Certifications. See Exhibits 99.1, 99.2, 99.3 and 99.4 to this annual report on Form 40-F.

(b) Disclosure Controls and Procedures. As of the end of the registrant's fiscal year ended December 31, 2013, an evaluation of the effectiveness of the registrant's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was carried out by the registrant's management with the participation of the principal executive officer and principal financial officer. Based upon that evaluation, the registrant's principal executive officer and principal financial officer have concluded that as of the end of that fiscal year, the registrant's disclosure controls and procedures are effective to ensure that information required to be disclosed by the registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's (the "Commission") rules and forms and (ii) accumulated and communicated to the registrant's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

It should be noted that while the registrant's principal executive officer and principal financial officer believe that the registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the registrant's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

(c) Management's Annual Report on Internal Control Over Financial Reporting. The required disclosure is included in the "Report of Management" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2013, filed as part of this annual report on Form 40-F.

(d) Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the "Auditors' Report" that accompanies the registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2013, filed as part of this annual report on Form 40-F.

(e) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2013, there was no change in the registrant's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

Notices Pursuant to Regulation BTR.

None.

Audit Committee Financial Expert.

The registrant's board of directors has determined that Colin Taylor, a member of the registrant's audit committee, qualifies as an "audit committee financial expert" (as such term is defined in paragraph (8) of General Instruction B to Form 40-F), and is "independent" as that term is defined in the rules of the New York Stock Exchange.

Code of Ethics.

The registrant has adopted a "code of ethics" (as that term is defined in paragraph (9) of general Instruction B to Form 40-F), entitled the "Code of Business Conduct & Ethics", that applies to all of its employees, including its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions.

The Code of Business Conduct & Ethics (the "Code") is available for viewing on the registrant's website at www.cenovus.com, and is available in print to any person without charge, upon request. Requests for copies of the Code should be made by contacting: Kerry D. Dyte, Executive Vice-President, General Counsel & Corporate Secretary, Cenovus Energy Inc., 2600, 500 Centre Street S.E., Calgary, Alberta, Canada T2G 1A6. Alternatively, requests for a copy of the Code may be made by contacting the registrant's Corporate Secretarial Department at (403) 766-2000 (Fax: (403) 766-7600). Information on or connected to our website, even if referred to herein, does not constitute part of this annual report on Form 40-F.

Since the adoption of the Code, there have not been any waivers, including implicit waivers, granted from any provision of the Code. During 2013, the board of directors approved amendments to the Code for clarity and to add new content. Clarity enhancements (including, where applicable, addition of language taken from related existing practices) were made with respect to fraud matters and other similar irregularities, confidentiality and disclosure, human rights and harassment and whistleblower protection. New content was added for acquisition and supply of goods and services.

Principal Accountant Fees and Services.

The required disclosure is included under the heading "Audit Committee – External Auditor Service Fees" in the registrant's Annual Information Form for the fiscal year ended December 31, 2013, filed as part of this annual report on Form 40-F.

Pre-Approval Policies and Procedures.

The required disclosure is included under the heading "Audit Committee Information – Pre-Approval Policies and Procedures" in the registrant's Annual Information Form for the fiscal year ended December 31, 2013, filed as part of this annual report on Form 40-F.

Off-Balance Sheet Arrangements.

The registrant does not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Tabular Disclosure of Contractual Obligations.

The required disclosure is included under the heading "Liquidity and Capital Resources - Contractual Obligations and Commitments" in the registrant's Management's Discussion and Analysis for the fiscal year ended December 31, 2013, filed as part of this annual report on Form 40-F.

Identification of the Audit Committee.

The registrant has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Patrick D. Daniel, Valerie A. A. Nielsen and Colin Taylor.

Mine Safety Disclosure.

Not applicable.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

The registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process

(1) The registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

(2) Any change to the name or address of the agent for service of process of the registrant shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

Date: February 19, 2014

CENOVUS ENERGY INC.

By: /s/ Ivor M. Ruste

Name: Ivor M. Ruste

Title: Executive Vice-President & Chief Financial Officer

EXHIBIT INDEX

Exhibits	Documents
99.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934
99.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934
99.3	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
99.4	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
99.5	Consent of PricewaterhouseCoopers LLP
99.6	Consent of McDaniel & Associates Consultants Ltd.
99.7	Consent of GLJ Petroleum Consultants Ltd.
99.8	Amended Code of Business Conduct & Ethics.

Exhibit 99.1

Certification of Chief Executive Officer
Pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934

I, Brian C. Ferguson, certify that:

1. I have reviewed this annual report on Form 40-F of Cenovus Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer’s internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer’s internal control over financial reporting; and

5. The issuer’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer’s auditors and the audit committee of the issuer’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer’s internal control over financial reporting.

Date: February 19, 2014

/s/ Brian C. Ferguson
Brian C. Ferguson
President & Chief Executive Officer
(Principal Executive Officer)

Exhibit 99.2

Certification of Chief Financial Officer
Pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934

I, Ivor M. Ruste, certify that:

1. I have reviewed this annual report on Form 40-F of Cenovus Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 19, 2014

/s/ Ivor M. Ruste
Ivor M. Ruste
Executive Vice-President & Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.3

Certification Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes Oxley Act of 2002

In connection with the annual report of Cenovus Energy Inc. (the "Company") on Form 40−F for the year ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Brian C. Ferguson, President & Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 19, 2014

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

Exhibit 99.4

Certification Pursuant to 18 U.S.C. Section 1350, As Adopted
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Cenovus Energy Inc. (the “Company”) on Form 40−F for the year ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Ivor M. Ruste, Executive Vice-President & Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 19, 2014

By: /s/ Ivor M. Ruste
Ivor M. Ruste
Executive Vice-President & Chief Financial Officer

Exhibit 99.5

CONSENT OF PRICEWATERHOUSECOOPERS LLP

We hereby consent to the inclusion in this Annual Report on Form 40-F for the year ended December 31, 2013 of Cenovus Energy Inc. of our report dated February 12, 2014, relating to the Consolidated Financial Statements of Cenovus Energy Inc., which comprise the Consolidated Balance Sheets as at December 31, 2013, December 31, 2012 and January 1, 2012 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for each of the three years in the period ended December 31, 2013 and the related notes and to the effectiveness of internal control over financial reporting of Cenovus Energy Inc. as at December 31, 2013, which appears in this Annual Report.

We also consent to the incorporation by reference in the Registration Statements on Form S-8 (File No. 333-163397), Form F-3D (File No. 333-166419), and Form F-10 (File No. 333-188478) of Cenovus Energy Inc. of our report dated February 12, 2014 referred to above. We also consent to reference to PricewaterhouseCoopers LLP under the heading "Interests of Experts," which appears in the Annual Information Form included in this Annual Report on Form 40-F, which is incorporated by reference in such Registration Statements.

/s/ PricewaterhouseCoopers LLP
Calgary, Alberta
February 19, 2014

Exhibit 99.6

CONSENT OF INDEPENDENT PETROLEUM ENGINEER

We hereby consent to the use and reference to our name and reports evaluating (i) a portion of Cenovus Energy Inc. oil and gas reserves data, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs, and (ii) the contingent resources and prospective resources of Cenovus Energy Inc. as at December 31, 2013, estimated using forecast prices and costs, and the information derived from our reports, as described or incorporated by reference in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2013 and Cenovus Energy Inc.'s registration statements on Form S-8 (File No. 333-163397), Form F-3D (File No. 333-166419), and Form F-10 (File No. 333-188478), filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ P.A. Welch

P.A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
February 19, 2014

Exhibit 99.7

CONSENT OF INDEPENDENT PETROLEUM ENGINEER

We hereby consent to the use and reference to our name and report evaluating a portion of Cenovus Energy Inc. oil and gas reserves data, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs, and the information derived from our reports, as described or incorporated by reference in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2013 and Cenovus Energy Inc.'s registration statements on Form S-8 (File No. 333-163397), Form F-3D (File No. 333-166419), and Form F-10 (File No. 333-188478), filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Keith M. Braaten

Keith M. Braaten, P. Eng.
President & CEO

Calgary, Alberta
February 19, 2014

Code of Business Conduct & Ethics

This Code of Business Conduct & Ethics reflects Cenovus's commitment to conducting our business ethically and legally while we pursue progressive and innovative approaches to developing energy resources. At Cenovus, we can be trusted to do what we say. We are a company that conducts its business with respect. This Code will be used to identify and manage ethical situations and to provide guidance in making ethical business decisions so that our staff can fulfill these commitments.

Compliance with Laws and Regulations

As employees, contractors and directors, we comply with the laws, rules and regulations of Canada, the United States and any other countries in which Cenovus operates. We comply with the requirements of applicable securities regulatory authorities and stock exchanges.

Corporate Opportunities

Our employees, contractors and directors are prohibited from taking opportunities, using Cenovus property or information or their position with Cenovus for personal gain or competing with Cenovus, based on information discovered through the use of corporate property, information or position.

Conflicts of Interest

Our employees, contractors and directors avoid situations where personal interests could conflict, or appear to conflict, with duties and responsibilities or the interests of Cenovus. A conflict of interest may occur where involvement in any activity, with or without the involvement of a related party, prevents the proper performance of employee, contractor and director duties for Cenovus, or creates, or appears to create, a situation where judgment or ability to act in the best interests of Cenovus is affected. The Conflict of Interest Practice provides further guidance and examples regarding conflict of interest situations.

When faced with an actual or potential conflict of interest, our employees follow the procedures outlined in the Conflict of Interest Practice and contractors review and follow the provisions of their written contracts. Our officers and directors follow obligations that are set out in relevant statutes and company by-laws and inform the Chair of the Board of Directors of any such conflict. Our commitment is to ensure that employees and contractors are not involved in any decision or operation related to a conflict and that officers or directors are not involved in any decision or operation related to a conflict. This is the commitment of our employees, our Executive Team and our Board of Directors.

Fraud and other Similar Irregularities

At Cenovus, we are committed to protecting the revenue, property, information and other assets of the company and our shareholders from any attempt, either by the public, contractors, agents or our own employees, to gain financial or other benefit by deceit, in the course of our business.

Our employees, contractors and directors must not, under any circumstances, misappropriate funds, property or other assets, or knowingly assist another individual to do so. Similarly, our employees, contractors and directors are not to use, borrow, loan, take, transfer or convert any assets that do not belong to them, or use them for the benefit of themselves or anyone other than the rightful owners, and are not to knowingly assist another individual to do so.

Our employees, contractors and directors will only claim those expenses that are eligible for reimbursement under Cenovus's expense guidelines and will not use the corporate credit card for personal expenses other than in accordance with Cenovus's credit card guidelines.

We have zero-tolerance for fraudulent activities and fully investigate any suspected acts of fraud, misappropriation or other similar irregularity. Cenovus will pursue every reasonable effort, including court-ordered restitution, to obtain recovery of Cenovus's losses from the offender or other appropriate sources.

Any employee or contractor who has knowledge of an occurrence of fraud, or has reason to suspect that a fraud has occurred, must immediately notify their supervisor or company contact or may report their suspicions in accordance with the Investigations Practice or to the Integrity Helpline.

Confidentiality and Disclosure

Confidential information includes all non-public information that might be of use to competitors, or harmful to Cenovus or its customers, if disclosed. Confidential or proprietary information and Cenovus's intellectual property must not be disclosed without proper safeguards, or specific authorization given, to do so or such disclosure is legally mandated. Knowledge of confidential information about another company gained in the course of work duties at Cenovus must be protected in the same manner as confidential information about Cenovus.

Our employees, contractors and directors must not violate or infringe the intellectual property rights or breach any obligations relating to the confidential information of Cenovus or of others. The Intellectual Property Practice provides further guidance regarding the use and protection of intellectual property at Cenovus.

Employees, contractors and directors must not speak on behalf of Cenovus unless authorized to do so and should refer to the Policy on Disclosure, Confidentiality and Employee Trading.

Taking advantage of, or benefiting from, information obtained at work that is not available to the public is not permitted. Friends, relatives and associates must not benefit from such information. Where insider information is known and not yet publicly disclosed, employees, contractors and directors must avoid acquiring or disposing of any business interest, including publicly traded securities, whether directly or through another person.

If an employee or contractor is not sure whether information has been publicly disclosed, they should consult with a member of Cenovus's Legal group for guidance before engaging in any transaction in any securities of Cenovus. Officers and directors should consult on such matters with the persons listed in the Restricted Trading and Insider Guidelines for guidance before engaging in any transaction in any Cenovus securities. All securities transactions are subject to the Policy on Disclosure, Confidentiality and Employee Trading and if applicable, the Restricted Trading and Insider Guidelines.

These confidentiality obligations remain in effect even beyond termination of employment, service agreements or Board of Directors appointments with Cenovus or its affiliates.

Acceptable Use of Cenovus's Systems and Assets

Cenovus's corporate information, data, information system assets, office equipment, tools, vehicles, supplies, facilities and services are provided for authorized business purposes. Our employees, contractors, and directors have an obligation to use these assets in accordance with fundamental principles of reasonable and acceptable use and are not permitted to engage in unacceptable use of those assets.

Acceptable use is demonstrated when each individual:

- consistently ensures the confidentiality, integrity and availability of Cenovus's information
- takes acceptable measures to protect Cenovus's rights and property ownership of information system assets

Personal use is considered reasonable if it:

- involves appropriate content
- does not put Cenovus at risk of violating the copyrights on any materials
- is in alignment with regional laws, legislation, and Cenovus values
- occurs for short periods of time and does not interfere with day-to-day responsibilities of Cenovus staff

Unacceptable use (whether personal or business) includes when an individual acts so as to:

- defame, slander, harass, annoy or cause needless anxiety to another person or another organization
- conduct any illegal or unethical activity
- conduct any activity that could adversely affect Cenovus or Cenovus's reputation
- intentionally transmit viruses or transmit virus warnings to any recipient other than the Service Desk
- make excessive or inappropriate use of non-business-related Internet sites, chat rooms, blogs, discussion rooms, or social networking sites (e.g. Facebook, MySpace, Twitter) for personal reasons
- replace personal assets (e.g. home telephone land line or personal PC)
- exchange any of the following types of content:
    - personal commercial, advertising or political material
    - pictures, jokes or content that conflict with this Code of Business Conduct & Ethics

- chain letters
- obscene or sexually explicit messages, pictures, cartoons or jokes
- ethnic, religious, gender-related, disability-related or racial slurs
- confidential, sensitive or proprietary information to unauthorized recipients
- material that could damage Cenovus's image or reputation

Cenovus’s information system assets and other assets must not be used for personal commercial ventures.

Cenovus staff should also consult the Records and Information Management Policy and the Information Management website for further guidance related to Acceptable Use.

Inducements and Gifts

At Cenovus, we do not accept or give gifts, favours, personal advantages, services payments, loans, or benefits of any kind, other than those of nominal value that can be made as a generally accepted business practice. The Acceptance of Gifts Guideline provides further guidance regarding gift-giving and receiving and should be referred to and or written approval from Cenovus leaders should be requested. Gift-giving practices may vary among different cultures, and therefore local gift practices and guidelines will be considered when addressing these issues.

We do not tolerate soliciting, accepting, or paying bribes or other illicit payments for any purpose. Situations must be avoided where judgment might be influenced by, or appears to be influenced by such unlawful or unethical behavior. Payment or acceptance of any "kickbacks" from a contractor or other external party is strictly prohibited.

Examples of laws to which Cenovus is subject and abides by include the Corruption of Foreign Public Officials Act (Canada), the Foreign Corrupt Practices Act (U.S.A.), the U.K. Bribery Act and equivalent legislation in other countries. Non-compliance could have serious ramifications.

While Cenovus does not normally support the use of facilitating payments, in some jurisdictions where it is determined to be absolutely necessary for the conduct of Cenovus’s business, the foregoing Acts allow such payments to be made if not prohibited by local law and only upon approval by the appropriate Executive Vice-President and upon consultation with and approval of internal legal counsel.

Political Activities

Cenovus does not participate in improper intervention in political processes and does not make financial contributions or contributions in kind (e.g. properties, materials or services) to political parties, committees or their representatives, unless permitted by law, and approved in advance by Cenovus’s Vice-President, Government Affairs and Corporate Responsibility, as delegated by the President & Chief Executive Officer and Executive Vice-President, Environment & Corporate Affairs. All contributions will be reported annually to the Board of Directors. In such situations, we fully comply with legal requirements for public disclosure.

At Cenovus, our employees, contractors and directors may choose to become involved in political activities as long as they undertake these activities on their own behalf and may, on a personal level, give to any political party or candidate. Reimbursement by the company is prohibited.

Lobbying Activities

We comply with the *Lobbying Act (Canada)* and the *Lobbyist Act (Alberta)* which impose reporting requirements on lobbying communications with certain officers and employees of the Government of Canada or the Government of Alberta (known as "Public Office Holders" or "POHs"). Employees do not have communications with a POH unless they have been registered by Cenovus under the *Lobbying Act* (Canada) or the *Lobbyist Act (Alberta)*, except where otherwise permitted by the applicable legislation.

Fair Dealing

Our employees, contractors and directors endeavour to deal fairly with Cenovus's customers, contractors, industry partners, employees and any other stakeholders, and to not take unfair advantage of anyone through manipulation, concealment, abuse of privileged information, misrepresentation of material facts, or any other unfair-dealing practice.

Acquisition and Supply of Goods & Services

It is the responsibility of all Cenovus employees and contractors involved in the acquisition of goods and services to act in a financially responsible and ethical manner.

Employees are required to:

- acquire goods and services through company defined practices and guidelines
- ensure the necessary parties are involved in the process, and that required approvals are obtained for agreements, contracts and purchasing activities
- support the principle of company-wide buying power to achieve security of supply, reduction in total cost of ownership, and the best supply arrangements to meet the needs of Cenovus
- engage with the supplier community in a manner that is fair and aligned with the Cenovus Values and Work Principles (e.g., safety focused, local and aboriginal, environmentally focused, and innovation focused suppliers)
- ensure that engagement of suppliers and contractors is conducted in a manner that avoids conflicts of interest or perceived conflicts of interest (as described earlier in the Code)

All employees are required to ensure suppliers and contractors are managed in accordance with the above, as well as all associated Practices. The associated practices once approved will provide further guidance regarding the acquisition and supply of goods and services at Cenovus.

Company Records

Records must be kept and maintained to fulfill relevant legal requirements. Recording and reporting information, including information related to operations, environment, health, safety, training, human resources and financial matters, must be done honestly, accurately and with care.

Accuracy of Books and Records

At Cenovus we understand that the books and records of Cenovus must reflect in reasonable detail its transactions in a timely, fair and accurate manner to, among other things, permit the preparation of accurate financial statements in accordance with generally accepted accounting principles and maintain recorded accountability for assets and liabilities. The accuracy of asset and liability records must be maintained by comparing the records to the existing assets and liabilities at reasonable intervals, and taking appropriate action with respect to any differences.

All business transactions that employees, contractors and directors have participated in must be properly authorized, properly recorded and supported by accurate documentation in reasonable detail.

Accounting, Auditing or Disclosure Concerns

Cenovus is required to provide full, fair, accurate, timely and understandable disclosure in reports and documents that are filed with, or submitted to, the U.S. Securities and Exchange Commission, the Alberta Securities Commission and other Canadian securities regulatory authorities, the Toronto Stock Exchange and the New York Stock Exchange, as well as in other public communications made by Cenovus. All employees and contractors responsible for the preparation of Cenovus's public disclosures, or who provide information as part of the process, ensure that disclosures are prepared and information is provided honestly, accurately and in compliance with the various Cenovus disclosure controls and procedures.

All employees, contractors and directors have a duty to submit any good faith questions and concerns regarding questionable accounting, auditing or disclosure matters or controls. Submissions about these or similar matters should be reported in accordance with the Investigations Practice.

To the extent that potential violations involve Cenovus's accounting, internal accounting controls or auditing matters (including questionable accounting or auditing matters), investigations under this Code will be overseen by, and be the ultimate responsibility of, the Audit Committee of the Board of Directors.

No information may be concealed from Cenovus's external auditors, internal auditors, the Board of Directors, or the Audit Committee of the Board of Directors. It is illegal to fraudulently influence, coerce, manipulate or mislead an external auditor who is auditing Cenovus's financial statements.

Human Rights and Harassment

We do not tolerate unlawful workplace conduct, including discrimination, intimidation or harassment. We are committed to maintaining a positive workplace where all staff adheres to relevant human rights legislation and acts ethically, honestly and treats all others we come in contact with during our work with dignity, fairness and respect. Any form of unlawful harassment or discrimination based on age, gender, race, color, religion, creed, national or ethnic origin, citizenship, linguistic or cultural background, marital or family status, sexual orientation or physical or mental disability will not be tolerated.

Observance of the Code of Business Conduct & Ethics

All employees and directors are personally accountable for learning, endorsing and promoting this Code and applying it to their own conduct and field of work. All employees and directors are asked to review this Code, to confirm on a regular basis, through written or electronic declaration, that they understand their individual responsibilities and to acknowledge they conform to the requirements of the Code.

Contractors are expected to develop and enforce with their staff, policies and/or practices that are consistent with this Code and its associated requirements and to acknowledge their compliance in writing.

Employees or contractors with questions about this Code or specific situations are encouraged to refer the matter to their supervisor or leader or the persons listed in any referenced policy or practice, as applicable. Applicable resource groups such as internal legal counsel or Human Resources may also be contacted. Officers and directors with questions about this Code or specific situations are encouraged to refer the matter to the Chief Executive Officer or the Chair of the Board of Directors or the persons listed in any referenced policy or practice, as applicable.

Reporting Violations of the Code of Business Conduct & Ethics

Actions that violate or appear to violate this Code will be reported in accordance with Cenovus's Investigations Practice. The Investigations Practice outlines how a report will be treated once it is made, protection for complainants and the consequences of violating this Code. Violations may be reported to Cenovus staff, the Investigations Committee, or through the Integrity Helpline.

Violation of this Code and its associated guidelines may result in disciplinary action up to and including termination of employment or contract for services.

Whistleblower Protection

Retaliation against individuals (whether employees, contractors or other third parties) who report violations of this Code will not be tolerated. Every supervisor has the responsibility to create an environment in which staff can raise business conduct concerns or violations under this Code without fear of retaliation.

No adverse action will be taken against individuals making a good faith report of a business conduct concern or violation under this Code, whether or not the report ultimately proves to be well founded. Good faith does not mean that the individual reporting the concern or violation has to be right; but it does mean that the individual believes he/she is providing truthful and accurate information.

On the other hand, we will not tolerate reports that are not made in good faith, such as reports intentionally providing false information or made maliciously to harm the company or another employee or contractor. Disciplinary action, up to and including termination of employment or services, may be taken against an employee or contractor knowingly making false reports.

Individuals are strongly encouraged to report business conduct concerns or violations of this Code to their supervisor or Human Resources advisor (if an employee or contractor), or to a member of the Investigations Committee or to the Integrity Helpline. Any individual who believes retaliation has occurred should contact the Integrity Helpline immediately.

Waivers and Amendments

Waivers of this Code for employees or contractors may be granted only by a Vice-President in limited, exceptional circumstances. Any waiver of this Code for officers or directors may only be made by the Board of Directors and will be promptly disclosed to shareholders to the extent required by law, rule, regulation or stock exchange requirement.

Amendments to this Code will be publicly disclosed to the extent required by law, rule, regulation or stock exchange requirement.