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, 2019 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))

4100, 225 - 6 Avenue S.W.
Calgary, Alberta, Canada T2P 1N2
(403) 766-2000
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
28 Liberty Street
New York, New York 10005
(212) 894-8940
(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	Trading Symbol(s)	Name of each exchange on which registered
Common shares, no par value (together with associated common share purchase rights)	**CVE**	**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:

1,228,828,226

Indicate by check mark whether the Registrant (1) has filed all reports required 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 such filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the Registrant has submitted electronically every Interactive Data File required to be submitted 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 such files).

Yes ☑ No ☐

Indicate by check mark whether the Registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange
Act. ☐

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

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. 333-202165) and Form F-10 (File No. 333-233702).

Principal Documents

The following documents, filed as Exhibits 99.1, 99.2, 99.3 and 99.4 to this annual report on Form 40-F, are hereby incorporated by reference in this annual report on Form 40-F:

(a) Annual Information Form of Cenovus Energy Inc. for the fiscal year ended December 31, 2019.

(b) Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2019.

(c) Consolidated Financial Statements of Cenovus Energy Inc. for the fiscal year ended December 31, 2019.

(d) Supplementary Information – Oil and Gas Activities (unaudited) for the fiscal year ended December 31, 2019.

ADDITIONAL DISCLOSURE

Certifications and Disclosure Regarding Controls and Procedures.

(a) Certifications. See Exhibits 99.5 99.6, 99.7 and 99.8 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, 2019, 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, 2019, filed as Exhibit 99.3 to this annual report on Form 40-F.

(d) Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the "Report of Independent Registered Public Accounting Firm" that accompanies the Registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2019, filed as Exhibit 99.3 to this annual report on Form 40-F.

(e) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2019, 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 the following members of the Registrant's audit committee each qualifies as an "audit committee financial expert" (as such term is defined in paragraph (8) of General Instruction B to Form 40-F), and each is "independent" as that term is defined in the rules of the New York Stock Exchange: Claude Mongeau, Susan F. Dabarno, Jane E. Kinney and Wayne G. Thomson.

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 the Registrant's Corporate Secretarial Department, Cenovus Energy Inc., 225 - 6 Avenue S.W., P.O. Box 766, Calgary, Alberta, Canada T2P 0M2. Any amendments to the Code from time to time will be posted to the Registrant's website within five business days of the amendment, and will remain available for a twelve-month period. 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 the 2019 fiscal year, the Registrant's board of directors approved amendments to the Code to address certain industry and societal risks and trends, added new content pertaining to ethical decision making, integrity and leadership, communi ty engagement, privacy and personal information, and communicating with the public and social media. Additional content was also added to address the following areas: protection from retaliation; safety; environmental commitment; diversity and inclusion; violence and a harassment free workplace; protecting sensitive information; third-party engagement; financial reporting and internal controls; bribery, corruption and sanctions; how to speak up and where to locate additional resources. A copy of the amended Code is filed as Exhibit 99.12 to this annual report on Form 40-F.

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, 2019, filed as Exhibit 99.1 to this annual report on Form 40-F.

Pre-Approval Policies and Procedures and Percentage of Services Approved by Audit Committee.

The required disclosure is included under the heading "Audit Committee - Pre-Approval Policies and Procedures" and "Audit Committee – External Auditor Service Fees" in the Registrant's Annual Information Form for the fiscal year ended December 31, 2019, filed as Exhibit 99.1 to this annual report on Form 40-F. All fees have been pre-approved by the Audit Committee and therefore none of the services therein were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

Off-Balance Sheet Arrangements.

The Registrant does not have any "off-balance sheet arrangements" (as that term is defined in paragraph (11) of General Instruction B to Form 40-F) 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, 2019, filed as Exhibit 99.2 to 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: Susan F. Dabarno, Jane E. Kinney, Harold N. Kvisle, Claude Mongeau (Chair), and Wayne G. Thomson.

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 12, 2020

CENOVUS ENERGY INC.

By: /s/ Jonathan M. McKenzie
Name: Jonathan M. McKenzie
Title: Executive Vice-President &
Chief Financial Officer

EXHIBIT INDEX

Exhibits	Documents
99.1	Annual Information Form of Cenovus Energy Inc. for the fiscal year ended December 31, 2019.
99.2	Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2019.
99.3	Consolidated Annual Financial Statements of Cenovus Energy Inc. for the fiscal year ended December 31, 2019.
99.4	Supplementary Information – Oil and Gas Activities (unaudited) for the fiscal year ended December 31, 2019.
99.5	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
99.6	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
99.7	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
99.8	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
99.9	Consent of PricewaterhouseCoopers LLP.
99.10	Consent of McDaniel & Associates Consultants Ltd.
99.11	Consent of GLJ Petroleum Consultants Ltd.
99.12	Amended Code of Business Conduct & Ethics
101	Interactive data file

Exhibit 99.1



Cenovus Energy Inc.

Annual Information Form

For the Year Ended December 31, 2019

February 11, 2020

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FORWARD-LOOKING INFORMATION

In this Annual Information Form ("AIF"), unless otherwise specified or the context otherwise requires, references to "we", "us", "our", "its", "the Corporation" or "Cenovus" mean Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries.

This AIF contains forward-looking statements and other information (collectively "forward-looking information") about Cenovus's current expectations, estimates and projections, made in light of the Corporation's experience and perception of historical trends. This forward-looking information is identified by words such as "anticipate", "believe", "expect", "estimate", "plan", "forecast", "future", "target", "project", "capacity", "could", "focus", "potential", "may", "schedule" or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: strategy and related milestones; schedules and plans; desire to realize the best margins and netbacks for our products; expected timing for oil sands expansion phases and associated expected production capacities; projections for 2020 and future years and our plans and strategies to realize such projections; future opportunities for oil and gas development; forecast operating and financial results, including forecast sales prices, costs and cash flows; priorities for and approach to capital investment decisions or capital allocation; planned capital expenditures, including the amount, timing and financing thereof; techniques expected to be used to recover reserves and forecasts of the timing thereof; future abandonment and reclamation costs and the timing of payments in relation thereto; expected payment of income taxes; potential impacts of various identified risk factors; expected future production, including the timing, stability or growth thereof; expected reserves and related information, including future net revenue and future development costs; expected capacities, including for projects, transportation and refining; improving cost structures, forecast cost savings and the sustainability thereof; anticipated timelines for future regulatory, partner or internal approvals; future impact of regulatory measures; forecast commodity prices and trends and expected impacts to Cenovus; potential impacts of various risks, including those related to commodity prices and climate change; and future use and development of technology, including expected effects on land footprint, steam to oil ratios and environmental performance and sustainability. Readers are cautioned not to place undue reliance on forward-looking information as the Corporation's 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, but are not limited to: forecast oil and natural gas, natural gas liquids, condensate and refined products prices, light-heavy crude oil price differentials and other assumptions identified in Cenovus's 2020 guidance, available at cenovus.com; bottom of the cycle commodity prices of about US$45/bbl WTI and C$44/bbl WCS; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to our share price and market capitalization over the long term; cash flows and cash balances on hand being sufficient to fund capital investments and dividends, including any increase thereto; future narrowing of crude oil differentials; the Government of Alberta's mandatory production curtailment will continue to maintain a relatively narrow differential between WTI and WCS crude oil prices thereby positively impacting cash flows for Cenovus; the ability of our refining capacity, dynamic storage, existing pipeline commitments, financial hedge transactions and plans to ramp up crude-by-rail loading capacity to partially mitigate a portion of our WCS crude oil volumes against wider differentials; ability to produce from our oil sands facilities on an unconstrained basis; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; accounting estimates and judgments; future use and development of technology and associated expected future results; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects, development programs or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; forecast inflation and other assumptions inherent in our current guidance set out below; our ability to access and implement all technology and equipment necessary to achieve expected future results, and that such results are realized.

2020 guidance, as updated December 9, 2019, assumes: Brent prices of US$60.00/bbl, WTI prices of US$55.00/bbl; WCS of US$37.50/bbl; AECO natural gas prices of $1.80/Mcf; Chicago 3-2-1 crack spread of US$16.00/bbl; and an exchange rate of $0.76 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include, but are not limited to: our ability to access or implement some or all of the technology necessary to efficiently and effectively operate our assets and achieve expected future results; volatility of and other assumptions regarding commodity prices; failure of the Government of Alberta's mandatory production curtailment to cause the differential between the WTI and the WCS crude oil prices to narrow or to narrow sufficiently to positively impact our cash flows;

unexpected consequences related to the Government of Alberta's mandatory production curtailment; the Government of Alberta may extend mandatory production curtailment beyond when takeaway capacity constraints have been sufficiently relieved; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; accuracy of our share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks, exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of our crude-by-rail terminal, including health, safety and environmental risks; our ability to maintain desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; accuracy of our reserves, future production and future net revenue estimates; accuracy of our accounting estimates and judgements; our ability to replace and expand oil and gas reserves; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of our assets or goodwill from time to time; our ability to maintain our relationship with our partners and to successfully manage and operate our integrated business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; ability to successfully complete development programs; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, including labour, materials, natural gas and other energy sources used in oil sands processes and increased insurance deductibles or premiums; potential failure of products to achieve or maintain acceptance in the market; risks associated with fossil fuel industry reputation and litigation related thereto; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and equipment and its application to our business, including potential cyberattacks; risks associated with climate change and our assumptions relating thereto; the timing and the costs of well and pipeline construction; our ability to secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; possible failure to obtain and retain qualified staff and equipment in a timely and cost efficient manner; changes in labour relationships; 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, climate change 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 general economic, market and business conditions; the political and economic conditions in the countries in which we operate or supply; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, shareholder proposals and regulatory actions against us.

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

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of Cenovus's material risk factors, refer to "Risk Management and Risk Factors" in the Corporation's annual 2019 Management's Discussion and Analysis ("MD&A"), which section of the MD&A is incorporated by reference into this AIF, and to the risk factors described in other documents Cenovus files from time to time with securities regulatory authorities in Canada, available on SEDAR at sedar.com, and with the U.S. Securities and Exchange Commission on EDGAR at sec.gov, and on the Corporation's website at cenovus.com.

Information on or connected to our website cenovus.com does not form part of this AIF unless expressly incorporated by reference herein.

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 (now Ovintiv Inc.). On January 1, 2011, Cenovus Energy Inc. amalgamated with its wholly owned subsidiary, Cenovus Marketing Holdings Ltd., through a plan of arrangement approved by the Court of Queen's Bench of Alberta.

On July 31, 2015, Cenovus Energy Inc. amalgamated with its wholly owned subsidiary, 9281584 Canada Limited (formerly 1528419 Alberta Ltd.), by way of a vertical short-form amalgamation. On August 1, 2018, Cenovus Energy Inc. amalgamated with its wholly owned subsidiary, 10904635 Canada Limited (formerly Cenovus FCCL Ltd.), by way of a vertical short-form amalgamation.

The Corporation's head and registered office is located at 4100, 225 – 6 Avenue S.W., Calgary, Alberta, Canada T2P 1N2.

INTERCORPORATE RELATIONSHIPS

Cenovus's material subsidiaries and partnerships as at December 31, 2019 are as follows:

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

(1) Reflects all voting securities of all subsidiaries and partnerships beneficially owned, or controlled or directed, directly or indirectly, by Cenovus.
(2) Cenovus non-operating interest held through Cenovus American Holdings Ltd. and Cenovus US Holdings Inc.

The Corporation's remaining subsidiaries and partnerships each account for (i) less than 10 percent of the Corporation's consolidated assets as at December 31, 2019 and (ii) less than 10 percent of the Corporation's consolidated revenues for the year ended December 31, 2019. In aggregate, Cenovus's subsidiaries and partnerships not listed above did not exceed 20 percent of the Corporation's total consolidated assets or total consolidated revenues as at and for the year ended December 31, 2019.

GENERAL DEVELOPMENT OF THE BUSINESS

OVERVIEW

Cenovus is an integrated oil and natural gas company headquartered in Calgary, Alberta. Cenovus is in the business of developing, producing and marketing crude oil, natural gas and natural gas liquids ("NGLs") in Canada, and also conducts marketing activities and owns refining interests in the United States ("U.S.").

All of Cenovus's oil and natural gas reserves and production are located in Canada, within the provinces of Alberta and British Columbia. As at December 31, 2019, Cenovus had a land base of approximately 5.3 million net acres. The estimated proved reserves life index based on working interest production as at December 31, 2019 was approximately 31 years.

BUSINESS SEGMENTS

The Corporation's reportable segments are as follows:

Oil Sands

Cenovus's Oil Sands segment includes the development and production of bitumen in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as other projects in the early stages of development. Cenovus's interest in certain of its operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, increased from 50 percent to 100 percent on May 17, 2017.

Deep Basin

The Deep Basin segment includes approximately 2.8 million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and NGLs. The assets are located in Alberta and British Columbia and include interests in numerous natural gas processing facilities (collectively, the "Deep Basin Assets"). The Deep Basin Assets were acquired on May 17, 2017.

Refining and Marketing

Cenovus's Refining and Marketing segment includes transporting and selling crude oil, natural gas and NGLs and joint ownership of two refineries in the U.S. with the operator, Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.

Corporate and Eliminations

This segment 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 ("G&A"), financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations include adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Corporation's rail terminal, crude oil production used as a feedstock by the Refining and Marketing segment and unrealized intersegment profits in inventory. Eliminations are recorded at transfer prices based on current market prices.

THREE YEAR HISTORY

The following describes significant events and conditions that have influenced the development of Cenovus's business during the last three financial years:

2017

- **Resumed Christina Lake phase G expansion.** Cenovus resumed the phase G expansion, with an approved design capacity of 50,000 gross barrels per day.
- **Common share issuance.** In the second quarter, Cenovus issued 187.5 million common shares ("Common Shares") at a price of $16.00 per share for gross proceeds of approximately $3 billion, with net proceeds used to fund a portion of the cash consideration for the May 17, 2017 acquisition by Cenovus of ConocoPhillips' 50 percent interest in the FCCL Partnership ("FCCL") and the majority of ConocoPhillips' western Canadian conventional assets in Alberta and British Columbia (the "Acquisition"). As part of the consideration for the Acquisition, Cenovus issued 208 million Common Shares to ConocoPhillips.
- **Increased FCCL interest to 100 percent and acquired Deep Basin Assets.** In the second quarter, Cenovus completed the Acquisition for consideration of approximately US$10.6 billion in cash, before closing adjustments, and 208 million Common Shares. The Acquisition gave Cenovus a 100 percent interest in and full control of the FCCL Partnership assets. The Deep Basin Assets provide short-cycle development opportunities with high return potential that complement our long-term oil sands development.
- **Senior notes offering.** In the second quarter of 2017, Cenovus completed an offering of US$2.9 billion senior unsecured notes at a weighted average cost of 4.9 percent, the net proceeds of which contributed to the funding of the Acquisition.
- **Divested legacy Conventional assets.** In the third quarter Cenovus sold its Pelican Lake heavy oil operations, including the adjacent Grand Rapids project, for cash proceeds of $975 million, before closing adjustments. In the fourth quarter, Cenovus sold its Palliser crude oil and natural gas assets for cash proceeds of $1.3 billion, before closing adjustments and sold its Weyburn carbon-dioxide enhanced oil recovery operation in Saskatchewan for cash proceeds of $940 million, before closing adjustments. As part of the Corporation's plan to deleverage its balance sheet, net proceeds from the divestitures were used to retire the $3.6 billion bridge credit facility that had been put in place for the Acquisition.
- **New President & Chief Executive Officer.** In the fourth quarter, Alex Pourbaix was appointed Cenovus's President & Chief Executive Officer and joined the Board of Directors.

2018

- **Sale of Suffield assets.** In the first quarter, Cenovus completed the sale of its Suffield crude oil and natural gas operations for cash proceeds of $512 million, before closing adjustments.
- **New Chief Financial Officer.** In the second quarter, Jon McKenzie was appointed Cenovus's Executive Vice-President & Chief Financial Officer.
- **Sale of Cenovus Pipestone Partnership.** In the third quarter, Cenovus completed the sale of its general partnership that held the natural gas and liquids business in northwestern Alberta for cash proceeds of $625 million, before closing adjustments.
- **Signed rail agreements to transport oil to U.S. Gulf Coast.** In the third quarter, Cenovus signed three-year agreements with major rail companies to transport approximately 100,000 barrels per day of heavy crude oil from Alberta to various destinations on the U.S. Gulf Coast.
- **Debt reduction.** In October, Cenovus redeemed US$800 million of its US$1.3 billion unsecured notes due October 2019. In December, Cenovus repurchased a principal amount of US$76 million of unsecured notes for US$69 million.
- **Reduced costs.** Cenovus reduced oil sands operating costs to $7.65 per barrel, a nine percent decrease from 2017. Sustaining capital costs were also reduced to $4.40 per barrel of installed nameplate capacity, a 31% decrease from 2017.
- **Sublease of excess office space.** In the third quarter, Cenovus subleased an additional eight floors of The Bow tower in Calgary, Alberta, further reducing our long-term fixed real estate costs.
- **Continued wide differentials.** The differentials between West Texas Intermediate ("WTI") and Western Canadian Select ("WCS") averaged US$26.31 per barrel, a 120 percent increase compared with 2017, reaching a record of US$52.00 per barrel in the fourth quarter. Average WCS prices remained flat in 2018 in relation to 2017.
- **Government production curtailment.** On December 2, 2018, the Government of Alberta announced a temporary mandatory oil production curtailment for Alberta producers, starting in January 2019, to, among other things, address the record-high differentials between WTI and WCS at Hardisty.
- **Re-rated refinery processing capacity.** As a result of consistently strong operating performance, higher utilization rates and optimizations executed in 2018, both U.S. refineries were re-rated to reflect higher processing capacity effective January 1, 2019. Crude capacity at the Wood River Refinery was re-rated to 333,000 barrels per day from 314,000 barrels per day, while capacity at the Borger Refinery was re-rated to 149,000 barrels per day from 146,000 barrels per day.

2019

- **Debt reduction.** In 2019 Cenovus repurchased a principal amount of US$1,276 million of unsecured notes for US$1,214 million. In October, Cenovus also repaid US$500 million in unsecured notes upon maturity.
- **Produced first steam from Christina Lake phase G.** In 2019 Cenovus began using steam from Christina Lake phase G to produce oil from other phases. Production from phase G is expected in the first half of 2020 to ramp up to approximately 50,000 barrels per day over the course of 2020.
- **Ramped up crude-by-rail shipments.** Using our fleet of railcars, we ramped up shipments of crude oil by rail over the course of 2019 to exit the year with our December loaded volumes averaging 105,985 barrels per day and rail sales of 91,059 barrels per day.
- **Alberta government extended curtailment.** In August, the Alberta government announced an extension of its mandatory oil production curtailment program to December 31, 2020.
- **Increased dividend by 25%.** In October, Cenovus announced a 25% increase to its dividend for the fourth quarter of 2019.
- **Moved headquarters.** In October, Cenovus completed the move of its headquarters in downtown Calgary, from The Bow tower to Brookfield Place.
- **Alberta government implemented Special Production Allowance program.** Cenovus qualified for a Special Production Allowance to produce crude oil above curtailment for incremental increases in rail shipments.
- **Re-rated Wood River Refinery processing capacity.** As a result of consistently strong operating performance, higher utilization rates and optimization executed in 2019, the Wood River Refinery crude capacity was re-rated to 346,000 barrels per day from 333,000 barrels per day, to reflect higher processing capacity, effective January 1, 2020.

OIL SANDS

Cenovus's Oil Sands segment includes 100 percent ownership of the Foster Creek and Christina Lake assets, both of which are producing. In addition, the Corporation has several emerging projects in the early stages of development, including 100 percent owned projects at Narrows Lake and Telephone Lake. The Oil Sands segment also includes Cenovus's 100 percent owned Athabasca natural gas property, from which all of the natural gas production since late April 2018 has been used as fuel at the adjacent Foster Creek operation.

As at December 31, 2019, Cenovus held bitumen rights of approximately 1.8 million gross acres (1.7 million net acres) within the Athabasca and Cold Lake areas, as well as the exclusive rights to lease an additional 536,000 gross acres on the Cold Lake Air Weapons Range, an active military base.

Development Approach

Cenovus uses steam-assisted gravity drainage ("SAGD") technology to recover bitumen. The Corporation does not employ mining techniques for extraction and none of its reserves are suitable for extraction using mining techniques. SAGD involves injecting steam into the reservoir to enable bitumen to be pumped to the surface. Cenovus applies a manufacturing-like, phased approach to developing its oil sands assets. This approach incorporates learnings from previous phases into future growth plans, helping the Corporation to minimize costs.

Technology

Cenovus continues to focus on technologies which are targeted to lower our cost structure, improve margins, and reduce greenhouse gas emissions amid continuing price uncertainty, a lower carbon future, increased environmental protection awareness and regulatory changes.

Foster Creek

Cenovus has a 100 percent working interest in Foster Creek. It is located on the Cold Lake Air Weapons Range, and has a reservoir depth up to 500 meters below the surface. Foster Creek produces from the McMurray formation using SAGD technology.

The Corporation holds 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, Cenovus holds exclusive rights to lease several hundred thousand acres of bitumen rights in other areas on the Cold Lake Air Weapons Range on the Corporation's and/or its assignee's behalf.

Production from phases A through G at Foster Creek averaged 159,598 barrels per day in 2019 (161,979 barrels per day in 2018).

Cenovus operates a 98 megawatt natural gas-fired cogeneration facility in conjunction with 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

Cenovus has a 100 percent working interest in Christina Lake. It is located approximately 120 kilometers south of Fort McMurray, Alberta and has a reservoir depth up to 375 meters below the surface. Christina Lake produces from the McMurray formation using SAGD technology.

Production from phases A through F at Christina Lake averaged 194,659 barrels per day in 2019 (201,017 barrels per day in 2018). Cenovus operates a 100 megawatt natural gas-fired cogeneration facility in conjunction with Christina Lake. 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. Cenovus resumed work on the phase G expansion in 2017, which was deferred in late 2014 due to the low commodity price environment. Phase G has an approved design capacity of 50,000 gross barrels per day. Cenovus began producing steam from phase G in 2019. The Corporation expects to ramp up production at phase G in 2020.

Narrows Lake

Cenovus has a 100 percent working interest in Narrows Lake. Narrows Lake is located adjacent to Christina Lake and has a reservoir depth up to 375 meters below the surface.

In 2012, Cenovus received regulatory approval for phases A, B and C for 130,000 gross barrels per day of production capacity. Due to the low commodity price environment, and historically high price differentials and curtailment, Cenovus has deferred new construction spending on phase A. Cenovus is considering development of the Narrows Lake resource by using existing infrastructure at Christina Lake and is progressing engineering and regulatory work to be ready for a potential final investment decision in 2020.

Telephone Lake

Cenovus's 100 percent owned Telephone Lake property is located in the Borealis Region in northeastern Alberta, approximately 90 kilometers northeast of Fort McMurray, Alberta.

Cenovus received approval from the Alberta Energy Regulator in late 2014 for a SAGD project with initial production capacity of 90,000 gross barrels per day. The Corporation is currently assessing what may be the optimal development plan for the Telephone Lake asset.

Marten Hills

As of December 31, 2019, Cenovus owned 100 percent working interest in 208 sections of oil sands rights in the Marten Hills area. Marten Hills is an early stage exploration play located approximately 70 kilometers northeast of Slave Lake, Alberta, targeting conventional heavy oil from the Clearwater formation.

In 2019, Cenovus substantially completed additional drilling to support appraisal work to be completed in the first quarter of 2020 to support a potential final investment decision for the first stage of commercial development in early 2020.

Capital Investment

In 2019, capital investment in the Oil Sands segment was $706 million, primarily related to sustaining existing production and completion of Christina Lake phase G and stratigraphic test wells, and includes expenditures on Marten Hills and other emerging assets.

- Foster Creek capital investment was focused on sustaining capital related to existing production and the drilling of stratigraphic test wells to determine pad placement for sustaining well pads and expansions.
- Christina Lake capital investment was focused on sustaining capital related to existing production and the drilling of stratigraphic test wells to determine pad placement for sustaining well pads and completion of phase G construction.

In 2020, Oil Sands capital spending is forecast to be between $865 million and $1,010 million and is expected to continue to focus on sustaining current production levels from existing oil sands facilities and progressing Foster Creek phase H and Christina Lake phase H to be ready for potential final investment decisions in the second half of 2020. Capital spending in 2020 is anticipated to also include the continued evaluation of the Marten Hills play and other emerging assets.

DEEP BASIN

Cenovus has western Canadian conventional crude oil and natural gas assets including undeveloped land, exploration and producing assets, and related infrastructure in Alberta and British Columbia in the Deep Basin. Cenovus's Deep Basin Assets include approximately 2.8 million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, with an average 71.5 percent working interest. In addition, the Deep Basin Assets include interests in numerous natural gas processing plants with an estimated net processing capacity of 1.2 billion cubic feet per day. The Deep Basin Assets are expected to provide short-cycle development opportunities with high return potential that complement Cenovus's long-term oil sands development. Deep Basin production is expected to provide an economic hedge for the natural gas required as a fuel source at both the Corporation's oil sands and refining operations.

Elmworth-Wapiti

Cenovus is one of the largest operators and producers in the Elmworth-Wapiti area, located in northwest Alberta and northeast British Columbia. As of December 31, 2019, Cenovus held leasehold rights of 1.13 million net acres in this area.

The Elmworth-Wapiti area provides production potential from more than 10 formations, with the most prospective being the Falher and Dunvegan. It is a mature area that was historically developed with conventional vertical well technology. Cenovus has shifted to horizontal drilling in its development programs with a view to unlock the vast resource potential in the tight sand plays.

The primary processing facility in the area is the Cenovus-operated Elmworth plant. The Corporation holds significant working interests in four other major natural gas processing facilities in the region. In 2019, Cenovus's net production in Elmworth-Wapiti averaged 31,992 barrels of oil equivalent per day (41,927 barrels of oil equivalent per day in 2018, including 6,523 barrels of oil equivalent per day of the Cenovus Pipestone Partnership that was sold on September 6, 2018).

Kaybob-Edson

As of December 31, 2019, Cenovus held leasehold rights of approximately 735,203 net acres in the Kaybob-Edson area, which is situated in west-central Alberta. Target development is in the Montney and Lower Cretaceous formations where successful industry drilling has proven the resource potential of those formations in lands offsetting Cenovus acreage.

In the Kaybob-Edson area, natural gas processing is primarily controlled by midstream operators and other oil and gas companies.

Cenovus has secured longer term contracts to manage both existing base and new-development volumes. Additionally, Cenovus operates natural gas processing facilities in the area, including the Peco and Wolf plants. Net production in Kaybob-Edson averaged 34,751 barrels of oil equivalent per day in 2019 (40,476 barrels of oil equivalent per day in 2018).

Clearwater

The Clearwater area is situated in west-central Alberta, south of Kaybob-Edson. As of December 31, 2019, Cenovus held leasehold rights of approximately 795,618 net acres. Cenovus's assets in the Clearwater area are characterized by multi-horizon, Cretaceous and Jurassic reservoirs at depths ranging from 1,900 meters to 3,000 meters, all with high NGL content in a predominantly gas prone area. This is a mature area historically developed with conventional vertical well technology, providing Cenovus with a series of lower risk horizontal drilling development programs. Cenovus operates natural gas processing facilities in the area, including the Sand Creek and Alder plants. Average net production was 30,680 barrels of oil equivalent per day in 2019 (37,855 barrels of oil equivalent per day in 2018).

Capital Investment

In 2019, capital investment of $53 million in the Deep Basin focused on disciplined development, which included maintaining safe and reliable operations as well as the completion and tie-in of well inventories from 2018's development program. The Elmworth-Wapiti operating area focused on maintaining existing production and infrastructure as well as completing and bringing on stream two net wells. The Kaybob-Edson operating area focused on maintaining existing production and infrastructure, while the Clearwater operating area focused on sustaining existing production and infrastructure and bringing one net well on stream.

In 2020, Deep Basin capital investment is forecast to be between $80 million to $95 million. Capital investment in 2020 will focus on maintaining safe and reliable operations, asset integrity programs and the execution of a two-rig drilling program targeting potentially high-return, liquids-rich opportunities in the Clearwater and Edson areas.

REFINING AND MARKETING

Cenovus's Refining and Marketing segment includes its U.S. refining non-operator ownership interests and operations involved in the coordination of Cenovus's marketing and transportation initiatives to optimize the value received for its products.

Refining

The refining interests allow Cenovus 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 regional North American light/heavy crude oil price differential fluctuations.

Through WRB, Cenovus has a 50 percent ownership interest in both the Wood River and Borger refineries located in Roxana, Illinois and Borger, Texas, respectively. Phillips 66, an unrelated U.S. public company, 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. The refineries have a combined stated processing capacity of approximately 482,000 gross barrels per day of crude oil in 2019, including heavy crude oil processing capability of up to 255,000 gross barrels per day. In addition, the Borger Refinery has a NGL fractionation facility with a capacity of 45,000 gross barrels per day. Effective January 1, 2020, the crude oil processing capacity increased to 495,000 gross barrels per day as a result of setting new maximum demonstrated rates at the Wood River Refinery in 2019.

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

Refinery Operations(1)	2019	2018
Crude Oil Capacity (Mbbls/d)(2)	**482**	460
Crude Oil Runs (Mbbls/d)	**443**	446
Heavy Oil	**177**	191
Light and Medium Oil	**266**	255
Crude Utilization (%)	**92**	97
Refined Products (Mbbls/d)		
Gasoline	**223**	233
Distillates	**167**	156
Other	**76**	81
Total	**466**	470

(1) Represents 100 percent of Wood River and Borger Refinery operations.
(2) Effective January 1, 2020, the nameplate capacity increased to 495,000 gross barrels per day.

Wood River Refinery

Wood River Refinery ranks in the top 10 percent of approximately 130 refineries in the U.S., based on total crude oil capacity. It is located in Roxana, Illinois, approximately 25 kilometers northeast of St. Louis, Missouri. 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 feedstock 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 various markets.

Wood River Refinery's stated crude oil processing capacity for 2019 was 333,000 gross barrels per day, including 220,000 gross barrels per day of heavy crude oil processing capacity. In 2019, approximately 55 percent of the crude oil processed at Wood River Refinery consisted of Canadian heavy crude oil. Effective January 1, 2020, Wood River Refinery's stated crude oil processing capacity increased to 346,000 gross barrels per day, including 240,000 gross barrels per day of heavy crude processing capacity due to new maximum demonstrated rates in 2019.

Borger Refinery

Borger Refinery is located in Borger, Texas, approximately 80 kilometers north of Amarillo, Texas. 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.

Borger Refinery's stated crude oil processing capacity for 2019 was 149,000 gross barrels per day, including 35,000 gross barrels per day of heavy crude oil. Borger Refinery also has a NGL fractionation facility with stated capacity of 45,000 gross barrels per day.

Capital Investment – Refining

In 2019, combined capital investment at both Wood River and Borger was $228 million net, focused on reliability and maintenance, and yield improvement projects.

Combined 2020 capital spending at Wood River and Borger is forecast to be $250 million to $280 million net, focused on sustaining capital and optimization projects to improve clean yields and product value. These optimization projects will continue to position WRB to address new International Maritime Organization ship emission regulations effective January 1, 2020.

Marketing

Cenovus's marketing activities are focused on optimizing netbacks of its production and asset base across crude oil, condensate, natural gas, and NGLs.

As part of managing market risk arising from optimization activities, Cenovus may enter into financial transactions from time to time. Details of these transactions in 2019 are provided in the notes to the Corporation's annual audited Consolidated Financial Statements for the year ended December 31, 2019.

Transportation

Cenovus continues to focus on near, mid, and long-term strategies to optimize netbacks for its production. As at December 31, 2019, Cenovus has entered into various transportation and storage commitments totaling $21 billion, $13 billion of which relates to pipelines that are in approval or construction phases but are not yet in service. With our committed capacity on pipeline projects, Cenovus has substantial potential future pipeline capacity to the Canadian West Coast and U.S. Gulf Coast.

The Corporation's portfolio of transportation commitments includes feeder pipelines from its production areas to the major Alberta trade centres, major pipelines to markets downstream of these centres and rail transportation agreements, including contracts with rail companies to transport approximately 100,000 barrels per day of heavy crude oil from Alberta to various destinations on the U.S. Gulf Coast. Other transportation commitments are primarily related to diluent supply, railcar transportation as well as tankage and terminalling of both crude oil blend and condensate volumes.

Cenovus's transportation portfolio also includes a crude-by-rail terminal located at Bruderheim, Alberta that is connected to the rail lines of Canadian National Railway and Canadian Pacific Railway, and allows crude oil to be delivered to major demand centres across Canada and the U.S. In 2019, volumes loaded at the Bruderheim terminal averaged 65,293 barrels per day compared with an average of 37,988 barrels per day in 2018.

Capital Investment - Marketing

In 2019, Marketing capital investment was $52 million, focused on strategic rail initiatives and infrastructure.

In 2020, Marketing capital investment is forecast to be between $35 million and $50 million and is expected to continue with the same focus as 2019.

COMPETITIVE CONDITIONS

All aspects of the oil and natural gas industry are highly competitive. For further information on the competitive conditions affecting Cenovus, refer to the section entitled "Risk Management and Risk Factors – Operational Risk" in the Corporation's annual 2019 MD&A, which section of the MD&A is incorporated by reference into this AIF.

ENVIRONMENTAL PROTECTION

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, the "environmental regulations"). For further information on the environmental regulations affecting Cenovus, refer to the section entitled "Risk Management and Risk Factors – Environmental Regulatory Risk" in the Corporation's annual 2019 MD&A, which section of the MD&A is incorporated by reference into this AIF.

CORPORATE RESPONSIBILITY POLICIES

Cenovus has established policies and standards relating to the conduct of business in a safe, healthy, ethical, legal and environmentally, socially and fiscally responsible manner. Cenovus's commitment in these areas is reflected in two key policies, the Code of Business Conduct & Ethics (the "Code") and the Corporate Responsibility Policy (the "CR Policy"). These policies apply to our directors, officers and all employees, as well as contractors and suppliers who conduct activities for, or on behalf of, Cenovus. Individuals subject to both policies are accountable for applying them to their own conduct and work. Each employee, officer and director is also asked to regularly review the Code to confirm they understand their individual responsibilities and that they conform to the requirements of the Code.

The Code addresses the identification and management of ethical situations and provides guidance in making ethical business decisions and reporting violations of the Code. The Code provides a message from the President & Chief Executive Officer and addresses a number of matters including: (a) Cenovus's values and reputation; (b) responsible information use; (c) acting with integrity; (d) compliance with laws and regulations; and (e) reporting potential violations.

The CR Policy addresses Cenovus business conduct to help ensure the Corporation's activities are undertaken in a responsible, transparent and respectful manner and in compliance with all applicable laws, regulations and industry standards in the jurisdictions in which Cenovus operates. The CR Policy specifically references the following matters: (a) leadership; (b) corporate governance and business practices; (c) people; (d) environmental performance; (e) stakeholder and Aboriginal engagement; and (f) community involvement and investment.

With respect to the environment specifically, the CR Policy provides that Cenovus recognizes the importance of: integrating an environmental perspective into Cenovus's business activities; applying risk management throughout its operations to mitigate environmental impact; and pursuing improvements in environmental performance through technology investment and other means.

With respect to social aspects, the CR Policy provides that Cenovus recognizes the importance of: conducting its business with respect and care for the people and communities affected by its activities, noting the Corporation's commitment to safety and support for the principles of the Universal Declaration of Human Rights; engaging stakeholders, including Aboriginal communities, in a manner based on honesty, trust and respect; and developing and maintaining positive relationships with the communities within which Cenovus operates by, among other means, striving to provide economic and social development opportunities and community investment programs that facilitate capacity-building opportunities.

In addition to the Code and CR Policy, Cenovus has established other policies and practices that in some instances relate to environmental and or social aspects of Cenovus's business. Stakeholders, employees and contractors are encouraged to report any business conduct concerns, including violations of legislation or any Cenovus policy, through the Corporation's anonymous Integrity Helpline. Employees and contractors may also report any such concerns to their supervisor, a human resources business partner, or a member of an investigations committee.

The aforementioned policies are accessible on the Corporation's website at cenovus.com, as is Cenovus's Environmental, Social & Governance Report ("ESG Report"). The ESG Report is published annually to detail management's efforts and performance across environment, social and governance topics that are important to its stakeholders.

EMPLOYEES

The following table summarizes Cenovus's full-time equivalent ("FTE") employees as at December 31, 2019:

	FTE Employees
Upstream	1,447
Downstream	97
Corporate	817
Total	2,361

Cenovus also engages contractors and service providers. Refer to the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2019 MD&A, which section of the MD&A is incorporated by reference into this AIF, for further information on employee and other workforce related risks affecting Cenovus.

RISK FACTORS

A discussion of risk factors can be found in the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2019 MD&A, which section of the MD&A is incorporated by reference into this AIF.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

As a Canadian issuer, Cenovus is subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of the Corporation's reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

The Corporation's reserves are located in Alberta and British Columbia, Canada. Cenovus retained two independent qualified reserves evaluators ("IQREs"), McDaniel & Associates Consultants Ltd. ("McDaniel") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and prepare reports on 100 percent of its bitumen, heavy crude oil, light crude oil and medium crude oil combined ("light and medium oil"), NGLs, conventional natural gas and shale gas proved and probable reserves. McDaniel evaluated approximately 95 percent of Cenovus's proved reserves, all located in Alberta, and GLJ evaluated approximately five percent of the Corporation's proved reserves, located in Alberta and British Columbia.

In April 2019, the Reserves Committee of Cenovus's board of directors (the "Board") was dissolved and the mandate and responsibilities of the Reserves Committee were transferred to the Safety, Environment and Responsibility Committee of the Board, which subsequently changed its name to the Safety, Environment, Responsibility and Reserves Committee (the "SERR Committee"). The SERR Committee, composed entirely of independent directors, reviews, among other things, 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 SERR Committee meets independently with the management of Cenovus and each IQRE to determine whether any restrictions affect the ability of the IQREs to report on the reserves data without reservation. In addition, the SERR Committee reviews the reserves data and the report of the IQREs and provides a recommendation regarding approval of the reserves disclosure to the Board.

Cenovus's bitumen reserves are expected to be recovered and produced using SAGD technology or such other technologies as may be developed in the future. 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. Cenovus has 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 petroleum 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 reserves 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 the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2019 MD&A, which section of the MD&A is incorporated by reference into this AIF, for additional information.

The reserves data and other oil and gas information contained in this AIF is dated February 11, 2020, with an effective date of December 31, 2019. McDaniel's preparation date of the information is January 21, 2020 and GLJ's preparation date is January 5, 2020.

DISCLOSURE OF RESERVES DATA

The reserves data presented summarizes the Corporation's bitumen, heavy crude oil, light and medium oil, NGLs, conventional natural gas, shale gas and total reserves and the net present values ("NPV") and future net revenue ("FNR") for these reserves. The reserves data uses forecast prices and costs prior to provision for interest, G&A expenses or the impact of any hedging activities. Estimates of FNR have been presented on a before and after income tax basis. For the purposes of this disclosure, references to "Company" are to Cenovus Energy Inc.

Summary of Company Interest Oil and Gas Reserves as at December 31, 2019
(Forecast prices and costs)

Before Royalties(1)	Bitumen(2) (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas(3) (Bcf)	Total (MMBOE)
Proved Reserves					
Developed Producing	718	8	49	1,015	944
Developed Non-Producing	281	–	1	19	286
Undeveloped	3,827	1	10	208	3,873
Proved Reserves	4,826	9	60	1,242	5,103
Probable Reserves	1,594	8	37	783	1,768
Proved plus Probable Reserves	6,420	17	97	2,025	6,871

After Royalties(4)	Bitumen(2) (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas(3) (Bcf)	Total (MMBOE)
Proved Reserves					
Developed Producing	531	7	40	952	737
Developed Non-Producing	208	–	1	18	212
Undeveloped	2,788	1	9	197	2,831
Proved Reserves	3,527	8	50	1,167	3,780
Probable Reserves	1,127	7	31	727	1,286
Proved plus Probable Reserves	4,654	15	81	1,894	5,066

(1) Before royalties excludes royalty interest reserves.
(2) Includes heavy crude oil that is not material representing less than 1% of total bitumen on a proved plus probable basis.
(3) Includes shale gas that is not material representing 5% of total conventional natural gas on a proved plus probable basis.
(4) Includes royalty interest reserves.

Summary of Net Present Value of Future Net Revenue as at December 31, 2019

(Forecast prices and costs)

	Discounted at %/year ($ millions)					Unit Value Discounted at 10%(1)
Before Income Taxes	0%	5%	10%	15%	20%	$/BOE
Proved Reserves						
Developed Producing	16,159	16,628	14,783	13,083	11,700	20.05
Developed Non-Producing	8,022	6,003	4,673	3,754	3,093	22.10
Undeveloped	116,185	50,153	25,022	13,963	8,457	8.84
Proved Reserves	140,366	72,784	44,478	30,800	23,250	11.77
Probable Reserves	60,816	19,460	8,359	4,617	3,020	6.50
Proved plus Probable Reserves	201,182	92,244	52,837	35,417	26,270	10.43

	Discounted at %/year ($ millions)				
After Income Taxes (2)	0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	12,546	13,542	12,145	10,777	9,649
Developed Non-Producing	6,206	4,620	3,583	2,870	2,358
Undeveloped	89,403	38,270	18,874	10,389	6,189
Proved Reserves	108,155	56,432	34,602	24,036	18,196
Probable Reserves	46,823	14,913	6,397	3,537	2,317
Proved plus Probable Reserves	154,978	71,345	40,999	27,573	20,513

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

(2) 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 taking into account current federal and provincial 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 the Corporation's Consolidated Financial Statements and MD&A for the year ended December 31, 2019.

Total Future Net Revenue (undiscounted) as at December 31, 2019

(Forecast prices and costs - $ millions)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Total Abandonment and Reclamation Costs(1)	Future Net Revenue Before Future Income Taxes	Future Income Taxes	Future Net Revenue After Future Income Taxes
Proved Reserves	321,806	86,842	57,910	29,866	6,822	140,366	32,211	108,155
Proved plus Probable Reserves	458,533	125,748	80,764	43,118	7,721	201,182	46,204	154,978

(1) Total abandonment and reclamation costs included for all wells, facilities and other liabilities, known and existing, and to be incurred as a result of future development activity.

Future Net Revenue by Product Type as at December 31, 2019

(Forecast prices and costs)

Reserves Category	Product Types	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($ millions)	Unit Value Discounted at 10%/year(1) ($/BOE)
Proved Reserves	Bitumen(2)	43,290	12.27
	Light and Medium Oil(3)	263	16.35
	Conventional Natural Gas(4)	925	3.91
	Total	44,478	11.77
Proved plus Probable Reserves	Bitumen(2)	50,792	10.91
	Light and Medium Oil(3)	405	12.39
	Conventional Natural Gas(4)	1,640	4.33
	Total	52,837	10.43

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

(2) Includes heavy crude oil that is not material.

(3) Includes solution gas and other byproducts.

(4) Includes shale gas and other byproducts, but excludes solution gas.

Additional Notes to Reserves Data Tables

- The estimates of FNR presented do not represent fair market value.
- FNR from reserves excludes cash flows related to Cenovus's risk management activities.
- For disclosure purposes, Cenovus has included heavy crude oil with bitumen and shale gas with conventional natural gas, as the reserves of heavy crude oil and shale gas are not material.
- In accordance with NI 51-101, NPV and FNR amounts presented include all of Cenovus's existing estimated abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.
- BOE estimates and tables may not sum 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 Cenovus.
4. **Gross** means: (a) in relation to wells, the total number of wells in which Cenovus has an interest; and (b) in relation to properties, the total acreage of properties in which Cenovus has an interest.
5. **Net** means: (a) in relation to wells, the number of wells obtained by aggregating Cenovus's working interest in each of its gross wells; and (b) in relation to Cenovus's interest in a property, the total acreage in which it has an interest multiplied by its working interest.
6. **Reserves** are estimated remaining quantities of crude 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 are disclosed later in this AIF.

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.

Pricing Assumptions

The forecast of prices, inflation and exchange rate provided in the table below is computed using the average of forecasts ("IQRE Average Forecast") by McDaniel, GLJ and Sproule Associates Limited ("Sproule") and is used to estimate FNR associated with the reserves disclosed herein. The IQRE Average Forecast is dated January 1, 2020. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs. For historical prices realized during 2019, see "Production History and Per-Unit Results" in this AIF.

	Oil and Liquids				Natural Gas		
Year	WTI Cushing Oklahoma (US$/bbl)	Edmonton Par Price 40 API (C$/bbl)	Western Canadian Select (C$/bbl)	Edmonton C5+ (C$/bbl)	AECO Gas Price (C$/MMBtu)	Inflation Rate (%/year)	Exchange Rate (US$/C$)
2020	61.00	72.64	57.57	76.83	2.04	0.0	0.760
2021	63.75	76.06	62.35	79.82	2.32	1.7	0.770
2022	66.18	78.35	64.33	82.30	2.62	2.0	0.785
2023	67.91	80.71	66.23	84.72	2.71	2.0	0.785
2024	69.48	82.64	67.96	86.71	2.81	2.0	0.785
2025	71.07	84.60	69.72	88.73	2.89	2.0	0.785
2026	72.68	86.57	71.49	90.77	2.96	2.0	0.785
2027	74.24	88.49	73.19	92.76	3.03	2.0	0.785
2028	75.73	90.31	74.80	94.65	3.10	2.0	0.785
2029	77.24	92.17	76.43	96.57	3.17	2.0	0.785
2030	78.79	94.01	77.96	98.53	3.24	2.0	0.785
2031+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.785

Future Development Costs

The following table outlines undiscounted future development costs deducted in the estimation of FNR for the years indicated:

Reserves Category ($ millions)	2020	2021	2022	2023	2024	Remainder	Total
Proved Reserves	587	839	884	1,197	1,164	25,195	29,866
Proved plus Probable Reserves	671	907	892	1,318	1,283	38,047	43,118

Cenovus believes that existing cash balances, internally generated cash flows, existing credit facility, management of its asset portfolio and access to capital markets will be sufficient to fund the Corporation's future development costs. However, there can be no guarantee that the necessary funds will be available or that Cenovus will allocate funding to develop all of its reserves. Failure to develop those reserves would have a negative impact on the Corporation's FNR.

The interest or other costs of external funding are not included in the reserves and FNR estimates and would reduce FNR depending upon the funding sources utilized. Cenovus does not believe that interest or other funding costs would make development of any property uneconomic.

Reserves Reconciliation

The following tables provide a reconciliation of Company Interest Before Royalties reserves for bitumen, heavy crude oil, light and medium oil, NGLs, conventional natural gas and shale gas for the year ended December 31, 2019, presented using forecast prices and costs.

Proved	Bitumen(1) (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas(2) (Bcf)	Total (MMBOE)
As at December 31, 2018	4,831	12	72	1,513	5,167
Extensions and Improved Recovery	19	–	2	37	27
Discoveries	–	–	–	–	–
Technical Revisions	106	(1)	(5)	(113)	81
Economic Factors	–	–	(1)	(37)	(8)
Acquisitions	–	–	–	1	1
Dispositions	–	–	–	(1)	–
Production(3)	(130)	(2)	(8)	(158)	(165)
As at December 31, 2019	4,826	9	60	1,242	5,103

Probable	Bitumen(1) (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas(2) (Bcf)	Total (MMBOE)
As at December 31, 2018	1,598	5	44	1,041	1,821
Extensions and Improved Recovery	(10)	3	5	83	12
Discoveries	–	–	–	–	–
Technical Revisions	6	–	(11)	(322)	(61)
Economic Factors	–	–	(1)	(21)	(4)
Acquisitions	–	–	–	3	–
Dispositions	–	–	–	(1)	–
Production(3)	–	–	–	–	–
As at December 31, 2019	1,594	8	37	783	1,768

Proved plus Probable	Bitumen(1) (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas(2) (Bcf)	Total (MMBOE)
As at December 31, 2018	6,429	17	116	2,554	6,988
Extensions and Improved Recovery	9	3	7	120	39
Discoveries	–	–	–	–	–
Technical Revisions	112	(1)	(16)	(435)	20
Economic Factors	–	–	(2)	(58)	(12)
Acquisitions	–	–	–	4	1
Dispositions	–	–	–	(2)	–
Production(3)	(130)	(2)	(8)	(158)	(165)
As at December 31, 2019	6,420	17	97	2,025	6,871

(1) Includes heavy crude oil that is not material.
(2) Includes shale gas that is not material.
(3) 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 Cenovus's share of gas volumes provided to FCCL for steam generation, but does not include royalty interest production.

Bitumen proved reserves decreased by five million barrels as additions from improved performance in Oil Sands were more than offset by current year production;

Bitumen proved plus probable reserves decreased by nine million barrels as additions from improved performance in Oil Sands were more than offset by current year production;

Light and medium oil proved reserves decreased by three million barrels as minor additions were more than offset by technical revisions attributed to changes to the Deep Basin development plan, and current year production;

Light and medium oil proved plus probable reserves were unchanged as minor additions were offset by technical revisions attributed to changes to the Deep Basin development plan, and current year production;

NGLs proved and proved plus probable reserves decreased by 12 million barrels and 19 million barrels, respectively, as minor additions were more than offset by reductions due to technical revisions attributed to changes to the Deep Basin development plan, and current year production; and

Conventional natural gas proved and proved plus probable reserves decreased by 271 billion cubic feet and 529 billion cubic feet, respectively, as additions attributed to Deep Basin development were more than offset by reductions due to technical revisions attributed to changes to the Deep Basin development plan, and current year production.

Undeveloped Reserves

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 Handbook. In general, undeveloped reserves are scheduled to be produced within the next one to 50 years.

The undeveloped tables presented here reflect the product type groups reported above, specifically, bitumen includes heavy crude oil and conventional natural gas includes shale gas.

Company Interest Proved Undeveloped – Before Royalties

	Bitumen(1) (MMbbls)		Light and Medium Oil (MMbbls)		NGLs (MMbbls)		Conventional Natural Gas(2) (Bcf)		Total (MMBOE)	
	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End
2017	2,051	3,928	1	1	33	33	449	449	2,159	4,036
2018	197	3,986	1	1	7	15	159	324	233	4,056
2019	37	3,827	–	1	2	10	30	208	43	3,873

(1) Includes heavy crude oil that is not material.
(2) Includes shale gas that is not material.

Company Interest Probable Undeveloped – Before Royalties

	Bitumen(1) (MMbbls)		Light and Medium Oil (MMbbls)		NGLs (MMbbls)		Conventional Natural Gas(2) (Bcf)		Total (MMBOE)	
	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End	First Attributed	Total at Year-End
2017	771	1,550	2	2	46	46	640	640	925	1,704
2018	30	1,502	2	2	15	25	365	619	108	1,632
2019	7	1,474	3	5	5	21	87	433	29	1,571

(1) Includes heavy crude oil that is not material.
(2) Includes shale gas that is not material.

DEVELOPMENT OF PROVED AND PROBABLE UNDEVELOPED RESERVES

Bitumen

At the end of 2019, Cenovus had proved undeveloped bitumen reserves of 3,827 million barrels Before Royalties, or approximately 79 percent of the Corporation's proved bitumen reserves. Of Cenovus's 1,594 million barrels of probable bitumen reserves, 1,474 million barrels, or approximately 92 percent, are undeveloped. The evaluation of these reserves anticipates that the reserves will be recovered using SAGD, except for the heavy crude oil, which is not material.

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. McDaniel's standard for sufficient drilling in the McMurray formation is a minimum of eight stratigraphic wells per section with 3D seismic, or 16 stratigraphic wells per section with no seismic. Additionally, all requisite legal and regulatory approvals must have been obtained, operator 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. McDaniel's standard for probable reserves is a minimum of four stratigraphic wells per section. 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 located outside of an approved development plan area, but within an approved project area. If reserves lie outside the approved development area, approval to include those reserves in the development area must be obtained before development drilling of SAGD well pairs can commence.

Development of the proved and probable Foster Creek and Christina Lake 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. Development and capital spending on the proved and probable undeveloped reserves at Narrows Lake continues with the project currently scheduled to be on stream before 2026. The forecast production of Cenovus's proved and proved plus probable bitumen reserves, extends approximately 37 years and 41 years, respectively. Production of the current proved developed portion is estimated to take approximately 20 years.

Light and Medium Oil, NGLs and Conventional Natural Gas

Cenovus's Deep Basin Assets proved undeveloped and proved plus probable undeveloped reserves are approximately one percent and two percent of the Corporation's proved and proved plus probable reserves, respectively. Cenovus plans to develop the Deep Basin proved and proved plus probable undeveloped reserves over the next five years and ten years, respectively.

SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The evaluation of reserves is a continuous process 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 the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2019 MD&A, which section of the MD&A is incorporated by reference into this AIF.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

The following tables summarize Cenovus's interests in producing and non-producing wells, as at December 31, 2019:

	Oil		Gas		Total	
Producing Wells	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Sands(1)	547	547	154	154	701	701
Deep Basin(2)	581	347	3,903	2,722	4,484	3,069
Total	1,128	894	4,057	2,876	5,185	3,770

(1) All producing Oil Sands wells are located in Alberta.
(2) Includes 4,072 gross producing wells (2,751 net producing wells) located in Alberta; 412 gross producing wells (318 net producing wells) located in British Columbia.

	Oil		Gas		Total	
Non-Producing Wells(1)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Sands(2)	177	177	194	194	371	371
Deep Basin(3)	245	178	579	493	824	671
Total	422	355	773	687	1,195	1,042

(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.
(2) All non-producing Oil Sands wells are located in Alberta.
(3) Includes 785 gross non-producing wells (636 net non-producing wells) located in Alberta; 36 gross non-producing wells (32 net non-producing wells) located in British Columbia; three gross non-producing wells (three net non-producing wells) located in Saskatchewan.

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

Exploration and Development Activity

The following tables summarize Cenovus's gross participation and net interest in wells drilled in 2019(1):

	Oil Sands		Deep Basin		Total	
Wells Drilled	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil	80	79	–	–	80	79
Gas	–	–	–	–	–	–
Dry & Abandoned	–	–	–	–	–	–
Total Canada	80	79	–	–	80	79

(1) Oil Sands drilled eleven gross exploration wells (eleven net wells) in 2019. No exploration wells were drilled in Deep Basin in 2019.

During the year ended December 31, 2019, Oil Sands drilled 58 gross stratigraphic test wells (57 net wells). Deep Basin drilled no stratigraphic test wells.

During the year ended December 31, 2019, no service wells were drilled within Oil Sands and no service wells were drilled in Deep Basin.

SAGD well pairs are counted as a single oil 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.

Development activities were focused on sustaining bitumen production at Foster Creek and Christina Lake, and the production and re-risking resource potential of the Deep Basin properties.

Properties With No Attributed Reserves

Cenovus has approximately 5.8 million gross acres (4.8 million net acres) of properties in Canada to which no reserves have been specifically attributed. For lands in which Cenovus holds multiple leases under the same surface area, both gross and net areas have been counted for each lease.

Cenovus has rights to explore, develop, and exploit approximately 117,738 net acres that could potentially expire by December 31, 2020, which relate entirely to Crown and freehold land.

Properties with no attributed reserves include Crown lands where bitumen contingent and prospective resources have been identified and Crown lands where exploration activities to date have not identified potential reserves in commercial quantities. The Corporation regularly reviews the economic viability of these unproved properties on the basis of product pricing, capital availability and level of related infrastructure development. From this process, some properties are selected for future development activity while others are retained as inactive, sold, swapped or relinquished back to the mineral rights owner.

Additional Information Concerning Abandonment and Reclamation Costs

The estimated total future abandonment and reclamation costs for existing wells, facilities, and infrastructure is based on management's estimate of costs to remediate, reclaim and abandon wells and facilities having regard to Cenovus's working interest and the estimated timing of the costs to be incurred in future periods. Cenovus has 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.

Cenovus has estimated undiscounted and uninflated future abandonment and reclamation costs for its existing upstream assets of approximately $2,606 million (approximately $518 million, discounted at 10 percent) at December 31, 2019, of which the Corporation expects to pay between $120 million and $170 million in the next three financial years on a portion of the 10,239 net wells.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Cenovus's proved reserves, approximately $6.8 billion has been deducted in estimating the FNR, which represents the Corporation's total existing estimated abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.

Tax Horizon

In 2019, the Corporation was subject to relatively insignificant cash taxes. Based on projected future net earnings, the Corporation expects to pay relatively insignificant cash taxes on its 2020 earnings. This estimate could vary significantly if underlying assumptions change with respect to commodity prices, capital spending levels and acquisition and disposition transactions.

Costs Incurred

($ millions)	2019
Acquisitions	
Unproved	4
Proved	5
Total Acquisitions	**9**
Exploration Costs	**73**
Development Costs	**686**
Total Costs Incurred	**768**

Forward Contracts

Cenovus may use financial derivatives to manage its exposure to fluctuations in commodity prices, foreign exchange and interest rates. A description of such instruments is provided in the notes to the Corporation's annual audited Consolidated Financial Statements for the year ended December 31, 2019.

Production Estimates

The following table summarizes the 2020 estimated production of Company Interest Before Royalties reserves for all properties held on December 31, 2019 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.

2020 Estimated Production Forecast Prices and Costs	Proved	Proved plus Probable
Bitumen (bbls/d)(1)(2)	393,170	403,146
Light and Medium Oil (bbls/d)	4,051	4,643
NGLs (bbls/d)	17,534	18,421
Conventional Natural Gas (MMcf/d)(3)	372	396
Total (BOE/d)	476,822	492,269

(1) Includes Foster Creek production of 164,971 barrels per day for proved and 170,219 barrels per day for proved plus probable, and Christina Lake production of 226,244 barrels per day for proved and 230,241 barrels per day for proved plus probable.
(2) Includes heavy crude oil that is not material.
(3) Includes shale gas that is not material.

Production History and Per-Unit Results

	2019	Q4	Q3	Q2	Q1
Bitumen					
Total Production (bbls/d)	354,257	374,132	354,595	344,973	342,980
Foster Creek	159,598	161,705	156,527	165,953	154,156
Christina Lake	194,659	212,427	198,068	179,020	188,824
Sales Price ($/bbl)	53.78	48.05	54.94	62.68	49.67
Royalties ($/bbl)	8.97	9.29	10.29	10.13	5.97
Transportation and blending ($/bbl)	8.94	10.73	9.93	8.07	6.76
Operating expenses ($/bbl)	8.15	8.06	6.90	8.70	9.06
Netback excluding realized risk management(1)	27.72	19.97	27.82	35.78	27.88
Light and Medium Oil					
Total Production (bbls/d)	4,911	4,991	4,929	4,904	4,820
Sales Price ($/bbl)	65.70	64.48	68.53	69.71	59.90
Royalties ($/bbl)	10.54	10.84	5.98	16.37	9.00
Transportation and blending ($/bbl)	3.07	2.05	1.09	6.12	3.07
Operating expenses ($/bbl)	11.11	10.54	11.04	12.30	10.56
Netback excluding realized risk management(1)	40.98	41.05	50.42	34.92	37.27
Conventional Natural Gas(2)					
Total Production (MMcf/d)	424	403	407	432	458
Sales Price ($/Mcf)	2.01	2.59	1.21	1.29	2.89
Royalties ($/Mcf)	0.02	0.04	(0.03)	(0.03)	0.09
Transportation and blending ($/Mcf)	0.32	0.33	0.32	0.30	0.33
Operating expenses ($/Mcf)	1.41	1.45	1.36	1.29	1.54
Production and mineral taxes ($/Mcf)	0.01	–	0.01	0.01	0.01
Netback excluding realized risk management(1)	0.25	0.77	(0.45)	(0.28)	0.92
NGLs					
Total Production (bbls/d)	21,762	21,206	21,175	21,513	23,183
Sales Price ($/bbl)	26.36	27.22	22.16	27.36	28.53
Royalties ($/bbl)	0.90	0.93	(2.55)	2.27	2.81
Transportation and blending ($/bbl)	3.44	3.81	3.74	4.19	2.12
Operating expenses ($/bbl)	9.35	8.01	8.12	12.44	8.87
Netback excluding realized risk management(1)	12.67	14.47	12.85	8.46	14.73

(1) Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold. This calculation is consistent with the definition found in the Canadian Oil and Gas Evaluation Handbook. The crude oil sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Netback does not have a standardized meaning as prescribed by IFRS and therefore is considered a non-GAAP measure. As such, it may not be comparable to similar measures presented by other issuers. This measure has been described and presented in this AIF in order to provide shareholders and potential investors with additional information regarding Cenovus's liquidity and its ability to generate funds to finance its operations, and to comply with the requirements of NI 51-101. This measure should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. For further information, refer to Cenovus's most recent MD&A available at cenovus.com. For the reconciliation of the financial components of Netback to the GAAP measure and the sales volumes used in the calculations, see "Netback Reconciliations" in Appendix D.
(2) Includes shale gas that is not material.

Capital Expenditures, Acquisitions and Divestitures

Cenovus plans to invest between $1.3 billion and $1.5 billion in 2020, with approximately 70 percent targeted for sustaining capital primarily to maintain base production at its Foster Creek and Christina Lake operations. Cenovus also plans to advance potentially high-return projects to sanction-ready status to facilitate possible final investment decisions.

The following table summarizes Cenovus's net capital investment for 2019 and 2018:

Net Capital Investment

($ millions)	2019	2018
Capital Investment		
Oil Sands		
Foster Creek	243	379
Christina Lake	362	445
Total	605	824
Other Oil Sands	101	63
	706	887
Deep Basin	53	211
Refining and Marketing	280	208
Corporate	137	57
Capital Investment	1,176	1,363
Acquisitions	13	341
Divestitures	(5)	(1,375)
Net Acquisition and Divestiture Activity	8	(1,034)
Net Capital Investment(1)	1,184	329

(1) Includes expenditures on: property, plant and equipment; exploration and evaluation assets; and assets held for sale.

DIVIDENDS

The declaration of dividends is at the sole discretion of Cenovus's Board and is considered each quarter. The Board has approved a first quarter dividend of $0.0625 per share payable on March 31, 2020 to holders of Common Shares of record as of March 13, 2020. Readers should also refer to the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2019 MD&A, which section of the MD&A is incorporated by reference into this AIF, for additional information.

Cenovus paid the following dividends over the last three years:

Dividends Paid

($ per share)	Year	Q4	Q3	Q2	Q1
2019	0.2125	0.0625	0.05	0.05	0.05
2018	0.20	0.05	0.05	0.05	0.05
2017	0.20	0.05	0.05	0.05	0.05

DESCRIPTION OF CAPITAL STRUCTURE

Cenovus is authorized to issue an unlimited number of Common Shares and First Preferred Shares and Second Preferred Shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding Common Shares. As at December 31, 2019, there were approximately 1,228.8 million Common Shares and no First or Second Preferred Shares outstanding.

COMMON SHARES

The holders of Common Shares are entitled to: (i) receive dividends if, as and when declared by Cenovus's Board; (ii) 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) participate in any distribution of the Corporation's assets in the event of liquidation, dissolution or winding up or other distribution of its assets among its shareholders for the purpose of winding up its affairs.

PREFERRED SHARES

Preferred Shares may be issued in one or more series. Cenovus's 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 the Corporation fails 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 of Cenovus's affairs. The aggregate number of Preferred Shares issued by the Corporation may not exceed 20 percent of the aggregate number of Common Shares then outstanding.

SHAREHOLDER RIGHTS PLAN

Cenovus has a shareholder rights plan (the "Shareholder Rights Plan") which was adopted in 2009 and 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 Cenovus's 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 the Corporation's 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 reconfirmed at the 2018 annual and special meeting of shareholders and must be reconfirmed by the Corporation's shareholders every three years.

DIVIDEND REINVESTMENT PLAN

Cenovus has 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 Corporation, the additional Common Shares may be issued from treasury at the volume weighted average price of the Common Shares (denominated in the currency in which the Common Shares trade on the applicable stock exchange) traded on the Toronto Stock Exchange ("TSX") during the last five trading days preceding the relevant dividend payment date or purchased on the market.

EMPLOYEE STOCK OPTION PLAN

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise options to purchase Common Shares. For more information with respect to options to purchase Common Shares ("Options"), and Common Shares issued upon the exercise of Options, see the "Share Capital" and "Stock-based Compensation Plans" Notes in Cenovus's 2019 audited Consolidated Financial Statements.

RATINGS

The following information relating to Cenovus's credit ratings is provided as it relates to the Corporation's financing costs and liquidity. Specifically, credit ratings affect Cenovus's ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current rating on Cenovus's debt by the Corporation's rating agencies or a negative change in its ratings outlook could adversely affect Cenovus's cost of financing, its access to sources of liquidity and capital, and potentially obligate it to post incremental collateral in the form of cash, letters of credit or other financial instruments. See the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2019 MD&A, which section of the MD&A is incorporated by reference into this AIF, for further information.

The following table outlines the current ratings and outlooks of Cenovus's debt:

	S&P Global Ratings ("S&P")	Moody's Investors Service ("Moody's")	DBRS Limited ("DBRS")	Fitch Ratings Inc. ("Fitch")
Senior Unsecured				
Long-Term Rating	BBB	Ba1	BBB	BBB-
Outlook/Trend	Stable	Positive	Stable	Stable

Credit ratings are intended to provide an independent measure of the credit quality of an issue of securities. The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the securities nor do the ratings comment on market price or suitability for a particular investor. A rating may not remain in effect for any given period of time and may be revised or withdrawn entirely by a rating agency at any time 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 "+" or "-" designation after a rating indicates the relative standing within the major rating categories. An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). Rating outlooks fall into five categories – "Positive", "Negative", "Stable", "Developing", and "Not Meaningful". In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions. A "Stable" outlook 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 Ba by Moody's is within the fifth highest of nine categories and is assigned to debt securities which are considered speculative and subject to substantial credit risk. 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. A Moody's rating outlook is an opinion regarding the likely rating direction over the medium term. Rating outlooks fall into four categories – "Positive", "Negative", "Stable", and "Developing". A designation of Positive indicates a higher likelihood of an upward rating change over the medium term.

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 BBB by DBRS is within the fourth highest of 10 categories and is assigned to debt securities considered to be of adequate credit quality, with acceptable capacity for payment of financial obligations. Entities in the BBB category may be vulnerable to future events. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. Rating trends provide guidance in respect of DBRS's opinion regarding the outlook for the rating in question, with rating trends falling into one of three categories - "Positive", "Stable" or "Negative". The rating trend indicates the direction in which DBRS considers the rating is headed should present circumstances continue, or in some cases, unless challenges are addressed.

Fitch'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 is within the fourth highest of 11 categories and is assigned to debt securities considered to be of good credit quality. BBB ratings indicate that expectations of default risk are currently low. The capacity for payment of financial commitments is considered adequate but adverse business or economic conditions are more likely to impair this capacity. The modifiers "+" or "-" may be appended to a rating to denote relative status within major rating categories. A Fitch rating outlook indicates the direction a rating is likely to move over a one to two-year period, with rating outlooks falling into four categories: "Positive", "Negative", "Stable" or "Evolving". Rating outlooks reflect financial or other trends that have not yet reached or have not been sustained at a level that would trigger a rating action, but which may do so if such trends continue. Positive or Negative outlooks do not imply that a rating change is inevitable and similarly, ratings with Stable outlooks can be raised or lowered without prior revision of the outlook. Where the fundamental trend has strong, conflicting elements of both positive and negative, the rating outlook may be described as Evolving.

Throughout the last three years, Cenovus has made payments to each of S&P, Moody's, DBRS and Fitch related to the rating of the Corporation's debt. Additionally, Cenovus has purchased products and services from S&P, Moody's, DBRS and Fitch.

MARKET FOR SECURITIES

All of the outstanding Common Shares are listed and posted for trading on the 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 2019:

	TSX				NYSE			
	Share Price Trading Range				Share Price Trading Range			
	High(1)	Low(1)	Close(1)	Share Volume(2)	High(3)	Low(3)	Close(3)	Share Volume(4)
	($ per share)			(thousands)	(US$ per share)			(thousands)
January	10.93	9.19	10.26	183,614	8.26	6.75	7.79	78,719
February	12.24	9.62	12.06	143,100	9.32	7.24	9.16	92,538
March	12.40	10.68	11.60	157,486	9.27	7.96	8.68	89,288
April	14.26	11.75	13.28	203,845	10.60	8.82	9.91	124,443
May	13.30	10.85	11.08	153,196	9.92	8.04	8.19	99,274
June	12.09	10.29	11.55	128,923	9.16	7.68	8.82	78,261
July	12.82	11.36	12.27	110,604	9.76	8.66	9.28	79,411
August	12.22	10.75	11.62	121,102	9.25	8.07	8.73	67,405
September	14.31	11.24	12.43	154,563	10.82	8.42	9.38	86,810
October	12.60	10.64	11.22	127,123	9.48	8.01	8.49	90,882
November	12.56	11.25	11.74	104,530	9.49	8.56	8.89	53,165
December	13.36	11.33	13.20	122,516	10.24	8.52	10.15	60,890

(1) As reported by the TSX.
(2) As reported by all Canadian marketplaces. Source: Bloomberg.
(3) As reported by the NYSE.
(4) As reported by all U.S. marketplaces. Source: Bloomberg.

DIRECTORS AND EXECUTIVE OFFICERS

DIRECTORS

The following individuals are directors of Cenovus as at December 31, 2019, unless otherwise indicated.

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Susan F. Dabarno[2,4] Bracebridge, Ontario, Canada	2017 Independent	Ms. Dabarno is a director of Manulife Financial Corporation, a publicly traded insurance and financial services company, since March 2013. Ms. Dabarno has extensive wealth management and financial expertise and served as Executive Chair of Richardson Partners Financial Limited ("Richardson"), an independent wealth management services firm, from October 2009 to April 2010, and as President and Chief Executive Officer from June 2003 to October 2009. Prior to joining Richardson, she was President and Chief Operating Officer at Merrill Lynch Canada Inc.
Patrick D. Daniel[6] Calgary, Alberta, Canada	2009 (Chair) Independent	Mr. Daniel has served as the Chair of Cenovus's Board since April 2017. He is a director of Canadian Imperial Bank of Commerce. Mr. Daniel served as Chair of the North American Review Board of American Air Liquide Holdings, Inc., a subsidiary of a publicly traded industrial gases service company from 2013 to 2018; a director of Capital Power Corporation, a publicly traded North American power producer from February 2015 to April 2018; and a director of Enbridge Inc. ("Enbridge"), a publicly traded energy delivery company, from April 2000 to October 2012. During his tenure with Enbridge, he also served as Chief Executive Officer from February 2012 to October 2012, as President & Chief Executive Officer from January 2001 to February 2012 and as a senior executive officer of Enbridge and its predecessor from 1994.
Jane E. Kinney[2,5] Toronto, Ontario, Canada	2019 Independent	Ms. Kinney is a director of Intact Financial Corporation, a publicly traded insurance company, since May 2019. Ms. Kinney spent 25 years with Deloitte LLP Canada ("Deloitte") and was admitted to the Deloitte Partnership in 1997. She was appointed Vice Chair, Leadership Team Member of Deloitte in June 2010 and served in this role until her retirement in June 2019. Previous positions with Deloitte include Canadian Managing Partner, Quality & Risk from May 2010 to June 2015, Global Chief Risk Officer from June 2010 to May 2012, and Risk and Regulatory Practice Leader from June 1999 to May 2010. She has also served as a lecturer at the University of Manitoba, Dalhousie University and Saint Mary's University.
Harold N. Kvisle[2,4] Calgary, Alberta, Canada	2018 Independent	Mr. Kvisle is a director, since May 2009, and Chairman of ARC Resources Ltd., a publicly traded oil and gas company; and a director, since June 2017, and Board Chair of Finning International Inc., a publicly traded heavy equipment company. He served as a director of Cona Resources Ltd. ("Cona"), a publicly traded heavy oil company, from November 2011 to May 2018 when Cona was acquired by Waterous Energy Fund. Mr. Kvisle served as President and Chief Executive Officer of Talisman Energy Inc. ("Talisman"), a publicly traded oil and gas company, from September 2012 to May 2015 and as a director of Talisman from May 2010 to May 2015. From 2001 to 2010, Mr. Kvisle was President and Chief Executive Officer of TransCanada Corporation, now TC Energy Corporation ("TC Energy"), a publicly traded energy infrastructure company. Prior to joining TC Energy in 1999, he was the President of Fletcher Challenge Energy Canada Inc. Mr. Kvisle has worked in the oil and gas industry since 1975 and in the utilities and power industries since 1999.

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Steven F. Leer[3,4] Boca Grande, Florida, United States	2015 Independent	Mr. Leer is lead director of Norfolk Southern Corporation, a publicly traded North American rail transportation provider, since 1999; and a director of Parsons Corporation, a publicly traded engineering, construction, technical, and management services firm, since April 2013. Mr. Leer served as a director and the non-executive Chairman of the Board of USG Corporation ("USG"), a publicly traded manufacturer and distributor of high performance building systems, from November 2016 to April 2019; he served as lead director of USG from January 2012 to November 2016, and as a director from June 2005 to January 2012. Mr. Leer also served as Chairman of Arch Coal, Inc. ("Arch Coal"), a publicly traded coal producing company, from April 2006 to April 2014 and served as a director of Arch Coal and its predecessor company from 1992 until April 2014. During his tenure with Arch Coal and its predecessor company, he also served as Chief Executive Officer from July 1992 to April 2012 and President from July 1992 to April 2006.
M. George Lewis [3,4] Toronto, Ontario, Canada	2019 Independent	Mr. Lewis is a director of Legal & General Group plc, a publicly traded global asset and risk management company, since November 2018; a director of AOG Group, a private European-based capital investment firm, since November 2018; and a director of the Ontario Teachers' Pension Plan, since April 2019. Mr. Lewis is a former director of and Chair of the Audit and Risk Committee at Ontario Power Generation, a government-owned energy company, and Enbridge Income Fund Holdings Inc., which was acquired by Enbridge Inc. in November 2018. Prior to his retirement in 2016, Mr. Lewis held progressively more responsible positions with Royal Bank of Canada ("RBC"). He was appointed as a member of RBC's Group Executive with responsibility for Wealth Management in 2007, adding Insurance in 2012.
Keith A. MacPhail[3,5] Calgary, Alberta, Canada	2018 Independent	Mr. MacPhail is a director, since November 1997, and Chairman of Bonavista Energy Corporation, formerly Bonavista Petroleum Ltd. ("Bonavista"), a publicly traded oil and gas company; a director and Chairman of NuVista Energy Ltd., a publicly traded oil and gas company, since July 2003; and serves on the board of directors of a private oil and gas service company. Mr. MacPhail served as Executive Chairman of Bonavista from 2012 to 2018; as Chairman and Chief Executive Officer from 2008 to 2012; and as President and Chief Executive Officer from 1997 to 2008. Prior to joining Bonavista in 1997, Mr. MacPhail held progressively more responsible positions with Canadian Natural Resources Limited, with his final position being Executive Vice President and Chief Operating Officer. Previously, he held the position of Production Manager with Poco Petroleums Ltd.
Richard J. Marcogliese[3,5] Alamo, California, United States	2016 Independent	Mr. Marcogliese is the Principal of iRefine, LLC, a privately owned petroleum refining consulting company, since June 2011; and Executive Advisor of Pilko & Associates L.P., a private chemical and energy advisory company, since June 2011. As of January 1, 2020, Mr. Marcogliese was appointed as a director of Delek US Holdings, Inc., a publicly traded downstream energy company. He served as Operations Advisor to NTR Partners III LLC, a private investment company from October 2013 to December 2017; and served as Operations Advisor to the CEO of Philadelphia Energy Solutions, a partnership between The Carlyle Group and a subsidiary of Energy Transfer Partners, L.P. that operates an oil refining complex on the U.S. Eastern seaboard, from September 2012 to January 2016.

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Claude Mongeau[2,5] Montreal, Quebec, Canada	2016 Independent	Mr. Mongeau is a director of The Toronto-Dominion Bank, an international financial institution, since March 2015; and a director of Norfolk Southern Corporation, a publicly traded North American rail transportation provider, since September 2019. He served as a director of TELUS Corporation, a publicly traded telecommunications company, from May 2017 to August 2019. He also served as a director of Canadian National Railway Company, a publicly traded railroad and transportation company, from October 2009 to July 2016 and as President and Chief Executive Officer from January 2010 to June 2016. During his tenure with Canadian National Railway Company, he also served as Executive Vice-President and Chief Financial Officer from October 2000 until December 2009, and held various increasingly senior positions from the time he joined in 1994. Mr. Mongeau also served as a director of SNC-Lavalin Group Inc. from August 2003 to May 2015.
Alexander J. Pourbaix[7] Calgary, Alberta, Canada	2017	Mr. Pourbaix has served as President & Chief Executive Officer of Cenovus since November 6, 2017 and is a director of Canadian Utilities Limited, a publicly traded diversified global energy infrastructure corporation, since November 2019. He served as a director of Trican Well Service Ltd., a publicly traded oilfield services provider, from May 2012 to December 2019. Mr. Pourbaix served as Chief Operating Officer of TC Energy from October 2015 to April 2017. During his tenure with TC Energy, he also served as Executive Vice-President and President, Development from March 2014 to September 2015 and President, Energy & Oil Pipelines from July 2010 to February 2014, and held various increasingly senior positions from the time he joined TC Energy in 1994.
Wayne G. Thomson[2,5] Calgary, Alberta, Canada	2009 Independent	Mr. Thomson is Chairman of Inventys Thermal Technologies Inc. (“Inventys”), a private carbon capture technology company, since October 2015; Chairman and President of Enviro Valve Inc., a private company manufacturing proprietary pressure relief valves, since July 2009; and serves on the board of directors of one other private company. Mr. Thomson served as a director and Chairman of Maha Energy Inc., a publicly traded Swedish oil and gas company, from November 2014 to May 2019; a director of TVI Pacific Inc., a publicly traded international mining company, from May 2011 to June 2017; interim Executive Chairman of Inventys from May 2016 to February 2017; and as Chief Executive Officer of Iskander Energy Corp., a private international oil and gas company, from November 2011 to August 2014 and as a director from November 2011 to March 2016.
Rhonda I. Zygocki[3,4] Friday Harbor, Washington, United States	2016 Independent	Ms. Zygocki served as Executive Vice President, Policy and Planning of Chevron Corporation (“Chevron”), a publicly traded integrated energy company, from March 2011 until her retirement in February 2015 and prior thereto, during her 34 years with Chevron, she held a number of senior management and executive leadership positions in international operations, public affairs, strategic planning, policy, government affairs and health, environment and safety.

(1) Directors were elected or appointed to Cenovus's Board as follows:
- *Messrs. Daniel and Thomson first became members of Cenovus's Board pursuant to the Arrangement;*
- *Mr. Leer was first elected as a director of Cenovus's Board at the annual and special meeting of shareholders held on April 29, 2015,*
- *Ms. Zygocki and Mr. Marcogliese were first elected as directors of Cenovus's Board at the annual meeting of shareholders held on April 27, 2016,*
- *Mr. Mongeau was appointed as a director of Cenovus's Board as of December 1, 2016;*
- *Ms. Dabarno was first elected as a director of Cenovus's Board at the annual meeting of shareholders held on April 26, 2017;*
- *Mr. Pourbaix was appointed as President and Chief Executive Officer and a director of Cenovus's Board as of November 6, 2017;*
- *Messrs. Kvisle and MacPhail were first elected as directors of Cenovus's Board at the annual meeting of shareholders held on April 25, 2018;*
- *Ms. Kinney was elected as a director of Cenovus's Board at the annual meeting of shareholders held on April 24, 2019; and*
- *Mr. Lewis was appointed as a director of Cenovus's Board as of July 24, 2019.*

The term of each of the directors is from the date of the meeting at which he or she is elected or appointed until the next annual meeting of shareholders or until a successor is elected or appointed.

(2) Member of the Audit Committee.

(3) Member of the Human Resources and Compensation Committee.

(4) Member of the Nominating and Corporate Governance Committee.

(5) Member of the Safety, Environment, Responsibility and Reserves Committee. (The Reserves Committee was dissolved as of April 24, 2019 and its mandate and responsibilities were transferred to the Safety, Environment and Responsibility Committee, which subsequently changed its name to the Safety, Environment, Responsibility and Reserves Committee.)

(6) Ex officio, by standing invitation, non-voting member of all other committees of the Board. As an ex officio non-voting member, Mr. Daniel attends as his schedule permits and may vote when necessary to achieve a quorum.

(7) As an officer and a non-independent director, Mr. Pourbaix is not a member of any of the committees of the Board.

EXECUTIVE OFFICERS

The following individuals served as executive officers of Cenovus as at December 31, 2019, unless otherwise indicated.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Alexander J. Pourbaix Calgary, Alberta, Canada	President & Chief Executive Officer Mr. Pourbaix's biographical information is included under "Directors".
Jonathan M. McKenzie Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer Mr. McKenzie has been Executive Vice-President & Chief Financial Officer of Cenovus since May 1, 2018. From April 2015 to April 2018, Mr. McKenzie was Chief Financial Officer of Husky Energy Inc. From April 2011 to April 2015, Mr. McKenzie was Chief Financial Officer and Chief Commercial Officer of Irving Oil Ltd. From March 2009 to May 2011, Mr. McKenzie was Vice-President and Controller of Suncor Energy Inc.
Harbir S. Chhina Calgary, Alberta, Canada	Executive Vice-President & Chief Technology Officer Mr. Chhina became Executive Vice-President & Chief Technology Officer on April 25, 2017. From September 2015 to April 2017, Mr. Chhina was Executive Vice-President, Oil Sands Development; from December 2010 to August 2015, Mr. Chhina was Executive Vice-President, Oil Sands; and from November 2009 to November 2010, Mr. Chhina was Executive Vice-President, Enhanced Oil Development & New Resource Plays of Cenovus.
Keith A. Chiasson Calgary, Alberta, Canada	Executive Vice-President, Downstream Mr. Chiasson became Executive Vice-President, Downstream on March 1, 2019. From December 2017 to February 2019, Mr. Chiasson was Senior Vice-President, Downstream. From May 2017 to December 2017, Mr. Chiasson was Vice-President, Oil Sands Production Operations; and from July 2016 to May 2017, Mr. Chiasson was Vice-President, Operations of Cenovus. From April 2016 to July 2016, Mr. Chiasson was Kearl Operations Manager at Imperial Oil Resources. From September 2013 to April 2016, Mr. Chiasson was U.S. Operations Manager for ExxonMobil. From January 2012 to September 2013, Mr. Chiasson was Planning and Business Analysis Manager for ExxonMobil Production Company.
Alan C. Reid Calgary, Alberta, Canada	Executive Vice-President, Stakeholder Engagement, Safety, Legal & General Counsel Mr. Reid became Executive Vice-President, Stakeholder Engagement, Safety, Legal & General Counsel on December 14, 2017. From December 2015 to December 2017, Mr. Reid was Executive Vice-President, Environment, Corporate Affairs & Legal and General Counsel; from September 2015 to November 2015, Mr. Reid was Executive Vice-President, Environment, Corporate Affairs & Legal; from January 2014 to August 2015, Mr. Reid was Senior Vice-President, Christina Lake & Narrows Lake; from January 2012 to January 2014, Mr. Reid was Cenovus's Senior Vice-President, Christina Lake; and from November 2009 to January 2012, Mr. Reid was Vice-President, Regulatory, Health & Safety of Cenovus.
Norrie C. Ramsay Calgary, Alberta, Canada	Executive Vice-President, Upstream Dr. Ramsay became Executive Vice-President of Cenovus on December 1, 2019 and was appointed Executive Vice-President, Upstream effective January 1, 2020. From June 2019 to November 2019, Dr. Ramsay was Senior Vice-President, Projects at TC Energy and from August 2014 to May 2019, Dr. Ramsay was Senior Vice-President, Technical Centre & Projects at TC Energy. From May 2010 to July 2014, Dr. Ramsay was Global Vice-President, Projects & Engineering at Talisman Energy Inc.
Karamjit S. Sandhar Calgary, Alberta, Canada	Senior Vice-President, Deep Basin Mr. Sandhar was appointed Senior Vice-President, Deep Basin effective January 1, 2020. From December 2017 to December 2019, Mr. Sandhar was Senior Vice-President, Strategy & Corporate Development. From July 2016 until December 2017, Mr. Sandhar was Vice-President, Investor Relations & Corporate Development; from May 2016 to July 2016, Mr. Sandhar was Vice-President, Investor Relations; from May 2015 to May 2016, Mr. Sandhar was Director, Investor Relations; and from April 2013 to May 2015 Mr. Sandhar was Principal, Portfolio Management.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Sarah J. Walters Calgary, Alberta, Canada	Senior Vice-President, Corporate Services Mrs. Walters became Senior Vice-President, Corporate Services on December 14, 2017. From January 2017 until December 2017, Mrs. Walters was Vice-President, Human Resources; from September 2015 to December 2016, Mrs. Walters was Vice-President, Organization & People; from March 2014 to August 2015, Mrs. Walters was Vice-President HR Business Partners & Organizational Design; from July 2013 to February 2014, Mrs. Walters was Vice-President, HR Business Partners; and from March 2013 to July 2013, Mrs. Walters was Vice-President, HR Advisory of Cenovus. Prior to joining Cenovus in March 2013, Mrs. Walters was Vice-President HR, International Operations West at Talisman Energy Inc.
J. Drew Zieglgansberger Calgary, Alberta, Canada	Executive Vice-President, Strategy & Corporate Development Mr. Zieglgansberger was appointed Executive Vice-President, Strategy & Corporate Development effective January 1, 2020. From January 2018 to December 2019, Mr. Zieglgansberger was Executive Vice-President, Upstream; from April 2017 to January 2018, Mr. Zieglgansberger was Executive Vice-President, Deep Basin; from September 2015 to April 2017, Mr. Zieglgansberger was Executive Vice-President, Oil Sands Manufacturing; from June 2015 to August 2015, Mr. Zieglgansberger was Executive Vice-President, Operations Shared Services; from June 2012 to May 2015, Mr. Zieglgansberger was Senior Vice-President, Operations Shared Services; from January 2012 to May 2012, Mr. Zieglgansberger was Senior Vice-President, Regulatory, Local Community & Military; and from December 2010 to January 2012, Mr. Zieglgansberger was Senior Vice-President, Christina Lake of Cenovus.

As of December 31, 2019, all of Cenovus's directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 2,234,156 Common Shares or approximately 0.18 percent of the number of Common Shares that were outstanding as of such date.

Investors should be aware that some of Cenovus's 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 the Corporation's knowledge, none of its current directors or executive officers are, as at the date of this AIF, or have 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 (each, an "Order") and that was issued while that director or executive officer 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 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 the Corporation's knowledge, none of its 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 the Corporation's knowledge, none of its 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 penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

The Audit Committee mandate is included as Appendix C to this AIF.

COMPOSITION OF THE AUDIT COMMITTEE

The Audit Committee consists of five members, each of whom is independent and financially literate in accordance with National Instrument 52-110 *Audit Committees*. The Board has determined that each of the following members of Cenovus's Audit Committee qualifies as an "audit committee financial expert", as that term is defined under U.S. securities legislation: Claude Mongeau, Susan F. Dabarno, Jane E. Kinney and Wayne G. Thomson. 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.

Claude Mongeau (Audit Committee Chair)

Mr. Mongeau holds a Masters of Business Administration degree from McGill University and has received honorary doctorate degrees from St. Mary's and Windsor University. He is a director of The Toronto-Dominion Bank, an international financial institution, and Norfolk Southern Corporation, a publicly traded rail transportation provider. He served as a director of TELUS Corporation, a publicly traded telecommunications company, from May 2017 to August 2019. He served as a director of Canadian National Railway Company, a publicly traded railroad and transportation company, from October 2009 to July 2016 and as President and Chief Executive Officer from January 2010 to June 2016. During his tenure with Canadian National Railway Company, he served as Executive Vice-President and Chief Financial Officer from October 2000 until December 2009 and from the time he joined Canadian National Railway Company in 1994 he held the titles of Senior Vice-President and Chief Financial Officer, Vice-President, Strategic and Financial Planning and Assistant Vice-President, Corporate Development.

Susan F. Dabarno

Ms. Dabarno is a chartered professional accountant, a Fellow of the Chartered Professional Accountants of Ontario (FCPA) and holds a Class II Diploma from McGill University. She has extensive wealth management and financial expertise gained from her many years of experience building and leading some of the largest wealth management platforms in Canada. Ms. Dabarno served as Executive Chairman of Richardson Partners Financial Limited ("Richardson"), an independent wealth management services firm, from October 2009 to April 2010, and as President and Chief Executive Officer of Richardson from June 2003 to October 2009, during which time she was responsible for leading the firm's growth strategy. Prior to joining Richardson, she was President and Chief Operating Officer at Merrill Lynch Canada Inc., and prior to that she held various increasingly senior roles with Canada Trust and later Midland Walwyn Inc., until it was acquired by Merrill Lynch in 1999. In each of these positions, Ms. Dabarno was progressively responsible for personal investment management, private equity and alternative investment strategies, while adhering to strict regulatory requirements and governance protocols applied to the industry.

Jane E. Kinney

Ms. Kinney is a chartered professional accountant, a Fellow of the Chartered Professional Accountants of Ontario (FCPA) and holds a Mathematics degree from the University of Waterloo. She is a seasoned business leader with over 30 years of experience in providing advisory services to global financial institutions and has extensive experience in enterprise risk management, regulatory compliance, cyber and IT risk management, digital transformation and stakeholder relations.

Ms. Kinney is a director of Intact Financial Corporation, a publicly traded insurance company. She spent 25 years with Deloitte, and was admitted to the Deloitte Partnership in 1997. She was appointed Vice Chair, Leadership Team Member of Deloitte in June 2010 and served in this role until her retirement in June 2019. Previous positions with Deloitte include Canadian Managing Partner, Quality & Risk from May 2010 to June 2015, Global Chief Risk Officer from June 2010 to May 2012, and Risk and Regulatory Practice Leader from June 1999 to May 2010.

Harold N. Kvisle

Mr. Kvisle holds a Bachelor of Science in Engineering degree from the University of Alberta, a Masters in Business Administration degree from the University of Calgary and an Honorary Bachelor of Arts from Mount Royal University.

Mr. Kvisle is a director and Chairman of ARC Resources Ltd., a publicly traded oil and gas company and is a director and Board Chair of Finning International Inc., a publicly traded heavy equipment company. Mr. Kvisle served as President and Chief Executive Officer of Talisman, a publicly traded oil and gas company, from September 2012 to May 2015 and as a director of Talisman from May 2010 to May 2015. From 2001 to 2010, Mr. Kvisle was President and Chief Executive Officer of TransCanada Corporation, now TC Energy, a publicly traded pipeline and power company. Prior to joining TC Energy in 1999, he was the President of Fletcher Challenge Energy Canada Inc. Previously, he held engineering, finance and management positions with Dome Petroleum Limited. Mr. Kvisle has worked in the oil and gas industry since 1975 and in the utilities and power industries since 1999. He also served as a director of Cona Resources Ltd., a publicly traded heavy oil company, from November 2011 to May 2018.

Wayne G. Thomson

Mr. Thomson holds a Bachelor of Science of Mechanical Engineering degree (University of Manitoba) and is a professional engineer. He is Chairman of Inventys Thermal Technologies Inc. ("Inventys"). He has also served as Chairman and President of Enviro Valve Inc., a private company manufacturing proprietary pressure relief valves, since 2009. Mr. Thomson served as a director and Chairman of Maha Energy Inc., a publicly traded Swedish oil and gas company from November 2014 to May 2019; a director of TVI Pacific Inc. from May 2011 to June 2017; as interim Executive Chairman of Inventys from May 2016 to February 2017; and as Chief Executive Officer of Iskander Energy Corp ("Iskander") from November 2011 to August 2014 and as director of Iskander from November 2011 to March 2016.

The above list does not include Patrick D. Daniel who is, by standing invitation as Chair of the Board, an *ex officio* member of Cenovus's Audit Committee.

PRE-APPROVAL POLICIES AND PROCEDURES

Cenovus has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP. The Audit Committee has established a budget for the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by PricewaterhouseCoopers LLP, the Corporation's auditor. 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 have 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, 2019 and 2018:

($ thousands)	**2019**	2018
Audit Fees(1)	**2,938**	2,885
Audit-Related Fees(2)	**226**	344
Tax Fees(3)	**2**	3
All Other Fees(4)	**284**	21
Total	**3,450**	3,253

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

(2) Audit-Related Fees consist of the aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as Audit Fees. The services provided in this category included audit-related services in relation to Cenovus's prospectuses, systems development, controls testing and participation fees levied by the Canadian Public Accountability Board. Fees related to the acquisition or divestiture of assets are also included in Audit-Related Fees.

(3) Tax Fees consist of the aggregate fees billed for tax compliance and tax advice.

(4) All Other Fees include fees billed for the review of Extractive Sector Transparency Measures Act filings, advisory services around Enterprise Resource Planning and the Corporation's Innovation Processes.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

During the year ended December 31, 2019, there were no legal proceedings to which Cenovus is or was a party, or that any of its property is or was the subject of, which involves a claim for damages in an amount, exclusive of interest and costs, that exceeds 10 percent of Cenovus's current assets and it is not aware of any such legal proceedings that are contemplated.

During the year ended December 31, 2019, there were no penalties or sanctions imposed against Cenovus by a court relating to 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 the Corporation that would likely be considered important to a reasonable investor in making an investment decision, and it has not entered into any settlement agreements before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Corporation's 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 Cenovus's outstanding voting securities, of which there are none that the Corporation is 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 within the three most recently completed financial years or any proposed transaction that has materially affected or is reasonably expected to materially affect Cenovus.

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

MATERIAL CONTRACTS

Other than as set forth below, during the year ended December 31, 2019, Cenovus has not entered into any contracts, nor are there any contracts still in effect, that are material to the business, other than contracts entered into in the ordinary course of business.

On March 29, 2017, Cenovus entered into a purchase and sale agreement (the "Acquisition Agreement") with ConocoPhillips to acquire: (i) ConocoPhillips' 50 percent interest (the "FCCL Interest") (being the remaining 50 percent interest that Cenovus did not already own) in FCCL Partnership, the owner of the Foster Creek, Christina Lake and Narrows Lake oil sands projects in northeast Alberta (the "FCCL Assets"), and (ii) the majority of ConocoPhillips' western Canadian conventional assets, including ConocoPhillips' exploration and production assets and related infrastructure and agreements in the Elmworth-Wapiti, Kaybob-Edson and Clearwater operating areas and other operating areas, and all of ConocoPhillips' interest in petroleum and natural gas rights and oil sands leases within a certain area of mutual interest northwest of Foster Creek (the "Deep Basin Assets"). The FCCL Interest and the Deep Basin Assets were acquired by Cenovus for total consideration of $17.6 billion, comprised of $15.0 billion cash, and 208 million Common Shares. Cenovus agreed to make quarterly payments to ConocoPhillips during the five years subsequent to the closing date of the Acquisition for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. The quarterly payment will be $6 million for each dollar that the WCS price exceeds $52 per barrel. There are no maximum payment terms. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment.

At closing of the Acquisition, Cenovus and ConocoPhillips entered into a registration rights agreement ("Registration Rights Agreement") and an investor agreement ("Investor Agreement"), which, among other things, restricted ConocoPhillips from selling or hedging its Common Shares until November 17, 2017. In addition, the Registration Rights Agreement provides ConocoPhillips with certain rights to facilitate the sale of its Common Shares, including the right to require Cenovus to qualify the distribution of the Common Shares held by ConocoPhillips and the right to piggy-back on an offering of Common Shares by Cenovus. The Investor Agreement places certain restrictions on ConocoPhillips, including from nominating new members to Cenovus's board of directors and by requiring ConocoPhillips to vote its Common Shares in accordance with management recommendations or abstain from voting. The Registration Rights Agreement and the Investor Agreement will terminate when ConocoPhillips owns 3.5 percent or less of the then outstanding Common Shares.

A copy of the Acquisition Agreement, which includes the forms of the Contingent Payment Agreement, Registration Rights Agreement and Investor Agreement, in redacted form, was filed on SEDAR on April 5, 2017, and a copy of

the amendment to the Acquisition Agreement was filed on SEDAR on May 17, 2017, each of which may be viewed under Cenovus's profile at sedar.com.

Particulars for each of the Arrangement Agreement and the Separation Agreement (previously filed material contracts that are still in effect) are defined and described in the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2019 MD&A, and such section of the MD&A is incorporated by reference into this AIF.

INTERESTS OF EXPERTS

The Corporation's independent auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated February 11, 2020 in respect of Cenovus's Consolidated Financial Statements which comprise the Consolidated Balance Sheets as at December 31, 2019 and December 31, 2018 and the Consolidated Statements of Earnings, Comprehensive Income, Shareholders' Equity and Cash Flows for the years ended December 31, 2019, 2018, and 2017 and Cenovus's internal control over financial reporting as at December 31, 2019. PricewaterhouseCoopers LLP has advised that they are independent with respect to Cenovus within the meaning of the Code of Professional Conduct of the Chartered Professional Accountants of Alberta and the rules of the SEC.

Information relating to reserves in this AIF has been calculated by McDaniel and GLJ as independent qualified reserves evaluators. The partners, employees or consultants of each of McDaniel and GLJ, in each case, as a group own beneficially, directly or indirectly, less than one percent of any class of the Corporation's outstanding securities.

ADDITIONAL INFORMATION

Additional information relating to Cenovus is available on SEDAR at sedar.com and EDGAR at sec.gov. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Cenovus's securities, and securities authorized for issuance under its equity-based compensation plans, is included in the Corporation's management information circular for its most recent annual meeting of shareholders.

Additional financial information can be found in Cenovus's audited annual Consolidated Financial Statements and MD&A for the year ended December 31, 2019.

As a Canadian corporation listed on the NYSE, Cenovus is not required to comply with most of the NYSE's corporate governance standards, and instead may comply with Canadian corporate governance practices. However, the Corporation is required to disclose the significant differences between its corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. Except as summarized on Cenovus's website at cenovus.com, it is 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, 2019 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

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	AECO	Alberta Energy Company
bbls/d	barrels per day	Bcf	billion cubic feet
Mbbls/d	thousand barrels per day	Mcf	thousand cubic feet
MMbbls	million barrels	MMcf	million cubic feet
NGLs	natural gas liquids	MMcf/d	million cubic feet per day
BOE	barrel of oil equivalent	MMBtu	million British thermal units
BOE/d	barrels of oil equivalent per day		
MMBOE	million barrels of oil equivalent		
WTI	West Texas Intermediate		
WCS	Western Canadian Select		

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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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.

5. The following table shows the net present value of 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 for the year ended December 31, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's Board of Directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Evaluated Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) $ millions
McDaniel & Associates Consultants Ltd.	December 31, 2019	Canada	$50,710
GLJ Petroleum Consultants Ltd.	December 31, 2019	Canada	$2,127
			$52,837

6. 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.

7. We have no responsibility to update our reports referred to in paragraph five for events and circumstances occurring after their respective effective dates.

8. 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:

/s/ Brian R. Hamm

Brian R. Hamm, P. Eng.
President & CEO
McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

/s/ Jodi L. Anhorn

Jodi L. Anhorn, P. Eng.
President and Chief Executive Officer
GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

February 11, 2020

APPENDIX B

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management 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.

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 Safety, Environment, Responsibility and Reserves Committee of the Board of Directors of the Corporation has:

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

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

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

The Board of Directors of the Corporation has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Safety, Environment, Responsibility and Reserves Committee, approved:

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

/s/ Alexander J. Pourbaix

Alexander J. Pourbaix
President & Chief Executive Officer

/s/ Jonathan M. McKenzie

Jonathan M. McKenzie
Executive Vice-President &
Chief Financial Officer

/s/ Patrick D. Daniel

Patrick D. Daniel
Director and Chair of the Board

/s/ Wayne G. Thomson

Wayne G. Thomson
Director and Chair of the Safety, Environment, Responsibility and Reserves Committee

February 11, 2020

APPENDIX C

AUDIT COMMITTEE MANDATE

PURPOSE

The Audit Committee (the "Committee") is a committee of the Board of Directors (the "Board") 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.
- Report to the Board 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.

CONSTITUTION, COMPOSITION AND DEFINITIONS

1. Reporting

The Committee shall report to the Board.

2. 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.

3. 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.

4. Vacancies

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

5. Chair

The Nominating and Corporate Governance Committee will recommend for approval to the Board an independent 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.

6. 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.

7. 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 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.

The Committee shall meet without the presence of management on a regular basis, to facilitate additional open and candid discussion among independent directors.

8. 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.

9. 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.

10. Attendance at Meetings

The Chief Executive Officer, the 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.

11. 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.

RESPONSIBILITIES

In carrying out its mandate, the Committee is expected to:

12. Review Procedures

(a) 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.

(b) 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.

13. Annual Financial Statements

(a) 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:

(i) 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.

(ii) Management's Discussion and Analysis.

(iii) The use of off-balance sheet financing including management's risk assessment and adequacy of disclosure.

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

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

(vi) 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.

(vii) Other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards.

(b) Review and formally recommend approval to the Board of the Corporation's:

(i) 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.

(ii) Management's Discussion and Analysis.

(iii) Annual Information Form as to financial information.

(iv) 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.

14. Quarterly Financial Statements

(a) 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:

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

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

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

15. Other Financial Filings and Public Documents

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 press 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.

16. Internal Control Environment

(a) 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.

(b) 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.

(c) 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.

(d) Review with the Chief Executive Officer, the 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.

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

17. Risk Oversight

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

18. Other Review Items

(a) Review the process for the certification of the interim and annual financial statements by the Chief Executive Officer and Chief Financial Officer, and the certifications made by the Chief Executive Officer and Chief Financial Officer.

(b) 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.

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

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

(e) 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.

(f) 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.

(g) Ensure that the Corporation's presentation of hydrocarbon reserves has been reviewed with the Safety, Environment, Responsibility and Reserves Committee of the Board.

(h) Review management's processes in place to prevent and detect fraud.

(i) Review:

  (i) 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

  (ii) a summary of any significant investigations regarding such matters.

(j) Meet on a periodic basis separately with management.

19. External Auditors

(a) 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.

(b) 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.

(c) Review and discuss a report from the external auditors at least quarterly regarding:

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

(ii) 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

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

(d) Obtain and review a report from the external auditors at least annually regarding:

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

(ii) 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.

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

(e) Review and discuss at least annually 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.

(f) Review and evaluate annually:

(i) 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.

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

(iii) External audit plans and results.

(iv) Any other related audit engagement matters.

(v) 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.

(vi) Review the Annual Report of the Canadian Public Accountability Board ("CPAB") concerning audit quality in Canada and discuss implications for Cenovus.

(vii) Review any reports issued by CPAB regarding the audit of Cenovus.

(g) Conduct periodically a comprehensive review of the external auditor, with the outcome intended to assist the Committee to identify potential areas for improvement for the audit firm, and to reach a final conclusion on whether the auditor should be reappointed or the audit put out for tender.

(h) Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 19.(c) through (f), 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.

(i) 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.

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

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

(l) Consider and review with the external auditors, management and the head of internal audit:

(i) Significant findings during the year and management's responses and follow-up thereto.
(ii) 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.
(iii) Any significant disagreements between the external auditors or internal auditors and management.
(iv) Any changes required in the planned scope of their audit plan.
(v) The resources, budget, reporting relationships, responsibilities and planned activities of the internal auditors.
(vi) The internal audit department mandate.
(vii) Internal audit's compliance with the Institute of Internal Auditors' standards.

20. Internal Audit Group and Independence

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

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

(c) Confirm and assure, annually, the independence of the internal audit group.

21. Approval of Audit and Non-Audit Services

(a) 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).

(b) 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.

(c) If the pre-approvals contemplated in paragraphs 21.(a) and (b) 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.

(d) 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 21.(a) through (c). The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

(e) Establish policies and procedures for the pre-approvals described in paragraphs 21.(a) and (b) 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.

22. Other Matters

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

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

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

(d) 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.

(e) 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.

(f) 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.

(g) Review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Nominating and Corporate Governance Committee for consideration and, if appropriate, recommendation to the Board for approval.

(h) 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.

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

(j) Consider any other matters referred to it by the Board of Directors.

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

Revised Effective: February 11, 2020

APPENDIX D

NETBACK RECONCILIATIONS

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold. Netbacks reflect Cenovus's margin on a per-barrel basis of unblended bitumen and crude oil. As such, the bitumen and crude oil sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the bitumen and heavy crude oil to reduce its thickness in order to transport it to market. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook.

The following tables provide a reconciliation of the financial components comprising Netbacks (in millions of dollars) to the nearest GAAP measure found in the annual and interim consolidated financial statements.

Year ended December 31, 2019
($ millions)

	Per Consolidated Financial Statements		
	Oil Sands(1)	Deep Basin(1)	Total Upstream
Revenues			
Gross Sales	10,838	691	**11,529**
Less: Royalties	1,143	29	**1,172**
	9,695	662	**10,357**
Expenses			
Transportation and Blending	5,152	82	**5,234**
Operating	1,039	337	**1,376**
Production and Mineral Taxes	–	1	**1**
Netback	3,504	242	**3,746**
(Gain) Loss on Risk Management	23	–	**23**
Operating Margin	3,481	242	**3,723**

	Basis of Netback Calculation				Adjustments		Per Above Table
	Bitumen	Light and Medium Oil	NGLs	Natural Gas	Condensate	Other	Total Upstream
Gross Sales	6,806	118	209	311	4,021	64	**11,529**
Royalties	1,136	19	7	3	–	7	**1,172**
Transportation and Blending	1,132	5	27	50	4,021	(1)	**5,234**
Operating	1,031	19	74	219	–	33	**1,376**
Production and Mineral Taxes	–	–	–	1	–	–	**1**
Netback	3,507	75	101	38	–	25	**3,746**
(Gain) Loss on Risk Management							**23**
Operating Margin							**3,723**

(1) Found in Note 1 of the Consolidated Financial Statements.

Three months ended December 31, 2019
($ millions)

	Per Consolidated Financial Statements		
	Oil Sands[1]	Deep Basin[1]	Total Upstream
Revenues			
Gross Sales	2,659	190	**2,849**
Less: Royalties	316	9	**325**
	2,343	181	**2,524**
Expenses			
Transportation and Blending	1,416	20	**1,436**
Operating	268	80	**348**
Netback	659	81	**740**
(Gain) Loss on Risk Management	(15)	–	**(15)**
Operating Margin	674	81	**755**

	Basis of Netback Calculation				Adjustments		Per Above Table
	Bitumen	Light and Medium Oil	NGLs	Natural Gas	Condensate	Other	Total Upstream
Gross Sales	1,597	30	53	96	1,060	13	**2,849**
Royalties	309	5	2	2	–	7	**325**
Transportation and Blending	356	1	7	13	1,060	(1)	**1,436**
Operating	268	5	16	53	–	6	**348**
Netback	664	19	28	28	–	1	**740**
(Gain) Loss on Risk Management							**(15)**
Operating Margin							**755**

(1) Found in Note 1 of the Interim Consolidated Financial Statements.

Three months ended September 30, 2019
($ millions)

	Per Consolidated Financial Statements		
	Oil Sands[1]	Deep Basin[1]	Total Upstream
Revenues			
Gross Sales	2,722	131	**2,853**
Less: Royalties	336	(4)	**332**
	2,386	135	**2,521**
Expenses			
Transportation and Blending	1,249	20	**1,269**
Operating	227	77	**304**
Production and Mineral Taxes	–	1	**1**
Netback	910	37	**947**
(Gain) Loss on Risk Management	(7)	–	**(7)**
Operating Margin	917	37	**954**

	Basis of Netback Calculation				Adjustments		Per Above Table
	Bitumen	Light and Medium Oil	NGLs	Natural Gas	Condensate	Other	Total Upstream
Gross Sales	1,796	31	43	45	924	14	**2,853**
Royalties	336	3	(5)	(2)	–	–	**332**
Transportation and Blending	325	1	7	12	924	–	**1,269**
Operating	225	4	16	51	–	8	**304**
Production and Mineral Taxes	–	–	–	1	–	–	**1**
Netback	910	23	25	(17)	–	6	**947**
(Gain) Loss on Risk Management							**(7)**
Operating Margin							**954**

(1) Found in Note 1 of the Interim Consolidated Financial Statements.

Three months ended June 30, 201 9
($ millions)

	Per Consolidated Financial Statements		
	Oil Sands[1]	Deep Basin[1]	Total Upstream
Revenues			
Gross Sales	3,030	150	**3,180**
Less: Royalties	314	10	**324**
	2,716	140	**2,856**
Expenses			
Transportation and Blending	1,340	23	**1,363**
Operating	270	87	**357**
Netback	1,106	30	**1,136**
(Gain) Loss on Risk Management	57	–	**57**
Operating Margin	1,049	30	**1,079**

	Basis of Netback Calculation				Adjustments		Per Above Table
	Bitumen	Light and Medium Oil	NGLs	Natural Gas	Condensate	Other	Total Upstream
Gross Sales	1,936	31	53	51	1,091	18	**3,180**
Royalties	314	7	4	(1)	–	–	**324**
Transportation and Blending	249	3	9	11	1,091	–	**1,363**
Operating	268	5	24	51	–	9	**357**
Netback	1,105	16	16	(10)	–	9	**1,136**
(Gain) Loss on Risk Management							**57**
Operating Margin							**1,079**

(1) Found in Note 1 of the Interim Consolidated Financial Statements.

Three months ended March 31, 2019
($ millions)

	Per Consolidated Financial Statements		
	Oil Sands[1]	Deep Basin[1]	Total Upstream
Revenues			
Gross Sales	2,427	220	**2,647**
Less: Royalties	177	14	**191**
	2,250	206	**2,456**
Expenses			
Transportation and Blending	1,147	19	**1,166**
Operating	274	93	**367**
Netback	829	94	**923**
(Gain) Loss on Risk Management	(12)	–	**(12)**
Operating Margin	841	94	**935**

	Basis of Netback Calculation				Adjustments		Per Above Table
	Bitumen	Light and Medium Oil	NGLs	Natural Gas	Condensate	Other	Total Upstream
Gross Sales	1,477	26	60	119	946	19	**2,647**
Royalties	177	4	6	4	–	–	**191**
Transportation and Blending	201	1	4	14	946	–	**1,166**
Operating	270	5	19	63	–	10	**367**
Netback	829	16	31	38	–	9	**923**
(Gain) Loss on Risk Management							**(12)**
Operating Margin							**935**

(1) Found in Note 1 of the Interim Consolidated Financial Statements.

The following table provides the sales volumes used to calculate Netback.

Sales Volumes

(barrels per day, unless otherwise stated)	2019	Q4	Q3	Q2	Q1
Bitumen					
Foster Creek	**157,770**	153,797	162,199	160,673	154,369
Christina Lake	**188,910**	207,399	192,929	178,845	176,079
Total Bitumen	**346,680**	361,196	355,128	339,518	330,448
Crude Oil and NGLs					
Light and Medium Oil	**4,911**	4,991	4,929	4,904	4,820
NGLs	**21,762**	21,206	21,175	21,513	23,183
Total Bitumen, Crude Oil and NGLs Sales	**373,353**	387,393	381,232	365,935	358,451
Natural Gas Sales (MMcf/d)(1)	**424**	403	407	432	458
Total Sales (BOE/d)	**444,103**	454,513	449,029	437,863	434,738

(1) Includes volume sold between segments.

Exhibit 99.2

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE PERIOD ENDED DECEMBER 31, 2019

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This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated February 11, 2020, should be read in conjunction with our December 31, 2019 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 11, 2020, 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 ("Management") prepared the MD&A. The Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended the MD&A for approval by the Board, which occurred on February 11, 2020. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at 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, (which includes references to "dollar" or "$"), except where another currency has been indicated, and 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. We adopted IFRS 16, "Leases" ("IFRS 16"), effective January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

Non-GAAP Measures and Additional Subtotals

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Netbacks, Adjusted Funds Flow, Operating Earnings, Free Funds Flow, Net Debt, Capitalization and Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. In addition, Operating Margin is considered an additional subtotal found in Notes 1 and 11 of our Consolidated Financial Statements. 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, if applicable, of each non-GAAP measure or additional subtotal is presented in the Operating and Financial Results, Liquidity and Capital Resources, or Advisory sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil and natural gas company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On December 31, 2019, we had an enterprise value of approximately $24 billion. Operations include oil sands projects in northeast Alberta and established crude oil, natural gas liquids ("NGLs") and natural gas production in Alberta and British Columbia. Total production from our upstream assets averaged approximately 452,000 BOE per day in 2019. We also conduct marketing activities and have ownership interest in refining operations in the United States ("U.S."). The refineries processed an average of 443,000 gross barrels per day of crude oil feedstock into an average of 466,000 gross barrels per day of refined products in 2019.

Our Strategy

Our strategy is focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. Our business plan through 2024 will focus on sustainably growing shareholder returns and further reducing Net Debt as well as continuing to integrate Environmental, Social and Governance ("ESG") considerations into our business plan. We believe that maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility and give us the flexibility to proceed with opportunities at all points in the price cycle. We aim to evaluate disciplined investment in our portfolio against dividend increases, share repurchases and maintaining the optimal debt level while retaining investment grade status. Our investment focus will be on areas where we believe we have the greatest competitive advantage.

Oil Sands

We are committed to maintaining and improving our industry-leading position as a low-cost oil sands operator and the largest in situ producer by leveraging our track record of strong operational performance while demonstrating technical leadership to improve reserves, production and earnings. We are focused on advancing innovation to unlock future opportunities that maximize value from our vast resource base and improve our environmental footprint.

Conventional Oil and Natural Gas

We are committed to disciplined investment in focused land positions across our conventional oil and natural gas portfolio to generate strong diversified returns, complementing our longer-term oil sands investments with short-cycle development opportunities.

Marketing, Transportation & Refining

We strive to maximize the value from our oil and gas resources through increased participation along the value chain. Our integrated approach to transportation, storage, marketing, upgrading and refining helps optimize margins from each barrel of oil we produce.

People

We strive to maintain an engaging workplace where people can grow their skills and capabilities to adapt to an ever-changing environment while delivering results for the business. We are focused on upholding trust in the communities where we operate by living up to our values and commitments.

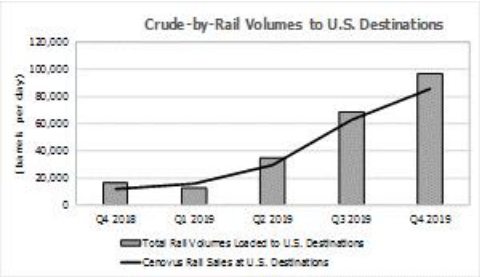
For a description of our operations, refer to the Reportable Segments section of this MD&A.

YEAR IN REVIEW

In 2019, we delivered on the commitments we made to our shareholders, as we:

- Progressed our deleveraging plans by repaying US$1.8 billion of our unsecured notes and reducing Net Debt to $6.5 billion;
- Improved our long-term market access position through incremental pipeline capacity, strategic rail agreements and securing additional storage in the U.S. Gulf Coast ("USGC") to support the ramp up of our crude-by-rail activity;
- Ramped up our crude-by-rail activity by loading 53,345 barrels per day for delivery to U.S. destinations. Of these volumes, we sold an average of 48,626 barrels per day. We exited the year with our December loaded volumes averaging 105,985 barrels per day and rail sales of 91,059

  barrels per day;



- Invested $1,176 million of capital compared with $1,363 million in 2018, reflecting our continued focus on capital discipline;
- Focused on cost leadership reflected in our operating cost reductions in our upstream assets;
- Increased our fourth quarter dividend 25 percent to $0.0625 per share; and
- Achieved production of one billion barrels of oil using steam-assisted gravity drainage ("SAGD") technology.

Upstream operational performance was very good, with production averaging 451,680 BOE per day, limited by the Government of Alberta's industry-wide mandatory production curtailment program. Our refineries demonstrated good performance despite unplanned outages throughout the year, and the turnaround activities at both the Wood River and Borger refineries (the "Refineries") in the fourth quarter. Effective January 1, 2020, as a result of new maximum demonstrated rates in 2019, Wood River was re-rated to reflect higher crude oil processing capacity of 346,000 gross barrels per day (2019 – 333,000 gross barrels per day).

Crude oil prices continued to be volatile throughout the year. West Texas Intermediate ("WTI") benchmark crude price ranged from a high of US$66.30 per barrel to a low of US$46.54 per barrel and averaged 12 percent lower than in 2018. The differential between WTI and Western Canadian Select ("WCS") at Hardisty prices narrowed to an average of US$12.76 per barrel, a 52 percent decrease compared with 2018, supported by the Government of Alberta's mandatory production curtailment program. The increase in the benchmark WCS prices to US$44.27 per barrel (2018 – US$38.46 per barrel) and a decrease in the cost of condensate used for blending had a positive impact on our upstream financial results (operating margin).

With market access constraints for Canadian crude oil production continuing, we have progressed on our strategy to maintain firm transportation through a combination of pipelines, rail and marine access. In 2019, we acquired additional pipeline and rail storage capacity allowing us to transport over 25 percent of our Oil Sands production to be sold at U.S. destinations which contributed to our increased realized price. We exited the year with 187,645 barrels per day of our Oil Sands production sold at U.S. destinations.

We achieved upstream operating margin from continuing operations of $3,723 million compared with $1,398 million in 2018, due to an increase in our average realized crude oil sales price and realized risk management losses of $23 million compared with $1,577 million in 2018.

Our Refining and Marketing segment generated operating margin of $737 million, down from 2018. While market crack spreads were relatively unchanged year-over-year, realized crack spreads were down due to the narrowing medium sour and heavy crude oil differentials, which resulted in lower crude advantage, partially offset by higher margins on fixed priced products associated with a lower benchmark WTI, and a reduction in the cost of Renewable Identification Numbers ("RINs").

In 2019, we:

- Increased our average realized crude oil sales price to $53.95 per barrel from $37.97 per barrel in 2018;
- Achieved Cash from Operating Activities of $3,285 million (2018 – $2,154 million), Adjusted Funds Flow of $3,724 million (2018 – $1,674 million), and Free Funds Flow of $2,548 million (2018 – $311 million); and
- Recorded Net Earnings from continuing operations of $2,194 million compared with a Net Loss from continuing operations of $2,916 million in 2018.

In the fourth quarter of 2019, the Government of Alberta announced a Special Production Allowance ("SPA") to provide curtailment relief equivalent to incremental increases in rail shipment and no curtailments on new conventional oil wells drilled to encourage more capital investment. Our production levels in 2020 are anticipated to be higher than in 2019 due to the SPA.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results

	2019	Percent Change	2018	Percent Change	2017
Upstream Production Volumes					
Oil Sands (barrels per day)					
Foster Creek	**159,598**	**(1)**	161,979	30	124,752
Christina Lake	**194,659**	**(3)**	201,017	20	167,727
	354,257	**(2)**	362,996	24	292,479
Deep Basin (BOE per day)	**97,423**	**(19)**	120,258	64	73,492
Total Production from Continuing Operations (1) (BOE per day)	**451,680**	**(7)**	483,458	32	367,635
Production From Discontinued Operations (Conventional) (BOE per day)	**-**	**(100)**	294	(100)	102,855
Sales from Continuing Operations (2) (BOE per day)	**390,813**	**(10)**	436,163	22	358,476
Oil and Gas Reserves (MMBOE)					
Proved	**5,103**	**(1)**	5,167	(1)	5,232
Probable	**1,768**	**(3)**	1,821	(5)	1,910
Proved plus Probable	**6,871**	**(2)**	6,988	(2)	7,142
Refining and Marketing					
Crude Oil Runs (3) (Mbbls/d)	**443**	**(1)**	446	1	442
Refined Product (3) (Mbbls/d)	**466**	**(1)**	470	-	470
Crude Utilization (3) (percent)	**92**	**(5)**	97	1	96
Crude-by-Rail (barrels per day)					
Crude-by-Rail Loads (4)	**53,345**	**1,197**	4,113	-	-
Crude-by-Rail Sales (5)	**48,626**	**1,367**	3,314	-	-

(1) Includes natural gas volumes used for internal consumption by the Oil Sands segment of 320 MMcf per day for the year ended December 31, 2019 (306 MMcf per day in 2018 and no internal usage of Deep Basin production in 2017).

(2) Excludes natural gas volumes used for internal consumption by the Oil Sands segment of 320 MMcf per day for the year ended December 31, 2019 (306 MMcf per day in 2018 and no internal usage of Deep Basin production in 2017).

(3) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.

(4) Represents volumes transported outside of Alberta.

(5) Represents volumes sold outside of Alberta.

Upstream Production Volumes

Our upstream operations performed very well in 2019. Oil Sands production was 354,257 barrels per day (2018 – 362,996 barrels per day) due to mandatory production curtailments set by the Government of Alberta.

Deep Basin production in 2019 decreased to 97,423 BOE per day compared with 120,258 BOE per day in 2018 due to natural declines from lower sustaining capital investment, the divestiture of Cenovus Pipestone Partnership ("CPP") on September 6, 2018, and temporary well shut-ins resulting from low natural gas prices.

Oil and Gas Reserves

Based on our reserves reports prepared by independent qualified reserves evaluators ("IQREs"), at the end of 2019 we had total proved reserves and total proved plus probable reserves of approximately 5.1 billion BOE and 6.9 billion BOE, respectively, decreases of one percent and two percent compared with 2018.

Additional information about our reserves is included in the Oil and Gas Reserves section of this MD&A.

Refining and Marketing

Crude oil runs and refined product output in 2019 were consistent with 2018. Operational performance was impacted by planned maintenance, unplanned outages, including a fire in a crude unit at Wood River, and planned turnaround activities at the Refineries. In the first quarter of 2018, both Refineries completed major planned turnarounds.

Further information on the changes in our financial and operating results 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 and Risk Factors section of this MD&A and in the notes to the Consolidated Financial Statements.

Selected Consolidated Financial Results

($ millions, except per share amounts)	2019	Percent Change	2018 (1)	Percent Change	2017 (1)
Operating Margin from Continuing Operations (2)	**4,460**	**86**	2,394	(20)	2,992
Cash From Operating Activities					
From Continuing Operations	**3,285**	**55**	2,118	(19)	2,611
Total	**3,285**	**53**	2,154	(30)	3,059
Adjusted Funds Flow (3)	**3,724**	**122**	1,674	(43)	2,914
Operating Earnings (loss) from Continuing Operations (3)	**456**	**117**	(2,755)	(8,003)	(34)
Per Share ($) (4)	**0.37**	**117**	(2.24)	(7,367)	(0.03)
Net Earnings (Loss)					
From Continuing Operations	**2,194**	**175**	(2,916)	(229)	2,268
Per Share ($) (4)	**1.78**	**175**	(2.37)	(215)	2.06
Total	**2,194**	**182**	(2,669)	(179)	3,366
Per Share ($) (4)	**1.78**	**182**	(2.17)	(171)	3.05
Total Assets	**35,713**	**2**	35,174	(14)	40,933
Total Long-Term Financial Liabilities (5)	**8,483**	**(1)**	8,602	(11)	9,717
Capital Investment (6)	**1,176**	**(14)**	1,363	(18)	1,661
Dividends					
Cash Dividends	**260**	**6**	245	9	225
Per Share ($)	**0.2125**	**6**	0.2000	-	0.2000

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.
(2) Additional subtotal found in Notes 1 and 11 of the Consolidated Financial Statements and defined in this MD&A.
(3) Non-GAAP measure defined in this MD&A.
(4) Represented on a basic and diluted per share basis.
(5) Includes Long-Term Debt, Lease Liabilities, Risk Management, Contingent Payment Liabilities and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(6) Includes expenditures on property, plant and equipment ("PP&E"), Exploration and Evaluation ("E&E") assets and assets held for sale.

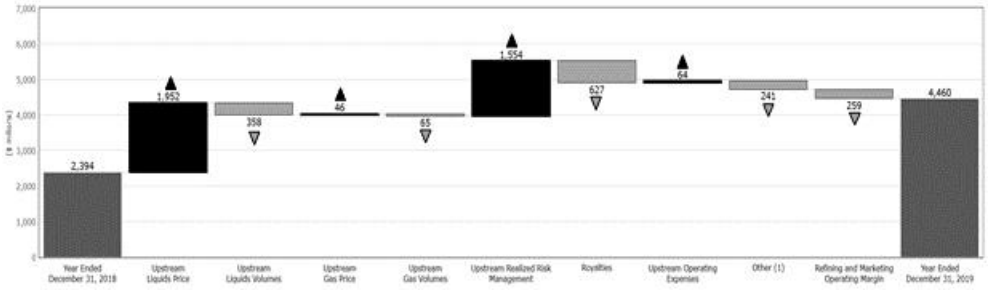
Operating Margin

Operating Margin is an additional subtotal found in Notes 1 and 11 of the Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, 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 Margin.

($ millions)	2019	2018 (1)	2017 (1)
Gross Sales	**22,042**	22,113	17,769
Less: Royalties	**1,172**	545	271
Revenues	**20,870**	21,568	17,498
Expenses			
Purchased Product	**8,844**	9,261	8,476
Transportation and Blending	**5,234**	5,969	3,760
Operating Expenses	**2,324**	2,367	1,956
Production and Mineral Taxes	**1**	1	1
Realized (Gain) Loss on Risk Management Activities	**7**	1,576	313
Operating Margin From Continuing Operations	**4,460**	2,394	2,992

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Operating Margin From Continuing Operations Variance



(1) Other includes the value of condensate sold as heavy oil blend recorded in revenues and condensate costs recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Operating Margin from continuing operations increased in 2019 compared with 2018 primarily due to:

- A higher average crude oil sales price resulting from narrower differentials and an increase in our sales volumes at U.S. locations;
- A decrease in transportation and blending expenses due to lower condensate prices and a reduction in condensate volumes required for blending, partially offset by increased rail transportation costs and pipeline tariffs due to higher volumes shipped to the U.S.;
- Lower upstream operating expenses; and
- Lower upstream realized risk management losses of $23 million (2018 – losses of $1,577 million).

These increases in Operating Margin were partially offset by:

- Higher royalties primarily due to Christina Lake achieving payout in August 2018 and higher realized prices;
- Lower sales volumes; and
- Lower Operating Margin from our Refining and Marketing segment primarily due to reduced realized crack spreads as a result of lower crude advantage.

Additional details explaining the changes in Operating Margin from continuing operations can be found in the Reportable Segments section of this MD&A.

Cash From Operating Activities and Adjusted Funds Flow

Adjusted Funds 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. Adjusted Funds Flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Non-cash working capital is composed of accounts receivable, inventories, income tax receivable, accounts payable and income tax payable. Net change in other assets and liabilities is composed of site restoration costs and pension funding.

($ millions)	**2019**	2018 (1) (2)	2017 (1) (2)
Cash From Operating Activities	**3,285**	2,154	3,059
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(84)**	(72)	(107)
Net Change in Non-Cash Working Capital	**(355)**	552	252
Adjusted Funds Flow	**3,724**	1,674	2,914

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

(2) Includes results from our Conventional segment, which has been classified as a discontinued operation.

Cash From Operating Activities and Adjusted Funds Flow were higher in 2019 compared with 2018 due to higher Operating Margin, lower general and administrative costs from a reduction in rent expense primarily due to the adoption of IFRS 16 and $60 million of severance costs incurred in 2018, and lower finance costs as a result of debt repayments, partially offset by a current income tax expense of $17 million compared with a recovery of $126 million in 2018. The change in non-cash working capital in 2019 was primarily due to an increase in accounts receivable and inventory, partially offset by an increase in accounts payable and a decrease in income tax receivable.

In 2018, the change in non-cash working capital was primarily due to a decrease in accounts receivable and inventory, partially offset by a decrease in accounts payable.

Operating Earnings (Loss)

($ millions)	2019	2018 (1)	2017 (1)
Earnings (Loss) From Continuing Operations, Before Income Tax	**1,397**	(3,926)	2,216
Add (Deduct):			
Unrealized Risk Management (Gain) Loss (2)	**149**	(1,249)	729
Non-Operating Unrealized Foreign Exchange (Gain) Loss (3)	**(787)**	593	(651)
Revaluation (Gain)	**-**	-	(2,555)
(Gain) Loss on Divestiture of Assets	**(2)**	795	1
Operating Earnings (Loss) From Continuing Operations, Before Income Tax	**757**	(3,787)	(260)
Income Tax Expense (Recovery)	**301**	(1,032)	(226)
Operating Earnings (Loss) From Continuing Operations	**456**	(2,755)	(34)

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.
(2) Includes the reversal of unrealized (gains) losses recorded in prior periods.
(3) Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and foreign exchange (gains) losses on settlement of intercompany transactions.

Operating Earnings (Loss) is a non-GAAP measure used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings (Loss) is defined as Earnings (Loss) Before Income Tax excluding gain (loss) on discontinuance, revaluation gain, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.

In 2019, Operating Earnings from continuing operations increased compared with 2018 primarily due to:

- Higher Cash From Operating Activities and Adjusted Funds Flow, as discussed above;
- A lower exploration expense of $82 million compared with $2,123 million;
- A deferred tax recovery related to the write-down of Deep Basin E&E assets in 2018; and
- The 2018 provision of $629 million recognized for onerous contracts.

The increase in our Operating Earnings in 2019 was partially offset by realized foreign exchange losses of $401 million on the repurchase of our unsecured notes compared with losses of $214 million in 2018, higher depreciation, depletion, and amortization ("DD&A") primarily due to our right-of-use ("ROU") assets and a loss on the re-measurement of the contingent payment of $164 million (2018 – $50 million).

Net Earnings (Loss)

($ millions)	2019 vs. 2018	2018 vs. 2017
Net Earnings (Loss) From Continuing Operations, Comparative Year (1)	**(2,916)**	**2,268**
Increase (Decrease) due to:		
Operating Margin From Continuing Operations	**2,066**	**(598)**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(1,398)**	**1,978**
Unrealized Foreign Exchange Gain (Loss)	**1,476**	**(1,506)**
Revaluation (Gain)	**-**	**(2,555)**
Re-measurement of Contingent Payment	**(114)**	**(188)**
Gain (Loss) on Divestiture of Assets	**797**	**(794)**
Expenses (2)	**573**	**(951)**
DD&A	**(118)**	**(293)**
Exploration Expense	**2,041**	**(1,235)**
Income Tax Recovery (Expense)	**(213)**	**958**
Net Earnings (Loss) From Continuing Operations, End of Year	**2,194**	**(2,916)**

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.
(2) Includes Corporate and Eliminations realized risk management (gains) losses, general and administrative, onerous contract provisions, finance costs, interest income, realized foreign exchange (gains) losses, transaction costs, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

In 2019, Net Earnings of $2,194 million from continuing operations increased from 2018 due to higher Operating Earnings, as discussed above, non-operating foreign exchange gains of $787 million compared with losses of $593 million in 2018, and the loss on the CPP divestiture in 2018. In 2019, we recorded a deferred income tax recovery of $671 million associated with the reduction in the Alberta corporate tax rate and a recovery of $387 million due to an internal restructuring of our U.S. operations resulting in a step-up in the tax basis of our

refining assets. In 2018, our deferred tax recovery was $884 million related to current period losses, including the write-down of Deep Basin E&E assets, and $78 million arising from an adjustment to the tax basis of our refining assets. These increases to our Net Earnings were partially offset by unrealized risk management losses of $149 million compared with gains of $1,249 million in 2018.

Net Earnings from discontinued operations for the year ended December 31, 2018 was $247 million and includes an after-tax gain of $220 million on the divestiture of the Suffield assets in the first quarter of 2018.

The Net Earnings (Loss) in 2018 decreased compared with 2017 primarily due to lower Operating Earnings, an after-tax revaluation gain of $1.9 billion on our pre-existing interest in the FCCL Partnership ("FCCL") recognized in 2017, non-operating foreign exchange losses compared with gains in 2017, and a loss on the divestiture of CPP, partially offset by unrealized risk management gains compared with losses, and a larger income tax recovery.

Capital Investment

($ millions)	**2019**	2018 (1)	2017 (1)
Oil Sands	**706**	887	973
Deep Basin	**53**	211	225
Refining and Marketing	**280**	208	180
Corporate and Eliminations	**137**	57	77
Conventional (Discontinued Operations)	**-**	-	206
Capital Investment (2)	**1,176**	1,363	1,661

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A.

(2) Includes expenditures on PP&E, E&E assets and assets held for sale.

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Selected Benchmark Prices and Exchange Rates (1)

Key performance drivers for our financial results include commodity prices, quality and location 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.

(US$/bbl, unless otherwise indicated)	Q4 2019	Q4 2018	2019	Percent Change	2018	2017
Brent						
Average	**62.50**	68.08	**64.18**	**(10)**	71.53	54.82
WTI						
Average	**56.96**	58.81	**57.03**	**(12)**	64.77	50.95
Average Differential Brent-WTI	**5.54**	9.27	**7.15**	**6**	6.76	3.87
WCS at Hardisty ("WCS")						
Average	**41.13**	19.39	**44.27**	**15**	38.46	38.97
Average Differential WTI-WCS	**15.83**	39.42	**12.76**	**(52)**	26.31	11.98
Average (C$/bbl)	**54.29**	25.60	**58.77**	**18**	49.81	50.56
WCS at Nederland						
Average	**51.47**	57.70	**55.56**	**(10)**	62.05	46.18
Average Differential WTI-WCS at Nederland	**5.49**	1.11	**1.47**	**(46)**	2.72	4.77
West Texas Sour ("WTS")						
Average	**57.26**	52.38	**56.27**	**(2)**	57.24	49.91
Average Differential WTI-WTS	**(0.30)**	6.43	**0.76**	**(90)**	7.53	1.04
Condensate (C5 @ Edmonton)						
Average	**53.01**	45.28	**52.86**	**(13)**	61.00	51.57
Average Differential WTI-Condensate (Premium)/Discount	**3.95**	13.53	**4.17**	**11**	3.77	(0.62)
Average Differential WCS-Condensate (Premium)/Discount	**(11.88)**	(25.89)	**(8.59)**	**(62)**	(22.54)	(12.60)
Average (C$/bbl)	**69.97**	59.74	**70.15**	**(11)**	79.02	66.89
Average Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**64.83**	66.65	**70.55**	**(10)**	77.96	66.95
Chicago Ultra-low Sulphur Diesel ("ULSD")	**78.09**	84.25	**77.97**	**(10)**	86.75	69.09
Refining Margin: Average 3-2-1 Crack Spreads (2)						
Chicago	**12.27**	13.43	**16.00**	**-**	15.97	16.77
Group 3	**14.60**	14.57	**16.67**	**-**	16.74	16.61
Average Natural Gas Prices						
AECO (3) (C$/Mcf)	**2.34**	1.90	**1.62**	**6**	1.53	2.43
NYMEX (US$/Mcf)	**2.50**	3.64	**2.63**	**(15)**	3.09	3.11
Foreign Exchange Rate (US$ per C$1)						
Average	**0.758**	0.758	**0.754**	**(2)**	0.772	0.771
End of Period	**0.770**	0.733	**0.770**	**5**	0.733	0.797

(1) These benchmark prices are not our realized sales prices and represent approximate values. For our average realized sales prices and realized risk management results, refer to the Netback tables in the Reportable Segments sections of this MD&A.

(2) The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.

(3) Alberta Energy Company ("AECO") natural gas monthly index.

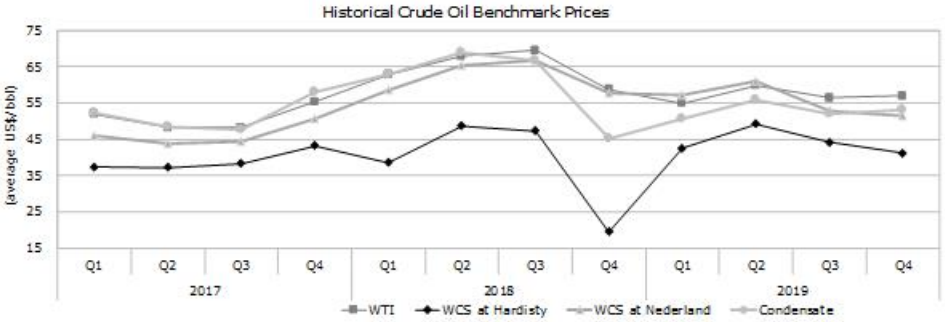
Crude Oil Benchmarks

In 2019, the average Brent and WTI crude oil benchmark prices were lower compared with 2018 as uncertainty from oversupply and decreased demand for crude oil due to U.S.-China trade tensions lowered crude oil benchmark pricing. Global prices were supported by the Organization of the Petroleum Exporting Countries ("OPEC")-led production cuts and by U.S.-led sanctions against Venezuela and Iran.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and the Canadian dollar equivalent is the basis for determining royalty rates for a number of our crude oil properties. In 2019, the Brent-WTI differential increased as a result of strong supply growth from the Permian basin, which increased congestion at Cushing, Oklahoma.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. In 2019, the average WTI-WCS differential narrowed in response to production curtailments mandated by the Government of Alberta to address record high differentials in the fourth quarter of 2018 and high levels of crude oil in storage. Decreased production due to mandatory curtailments continues to support Alberta benchmark prices. WCS at Nederland is a heavy oil benchmark at the USGC which is representative of our pricing in relation to our

increasing sales in the USGC. Heavy crude supply and demand remained tight globally and this was evident in strong pricing at the USGC throughout 2019. Key factors include production cuts between OPEC and their allies, and U.S. sanctions against Venezuela and Iran.



WTS is an important North American crude oil benchmark, representing the heavier, more sour counterpart to WTI crude oil, and is a primary component of the input feedstock at the Borger refinery. The differential between WTI and WTS benchmark prices narrowed in 2019, due to additional pipeline capacity coming online.

Blending condensate with bitumen enables our production to be transported through pipelines. Our blending ratios, diluent volumes as a percentage of total blended volumes, range from approximately 25 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by USGC condensate prices plus the cost to transport the condensate to Edmonton.

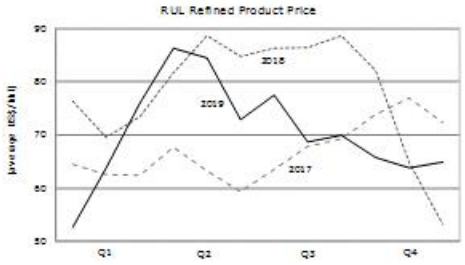
Average condensate benchmark prices were at a wider discount relative to WTI in 2019 compared with 2018 due to increasing North American supply and lower demand as production curtailments in Alberta were implemented.

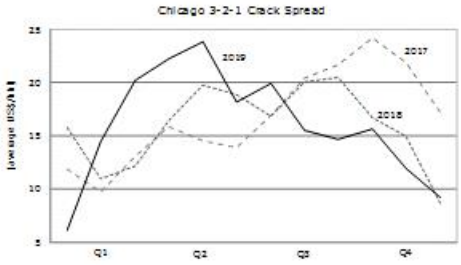
Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("ULSD") benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market 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 Chicago refined product prices decreased in 2019 primarily due to lower global crude oil prices. As North American refining crack spreads are expressed on a WTI basis, while refined products are set by international prices, the strength of refining crack spreads in the U.S. Midwest and Midcontinent will reflect the differential between Brent and WTI benchmark prices.

Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock which is valued on a first in, first out ("FIFO") accounting basis.





Natural Gas Benchmarks

Average AECO prices strengthened during 2019 compared with 2018, however, they remained at low levels primarily due to little incremental demand and pipeline maintenance in the Alberta market. The Canada Energy Regulator recently approved a plan to get natural gas into storage during summer maintenance periods to improve intra Alberta supply and demand balances and reduce pricing pressure on AECO. Average NYMEX prices decreased compared with 2018 due to increased supply from the continuing development of U.S. shale gas and natural gas associated with crude oil plays.

Foreign Exchange Benchmark

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, NGLs, natural gas and refined products are determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar compared with the U.S. dollar has a negative impact on our reported results. Likewise, as the Canadian dollar weakens, there is a positive impact on our reported results. In addition to our revenues being denominated in U.S. dollars, our long-term debt is also U.S. dollar denominated. In periods of a strengthening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange gains when translated to Canadian dollars.

The Canadian dollar on average weakened relative to the U.S. dollar in 2019, compared with 2018, resulting in a positive impact of approximately $470 million on our revenues in 2019. The strengthening of the Canadian dollar relative to the U.S. dollar as at December 31, 2019 compared with December 31, 2018, and the realization of foreign exchange losses on the repayment of our unsecured notes of $412 million, resulted in unrealized foreign exchange gains of $800 million on the translation of our U.S. dollar debt.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of bitumen in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as other projects in the early stages of development. The Company's interest in certain of its operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, increased from 50 percent to 100 percent on May 17, 2017.

Deep Basin, which includes approximately 2.8 million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and NGLs. The assets reside in Alberta and British Columbia and include interests in numerous natural gas processing facilities. These assets were acquired on May 17, 2017.

Refining and Marketing, which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification. The marketing of crude oil and natural gas sourced from Canada, including physical product sales that settle in the U.S., is considered to be undertaken by a Canadian business. U.S. sourced crude oil and natural gas purchases and sales are attributed to the U.S.



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, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. Eliminations include adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Company's rail terminal, crude oil production used as feedstock by the Refining and Marketing segment, and unrealized intersegment profits in inventory. Eliminations are recorded at transfer prices based on current market prices.

On May 17, 2017, we acquired from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") their 50 percent interest in FCCL, and the majority of ConocoPhillips' western Canadian conventional assets in the Deep Basin in Alberta and British Columbia ("the Acquisition").

In 2017, Cenovus announced its intention to divest of its Conventional segment that included its heavy oil assets at Pelican Lake, the carbon dioxide ("CO2") enhanced oil recovery project at Weyburn and conventional crude oil, NGLs and natural gas assets in the Suffield and Palliser areas in southern Alberta. As such, the associated results of operations have been reported as a discontinued operation. As at January 5, 2018, all of the Conventional segment assets were sold. Refer to the Discontinued Operations section of this MD&A for more information.

Revenues by Reportable Segment

($ millions)	**2019**	2018	2017 (1)
Oil Sands	**9,695**	9,553	7,132
Deep Basin	**662**	832	514
Refining and Marketing	**10,513**	11,183	9,852
Corporate and Eliminations	**(689)**	(724)	(455)
	20,181	20,844	17,043

(1) Our 2017 results include 229 days of FCCL operations at 100 percent and 229 days of operations from the Deep Basin operations.

Oil Sands revenues increased slightly compared with 2018 due to higher realized crude oil pricing, partially offset by higher royalties and lower sales volumes. Deep Basin revenues declined in 2019 compared with 2018 due to lower sales volumes and realized natural gas liquids pricing, partially offset by lower royalties.

Refining and Marketing revenues declined in 2019 compared with 2018. Refining revenues decreased due to lower refined product pricing consistent with the decline in average refined product benchmark prices. Revenues from third-party crude oil and natural gas sales undertaken by our marketing group increased in 2019 compared with 2018 due to higher crude oil and natural gas volumes partially offset by lower prices.

Corporate and Eliminations revenues relate to sales of natural gas or crude oil and operating revenue between segments and are recorded at transfer prices based on current market prices.

Overall, revenues increased in 2018 compared with 2017 primarily due to incremental sales volumes due to the Acquisition and higher refined product pricing, partially offset by lower realized crude oil and natural gas pricing and higher royalties.

OIL SANDS

In 2019, we:

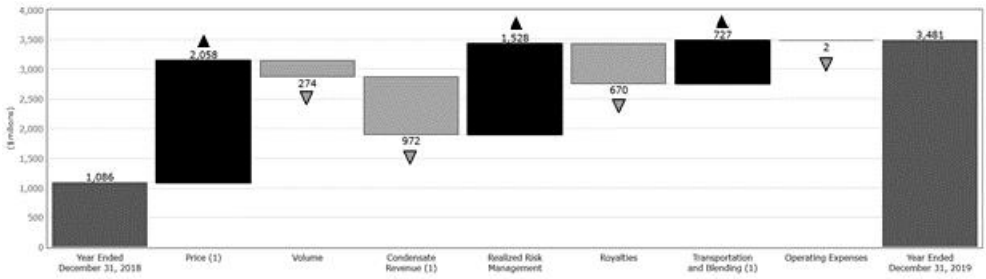
- Managed total production to mandated curtailment requirements;
- Completed construction of Christina Lake phase G in March, ahead of schedule and below the anticipated capital required;
- Safely and successfully completed our largest planned turnaround at Christina Lake;
- Generated Operating Margin of $3,481 million, an increase of $2,395 million compared with 2018 due to higher average realized sales prices, decreased transportation and blending costs, and realized risk management losses of $23 million compared with losses of $1,551 million in 2018, partially offset by lower sales volumes and higher royalties;
- Earned crude oil Netbacks of $27.72 per barrel, excluding realized risk management activities, a 41 percent increase compared with 2018; and
- Sold more than 25 percent of our Oil Sands production at sales locations outside of Alberta achieving higher realized sales prices.

Financial Results

($ millions)	**2019**	2018 (1)	2017 (1)
Gross Sales	**10,838**	10,026	7,362
Less: Royalties	**1,143**	473	230
Revenues	**9,695**	9,553	7,132
Expenses			
Transportation and Blending	**5,152**	5,879	3,704
Operating	**1,039**	1,037	934
(Gain) Loss on Risk Management	**23**	1,551	307
Operating Margin	**3,481**	1,086	2,187
Depreciation, Depletion and Amortization	**1,543**	1,439	1,230
Exploration Expense	**18**	6	888
Segment Income (Loss)	**1,920**	(359)	69

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Operating Margin Variance



(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

Price

In 2019, our realized crude oil sales price was $53.78 per barrel compared with $37.51 per barrel in 2018. While WTI benchmark was 12 percent lower than 2018, the narrowing of the WTI-WCS differential by 52 percent to average US$12.76 per barrel (2018 – US$26.31 per barrel), the narrower WCS-Christina Dilbit Blend ("CDB") differential, lower cost of condensate used in blending, and an increase in volumes sold outside of Alberta increased our crude oil sales price. In 2019, we sold more than 25 percent of our production at sales locations outside of Alberta, contributing to the increase in our realized sales prices.

Our realized crude oil sales price is influenced by the cost of condensate used in blending. Our blending ratios range between 25 percent and 33 percent. As the cost of condensate decreases relative to the price of blended crude oil, our bitumen sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets and deliver it to the Edmonton hub. As such, our average cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and transportation to field locations. In addition, up to three months may elapse from when we purchase condensate to when we sell our blended production. In a rising crude oil price environment, we expect to see a positive impact on our bitumen sales price as we are using condensate purchased at a lower price earlier in the year. The increase in our crude oil price also reflects the narrower WCS-Condensate premium of US$8.59 per barrel (2018 – premium of US$22.54 per barrel).

Production Volumes

(barrels per day)	**2019**	**Percent Change**	2018	Percent Change	2017
Foster Creek	**159,598**	**(1)**	161,979	30	124,752
Christina Lake	**194,659**	**(3)**	201,017	20	167,727
	354,257	**(2)**	362,996	24	292,479

Production at Foster Creek and Christina Lake was slightly lower compared with 2018 due to the mandated production curtailments. In the first and fourth quarters of 2018, we made the decision to operate both facilities at reduced production levels due to limited takeaway capacity and discounted heavy oil pricing.

Royalties

Royalty calculations for our oil sands projects 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 for a pre-payout project are based on a monthly calculation that applies a royalty rate (ranging from one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Royalties for 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 percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 percent to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales revenues less diluent costs and transportation costs. Net profits are a function of sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

Foster Creek and Christina Lake are post-payout projects for determining royalties. Our Christina Lake property achieved payout in the third quarter of 2018.

Effective Royalty Rates

(percent)	**2019**	2018	2017
Foster Creek	**18.8**	18.0	11.4
Christina Lake	**21.6**	4.8	2.5

In 2019, royalties increased $670 million compared with 2018 due to Christina Lake achieving project payout in August 2018 and higher net profits as a result of the mandated curtailment, partially offset by lower annual average WTI benchmark pricing (which determines the royalty rate).

Expenses

Transportation and Blending

Transportation and blending costs decreased $727 million to $5,152 million in 2019. Blending costs decreased due to lower condensate costs and a decline in condensate volumes required for our lower production. Our condensate costs were higher than the average Edmonton benchmark price primarily due to the transportation expense associated with moving the condensate between market hubs and to our oil sands projects.

Transportation costs increased primarily due to an increase in volumes shipped by rail and higher pipeline tariff costs from increased U.S. sales. We transported over 25 percent of our volumes to U.S. destinations, either by pipeline or rail, allowing us to achieve better market prices.

Per-unit Transportation Expenses

Foster Creek per-unit transportation costs increased $3.36 per barrel to $11.70 per barrel due to higher sales volumes shipped by rail and pipeline to the U.S. and decreased total sales volumes, partially offset by IFRS 16 adoption impacts. Christina Lake per-unit transportation costs increased $1.39 per barrel to $6.64 per barrel as a result of higher sales volumes shipped by rail to the U.S. and decreased total sales volumes, partially offset by IFRS 16 adoption impacts. For further information on the adoption of IFRS 16 refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Operating

Primary drivers of our operating expenses in 2019 were workforce, fuel, repairs and maintenance, chemical costs, and workovers. Total operating costs were relatively flat compared with 2018 due to higher fuel costs from higher natural gas prices and our decision to maintain steam production levels at pre-curtailment levels, and increased repairs and maintenance, offset by lower chemical costs, lower workforce costs and less workovers.

Per-unit Operating Expenses

($/bbl)	**2019**	**Percent Change**	2018 (1)	Percent Change	2017 (1)
Foster Creek					
Fuel	**2.47**	**16**	2.13	(13)	2.44
Non-fuel	**6.67**	**(2)**	6.84	(15)	8.02
Total	**9.14**	**2**	8.97	(14)	10.46
Christina Lake					
Fuel	**2.06**	**10**	1.87	(9)	2.06
Non-fuel	**5.27**	**11**	4.73	(1)	4.78
Total	**7.33**	**11**	6.60	(4)	6.84
Total	**8.15**	**7**	7.65	(9)	8.40

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

At Foster Creek and Christina Lake, per-barrel fuel costs increased due to lower sales volumes, higher natural gas prices and fuel consumption. Steam production levels were maintained at pre-curtailment levels during the year.

Per-barrel non-fuel operating expenses at Foster Creek decreased in 2019 compared with 2018 due to lower chemical costs, less workovers and lower workforce costs partially offset by lower sales volumes.

Per-barrel non-fuel operating expenses at Christina Lake increased in 2019 primarily due to lower sales volumes, increased repairs and maintenance and waste, fluid handling and trucking costs due to the planned turnaround in the second quarter, partially offset by lower chemical costs due to lower bitumen production and a volume related decrease in sulphur treating.

Netbacks (1)

	Foster Creek			**Christina Lake**		
($/bbl)	**2019**	2018 (2)	2017 (2)	**2019**	2018 (2)	2017 (2)
Sales Price	**57.21**	42.63	43.75	**50.91**	33.42	39.78
Royalties	**8.44**	6.25	4.00	**9.42**	1.37	0.87
Transportation and Blending	**11.70**	8.34	8.73	**6.64**	5.25	4.52
Operating Expenses	**9.14**	8.97	10.46	**7.33**	6.60	6.84
Netback Excluding Realized Risk Management	**27.93**	19.07	20.56	**27.52**	20.20	27.55
Realized Risk Management Gain (Loss)	**(0.16)**	(11.49)	(2.95)	**(0.19)**	(11.66)	(2.99)
Netback Including Realized Risk Management	**27.77**	7.58	17.61	**27.33**	8.54	24.56

(1) Netbacks reflect our margin on a per-barrel basis of unblended crude oil.

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). Netbacks reflect our margin on a per-barrel of oil equivalent basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. Netbacks do not reflect the non-cash writedowns of product inventory until the product is sold. The sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the heavy oil to transport it to market. For a reconciliation of our Netbacks see the Advisory section of this MD&A.

Our average Netback, excluding realized risk management gains and losses, at Foster Creek and Christina Lake increased in 2019 compared with 2018, primarily due to higher realized sales prices, partially offset by higher per-unit royalties, transportation and blending costs, operating costs and lower sales volumes. The weakening of the Canadian dollar relative to the U.S. dollar compared with 2018 had a positive impact on our reported sales price of approximately $1.18 per barrel.

In 2019, we sold more than 25 percent of our Oil Sands production, at sales locations outside of Alberta, contributing to the increase in our realized sales prices and transportation and blending costs (2018 – approximately 18 percent of our Oil Sands production).

Risk Management

Risk management positions in 2019 resulted in realized losses of $23 million (2018 – realized losses of $1,551 million), consistent with average benchmark prices exceeding our contract prices on hedging contracts.

DD&A and Exploration Expense

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with estimated future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves.

We depreciate our ROU assets on a straight-line basis over the shorter of the estimated useful life or the lease term.

In 2019, Oil Sands DD&A was $1,543 million and increased compared with 2018 due to an increase in our average depletion rate, partially offset by lower sales volumes and additional depreciation expense on our ROU assets. Our depletion rate increased as a result of higher future development costs due to additional capital required to improve recovery performance and develop thin pay volumes at Christina Lake and Foster Creek, as well as an increase in maintenance capital at Foster Creek. The average depletion rate for the year ended December 31, 2019 was approximately $11.15 per barrel (2018 – $10.60 per barrel).

Exploration expense of $18 million was recorded for the year ended December 31, 2019 (2018 – $6 million) related to previously capitalized E&E costs written off as the carrying value was not considered to be recoverable.

Capital Investment

($ millions)	**2019**	2018 (1)	2017 (1)
Foster Creek	**243**	379	455
Christina Lake	**362**	445	426
	605	824	881
Other (2)	**101**	63	92
Capital Investment (3)	**706**	887	973

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

(2) Includes new resource plays, Marten Hills, Narrows Lake, Telephone Lake and Athabasca natural gas.

(3) Includes expenditures on PP&E and E&E assets.

In 2019, Oil Sands capital investment was $706 million, $181 million lower compared with 2018 mainly due to a continued focus on capital discipline, reduced spending on sustaining well programs, completion of Christina Lake phase G construction, a smaller stratigraphic test well program and deferred capital spending due to the mandatory curtailment. At Foster Creek, capital investment focused on sustaining capital related to existing production and stratigraphic test wells. Christina Lake capital investment focused on sustaining capital related to existing production, stratigraphic test wells, and the completion of the phase G construction in March. Other capital investment related to advancing key initiatives and technical development costs.

Drilling Activity

	Gross Stratigraphic Test Wells			Gross Production Wells (1)		
	2019	2018	2017	**2019**	2018	2017
Foster Creek	**14**	43	96	**-**	14	41
Christina Lake	**18**	63	108	**11**	38	25
	32	106	204	**11**	52	66
Other	**26**	23	16	**11**	3	-
	58	129	220	**22**	55	66

(1) SAGD well pairs are counted as a single producing well.

Stratigraphic test wells were drilled to help identify well pad locations for sustaining wells and near-term expansion phases, and to further progress the evaluation of emerging assets.

Future Capital Investment

Oil Sands capital investment for 2020 is forecast to be between $865 million and $1,010 million. 2020 guidance dated December 9, 2019 is available on our website at cenovus.com.

Foster Creek capital investment for 2020 is forecast to be between $360 million and $410 million. We plan to continue focusing on sustaining capital related to existing production.

Christina Lake capital investment for 2020 is forecast to be between $310 million and $360 million focused on sustaining capital. Field construction of phase G was completed at the end of the first quarter of 2019 and is well positioned to bring on oil production in the first quarter of 2020 and ramp up towards its nameplate capacity of 50,000 barrels per day throughout 2020.

In 2020, we plan to spend capital on Foster Creek phase H, Christina Lake phase H and Narrows Lake to continue to advance each opportunity to sanction-ready status.

In 2020, our Technology and other capital investment, is forecast to be between $160 million and $190 million, advancing key strategic initiatives that are expected to provide both cost and environmental benefits. This includes ongoing work on solvents, partial upgrading and advancing our new oil sands facility design.

DEEP BASIN

In 2019, we:

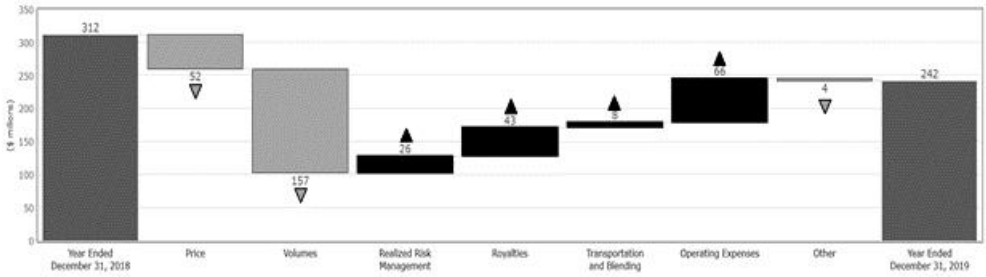
- Produced a total of 97,423 BOE per day, a decrease compared with 2018 due to natural declines from lower sustaining capital investment, the divestiture of CPP and temporary well shut-ins for low natural gas prices;
- Delivered total operating cost reductions by optimizing operations, focusing on well interventions, maintenance and repair activities and leveraging our infrastructure;
- Generated Operating Margin of $242 million, a decrease of $70 million due to lower volumes and natural gas liquids prices, partially offset by lower operating expenses, royalties, realized risk management activities, and transportation and blending costs; and
- Earned a Netback of $6.02 per BOE, excluding realized risk management activities.

Financial Results

($ millions)	**2019**	2018 (1)	May 17 - December 31, 2017 (1)
Gross Sales	**691**	904	555
Less: Royalties	**29**	72	41
Revenues	**662**	832	514
Expenses			
Transportation and Blending	**82**	90	56
Operating	**337**	403	250
Production and Mineral Taxes	**1**	1	1
(Gain) Loss on Risk Management	**-**	26	-
Operating Margin	**242**	312	207
Depreciation, Depletion and Amortization	**319**	412	331
Exploration Expense	**64**	2,117	-
Segment Income (Loss)	**(141)**	(2,217)	(124)

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Operating Margin Variance



Revenues

Price

	2019	2018	May 17 - December 31, 2017
Light and Medium Oil ($/bbl)	**65.70**	66.71	60.01
NGLs ($/bbl)	**26.36**	38.56	33.05
Natural Gas ($/mcf)	**2.01**	1.72	2.03
Total Oil Equivalent ($/BOE)	**17.95**	19.31	19.52

For the year ended December 31, 2019, revenues declined due to lower volumes and realized liquids sales prices, partially offset by an increase in our realized natural gas sale price. In 2019, revenues included $53 million of processing fee revenue related to our interests in natural gas processing facilities (2018 – $57 million). We do not include processing fee revenue in our per-unit pricing metrics or our Netbacks.

Production Volumes

	2019	2018	2017 (1)
Liquids			
Crude Oil (barrels per day)	**4,911**	5,916	3,922
NGLs (barrels per day)	**21,762**	26,538	16,928
	26,673	32,454	20,850
Natural Gas (MMcf per day)	**424**	527	316
Total Production (BOE/d)	**97,423**	120,258	73,492
Natural Gas Production (percentage of total)	**73**	73	72
Liquids Production (percentage of total)	**27**	27	28

(1) From the closing of the Acquisition on May 17, 2017 to December 31, 2017, production averaged 117,138 BOE per day.

Production in 2019 decreased from 2018 due to natural declines from lower sustaining capital investment, the divestiture of CPP and temporary well shut-ins for low natural gas prices.

CPP was sold on September 6, 2018 and produced approximately 6,523 BOE per day for the twelve months ended December 31, 2018.

Royalties

The Deep Basin assets are subject to royalty regimes in both Alberta and British Columbia. In Alberta, royalties benefit from a number of different programs that reduce the royalty rate on natural gas production. Natural gas wells in Alberta also benefit from the Gas Cost Allowance ("GCA"), which reduces royalties, to account for capital and operating costs incurred to process and transport the Crown's portion of natural gas production.

In British Columbia, royalties also benefit from programs to reduce the rate on natural gas production. British Columbia applies a GCA, but only on natural gas processed through producer-owned plants. British Columbia also offers a Producer Cost of Service allowance, which reduces the royalty for the processing of the Crown's portion of natural gas production.

In 2019, our effective royalty rate was 8.7 percent for liquids (2018 – 12.8 percent) and 1.1 percent for natural gas (2018 – 3.6 percent) due to GCA royalty credits being higher than the royalty expenses, resulting in negative royalty rates in certain months of 2019, and declines in price and production.

Expenses

Transportation

Per unit transportation costs averaged $2.31 per BOE compared with $1.97 per BOE in 2018, due to higher pipeline tariffs. Our transportation costs reflect charges for the movement of crude oil, NGLs and natural gas from the point of production to where the product is sold. The majority of Deep Basin production is sold into the Alberta market.

Operating

Total operating costs decreased 16 percent to $337 million (2018 – $403 million) as a result of the divestiture of CPP, optimizing operations, focusing on well interventions, maintenance and repair activities and leveraging our infrastructure to lower the cost structure.

While total operating costs have declined significantly, per-unit operating costs increased slightly averaging $8.79 per BOE in 2019 (2018 – $8.58 per BOE). The increase in per-unit operating costs was driven by lower sales volumes, partially offset by decreased third-party processing fees due to less throughput and from leveraging our infrastructure to reduce fees paid, lower repairs and maintenance activity, decreased property tax and lease costs and lower workforce costs.

Netbacks

($/BOE)	**2019**	2018 (1)	May 17 - December 31, 2017 (1)
Sales Price	**17.95**	19.31	19.52
Royalties	**0.81**	1.64	1.54
Transportation and Blending	**2.31**	1.97	2.08
Operating Expenses	**8.79**	8.58	8.56
Production and Mineral Taxes	**0.02**	0.03	0.02
Netback Excluding Realized Risk Management	**6.02**	7.09	7.32
Realized Risk Management Gain (Loss)	**(0.01)**	(0.59)	-
Netback Including Realized Risk Management	**6.01**	6.50	7.32

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Risk Management

Risk management activities in 2019 were minimal (2018 – realized losses of $26 million).

DD&A and Exploration Expense

We deplete crude oil and natural gas properties on a unit-of-production basis over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves. The average depletion rate was approximately $9.15 per BOE year ended December 31, 2019 (2018 – $10.55 per BOE, respectively).

For the year ended December 31, 2019 total Deep Basin DD&A was $319 million (2018 – $412 million). The decrease was due to lower sales volumes and a lower depletion rate.

Exploration expense of $64 million was recorded for the year ended December 31, 2019 compared with $2.1 billion in 2018 resulting from previously capitalized E&E costs written off as a result of Management's review of the Deep Basin development plan.

Capital Investment

In 2019, we invested $53 million compared with $211 million in 2018. 2019 investment focused on the disciplined development of our Deep Basin assets, which included maintaining safe and reliable operations, as well as the completion and tie-in of well inventories from the previous year's development program.

($ millions)	**2019**	2018	May 17 - December 31, 2017
Drilling and Completions	**4**	111	152
Facilities	**20**	56	32
Other	**29**	44	41
Capital Investment (1)	**53**	211	225

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

Drilling Activity

In 2019, there were two net wells completed and three net wells tied-in. In 2018, there were 15 net horizontal wells drilled, 21 net wells completed, and 25 net wells tied-in.

Future Capital Investment

In 2020, Deep Basin capital investment is forecast to be between $80 million and $95 million.

We continue to take a disciplined approach to the development of our Deep Basin assets considering factors such as well inventory, pace of development, infrastructure constraints, economic thresholds and limited capital spending on the assets going forward. 2020 Guidance dated December 9, 2019 is available on our website at cenovus.com.

REFINING AND MARKETING

In 2019, we:

- Achieved crude oil runs averaging 443,000 barrels per day, consistent with 2018 and attained a record monthly crude oil run rate in July at Wood River;
- Increased rail volumes loaded at the Bruderheim crude-by-rail terminal, averaging 65,293 barrels per day compared with 37,988 barrels per day in 2018. We exited the year with loaded volumes averaging 101,014 barrels per day; and
- Generated Operating Margin of $737 million, a decrease of $259 million compared with 2018. While market crack spreads were relatively unchanged year over year, realized crack spreads were down due to narrowing medium sour and heavy crude oil differentials resulting in lower crude advantage.

Financial Results

($ millions)	**2019**	2018 (1)	2017 (1)
Revenues	**10,513**	11,183	9,852
Purchased Product	**8,844**	9,261	8,476
Gross Margin	**1,669**	1,922	1,376
Expenses			
Operating	**948**	927	772
(Gain) Loss on Risk Management	**(16)**	(1)	6
Operating Margin	**737**	996	598
Depreciation, Depletion and Amortization	**280**	222	215
Segment Income (Loss)	**457**	774	383

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Refinery Operations (1)

	2019	2018	2017
Crude Oil Capacity (Mbbls/d) (2)	**482**	460	460
Crude Oil Runs (Mbbls/d)	**443**	446	442
Heavy Crude Oil	**177**	191	202
Light/Medium	**266**	255	240
Refined Products (Mbbls/d)	**466**	470	470
Gasoline	**223**	233	238
Distillate	**167**	156	149
Other	**76**	81	83
Crude Utilization (percent)	**92**	97	96

(1) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.

(2) Effective January 1, 2020, our Refineries have crude oil nameplate capacity of 495,000 gross barrels per day.

On a 100 percent basis, the Refineries had total processing capacity in 2019 of 482,000 gross barrels per day of crude oil, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil and 45,000 gross barrels per day of NGLs. Effective January 1, 2020, as a result of new maximum demonstrated rates in 2019, Wood River was re-rated, increasing our total crude oil processing nameplate capacity to 495,000 gross barrels per day including processing capability of up to 275,000 gross barrels per day of blended heavy crude oil. The ability to process a wide slate of crude oils allows the Refineries to economically integrate heavy crude oil production. Processing less expensive crude oil relative to WTI creates a feedstock cost advantage, illustrated by the discount of both WCS and WTS relative to WTI. 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 optimized at each refinery to maximize economic benefit. Crude utilization represents the percentage of total crude oil processed in the Refineries relative to the total capacity.

Crude oil runs and refined product output in 2019 remained consistent compared with 2018. Operational performance in 2019 was impacted by the unplanned maintenance and outages, including a fire in the crude unit at Wood River in the first quarter, and planned turnaround activities at the Refineries in the fourth quarter. Both Refineries had major planned turnarounds in 2018.

Crude-By-Rail Terminal

We continue to increase total rail volumes loaded at our Bruderheim crude-by-rail terminal. In 2019, we loaded an average of 65,293 barrels per day (45,324 barrels per day of our volumes) from our Bruderheim crude-by-rail terminal compared with an average of 37,988 barrels per day (28,531 barrels per day of our volumes) in 2018.

Gross Margin

The refining realized crack spread, which is the gross margin on a per barrel basis, is affected by many factors, such as the variety of feedstock crude oil processed; refinery configuration and the proportion of gasoline, distillate and secondary product output; the time lag between the purchase of crude oil feedstock and the processing of that crude oil through the Refineries; and the cost of feedstock. Feedstock costs are valued on a FIFO accounting basis.

In 2019, Refining and Marketing gross margin decreased $253 million. While market crack spreads were relatively unchanged year over year, realized crack spreads were down due to narrowing medium sour and heavy crude oil differentials which resulted in lower crude advantage, partially offset by higher margins on fixed priced products associated with a lower benchmark WTI, and a reduction in the cost of RINs. Our gross margin was positively impacted by approximately $37 million for the year ended December 31, 2019, due to the weakening of the Canadian dollar relative to the U.S. dollar.

For the year ended December 31, 2019, the cost of RINs was $99 million (2018 – $131 million). RIN costs declined, primarily due to the decrease in RINs benchmark prices as a result of small refiners being granted exemptions from volume obligations.

Operating Expense

Primary drivers of operating expenses in 2019 were maintenance, labour and utilities. Refining operating expenses increased due to the weakening of the Canadian dollar relative to the U.S dollar. Marketing operating expense increased $14 million due to higher rail transportation and workforce costs.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 60 years. The service lives of these assets are reviewed on an annual basis. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. Refining and Marketing DD&A was $280 million compared with $222 million in 2018. The increase is primarily attributable to depreciation of our ROU assets which commenced January 1, 2019 on the adoption of IFRS 16.

Capital Investment

($ millions)	**2019**	2018 (1)	2017 (1)
Wood River Refinery	**128**	119	114
Borger Refinery	**100**	85	54
Marketing	**52**	4	12
Capital Investment	**280**	208	180

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

Capital expenditures in 2019 focused primarily on capital maintenance projects and yield enhancements as well as strategic rail initiatives and infrastructure.

In 2020, we expect to invest between $285 million and $330 million and will continue to focus on capital maintenance, reliability work and yield improvement projects. Our 2020 guidance dated December 9, 2019 is available on our website at cenovus.com.

CORPORATE AND ELIMINATIONS

In 2019, our risk management activities resulted in unrealized risk management losses of $149 million (2018 – gains of $1,249 million).

Expenses

($ millions)	2019	2018 (1)	2017 (1)
General and Administrative	**336**	391	300
Onerous Contract Provisions	**(5)**	629	8
Finance Costs	**511**	627	645
Interest Income	**(12)**	(19)	(62)
Foreign Exchange (Gain) Loss, Net	**(404)**	854	(812)
Revaluation (Gain)	**-**	-	(2,555)
Transaction Costs	**-**	-	56
Re-measurement of Contingent Payment	**164**	50	(138)
Research Costs	**20**	25	36
(Gain) Loss on Divestiture of Assets	**(2)**	795	1
Other (Income) Loss, Net	**(11)**	(12)	(5)
	597	3,340	(2,526)

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs, employee long-term incentive costs and operating costs associated with our real estate portfolio. In 2019, general and administrative expenses decreased $55 million primarily due to lower rent expense of $42 million compared with $134 million in 2018 primarily from the adoption of IFRS 16, lower headcount and minimal severance costs in 2019 compared with $60 million of severance costs in 2018, partially offset by higher employee long-term incentive costs (2019 – $98 million; 2018 – $9 million).

Onerous Contract Provisions

In 2019, due to the adoption of IFRS 16, onerous contract provisions are composed of non-lease components of real estate contracts which consist of operating costs and unreserved parking. In 2018, onerous contract provisions included the lease components of base rent and reserved parking as well as the non-lease components. For further information on the adoption of IFRS 16 refer to Note 4 of the Consolidated Financial Statements.

In 2019, we recorded a non-cash recovery for onerous contracts of $5 million, due to an update in the underlying assumptions associated with certain Calgary office space (2018 – expense of $629 million).

Finance Costs

In 2019, finance costs decreased by $116 million compared with 2018 due to the significant reduction of total debt and a discount of $63 million on the repurchase of unsecured notes in 2019, partially offset by an increase in interest of $82 million related to lease liabilities from the adoption of IFRS 16.

The weighted average interest rate on outstanding debt for the year ended December 31, 2019 was 5.1 percent (2018 – 5.1 percent).

Foreign Exchange

($ millions)	2019	2018	2017
Unrealized Foreign Exchange (Gain) Loss	**(827)**	649	(857)
Realized Foreign Exchange (Gain) Loss	**423**	205	45
	(404)	854	(812)

In 2019, unrealized foreign exchange gains of $827 million were recorded primarily as a result of the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar as at December 31, 2019 was stronger compared with December 31, 2018. For the year ended December 31, 2019, realized foreign exchange losses of $423 million, were recorded primarily as a result of the recognition of foreign exchange losses from the repurchase of debt.

Re-measurement of Contingent Payment

Related to oil sands production, Cenovus has agreed to make quarterly payments to ConocoPhillips during the five years subsequent to the closing date of the Acquisition for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. The quarterly payment is $6 million for each dollar that the WCS price exceeds $52 per barrel. There are no maximum payment terms. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment.

The contingent payment is accounted for as a financial option. The fair value of $143 million as at December 31, 2019 was estimated by calculating the present value of the future expected cash flows using an

option pricing model. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. For the year ended December 31, 2019, a non-cash re-measurement loss of $164 million was recorded.

As at December 31, 2019, average WCS forward pricing for the remaining term of the contingent payment is $46.57 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately $41.20 per barrel and $54.60 per barrel.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements, office furniture, and ROU assets. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. ROU assets (real estate assets) are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. DD&A in 2019 was $107 million (2018 – $58 million). The increase in DD&A compared with 2018 was due to depreciation expense on our ROU assets.

Income Tax

($ millions)	**2019**	2018	2017
Current Tax			
Canada	**14**	(128)	(217)
United States	**3**	2	(38)
Current Tax Expense (Recovery)	**17**	(126)	(255)
Deferred Tax Expense (Recovery)	**(814)**	(884)	203
Total Tax Expense (Recovery) From Continuing Operations	**(797)**	(1,010)	(52)

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

($ millions)	**2019**	2018	2017
Earnings (Loss) From Continuing Operations Before Income Tax	**1,397**	(3,926)	2,216
Canadian Statutory Rate (percent)	**26.5**	27.0	27.0
Expected Income Tax Expense (Recovery) From Continuing Operations	**370**	(1,060)	598
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**(52)**	(57)	(17)
Non-Taxable Capital (Gains) Losses	**(38)**	89	(148)
Non-Recognition of Capital (Gains) Losses	**(39)**	87	(118)
Adjustments Arising from Prior Year Tax Filings	**4**	3	(41)
Recognition of Previously Unrecognized Capital Losses	**-**	-	(68)
Recognition of U.S. Tax Basis	**(387)**	(78)	-
Change in Statutory Rates	**(671)**	-	(275)
Non-Deductible Expenses	**-**	3	(5)
Other	**16**	3	22
Total Tax Expense (Recovery) From Continuing Operations	**(797)**	(1,010)	(52)
Effective Tax Rate (percent)	**(57.1)**	25.7	(2.3)

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 income taxes is adequate. There are usually a number of tax matters under review and as a result, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

For the year ended December 31, 2019, a current tax expense was recorded compared with a recovery in 2018 and 2017 due to the carry back of losses to recover tax paid in previous years. The maximum recovery was reached in 2018.

In 2019, the Government of Alberta enacted a reduction in the provincial corporate tax rate from 12 percent to eight percent over four years. As a result, we recorded a deferred income tax recovery of $671 million for the year ended December 31, 2019. In addition, we have recorded a deferred income tax recovery of $387 million due to an internal restructuring of our U.S. operations resulting in a step-up in the tax basis of our refining assets.

In 2018, we recorded a deferred tax recovery related to current period losses, including the write-down of the Deep Basin E&E assets and a $78 million recovery arising from an adjustment to the tax basis of the Company's refining assets. The increase in tax basis was a result of the Company's partner recognizing a taxable gain on its interest in WRB, which due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. A deferred tax expense was recorded in 2017 due to the revaluation gain of our pre-existing interest in

connection with the Acquisition, net of a reduction of the U.S. federal corporate income tax rate from 35 percent to 21 percent reducing our deferred income tax liability and the impact of E&E write-downs.

Our effective tax rate is a function of the relationship between total tax expense (recovery) and the amount of earnings (loss) before income taxes. The effective tax rate differs from the statutory tax rate as it reflects different tax rates in other jurisdictions, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other tax legislation, adjustments to the tax basis of the refining assets, variations in the estimate of reserves, differences between the provision and the actual amounts subsequently reported on the tax returns, and other permanent differences.

Capital Investment

Capital expenditures of $137 million for the year ended December 31, 2019 focused primarily on the build-out of office space at Brookfield Place Calgary and information technology capital.

In 2020, we expect to invest between $90 million and $100 million, which includes continued investments in technology and equipment to further modernize our workplace, improve our cost structure and better manage risk. Guidance dated December 9, 2019 is available on our website at cenovus.com.

DISCONTINUED OPERATIONS

On January 5, 2018, we completed the sale of the Suffield crude oil and natural gas operations in southern Alberta for cash proceeds of $512 million, before closing adjustments. After-tax earnings from discontinued operations for the year ended December 31, 2018 were $27 million. An after-tax gain on discontinuance of $220 million was recorded on the sale.

QUARTERLY RESULTS

Our results over the last four quarters were impacted primarily by mandatory production curtailments and the last eight quarters were impacted by volatility in commodity prices. Light oil benchmark prices remained depressed throughout the majority of 2019, consistent with the substantial fall in the price of WTI in the fourth quarter of 2018, due to continued uncertainty from oversupply, decreased demand and trade tensions compared with the price improvements throughout the first three quarters of 2018. The mandatory production curtailments significantly narrowed light-heavy crude oil differentials in Alberta and reduced crude price spread between the USGC and Alberta in 2019 compared with 2018. As a result, our Operating Margin from continuing operations was $864 million in the fourth quarter of 2019, a substantial increase from $135 million in the fourth quarter of 2018. Net Earnings from continuing operations was $113 million compared with a loss of $1,350 million in 2018.

Selected Operating and Consolidated Financial Results

($ millions, except per share amounts)	2019				2018 (1)			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production Volumes								
Liquids (barrels per day)	**400,329**	380,699	371,390	370,983	354,592	408,950	423,340	395,474
Natural Gas (MMcf per day)	**403**	407	432	458	469	520	572	558
Total Production (BOE per day)	**467,448**	448,496	443,318	447,270	432,714	495,608	518,609	488,561
Total Production From Continuing Operations (BOE per day)	**467,448**	448,496	443,318	447,270	432,713	495,592	518,530	487,464
Refinery Operations								
Crude Oil Runs (Mbbls/d)	**456**	465	474	375	477	492	464	349
Refined Products (Mbbls/d)	**477**	485	501	402	502	518	490	369
Revenues	**4,838**	4,736	5,603	5,004	4,545	5,857	5,832	4,610
Operating Margin from Continuing Operations (2)	**864**	1,080	1,277	1,239	135	1,191	911	157
Cash From Operating Activities								
From Continuing Operations	**740**	834	1,275	436	488	1,258	506	(134)
Total	**740**	834	1,275	436	485	1,259	533	(123)
Adjusted Funds Flow (3)	**678**	916	1,082	1,048	(36)	977	774	(41)
Operating Earnings (Loss) from Continuing Operations (3)	**(164)**	284	267	69	(1,670)	(41)	(292)	(752)
Per Share ($) (4)	**(0.13)**	0.23	0.22	0.06	(1.36)	(0.03)	(0.24)	(0.61)
Net Earnings (Loss)								
From Continuing Operations	**113**	187	1,784	110	(1,350)	(242)	(410)	(914)
Per Share ($) (4)	**0.09**	0.15	1.45	0.09	(1.10)	(0.20)	(0.33)	(0.74)
Total Net Earnings (Loss)	**113**	187	1,784	110	(1,356)	(241)	(418)	(654)
Per Share ($) (4)	**0.09**	0.15	1.45	0.09	(1.10)	(0.20)	(0.34)	(0.53)
Capital Investment (5)	**317**	294	248	317	276	271	292	524
Dividends	**77**	60	62	61	62	61	62	60
Per Share ($)	**0.0625**	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

(2) Additional subtotal found in Notes 1 and 11 of the Consolidated Financial Statements, in Notes 1 and 7 of the Interim Consolidated Financial Statements and defined in this MD&A.

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

(4) Represented on a basic and diluted per share basis.

(5) Includes expenditures on PP&E, E&E assets, and assets held for sale.

Fourth Quarter 2019 Results Compared With the Fourth Quarter 2018

Production Volumes

Total production from continuing operations increased eight percent in the fourth quarter of 2019 compared with 2018. In the fourth quarter of 2018, we decided to restrict oil sands production rates in response to takeaway capacity constraints and the wide heavy oil differentials. In the fourth quarter of 2018, the WTI-WCS differential averaged US$39.42 per barrel and reached a record of US$52.00 per barrel.

In the fourth quarter of 2019, we sold 181,366 barrels per day, approximately 35 percent, of our Oil Sands production at sales locations outside of Alberta compared with 99,041 barrels per day, approximately 20 percent, in the fourth quarter of 2018.

Deep Basin production in the fourth quarter of 2019 decreased 12 percent to 93,317 BOE per day mainly due to natural declines from lower sustaining capital investment.

Refining and Marketing Operations

Crude oil runs of 456,000 gross barrels per day and refined product output of 477,000 gross barrels per day were lower compared with the same period in 2018 due to planned turnaround activities and a crude supply constraint at Wood River as a result of the Keystone pipeline leak, partially offset by optimization of the total crude input slate. In the fourth quarter of 2018 both Refineries operated above nameplate capacity of 460,000 gross barrels per day.

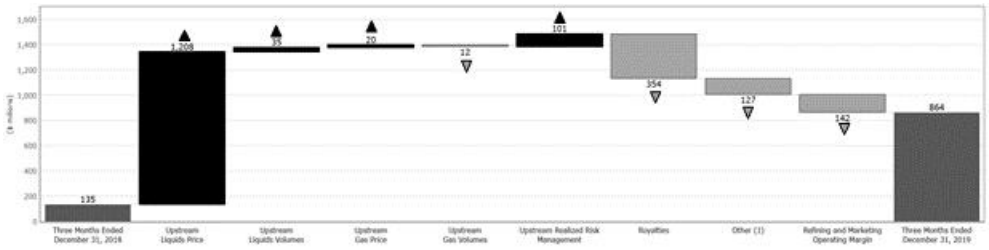
In the fourth quarter of 2019 we increased total rail volumes loaded at our Bruderheim crude-by-rail terminal by loading an average of 89,630 barrels per day (71,708 barrels per day of our volumes) compared with an average of 70,323 barrels per day (51,475 barrels per day of our volumes) in 2018.

Revenues

Revenues increased $293 million in the fourth quarter of 2019 primarily due to higher realized liquids sales pricing of $47.12 per barrel compared with $13.26 per barrel in 2018, and increased sales volumes.

The increase was partially offset by higher royalties, decreased refining revenues due to lower refined product pricing consistent with the decline in average refined product benchmark prices, lower volumes and decreased revenues from third-party crude oil and natural gas sales undertaken by the marketing group.

Operating Margin From Continuing Operations Variance



(1) Other includes the value of condensate sold as heavy oil blend recorded in revenues and condensate costs recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Operating Margin

Operating Margin from continuing operations increased in the fourth quarter of 2019 compared with 2018 due to a higher average liquids sales price as a result of narrower differentials, increased sales volumes and upstream realized risk management gains of $15 million (2018 – losses of $86 million).

These increases were partially offset by:

- Higher royalties primarily due to our higher realized crude oil sales price, partially offset by lower annual average WTI benchmark pricing;
- An increase in our transportation and blending costs due to an increase in rail transportation costs and pipeline tariffs due to higher volumes shipped to the U.S.; and
- Lower Operating Margin from our Refining and Marketing segment due to lower crude advantage, decreased crude oil runs, lower market crack spreads and higher operating expenses.

Cash From Operating Activities and Adjusted Funds Flow

Total Cash From Operating Activities and Adjusted Funds Flow increased in the fourth quarter of 2019 compared with the same period in 2018, primarily due to higher Operating Margin, as discussed above, and a reduction in rent expense due to the adoption of IFRS 16. The increase in Cash From Operating Activities was partially offset by a lower tax recovery, realized risk management gains of $23 million in 2018 related to interest rate swaps and changes in non-cash working capital.

The change in non-cash working capital in the fourth quarter of 2019 was primarily due to an increase in accounts payable and a decrease in income tax receivable, partially offset by an increase in accounts receivable and inventory. For 2018, the change in non-cash working capital was primarily due to a decrease in accounts receivable and inventory, partially offset by a decrease in accounts payable and income tax payable.

Operating Earnings (Loss)

Operating Loss from continuing operations decreased in the three months ended December 31, 2019 compared with 2018 primarily due to exploration expense of $72 million compared with $2,115 million in the fourth quarter of 2018, as well as higher Cash From Operating Activities and Adjusted Funds Flow, as discussed above. These decreases were partially offset by a re-measurement loss of $27 million on the contingent payment compared with a gain of $361 million in 2018 and higher employee long-term incentive costs.

Net Earnings (Loss)

Net Earnings from continuing operations of $113 million increased for the three months ended December 31, 2019 compared with a Net Loss of $1,350 million in 2018. The change was primarily due to a lower Operating Loss, as discussed above, and non-operating foreign exchange gains of $258 million compared with losses of $296 million in 2018. These increases to our Net Earnings from continuing operations were partially offset by unrealized risk management gains of $8 million compared with unrealized gains of $741 million in 2018 and a deferred income tax recovery of $24 million compared with a deferred tax recovery of $580 million.

Capital Investment

Capital investment from continuing operations in the fourth quarter of 2019 was $317 million, $41 million higher compared with the fourth quarter of 2018, primarily due to advancing key initiatives and technical developments as well as higher spending on rail initiatives and infrastructure.

OIL AND GAS RESERVES

We retain IQREs to evaluate and prepare reports on 100 percent of our bitumen, heavy crude oil, light and medium oil, NGLs, conventional natural gas and shale gas proved and probable reserves.

Reserves

As at December 31, 2019 (before royalties)	**Bitumen (1)** (MMbbls)	**Light and Medium Oil** (MMbbls)	**NGLs** (MMbbls)	**Conventional Natural Gas (2)** (Bcf)	**Total** (MMBOE)
Proved	**4,826**	**9**	**60**	**1,242**	**5,103**
Probable	**1,594**	**8**	**37**	**783**	**1,768**
Proved plus Probable	**6,420**	**17**	**97**	**2,025**	**6,871**

As at December 31, 2018 (before royalties)	**Bitumen (1)** (MMbbls)	**Light and Medium Oil** (MMbbls)	**NGLs** (MMbbls)	**Conventional Natural Gas (2)** (Bcf)	**Total** (MMBOE)
Proved	**4,831**	**12**	**72**	**1,513**	**5,167**
Probable	**1,598**	**5**	**44**	**1,041**	**1,821**
Proved plus Probable	**6,429**	**17**	**116**	**2,554**	**6,988**

(1) Includes heavy crude oil reserves that are not material.
(2) Includes shale gas reserves that are not material.

Developments in 2019 compared with 2018 include:

- Bitumen proved reserves decreasing five million barrels as additions from improved performance in Oil Sands were more than offset by current year production;
- Bitumen proved plus probable reserves decreasing nine million barrels as additions from improved performance in Oil Sands were more than offset by current year production;
- Light and medium oil proved reserves decreasing three million barrels as minor additions were more than offset by technical revisions attributed to changes to the Deep Basin development plan, and current year production;
- Light and medium oil proved plus probable reserves were unchanged as minor additions were offset by technical revisions attributed to changes to the Deep Basin development plan, and current year production;
- NGLs proved and proved plus probable reserves decreasing 12 million barrels and 19 million barrels, respectively, as minor additions were more than offset by reductions due to technical revisions attributed to changes to the Deep Basin development plan, and current year production; and
- Conventional natural gas proved and proved plus probable reserves decreasing by 271 billion cubic feet and 529 billion cubic feet, respectively, as additions were more than offset by reductions due to technical revisions attributed to changes to the Deep Basin development plan, and current year production.

The reserves data is presented as at December 31, 2019 using an average of forecasts ("IQRE Average Forecast") by McDaniel & Associates Consultants Ltd., GLJ Petroleum Consultants Ltd. and Sproule Associates Limited. The IQRE Average Forecast prices and costs are dated January 1, 2020. Comparative information as at December 31, 2018 uses the January 1, 2019 IQRE Average Forecast prices and costs.

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") is contained in our AIF for the year ended December 31, 2019. Our AIF is available on SEDAR at sedar.com, on EDGAR at sec.gov and on our

website at cenovus.com. Material risks and uncertainties associated with estimates of reserves are discussed in this MD&A in the Risk Management and Risk Factors section.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2019	2018	2017
Cash From (Used In)			
Total Operating Activities	**3,285**	2,154	3,059
Total Investing Activities	**(1,432)**	(613)	(12,866)
Net Cash Provided (Used) Before Financing Activities	**1,853**	1,541	(9,807)
Financing Activities	**(2,413)**	(1,410)	6,515
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(35)**	40	182
Increase (Decrease) in Cash and Cash Equivalents	**(595)**	171	(3,110)

As at December 31,	2019	2018	2017
Cash and Cash Equivalents	**186**	781	610
Net Debt	**6,513**	8,383	8,903
Committed and Undrawn Credit Facility	**4,235**	4,500	4,500

As at December 31, 2019, we were in compliance with all of the terms of our debt agreements.

Cash From (Used In) Operating Activities

For the year ended December 31, 2019, cash generated by operating activities increased mainly due to:

- Higher Operating Margin, as discussed in the Operating and Financial Results section of this MD&A;
- A decrease in general and administrative costs, due to a decrease in rent expense primarily from the adoption of IFRS 16 and $60 million of severance costs recognized in 2018; and
- A decrease in finance costs, as discussed in the Corporate and Eliminations section of this MD&A.

The increases in cash from operating activities for the year ended December 31, 2019 were partially offset a current income tax expense in 2019 compared with a recovery in 2018 and changes in non-cash working capital, as discussed in the Operating and Financial Results section of this MD&A.

Excluding risk management assets and liabilities and the current portion of the contingent payment, our working capital was $839 million at December 31, 2019 compared with $450 million at December 31, 2018.

We anticipate that we will continue to meet our payment obligations as they come due.

Cash From (Used In) Investing Activities

Cash used in investing activities was higher in 2019 compared with 2018 primarily due to proceeds from the divestiture of CPP and the Suffield assets in 2018, partially offset by decreased capital investment in 2019.

Cash From (Used In) Financing Activities

In 2019, cash was used in financing activities primarily for the repayment of debt. We repaid US$1.8 billion of unsecured notes for cash consideration of US$1.7 billion ($2.3 billion). Total debt as at December 31, 2019 was $6,699 million (December 31, 2018 – $9,164 million).

In 2018, cash was used in financing activities primarily for the repayment of US$876 million ($1.1 billion) of debt, as well as dividends paid on common shares. In 2017, cash was generated by financing activities from the issuance of debt and common shares to finance the Acquisition.

As at December 31, 2018 we had US$6,774 million in U.S. dollar debt ($9,241 million) compared with US$7,650 million ($9,597 million) at December 31, 2017.

Dividends

In 2019, we paid dividends of $0.2125 per common share or $260 million (2018 – $0.20 per common share or $245 million). Our Board declared a first quarter dividend of $0.0625 per share, payable on March 31, 2020, to common shareholders of record as of March 13, 2020. The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Available Sources of Liquidity

We expect cash flows from our upstream and refining operations to fund all of our cash requirements in 2020. Any potential shortfalls may be funded through prudent use of our balance sheet capacity including draws on our credit facility, management of our asset portfolio and other corporate and financial opportunities that may be available to us.

Moody's Investors Service ("Moody's") changed their outlook on our Ba1 rating to positive from stable in the fourth quarter. In addition to making progress towards re-establishing an investment grade credit rating at Moody's we remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, DBRS Limited and Fitch Ratings.

The following sources of liquidity are available at December 31, 2019:

($ millions)	Term	Amount
Cash and Cash Equivalents	**Not applicable**	**186**
Committed Credit Facility – Tranche A	**November 2023**	**3,035**
Committed Credit Facility – Tranche B	**November 2022**	**1,200**

Committed Credit Facility

We have a committed credit facility in place that consists of a $1.2 billion tranche and a $3.3 billion tranche. In the fourth quarter of 2019, we amended the committed credit facility to extend the maturity date of the $1.2 billion tranche to November 30, 2022 and the maturity date of the $3.3 billion tranche to November 30, 2023. As at December 31, 2019, $265 million was drawn on our committed credit facility.

Base Shelf Prospectus

Cenovus has in place a base shelf prospectus which expires in October 2021. As at December 31, 2019, US$5.0 billion remains available under the base shelf prospectus. Offerings under the base shelf prospectus are subject to market conditions. Refer to Note 23 of the Consolidated Financial Statements for more details on our Base Shelf Prospectus.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Net Debt to Adjusted EBITDA and Net Debt to Capitalization. We define our non-GAAP measure of Net Debt as short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. We define Capitalization as Net Debt plus Shareholders' Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense, DD&A, E&E Write-down, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, and other income (loss), net, calculated on a trailing twelve-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

As at December 31,	**2019**	2018	2017
Net Debt to Capitalization (1) (percent)	**25**	32	31
Net Debt to Adjusted EBITDA (2)	**1.6x**	5.9x	2.8x

(1) Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

A reconciliation of Adjusted EBITDA, and the calculation of Net Debt to Adjusted EBITDA can be found in Note 23 of the Consolidated Financial Statements.

Cenovus targets a Net Debt to Adjusted EBITDA ratio of less than 2.0 times over the long-term. This ratio may periodically be above the target due to factors such as persistently low commodity prices. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, Cenovus may, among other actions, adjust capital and operating spending, draw down on our credit facility or repay existing debt, adjust dividends paid to shareholders, purchase our common shares for cancellation, issue new debt, or issue new shares. We also manage our Net Debt to Capitalization ratio to ensure compliance with the associated covenants as defined in our committed credit facility agreement.

As at December 31, 2019, Cenovus's Net Debt to Adjusted EBITDA was 1.6 times. Net Debt to Adjusted EBITDA decreased compared with 2018 as result of significant repayments of our debt as mentioned in the Cash From (Used In) Financing Activities above.

Under the committed credit facility, Cenovus is required to maintain a debt to capitalization ratio not to exceed 65 percent; we are well below this limit.

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

Share Capital and Stock-Based Compensation Plans

As at December 31, 2019, there were approximately 1,229 million common shares outstanding (2018 – 1,229 million common shares).

Refer to Note 32 of the Consolidated Financial Statements for more details on our Stock Option Plan and our Performance Share Unit, Restricted Share Unit and Deferred Share Unit Plans.

As at January 31, 2020	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares (1)	**1,228,870**	**N/A**
Stock Options	**31,459**	**27,083**
Other Stock-Based Compensation Plans	**16,606**	**1,339**

(1) ConocoPhillips continued to hold 208 million common shares issued as partial consideration related to the Acquisition.

Capital Investment Decisions

Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria based on a US$45.00 per barrel WTI price and US$13.00 per barrel WTI-WCS differential environment, which we believe are the bottom-of-the-cycle commodity prices, with the objective of maintaining a prudent and flexible capital structure and strong balance sheet metrics. This approach helps position us to be financially resilient in times of lower cash flows. Balance sheet strength will continue to be a top priority and we plan to direct the majority of our Free Funds Flow towards debt reduction until we reach our longer-term Net Debt target of $5.0 billion. This level of Net Debt approximates a Net Debt to EBITDA ratio of two times at bottom-of-the-cycle commodity prices. As we progress towards our longer-term Net Debt target, we will also consider opportunities for shareholder returns in the form of dividend increases and share repurchases.

Our capital allocation priorities include committed capital priorities and discretionary capital priorities. Committed capital priorities include safe and reliable operations, sustaining and maintenance capital for our existing business operations, funding our base dividend, and funding our targeted five percent to 10 percent annual dividend growth.

Discretionary capital allocation priorities, as we continue to reduce our Net Debt are:

- First, to continue to deleverage and reach our Net Debt target;
- Second, to support the potential sale of ConocoPhillips's ownership of Cenovus's common shares; and
- Third, balance other opportunistic share repurchases with disciplined investment in growing our business, while continuing to strengthen our balance sheet.

Refer to the Liquidity and Capital Resources section of this MD&A for further information.

($ millions)	**2019**	2018 (1) (2)	2017 (1) (2)
Adjusted Funds Flow	**3,724**	1,674	2,914
Total Capital Investment	**1,176**	1,363	1,661
Free Funds Flow (3)	**2,548**	311	1,253
Cash Dividends	**260**	245	225
	2,288	66	1,028

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

(2) Includes our Conventional segment, which has been classified as a discontinued operation.

(3) Free Funds Flow is a non-GAAP measure defined as Adjusted Funds Flow less capital investment.

We expect our capital investment and cash dividends for 2020 to be funded from our internally generated cash flows and our cash balance on hand.

Contractual Obligations and Commitments

Cenovus has obligations for goods and services entered into in the normal course of business. Obligations are primarily related to transportation agreements, our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. Obligations that have original maturities of less than one year are excluded. For further information, see the notes to the Consolidated Financial Statements.

On January 1, 2019, the Company adopted IFRS 16, which resulted in the recognition of lease liabilities related to operating leases on the balance sheet. These liabilities were previously reported as commitments. For a reconciliation of our commitments as at December 31, 2018 to our lease liabilities as at January 1, 2019, see Note 4 of the Consolidated Financial Statements.

As at December 31, 2019, total commitments were $23 billion, of which $21 billion are for various transportation and storage commitments. Terms are up to 20 years subsequent to the date of commencement and should help align the Company's future transportation requirements with anticipated production growth. Transportation and storage commitments include future commitments relating to railcar and storage tank leases of $31 million and $11 million, respectively, that have not yet commenced. The railcar leases are expected to commence in 2020 with lease terms between six and eight years and the storage tank leases are expected to commence in 2020 with lease terms of five years.

($ millions)	Expected Payment Date 2020	2021	2022	2023	2024	Thereafter	**Total**
Commitments							
Transportation and Storage (1)	1,005	959	1,026	1,456	1,381	15,672	**21,499**
Real Estate (2)	35	36	38	39	42	662	**852**
Other Long-Term Commitments	104	44	36	34	28	108	**354**
Total Commitments (3)	1,144	1,039	1,100	1,529	1,451	16,442	**22,705**
Other Obligations							
Long-term Debt (Principal and Interest)	344	344	994	1,174	291	9,326	**12,473**
Decommissioning Liabilities	57	44	44	39	41	2,437	**2,662**
Contingent Payment	79	50	19				**148**
Lease Liabilities (Principal and Interest) (4)	277	243	223	196	214	1,544	**2,697**
Total Commitments and Obligations	1,901	1,720	2,380	2,938	1,997	29,749	**40,685**

(1) Includes transportation commitments of $13 billion (December 31, 2018 – $14 billion) that are subject to regulatory approval or have been approved but are not yet in service.

(2) Relates to the non-lease components of lease liabilities consisting of operating costs and unreserved parking for office space. Excludes committed payments for which a provision has been provided.

(3) Contracts undertaken on behalf of WRB are reflected at our 50 percent interest.

(4) Lease contracts related to office space, railcars, storage assets, drilling rigs and other refining and field equipment.

We continue to focus on near and mid-term strategies to broaden market access for our crude oil production. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving our crude oil production to market by rail, and assessing options to maximize the value of our crude oil.

As at December 31, 2019, there were outstanding letters of credit aggregating $364 million issued as security for performance under certain contracts (December 31, 2018 – $336 million).

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations. We believe that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on our Consolidated Financial Statements.

Contingent Payment

In connection with the Acquisition and related to our Oil Sands production, we agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. As at December 31, 2019, the estimated fair value of the contingent payment was $143 million. See the Corporate and Eliminations section of this MD&A for more details.

RISK MANAGEMENT AND RISK FACTORS

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. The impact of any risk or a combination of risks may adversely affect, among other things, Cenovus's business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict our ability to pursue our strategic priorities, respond to changes in our operating environment, pay dividends to our shareholders and fulfill our obligations (including debt servicing requirements) and may materially affect the market price of our securities.

Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of risk across Cenovus and is integrated with the Cenovus Operations Management System ("COMS"). In addition, we continuously monitor our risk profile as well as industry best practices.

Risk Governance

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 Standards, a Risk Management Framework and Risk Assessment Tools, including a Risk Matrix. Our Risk Management Framework contains the key attributes recommended by the International Standards Organization ("ISO") in its ISO 31000 – Risk Management Guidelines (2017). The results of our ERM program are documented in an Annual Risk Report presented to the Board as well as through regular updates.

Risk Factors

The following discussion describes the financial, operational, regulatory, environmental, reputational and other risks related to Cenovus. Each risk identified in this MD&A may individually, or in combination with other risks, have a material impact on our business, financial condition, results of operations, cash flows, or reputation.

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. Financial risks include, but are not limited to: fluctuations in commodity prices, development or operating costs; risks related to Cenovus's hedging activities; exposure to counterparties; availability of capital and access to sufficient liquidity; risks related to Cenovus's credit ratings; and fluctuations in foreign exchange and interest rates. In addition, we identify risks related to our ability to pay a dividend to shareholders; and risks related to internal control over financial reporting ("ICFR"). Changes in financial management and/or market conditions could impact a number of factors including, but not limited to, Cenovus's cash flows, Cenovus's ability to maintain desirable ratios of debt (and Net Debt) to Adjusted EBITDA as well as debt (and Net Debt) to capitalization, financial condition, results of operations and growth, the maintenance of our existing operations and business plans, financial strength of our counterparties, access to capital and cost of borrowing.

Commodity Prices

Our financial performance is significantly 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: global and regional supply of and demand for crude oil; global economic conditions including factors impacting global trade; the actions of OPEC including, without limitation, compliance or non-compliance with quotas agreed upon by OPEC members and decisions by OPEC not to impose production quotas on its members; actions by the Government of Alberta including, without limitation, imposing, amending, or lifting crude oil production curtailments or SPA for crude-by-rail, and compliance or non-compliance with imposed crude oil production curtailments or SPA for crude-by-rail; enforcement of government or environmental regulations; public sentiment towards the use of non-renewable resources, including crude oil; political stability; market access constraints and transportation interruptions (pipeline, marine or rail) and access to markets; prices and availability of alternate fuel sources; outbreak of war; terrorist threats; and weather conditions. Natural gas prices 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; prices and availability of alternate sources of energy; government or environmental regulations; public sentiment towards the use of non-renewable resources, including natural gas; and economic conditions. Refined product prices are impacted by a number of factors including, but not limited to: global and regional supply and demand for refined products; market competitiveness; levels of refined product inventories; refinery availability; planned and unplanned refinery maintenance; weather conditions; current and potential future environmental regulations pertaining to the production and use of refined products; prices and availability of alternate sources of energy; public sentiment towards the use refined products; and the availability of alternate fuel sources. In addition, and relating to the level of future demand (and corresponding price levels) for each of crude oil, natural gas and refined products, there has been a significant increase in focus recently on the timing for and pace of the transition to a lower-carbon economy. Governments, financial institutions, environmental and governance organizations, institutional investors, social and environmental activists, and individuals, are increasingly seeking to implement, among other things, regulatory and policy changes, changes in investment patterns, and modifications in energy consumption habits and trends which, individually and collectively are intended to or have the effect of accelerating the reduction in the global consumption of carbon-based energy, the conversion of energy usage to less carbon-intensive forms and the general migration of energy usage away from carbon-based forms of energy. This focus and resulting trends will likely affect global energy demand and usage, including the composition of the types of energy generally used by industry and individual consumers. However it is not currently possible to predict the timelines for and precise effects of this transition to a potential lower-carbon economy, which will depend on a multitude of factors including the ability to develop adequate replacement sources of energy, technology development and adaptation including in the area of transportation electrification, the ability to conceptualize, develop and commercialize technologies for the production, storage and distribution of adequate alternative supplies of alternative energy, consumption patterns, global growth and industrial activity, in order to predict the longer term demand trends for carbon-based energy sources. 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 is also impacted by discounted or reduced commodity prices for our oil production relative to certain international benchmark prices, due, in part, to constraints on the ability to transport and sell products to domestic or international markets and the quality of oil produced. Of particular importance to us are diluent cost and supply and the price differentials between bitumen and both light to medium crude oil and heavy crude oil. Bitumen is more expensive for refineries to process and therefore generally trades at a discount to the market price for light and medium crude oil and heavy crude oil.

The financial performance of our refining operations is impacted by the relationship, or margin, between refined product prices and the prices of refinery feedstock. 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 our ability to meet guidance targets, the value of our assets, our cash flows, our ability to maintain our business and to fund

projects including, but not limited to, the continued development of our oil sands properties. A substantial decline in these commodity prices or extended period of low commodity prices may result in an inability to meet all of our financial obligations as they come due, a delay or cancellation of existing or future drilling, development or construction programs, curtailment in production (independent of any crude oil production curtailment mandated by the Government of Alberta then in effect), unutilized long-term transportation commitments and/or low utilization levels at Cenovus's refineries. Fluctuations in commodity prices, associated price differentials and refining margins impact our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

The commodity price risks noted above, as well as other risks such as market access constraints and transportation restrictions, reserves replacement and reserves estimates, and cost management that are more fully described herein, and may have a material impact on our business, financial condition, results of operations, cash flows or reputation, may be considered to be indicators of impairment. Another indication of impairment is the comparison of the carrying value of our assets to our market capitalization.

As discussed in this MD&A, we conduct an annual assessment of the carrying value of our assets in accordance with IFRS. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, or if the costs of our development of such resources significantly increases, the carrying value of our assets may be subject to impairment and our net earnings could be adversely affected.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts, market access commitments and generally through our access to committed credit facilities. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For 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 35 and 36 of the Consolidated Financial Statements.

Development and Operating Costs

Our financial outlook and performance is significantly affected by the cost of developing, sustaining and operating our assets. Development and operating costs are affected by a number of factors including, but not limited to: development, adoption and success of new technologies; inflationary price pressure; changes in regulatory compliance costs; 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

Cenovus's Market Risk Management Policy, which has been approved by the Board, allows Management to use derivative instruments to help mitigate the impact of changes in crude oil and natural gas prices, crude oil differentials, diluent or condensate supply prices and differentials, refining margins, as well as fluctuations in foreign exchange rates and interest rates. Cenovus also uses derivative instruments in various operational markets to help optimize our supply costs or sales of our production.

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 valuation of the hedge instrument being not well correlated to the change in the valuation of the underlying exposures being hedged; change in price of the underlying commodity; lack of market liquidity; insufficient counterparties to transact with; counterparty default; deficiency in systems or controls; human error; and the unenforceability of contracts.

There is risk that the consequences of hedging to protect against unfavourable market conditions 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 related to the underlying physical transaction.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For 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, 35 and 36 of the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

	2019			2018		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**23**	**143**	**166**	1,577	(1,219)	358
Refining	**(16)**	**1**	**(15)**	(1)	(5)	(6)
Interest Rate	**1**	**7**	**8**	(23)	(26)	(49)
Foreign Exchange	**(1)**	**(2)**	**(3)**	1	1	2
(Gain) Loss on Risk Management	**7**	**149**	**156**	1,554	(1,249)	305
Income Tax Expense (Recovery)	**(2)**	**(36)**	**(38)**	(422)	336	(86)
(Gain) Loss on Risk Management, After Tax	**5**	**113**	**118**	1,132	(913)	219

In 2019, we incurred realized losses on crude oil risk management activities as the settlement prices exceeded our contract prices. Unrealized losses were recorded on our crude oil financial instruments in the twelve months ended December 31, 2019 primarily due to the realization of settled positions and changes in market prices.

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. The impact of fluctuations in commodity prices on our open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

	Sensitivity Range	**Increase**	**Decrease**
Crude Oil Commodity Price	± US$5.00 per bbl Applied to WTI and Condensate Hedges	**3**	**(3)**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**5**	**(5)**

For further information on our risk management positions, see Notes 35 and 36 of the Consolidated Financial Statements.

Risks Associated with Derivative Financial Instruments

Financial instruments expose Cenovus to the risk that a counterparty will default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our *Credit Policy*.

Financial instruments also expose Cenovus to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. Financial instruments may limit the benefit to Cenovus if commodity prices, interest or foreign exchange rates change. These risks are managed through hedging limits authorized according to our *Market Risk Management Policy*.

Exposure to Counterparties

In the normal course of business, we enter into contractual relationships with suppliers, partners, lenders and other counterparties for the provision and sale of goods and services. If such counterparties do not fulfill their contractual obligations on a timely basis or at all, we may suffer financial losses, delays of our development plans or we may have to forego other opportunities which could 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. Among other things, unpredictable financial markets, a sustained commodity price downturn, a change in market fundamentals, business operations, investor or lender sentiment towards our business and/or the industry in which we operate or credit rating, or significant unanticipated expenses, may impede our ability to secure and maintain cost-effective financing. An inability to access capital, on terms acceptable to Cenovus or at all, could affect our ability to make future capital expenditures, to maintain desirable ratios of debt (and Net Debt) to Adjusted EBITDA as well as debt (and Net Debt) to capitalization and to meet all of our financial obligations as they come due, potentially creating a material adverse effect on our financial condition, results of operations, ability to comply with various financial and operating covenants, credit ratings and reputation.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic, business, market and other conditions, some of which are beyond our control. If our operating and financial results are not sufficient to service current or future indebtedness, Cenovus may take actions such as reducing dividends, reducing or delaying business activities, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional capital that could have less favourable terms.

We mitigate our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital.

We are required to comply with various financial and operating covenants under our credit facility and the indentures governing our debt securities. We routinely review our covenants and ensure compliance. In the event that we do not comply with such covenants, our access to capital could be restricted or repayment could be accelerated.

Credit Ratings

Our company and our capital structure are regularly evaluated by credit rating agencies. Credit ratings are based on our financial and operational strength and a number of factors not entirely within our control, including conditions affecting the oil and gas industry generally, and the state of the economy. There can be no assurance that one or more of our credit ratings will not be downgraded or withdrawn entirely by a rating agency.

A reduction in any of our credit ratings could adversely affect the cost and availability of borrowing, and access to sources of liquidity and capital. A failure by Cenovus to maintain current credit ratings could affect our business relationships with counterparties, operating partners and suppliers.

If one or more of our credit ratings falls below certain ratings floors we may be obligated to post collateral in the form of cash, letters of credit or other financial instruments in order to establish or maintain business arrangements. Additional collateral may be required due to further downgrades below certain ratings floors. Failure to provide adequate credit risk assurance to counterparties and suppliers may result in foregoing or having contractual business arrangements terminated.

Foreign Exchange Rates

Fluctuations in foreign exchange rates may affect our results as global prices for crude oil, natural gas and refined products are generally set in U.S. dollars, while many of our operating and capital costs are in Canadian dollars. A change in the value of the Canadian dollar relative to the U.S. dollar will increase or decrease revenues, as expressed in Canadian dollars, received from the sale of oil and refined products, and from some of our natural gas sales. In addition, we have chosen to borrow U.S. dollar long-term debt. A change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in our U.S. dollar denominated debt and related interest expense, as expressed in Canadian dollars.

We may periodically enter into transactions to manage our exposure to exchange rate fluctuations. Exchange rate fluctuations could have a material adverse effect on our financial condition, results of operations and cash flows.

Interest Rates

We may be exposed to fluctuations in interest rates as a result of the use of floating rate securities or borrowings. An increase in interest rates could increase our net interest expense and affect how certain liabilities are recorded, both of which could negatively impact financial results. Additionally, we are exposed to interest rate fluctuations upon the refinancing of maturing long-term debt and potential future financings at prevailing interest rates.

We may periodically enter into transactions to manage our exposure to interest rate fluctuations.

Dividend Payment and Share Repurchase

The payment of dividends, continuation of Cenovus's dividend reinvestment plan and any potential share repurchase by Cenovus of its common shares is at the discretion of the Board, and is dependent upon, among other things, financial performance, debt covenants, satisfying solvency testing, ability to meet financial obligations as they come due, working capital requirements, future tax obligations, future capital requirements, commodity prices and the other risk factors set forth in this MD&A.

Disclosure Controls and Procedures and ICFR

Based on their inherent limitations, disclosure controls and procedures and ICFR may not prevent or detect misstatements, and even those controls determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on our business, financial condition, results of operations, cash flows, and our reputation.

Operational Risk

Operational risks are those risks that 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. To partially mitigate our risks, we have a system of standards, practices and procedures called COMS to identify, assess and mitigate safety, operational and environmental risk across our operations. In addition to leveraging COMS, we attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations. However, there can be no assurance as to the amount, if any, or timing of recovery under our insurance policies in connection with losses associated with these events and risks. Although we maintain insurance for a number of risks and hazards, we may not be insured or fully insured against all losses or liabilities that could arise from our assets or operations.

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; railcar incident or derailment; gaseous leaks; migration of harmful substances; oil spills; corrosion; acts of vandalism and terrorism; and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites. 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, cause environmental damage that may include polluting water, land or air, and may result in fines, civil suits, or criminal charges against Cenovus, any of which may have a material adverse effect on our business, financial condition, results of operations, cash flows, and our reputation.

Market Access Constraints and Transportation Restrictions

Our production is transported through various pipelines and rail networks and our refineries are reliant on various pipelines and rail networks to receive feedstock. Disruptions in, or restricted availability of, pipeline service and/or marine or rail transport, could adversely affect crude oil and natural gas sales, projected production growth, upstream or refining operations and cash flows.

Interruptions or restrictions in the availability of these pipeline and rail systems may also limit the ability to deliver production volumes and could adversely impact commodity prices, sales volumes and/or the prices received for our products. These interruptions and restrictions may be caused by the inability of the pipeline or rail network to operate, or may 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 new pipeline projects, which would result in an increase in long-term takeaway capacity, will be made by applicable third-party pipeline providers or that any applications to expand capacity will receive the required regulatory approval, or that any such approvals will result in the construction of the pipeline project. 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 no certainty that crude-by-rail, marine transport 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 and marine shipments may be impacted by service delays, inclement weather, railcar availability, railcar derailment or other rail or marine transport incidents and could adversely impact crude oil sales volumes or the price received for product or impact our reputation or result in legal liability, loss of life or personal injury, loss of equipment or property, or environmental damage. In addition, new regulations, will require tank cars used to transport crude-by-rail to be replaced with newer tank cars, or to be retrofitted to meet the same standards. The costs of complying with the new standards, or any further revised standards, will likely be passed on to rail shippers and may adversely affect our ability to transport crude-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.

Insufficient transportation capacity for our production will impact our ability to efficiently access end markets. This may negatively impact our financial performance by way of higher transportation costs, wider price differentials, lower sales prices at specific locations or for specific grades of crude oil, and, in extreme situations, production curtailment.

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; fires; explosions; blowouts; gaseous leaks; power outages; migration of harmful substances into water systems; oil spills; uncontrollable flows of crude oil, natural gas or well fluids; failure to follow operating procedures or operate within established operating parameters; equipment failures and other accidents; 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.

Although we are not the operator of the two U.S. refineries in which we have a 50 percent interest, the 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; failure to follow operating procedures or operate within established operating parameters; slowdowns due to equipment failure or transportation disruptions; railcar incidents or derailments; marine transport incidents; weather; fires and/or explosions; unavailability of feedstock; and price and quality of feedstock.

We do not insure against all potential occurrences and disruptions in respect of our assts or operations, and it cannot be guaranteed that our insurance coverage will be available or sufficient to fully cover any claims that may arise from such occurrences or disruptions. Our operations could also be interrupted by natural disasters or other events beyond our control. The occurrence of an event that is not fully covered by our insurance program could have a material adverse effect on our business, financial condition, results of operation and cash flows.

Reserves Replacement and Reserve Estimates

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

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 and revenue derived therefrom are based on 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 environmental regulations and royalty payments and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines, rail transportation and processing facilities, all of which may cause actual results to vary materially from estimated 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 revenue 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 on volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based on production history will result in variations, which may be material, in the estimated reserves.

The production rate of oil and gas properties tends to decline as reserves are depleted while the associated operating costs increase. Maintaining an inventory of developable projects to support future production of crude oil and natural gas depends on, among other things: obtaining and renewing rights to explore, develop and produce oil and natural gas; drilling success; completing long-lead time capital intensive projects on budget and on schedule; and the application of successful exploitation techniques on mature properties. Our business, financial condition, results of operations and cash flows are highly dependent upon successfully producing current reserves and adding additional reserves.

Cost Management

Our operating costs could escalate and become uncompetitive due to inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, higher steam-to-oil ratios in our oil sands operations, and additional government or environmental regulations. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial condition, results of operations and cash flows.

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 refining, 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 our company does. 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, including renewable energy sources which may become more prevalent in the future.

Companies may announce 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, constrain transportation and increase our input costs for and constrain the supply of skilled labour and materials.

Project Execution

There are risks associated with the execution and operation of our upstream growth and development projects. These risks include, but are not limited to: our ability to obtain the necessary environmental and regulatory approvals; our ability to obtain favourable terms or to be granted access within land-use agreements; 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; risk related to the accuracy of poject cost estimates; our ability to finance capital and expenses; 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 and conventional development on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving performance targets and objectives. Failure to manage these risks could have a material adverse effect on our financial condition, results of operations and cash flows.

Partner Risks

Some of our assets are not operated by us or are held in partnership with others. Therefore, our results of operations and cash flows may be affected by the actions of third-party operators or partners. Our refining assets are held in a partnership with Phillips 66 and operated by Phillips 66. The success of the 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 information on the status of such refining assets and related results of operations.

Phillips 66 may have objectives and interests that do not align with or may conflict with our interests. Major capital decisions affecting these refining assets require agreement between each respective partner, while certain operational decisions may be made by the operator of the assets. While we generally seek consensus with respect to major decisions concerning the direction and operation of these 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 licences or approvals or affect the timing of undertaking various activities.

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

Information Systems

We rely heavily on information technology, such as computer hardware and software systems, in order to properly operate our business. In the event we are unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data.

In the ordinary course of business, we collect, use and store sensitive data, including intellectual property, proprietary business information and personal information of our employees and third parties. Despite our security measures, our information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions, including natural disasters and acts of war. Any such breach could compromise information used or stored on our systems and/or networks and, as a result, the information could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, operational disruption, site shut-down, leaks or other negative consequences, including damage to our reputation, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

There is also a risk of cyber-related fraud whereby perpetrators attempt to take control of electronic communications or attempt to impersonate internal personnel or business partners to divert payments and financial assets to accounts controlled by the perpetrators. If a perpetrator is successful in bypassing Cenovus's cyber-security measures and business process controls, such cyber-related fraud could result in financial losses, remediation and recovery costs, and an adverse reputational impact.

Leadership and Talent

Our success is dependent upon our Management, our leadership capabilities and the quality and competency of our talent. If we are unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our financial condition, results of operations and pace of growth.

Litigation

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. Various types of claims may be made including, without limitation, environmental damages, breach of contract, negligence, product liability, antitrust, bribery and other forms of corruption, tax, patent infringement and employment matters. In recent years there has been an increase in climate change related litigation in various jurisdictions including the U.S. and Canada, asserting various claims, including that energy producers contribute to climate change, that such entities are not reasonably managing business risks associated with climate change, and that such entities have not adequately disclosed business risks of climate change. While many of the climate change related actions are in preliminary stages of litigation, and in some cases assert novel or untested causes of action, there can be no assurance that legal, societal, scientific and political developments will not increase the likelihood of successful climate change related litigation against energy producers including us. The outcome of any such litigation is uncertain and may materially impact our financial condition or results of operations. Moreover, unfavourable outcomes or settlements of litigation could encourage the commencement of additional litigation. We may also be subject to adverse publicity associated with such matters, regardless of whether we are ultimately found responsible. We may be required to incur significant expenses or devote significant resources in defense against any such litigation.

Aboriginal Land and Rights Claims

Some Aboriginal groups have established or asserted Aboriginal treaty, title and rights to portions of Western Canada, including British Columbia and Alberta. There are outstanding Aboriginal and treaty rights claims, which may include Aboriginal title claims, on lands where we operate, and such claims, if successful, could have a material adverse impact on our operations or pace of growth. No certainty exists that any lands currently unaffected by claims brought by Aboriginal groups will remain unaffected by future claims. Recent outcomes of litigation concerning Aboriginal rights may result in increased claims and litigation activity in the future.

The federal and provincial governments have a duty to consult with Aboriginal people on actions and decisions that may affect the asserted Aboriginal or treaty rights and, in certain cases, accommodate their concerns. The scope of the duty to consult by federal and provincial governments is subject to ongoing litigation. The fulfillment of the duty to consult Aboriginal people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew, permits, leases, licenses and other approvals, or to meet the terms and conditions of those approvals. Opposition by Aboriginal groups may also negatively impact us in terms of public perception, diversion of Management's time and resources, legal and other advisory expenses, potential blockades or other interference by third parties in our operations, or court-ordered relief impacting operations. Challenges by Aboriginal groups could adversely impact our progress and ability to explore and develop properties.

In May 2016, Canada announced its support for the *United Nations Declaration on the Rights of Indigenous Peoples* ("UNDRIP"). The principles and objectives of UNDRIP have also been considered by the Government of Alberta and affirmed in legislation by the Government of British Columbia. The federal government has committed to introducing legislation to implement UNDRIP. The means of implementation of UNDRIP by government bodies are uncertain and may include an increase in consultation obligations and processes associated with project development and operations, posing risks and creating uncertainty with respect to project regulatory approval timelines and requirements, and operating conditions. The Government of British Columbia is developing an action plan to harmonize provincial laws with UNDRIP.

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 upstream or downstream development projects. The implementation of new regulations or the modification of existing regulations could impact our existing and planned projects as well as result in increased compliance costs, adversely impacting our financial condition, results of operations and cash flows.

The oil and gas industry in general and our operations in particular are subject to regulation and intervention under federal, provincial, territorial, 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 greenhouse gases ("GHGs") and other emissions; the export of crude oil, natural gas and other products; the transportation of crude-by-rail or marine transport; the awarding or acquisition of exploration and production, oil sands or other interests; the imposition of specific drilling obligations; control over the development, abandonment and reclamation of fields (including restrictions on production) and/or facilities; and possibly expropriation or cancellation of contract rights. Changes to government regulation could impact our existing and planned projects or increase capital investment or operating expenses, adversely impacting our financial condition, results of operations and cash flows.

Regulatory Approvals

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 licences, 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; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and 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.

Abandonment and Reclamation Cost Risk

As a general rule, the current oil and gas asset abandonment, reclamation and remediation ("A&R") liability regime in Alberta limits each party's liability to its proportionate ownership of an asset. Cenovus currently has direct A&R liability. In the case where one joint owner of an oil and gas asset becomes insolvent and is unable to fund its required A&R activities associated with such asset, the solvent counterparties can claim the insolvent party's share of the remediation costs against the Orphan Well Fund, which is administered by the Orphan Well Association (the "OWA"). The OWA administers orphaned assets and is funded through a levy imposed on licensees, including Cenovus, based on their proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites in Alberta. British Columbia has a similar liability management regime.

On January 31, 2019, the Supreme Court of Canada released its decision in the case of Redwater Energy Corporation ("Redwater"). Reversing the lower court decisions, the Supreme Court of Canada held that the AER may use the provincial legislative scheme to prevent a trustee in bankruptcy from renouncing a debtor's uneconomic oil and gas assets and require a trustee to satisfy certain environmental obligations in priority to the claims of secured and unsecured creditors.

The Supreme Court of Canada's decision in Redwater is anticipated to reduce the availability and increase the cost of credit for borrowers with relatively high levels of A&R obligations within their asset bases, thereby negatively affecting the financial capacity of such borrowers, including potential counterparties to Cenovus, resulting in additional or more stringent A&R related covenants being imposed on borrowers, and resulting in increased scrutiny of oil and gas assets and associated A&R liabilities.

Following the lower court decisions in Redwater, changes were made to the regulatory regimes in Alberta and British Columbia. The AER released Bulletin 2016-16 which, among other things, implements important changes to the AER's procedures relating to liability management ratings, licence eligibility and licence transfers. In addition, changes with respect to licence eligibility were codified in amendments to AER *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals ("Directive 067")*. Among other things, *Directive 067* provides the AER with broad discretion to determine if a party poses an "unreasonable risk" such that it should not be eligible to hold AER licences. The British Columbia Oil and Gas Commission has a similar liability management program to manage public liability. The program requires permit holders to carry the financial risks and regulatory responsibility of their operations by requiring permit holders who are considered high risk to submit a security deposit. These changes may impact Cenovus's ability to transfer our licences, approvals or permits, and may result in increased costs and delays or require changes to or abandonment of projects and transactions.

The aggregate value of the A&R liabilities assumed by the OWA has increased in recent years following the lower court decisions in Redwater and as a result of the current economic environment. To the extent the Supreme Court of Canada's decision in Redwater makes the transfer of oil and gas assets from insolvent parties more challenging because a trustee in bankruptcy is unable to separate economic assets from uneconomic assets within the insolvent party's estate in order to facilitate a sale process, the result could be additional assets being placed upon the OWA.

While the Supreme Court of Canada's decision in Redwater may reduce the A&R liabilities assumed by the OWA in the long-term, the OWA's A&R liabilities will remain at elevated levels until a significant number of orphaned wells are decommissioned by the OWA. As a result, the OWA may seek additional funding for such liabilities from industry participants, including Cenovus, through an increase in its annual levy, further changes to regulations or other means. While the impact on Cenovus of any legislative, regulatory or policy decisions cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and materially and adversely affect, among other things, our business, financial condition, results of operations and cash flows.

Royalty Regimes

Our cash flows may be directly affected by changes to royalty regimes. The governments of Alberta and British Columbia receive royalties on the production of hydrocarbons from lands in which they respectively own the mineral rights. Government regulation of Crown royalties is subject to change for a number of reasons, including, among other things, political factors. Royalties are typically calculated based on benchmark prices, productivity per well, location, date of discovery, recovery method, well depth and the nature and quality of petroleum product produced. There is also a mineral tax in each province levied on hydrocarbon production from lands in which the Crown does not own the mineral rights. The potential for changes in the royalty and mineral tax regimes applicable in the provinces in which Cenovus operates creates uncertainty relating to the ability to accurately estimate future Crown burdens and could have a significant impact on our business, financial condition, results of operations and cash flows.

Alberta's Modernized Royalty Framework ("MRF") applies to all conventional wells spud on or after January 1, 2017. Wells spud prior to January 1, 2017 will continue to operate under the previous Alberta Royalty Framework until December 31, 2026 when all conventional wells will be subject to MRF. The Government of Alberta's Royalty Guarantee Act, which took effect on July 18, 2019, guarantees that the royalty structure in place when a well is drilled remains in place for at least 10 years. The Act applies to current crude oil, oil sands and natural gas royalty frameworks, including crude oil, pentanes, methane, ethane, propane and butane. It also confirms that the transition to the MRF for wells spud prior to January 1, 2017 will occur in 2026. The MRF does not apply to oil sands production, which has its own separate royalty framework.

Further changes to any of the royalty regimes in Alberta, changes to the existing royalty regimes in British Columbia, or changes to how existing royalty regimes are interpreted and applied by the applicable governments, could have a significant impact on our business, financial condition, results of operations and cash flows. An increase in the royalty rates in Alberta or British Columbia 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.

Canada-United States-Mexico Agreement ("CUSMA")

On December 20, 2019, Canada, the U.S. and Mexico signed an Amending Protocol that revises the CUSMA, which is intended to replace the North American Free Trade Agreement ("NAFTA"). Mexico and the U.S. have ratified the revised CUSMA, and Canada is currently working through its domestic ratification procedures. While the outcome of the ratification process is not certain, it is anticipated that the CUSMA will come into force around July 1, 2020. According to a Government of Canada technical summary of negotiated outcomes related to the energy sector, under CUSMA, the rule of origin applicable to heavy oil containing diluent has been relaxed to allow up to 40 percent of non-originating diluent in pipelines for transportation of crude oil without affecting the originating status of the product, which will allow Canadian products to more easily qualify for duty-free treatment when imported into the U.S. The related CUSMA side letter on energy between Canada and the U.S. also promotes regulatory transparency and non-discrimination in access to or use of energy infrastructure, which may potentially benefit the Canadian heavy oil industry.

However, CUSMA also reduces the availability of investor-state dispute settlement mechanisms for Canadian investments in the U.S. or U.S. investments in Canada. For three years after the termination of NAFTA, existing "legacy investments" will maintain their access to investor-state dispute settlement under NAFTA Chapter 11. Thereafter, under CUSMA this dispute settlement mechanism will not be available for Canadian investments in the U.S. or U.S. investments in Canada. If CUSMA is not ratified, this may alter the terms of trade for energy products and affect the sale and transportation of Cenovus's products within North America, which could have a negative impact on Cenovus's business, financial condition and results from operations.

Environmental Risk

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, the "environmental regulations"). Environmental regulations provide that wells, facility sites, refineries and other properties and practices associated with our operations be constructed, operated, maintained, abandoned, reclaimed and undertaken in accordance with the requirements set out therein. 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, costs, 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 water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to Cenovus.

Compliance with environmental regulations requires significant expenditures. Our future capital expenditures and operating expenses could continue to increase as a result of, among other things, developments in our business, operations, plans and objectives and changes to existing, or implementation of new, environmental regulations. Failure to comply with environmental regulations may result in, among other things, the imposition of fines, penalties, environmental protection orders, suspension of operations, and could adversely affect our reputation. The costs of complying with environmental regulations may have a material adverse effect on our business, financial condition, results of operations and cash flows. 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 as well as shift hydrocarbon demand toward relatively lower carbon sources, increase compliance costs, lengthen project implementation times, and have an adverse effect on our business, financial condition, results of operations and cash flows.

Greenhouse Gas Emissions & Targets

Our ability to lower scope 1 and 2 GHG emissions (see Definitions section of this MD&A) on both an absolute basis and in terms of intensity in our operations and in respect of Cenovus's target of reducing GHG emissions intensity by 30 percent and holding overall emissions flat by 2030, and our long-term ambition of reaching net-zero emissions by 2050 (which is inherently less certain due to the longer time frame and certain factors outside of our control, including the commercial application of future technologies) are subject to numerous risks and uncertainties and our actions taken in implementing such targets may also expose us to certain additional and/or heightened financial and operational risks.

A reduction in GHG emissions relies on the commercial viability and scalability of emission reduction strategies and related technology and products. In the event that we are unable to implement these strategies and technologies as planned without negatively impacting our expected operations or cost structure, or such strategies or technologies do not perform as expected, we may be unable to meet our GHG 2030 targets or 2050 ambition on the current timelines, or at all.

In addition, achieving our GHG 2030 targets and 2050 ambition will require capital expenditures and company resources, with the potential that expectations regarding the costs required to achieve these targets and ambitions differ from our original estimates.

Additional ESG Focus Areas and Targets

Cenovus's other ambitious ESG targets, not related directly to GHG emissions, which include its target to spend $1.5 billion with Indigenous owned or operated businesses, to reclaim 1,500 abandoned well sites, to invest $40 million to restore an area of land within caribou ranges greater than the amount of land disturbed by our activity in those ranges and to achieve a fresh water intensity of 0.1 barrels per barrel of oil equivalent, all by the end of 2030, depend significantly on its ability to execute its current business strategy, related milestones and schedules which can be impacted by the numerous risks and uncertainties associated with our business and the industry in which we operate as outlined in this MD&A. There is also a risk that some or all of the expected benefits and opportunities of achieving the various ESG targets may fail to materialize, may cost more to achieve or may not occur within the anticipated time periods. In addition, there are risks that the actions taken by Cenovus in implementing targets and goals for ESG focus areas may have a negative impact on our existing business, operations and increase capital expenditures, which could have a negative impact on our future operating and financial results. There is a risk that some or all of the expected benefits and opportunities of achieving the various ESG targets may fail to materialize.

Climate Change Regulation

Various federal, provincial and state governments have announced intentions to regulate GHG emissions. Some of these regulations are in effect while others remain in various phases of review, discussion or implementation in the U.S. and Canada.

The *Technology Innovation and Emissions Reduction* ("TIER") system replaces the *Carbon Competitiveness Incentive Regulation* ("CCIR") (effective January 1, 2020). The TIER system has been deemed equivalent to the federal output-based pricing system for 2020, but in the absence of an equivalent economy-wide price on carbon, the federal fuel charge will apply to Alberta-based facilities outside the TIER system. The TIER system will automatically apply to industrial sources that emit greater than 100,000 tonnes of GHG emissions per year. Facilities that do not meet the emissions threshold of 100,000 tonnes of GHG emissions per year can opt into the TIER system, thereby avoiding the federal fuel charge, if they compete against a facility regulated under the TIER system or emit over 10,000 tonnes of GHG emissions and belong to a sector with high emissions intensity and trade exposure. Companies in the conventional oil and gas sector will be regulated under the TIER system.

Facilities subject to TIER are required to meet an emissions intensity benchmark which is set based on industry or facility performance. Where emissions exceed the benchmark, the facility must reduce its net emissions by applying emissions offsets, emissions performance credits or fund credits against its actual emissions level. The benchmarks are subject to future adjustment. Both of Cenovus's Christina Lake SAGD facility and Foster Creek SAGD facility are subject to TIER (and previously CCIR). Cenovus does not expect the changes in the emissions intensity calculations under TIER to result in a material financial impact.

The British Columbia *Carbon Tax Act* sets a carbon price of $40 per tonne of CO_2e on fuel combustion and is expected to increase by $5 per tonne of CO_2e per year, reaching the federal target carbon price of $50 on April 1, 2021. The federal government has stated this program meets the requirements of the federal *Greenhouse Gas Pollution Pricing Act*. The CleanBC Program for Industry directs an amount equal to the incremental carbon tax paid by industry above $30/tonne into incentives to reduce emissions. The Government of British Columbia has also introduced measures to reduce upstream methane emissions by 45 percent and establish separate sector-level benchmarks to reduce carbon tax costs for industrial facilities.

In 2018, the federal government finalized regulations to limit the release of methane and volatile organic compounds with staged implementation over the 2020 to 2023 time period. Provinces may establish their own methane reduction regulations and set up equivalency agreements with the federal government. British Columbia has entered into an equivalency agreement with the Government of Canada, declaring that the federal methane

regulations do not apply in British Columbia. Alberta is attempting to negotiate an equivalency agreement with the Government of Canada.

Uncertainties exist relating to the timing and effects of these emerging regulations, other contemplated legislation, including how they may be harmonized, making it difficult to accurately determine the cost impacts and effects on our suppliers. Additional changes to climate change legislation may adversely affect our business, financial condition, results of operations and cash flows, which cannot be reliably or accurately estimated at this time.

Other possible effects from emerging regulations may also include, but are not limited to: increased compliance costs; permitting delays; and substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses. Further, emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis, required emissions reductions may not be technically or economically feasible to implement, in whole or in part, and failure to have access to resources or technology to meet emissions 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.

The extent and magnitude of any adverse impacts of current or additional programs or regulations beyond reasonably foreseeable requirements cannot be reliably or accurately estimated at this time, in part 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. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to Cenovus. There is also risk that we could face claims initiated by third parties relating to climate change or other environmental regulations. These claims could, among other things, result in litigation targeted against Cenovus and the oil and gas industry generally, and should any such litigation claims arise, they may have a material adverse effect on our business and reputation.

Low Carbon Fuel Standards

Existing and proposed environmental legislation and regulation developed by certain U.S. states, Canadian provinces, the Canadian federal government and members of the European Union, regulating carbon fuel standards could result in increased costs and reduced revenue. The potential regulation may negatively affect the marketing of Cenovus's bitumen, crude oil or refined products, and may require us to purchase emissions credits in order to affect sales in such jurisdictions. As an oil sands producer, we are not directly regulated and are not expected to have a compliance obligation for carbon intensity reduction requirements for liquid fuels. Refiners, importers, and fuel distributors in these jurisdictions are required to comply with the legislation.

Environment and Climate Change Canada published a proposed regulatory framework in 2017 for the Clean Fuel Standard under the *Canadian Environmental Protection Act, 1999*. The proposed new regulatory framework would impose lifecycle carbon intensity requirements for certain liquid, gaseous and solid fuels that are used in transportation, industry and buildings, and establish rules relating to the trading of compliance credits. The stated purpose of the clean fuel standard is to incent the use of a broad range of low carbon fuels, energy sources and technologies.

Carbon intensity requirements under the Clean Fuel Standard regulation would become more stringent over time and would be differentiated between different types of renewable fuels to reflect the associated emissions reduction potential. Regulated parties, which may include fuel producers and importers, would have some flexibility with respect to how to achieve lower carbon fuels in Canada.

Environment and Climate Change Canada has since published a Regulatory Design Paper for the Clean Fuel Standard in December 2018 and a Proposed Regulatory Approach for the Clean Fuel Standard in June 2019. These documents present additional details of the proposed regulatory design of the Clean Fuel Standard. The Canadian Government is reporting that new regulations under the Clean Fuel Standard are targeted to come into force on January 1, 2022 (for liquid fuels) and January 1, 2023 (for gaseous and solid fuel regulations). The Canadian federal government has indicated that over time, the new Clean Fuel Standard would replace the current Renewable Fuels Regulations.

The Clean Fuel Standard regulation has the potential to impact our business, financial condition, results of operations and cash flows, though at this time it is difficult to predict or quantify any such impacts.

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 and Security Act of 2007* ("EISA 2007") that established energy management goals and requirements. Pursuant to EISA 2007 and the *Energy Policy Act of 2005*, among other things, the Environmental Protection Agency implemented the Renewable Fuel Standard program that mandates that a certain volume of renewable fuel replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel sold or introduced in the U.S. Obligated parties, including refiners or importers of gasoline or diesel fuel, achieve compliance with targets set by the U.S. Environmental Protection Agency by blending certain types of renewable fuel into transportation fuel, or by purchasing credits (RINs) from other obligated parties on the open market. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. A RIN is a number assigned to each gallon of renewable fuel

produced or imported into the U.S. RIN numbers 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, through WRB, 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 flows may be materially adversely impacted as a result.

Marine Fuel Oil Sulphur Specification

As a specialized agency of the United Nations and the main regulatory body for the shipping industry, the International Maritime Organization ("IMO") is the global standard-setting authority for the safety, security and environmental performance of international shipping. IMO has set a global limit for sulphur in fuel oil used on board ships of 0.5 weight percent from January 1, 2020, drastically changed from the current upper limit of 3.5 weight percent. The IMO's goal is to significantly reduce the amount of sulphur oxide emanating from ships and it expects major health and environmental benefits for the world, particularly for populations living close to ports and coasts.

Refineries worldwide currently blend around three million barrels per day of high sulphur Residual Fuel Oil ("RFO") with lighter oil to make bunker fuel oil for the shipping industry. RFO is an outlet at the refinery for difficult to process crude components, usually high sulphur residuum. Sulphur reduction for RFO is more difficult than for lighter distillates as the asphaltene content in RFO requires more costly and complex processing.

Cenovus crude production contains a large amount of high sulphur residuum. Most of Cenovus's crude is processed by complex refineries. However, after 2020, the availability of complex refining capacity may become scarce. This IMO sulphur regulation has the potential to materially adversely impact our crude marketing and may materially contribute to increased widening of the light to heavy crude oil differential, distressing pricing for heavier crude oils including bitumen. The severity of the impact depends on the enforcement of the regulation, the ability of ship owners to install scrubbers, worldwide heavy sour crude production and additional heavy processing availability.

Species at Risk Act

The Canadian federal legislation, *Species at Risk Act,* and provincial counterparts regarding threatened or endangered species may limit the pace and the amount of development or activity in areas identified as critical habitat for species of concern, such as woodland caribou. Recent petitions and litigation against the federal government in relation to their obligations under the *Species at Risk Act* have raised issues associated with the protection of species at risk and their critical habitat both federally and on a provincial level. In Alberta, a suite of initiatives have been identified within the Draft Provincial Woodland Caribou Range Plan, including: (a) recovering caribou habitat through restoration of legacy seismic lines and inactive oil and gas infrastructure; (b) working with oil and gas companies to reschedule development; (c) developing stringent requirements for new oil and gas approvals, and seismic exploration programs; (d) developing Regional Access Management Plans for all land users within and directly adjacent to caribou ranges; (e) consolidating forest harvesting operations in pre-defined areas per decade; and (f) identifying conservation areas in some ranges where impacts to existing industrial tenure are avoided and lands contribute to caribou recovery. The Draft Provincial Woodland Caribou Range Plan was drafted in 2017, but has not yet been finalized. More recent initiatives include negotiation of conservation agreements under Section 11 of the *Species at Risk Act* (which codifies concrete measures to support the conservation of the species and the protection of its critical habitat), and e) the creation of sub-regional ministerial task forces to develop recommendations to government on sub-regional plans for the Cold Lake, Bistcho and Upper Smokey areas.

If plans and actions undertaken by the provinces are deemed insufficient to support caribou recovery, the federal legislation includes the ability to implement measures that would preclude further development or modify existing operations. Further, on January 24, 2019, the Athabasca Chipewyan and Mikisew Cree First Nations in northern Alberta, together with the Alberta Wilderness Association and the David Suzuki Foundation, filed an application for judicial review at the Federal Court of Canada arguing that the Minister has failed to protect the habitat of five boreal woodland caribou herds. The applicants claim that although the Minister acknowledges that provincial recovery plans for the threatened species are inadequate, the federal government has not fulfilled its duty to issue a protective order under the *Species at Risk Act*. The litigation has been adjourned while the parties discuss potential settlement of the matter.

The extent and magnitude of any adverse impacts of the legislation on project development and operations cannot be estimated at this time as uncertainty exists with respect to whether plans and actions undertaken by the provinces will be deemed sufficient to support caribou recovery.

Federal Air Quality Management System

The Multi-sector Air Pollutants Regulations ("MSAPR"), issued under the *Canadian Environmental Protection Act, 1999*, seek to protect the environment and health of Canadians by setting mandatory, nationally-consistent air pollutant emission standards. The MSAPR are aimed at equipment-specific Base-Level Industrial Emissions Requirements ("BLIERs"). Nitrogen oxide BLIERs from our non-utility boilers, heaters and stationary engines are regulated in accordance with specified performance standards. We anticipate that the MSAPR will result in adverse

impacts including but not limited to capital investment required to retrofit existing equipment and increased operating costs.

Canadian Ambient Air Quality Standards ("CAAQS") for nitrogen dioxide, sulphur dioxide, fine particulate matter and ozone were introduced as part of a national Air Quality Management System. Provincial level implementation of the CAAQS may occur at the regional air zone level and air zone management actions may include more stringent emissions standards applicable to industrial sources from approval holders in regions where Cenovus operates that may result in adverse impacts including but not limited to capital investment related to retrofit existing facilities and increased operating costs.

Federal Review of Environmental and Regulatory Processes

In 2016, the Government of Canada commenced a review of the federal environmental and regulatory processes administered under the *National Energy Board Act*, *Canadian Environmental Assessment Act*, *Fisheries Act*, and the *Navigation Protection Act*. This review culminated on August 28, 2019 with the coming into force of Bill C-69, *An Act to enact the Impact Assessment Act* and the *Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts,* Bill C-68 amends the *Fisheries Act,* and came into force in August 2019.

The *Fisheries Act* amendments restore the previous prohibition against "harmful alteration, disruption or destruction of fish habitat" and the prohibition against causing the death of fish by means other than fishing. The amendments also introduce several new requirements that expand the scope of protection and role of Indigenous groups and interests. The prohibitions against the death of fish, and the harmful alteration, disruption or destruction of fish habitat may result in increased permitting requirements where the Company's operations potentially impact fish or habitat.

The changes to the *Navigation Protection Act*, including its renaming to the *Canadian Navigable Waters Act*, expands its scope to all navigable waters, creates greater oversight for navigable waters and, consistent with the *Fisheries Act*, introduces requirements to expand the scope of protection and the role of Indigenous groups and interests. The broader application of the *Canadian Navigable Waters Act* may result in increased permitting requirements where the Company's operations potentially impact navigable waters. These amendments came into force in August 2019.

The *Impact Assessment Act* ("IAA"), replaces the *Canadian Environmental Assessment Act* and establishes the Impact Assessment Agency of Canada, which will lead and coordinate impact assessments for all designated projects, including those previously administered by the National Energy Board. The IAA expands the assessment considerations beyond the environment to include health, economy, social, gender and as well as considerations related to sustainability and Canada's climate change commitments. The *Canadian Energy Regulator Act* replaces the National Energy Board with the Canadian Energy Regulator and modifies the regulator's role.

Of note, the revised Project List outlined in the *Physical Activities Regulations* enabled under the IAA captures in situ oil sands facilities but provides an exemption for a project proposed within a province in which there is a legislated limit on GHG emissions produced by the oil sands sector. For as long as the provincial government maintains the cap on oil sands emissions in Alberta and the cap has not been reached, Cenovus's in situ oil sands project should be exempted from the application of the new federal impact assessment system. However, other types of projects would undergo a federal assessment.

The extent and magnitude of any adverse impacts resulting from these legislative changes on project development and operations cannot be reliably or accurately estimated at this time as uncertainty exists with respect to the implementation of the Acts and their accompanying regulations. Increased environmental assessment and reporting obligations may create risk of increased costs and project development delays.

British Columbia Review of Environmental and Regulatory Processes

In 2018, the Government of British Columbia continued progressing their commitments to reviewing the province's environmental assessment process and other regulatory processes. The *Environmental Assessment Act* came into force in December 2019 and allows wide discretionary powers to the Minister to designate a project for review. The Act also sets out to integrate the principles embedded in the UNDRIP, including by seeking consensus in review processes from Indigenous communities; how this will be implemented is being defined through the work of an Indigenous Implementation Committee.

On November 26, 2019, British Columbia passed Bill 41, draft legislation to implement UNDRIP, becoming the first Canadian province to do so. Government fact sheets on the legislation emphasize that the Province retains authority for making decisions in the public interest and the legislation does not provide for the ability to veto decisions on resource projects.

The government has also implemented its commitment to proceed with a scientific review of hydraulic fracturing to determine impacts on water and the relationship to seismic activity for which the report was released in February 2019 with 97 recommendations which are to be implemented in a phased approach that will include increased monitoring, aquifers mapping and efforts to improve the regulatory regime.

In January 2018, the Government of British Columbia proposed restrictions on the increase of diluted bitumen transportation as part of amendments to the *Environmental Management Act* and its regulations to improve preparedness, response and recovery from potential oil spills. The proposed restrictions could have had a material adverse impact on our ability to transport diluted bitumen through British Columbia. In March of 2018, the Government of British Columbia submitted a court reference to the British Columbia Court of Appeal to confirm whether or not it is within their jurisdiction to regulate transportation of hazardous substances (defined as heavy oil or bitumen) within the province, as set out in the proposed amendments. In May of 2019, the British Columbia Court of Appeal unanimously held that the proposed amendments were beyond the jurisdiction of the Government of British Columbia. In January 2020, the Supreme Court of Canada unanimously upheld the decision of the British Columbia Court of Appeal.

The extent and magnitude of any adverse impacts of changes to the legislation or policies on project development and operations cannot be estimated at this time as uncertainty exists with respect to recommendations being considered or to be developed. Increased environmental assessment obligations or transportation restrictions may create risk of increased costs and project development delays.

Water Licences

In Alberta, we utilize fresh water in certain operations, which is obtained under licences issued pursuant to the *Water Act* to provide domestic, utility and make-up water at our SAGD facilities, as well as our bitumen delineation programs and our activities in the Deep Basin. Currently, we are not required to pay for the water we use under 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. If a change under these licences reduces the amount of water available for our use, production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. In addition, the expansion of our projects rely on securing licences for additional water withdrawal, and there can be no assurance that these licences 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 licences.

In British Columbia, groundwater use is regulated under the *Water Sustainability Act*. Most groundwater and surface water use (other than domestic use) requires a water licence. Annual water rental fees are established by the regulations to the *Water Sustainability Act*, and additional supporting regulations continue to be proposed and may be brought into force. Water use fees may increase and licence terms and conditions may be amended in the future, which may adversely affect our business, including the ability to operate. In addition, there is no assurance that if we require new licences or amendments to existing licences, that these licences or amendments will be granted on favourable terms.

Alberta Wetland Policy

Developers of oil and gas assets in wetlands areas may be required to obtain an approval under the *Water Act* and, pursuant to the Alberta Wetland Policy, may be required to avoid the wetlands or mitigate the development's effects on wetlands.

The Alberta Wetland Policy is not expected to affect Cenovus's existing operations in Foster Creek, Christina Lake and Narrows Lake, as projects in these areas approved prior to July 4, 2016 are exempted from the policy. However, new project developments and future phase expansions that have not yet been approved are expected to be subject to this policy. In these cases, we are required to comply with requirements for wetland reclamation or, where permanent wetland loss will occur, make payment to an in-lieu fee program, or take permittee responsible-replacement action.

Based on the *Alberta Wetland Mitigation Directive, 2018* and consultation with Alberta Environment and Parks as well as the AER, we do not anticipate a material impact of the policy on our oil sands or conventional assets in the Deep Basin.

Hydraulic Fracturing

Certain stakeholders have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and suggest that additional federal, provincial, territorial and/or municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process.

The Canadian federal government and certain provincial governments continue to review certain aspects of the existing scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. Further, certain governments in jurisdictions where the Company does not currently operate have considered or implemented moratoriums on hydraulic fracturing until further studies can be completed and some governments have adopted, and others have considered adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations.

Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to limitations or restrictions to oil and gas development activities, operational delays, additional operating requirements, or

increased third-party or governmental claims that could increase our cost of compliance and doing business as well as reduce the amount of natural gas and oil that Cenovus is ultimately able to produce from its reserves.

Seismic Activity

Some areas of British Columbia and Alberta are experiencing increasing localized frequency of seismic activity which has been associated with oil and gas operations. Although the occurrence of seismicity in relation to oil and gas operations is generally very low, it has been linked to deep disposal of wastewater in the U.S. and has been correlated with hydraulic fracturing in western Canada which has prompted legislative and regulatory initiatives intended to address these concerns.

These initiatives have the potential to require additional monitoring, restrict the injection of produced water in certain disposal wells and/or modify or curtail hydraulic fracturing operations which could lead to operational delays, increase compliance costs or otherwise adversely impact Cenovus's operations.

Reputation Risk

We rely on our reputation to build and maintain positive relationships with investors and other stakeholders, to recruit and retain staff, and to be a credible, trusted company. Any actions we take that influence public or key stakeholder opinions have the potential to impact our reputation which may adversely affect our share price, development plans and our ability to continue operations.

Public Perception of Alberta Oil Sands

Development of the Alberta oil sands has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous engagement. The influence of anti-fossil fuels activists (with a focus on oil sands) targeting equity and debt investors, lenders and insurers may result in policies which reduce support for or investment in the Alberta oil sands sector. Concerns about oil sands 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 uncertainty in economic modeling of current and future projects and delays relating to the sanctioning of future projects. In addition, evolving decarbonization policies of institutional investors, lenders and insurers could affect Cenovus's ability to access capital pools. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of our insurance policies could increase substantially. In some instances, coverage may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to extend or renew our existing policies, or procure other desirable insurance coverage, either on commercially reasonable terms, or at all.

Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, changes in environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, 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, reduce its price and may result in stranded assets or an inability to further develop oil resources.

Other Risks

Risks Related to the Acquisition

Unexpected Costs or Liabilities Related to the Acquisition

Acquisitions of crude oil and natural gas properties are based largely on engineering, environmental and economic assessments made by the acquirer, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of crude oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of crude oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

In connection with the Acquisition, there may be liabilities that we failed to discover or were unable to quantify in our due diligence conducted prior to the execution of the purchase and sale agreement between ConocoPhillips and Cenovus dated March 29, 2017, as amended (the "Acquisition Agreement"), and we may not be indemnified for some or all of these liabilities. The discovery or quantification of any material liabilities could have a material adverse effect on our business, financial condition or future prospects. In addition, the Acquisition Agreement limits the amount for which we are indemnified, such that liabilities in respect of the Acquisition may be greater than the amounts for which we are indemnified under the Acquisition Agreement.

Amount of Contingent Payments

In connection with the Acquisition, we agreed to make contingent payments under certain circumstances. The amount of contingent payments vary depending on the Canadian dollar WCS price from time to time during the five year period following the closing of the Acquisition (May 17, 2017), and such payments may be significant. In addition, in the event that such further payments are made, this could have an adverse impact on our reported results and other metrics.

Effect on Market Price from Future Sales of common shares of Cenovus by ConocoPhillips

The future sales of common shares of Cenovus into the market held by ConocoPhillips, either through open market trades on the Toronto and New York stock exchanges, through privately arranged block trades, or pursuant to prospectus offerings made in accordance with the registration rights agreement, could adversely affect prevailing market prices for the common shares. In addition, market perception regarding ConocoPhillips' intention to make sales of Cenovus common shares may have a negative impact on the trading price of these common shares.

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 Cenovus, its financial results and its shareholders. Tax authorities having jurisdiction over Cenovus may disagree with the manner in which we calculate our tax liabilities such that its provision for income taxes may not be sufficient, or such authorities could change their administrative practices to Cenovus's detriment or the detriment of its shareholders. In addition, all of our tax filings are subject to audit by tax authorities who may disagree with such filings in a manner that adversely affects Cenovus and its shareholders.

U.S. Tax Risk

In the U.S., the Tax Cuts and Jobs Act which was signed into law on December 22, 2017, made substantial changes to the U.S. tax system. Regulatory guidance from the U.S. Treasury as to how certain of these changes are to be implemented was not complete as at December 31, 2019. There is a possibility that when final Treasury guidance is issued, negative consequences to Cenovus could result.

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 Corporation ("Encana"), now Ovintiv Inc., 7050372 Canada Inc. and Cenovus Energy Inc. (formerly, Encana Finance Ltd.), 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 Cenovus's 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 us 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 MD&A, 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 subsequently filed MD&A, available on SEDAR at sedar.com, on EDGAR at sec.gov and cenovus.com.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, and use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from 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 recorded in our Consolidated Financial Statements.

Joint Arrangements

The classification of a joint arrangement as either a joint operation or a joint venture requires judgment. Cenovus holds a 50 percent interest in WRB, a jointly controlled entity. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of WRB. As a result, the joint arrangement is classified as a joint operation

and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

Prior to May 17, 2017, Cenovus held a 50 percent interest in FCCL, which was jointly controlled with ConocoPhillips and met the definition of a joint operation under IFRS 11, *"Joint Arrangements"*. As such, Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the Acquisition (refer to Note 9 of the Consolidated Financial Statements), Cenovus controls FCCL, as defined under IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10") and, accordingly, FCCL has been consolidated.

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 partnerships. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans.
- FCCL operated 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 expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's internal approval process.

Identification of Cash-Generating Units ("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 interpretation. 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, crude-by-rail terminal, railcars, storage tanks, and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses and reversals.

Determining the Lease Term

In determining the lease term, Management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option. The assessment is reviewed if a significant event or a significant change in circumstances occurs which affects this assessment.

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 recorded 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.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas 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 affect the impairment test fair value less costs to sell and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands and Deep Basin segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses, and income tax rates. Recoverable amounts for the Company's refining assets and crude-by-rail terminal use assumptions such as throughput, forward commodity prices, operating expenses, transportation capacity, supply and demand conditions and income tax rates. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

The recoverable amounts of Cenovus's upstream CGUs were determined based on FVLCOD or an evaluation of comparable asset transactions. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs (Level 3). Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves have been evaluated as at December 31, 2019 by the IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2019, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2020	2021	2022	2023	2024	Average Annual Increase Thereafter (percent)
WTI (US$/barrel)	61.00	63.75	66.18	67.91	69.48	2.0
WCS (C$/barrel)	57.57	62.35	64.33	66.23	67.97	2.1
Edmonton C5+ (C$/barrel)	76.83	79.82	82.30	84.72	86.71	2.0
AECO (1) (C$/Mcf)	2.04	2.32	2.62	2.71	2.81	2.1

(1) Assumes gas heating value of one million British thermal units per thousand cubic feet.

Discount and Inflation Rates

Discounted future cash flows are determined by applying a discount rate between 10 percent and 15 percent based on the individual characteristics of the CGU, and other economic and operating factors. Inflation is estimated at two percent.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration 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.

Onerous Contract Provisions

A contract is considered to be onerous when the unavoidable cost of meeting the obligations of the contract exceed the economic benefits expected to be derived from the contract. Determining when to record a provision for an onerous contract requires Management judgment and the use of estimates and assumptions, including the nature, extent and timing of future cash flows and discount rates related to the contract.

Fair Value of Assets Acquired and Liabilities Assumed in a Business Combination

The fair value of assets acquired and liabilities assumed in a business combination, including contingent consideration and goodwill, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparables and discounted cash flows which rely on assumptions such as forward commodity prices, reserves and resources estimates, production costs, volatility, Canadian-U.S. foreign exchange rates and discount rates. Changes in these variables could significantly impact the carrying value of the net assets.

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 recorded 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

Adoption of IFRS 16

Effective January 1, 2019, we adopted IFRS 16. We applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Therefore, the comparative information in the consolidated balance sheet, consolidated statements of earnings, other comprehensive income, shareholders' equity and cash flows have not been restated.

On adoption, Management elected to use the following practical expedients permitted under the new standard:

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a ROU asset if the underlying asset is of a low dollar value;
- The use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease;
- Account for lease and non-lease components as a single lease component for lease liabilities related to storage tanks; and
- Use the Company's previous assessment under IAS 37, "*Provisions, Contingent Liabilities and Contingent Assets*" ("IAS 37") for onerous contracts instead of reassessing the ROU asset for impairment on January 1, 2019.

IFRS 16 requires entities to recognize lease liabilities in relation to leases which had previously been classified as operating leases under the principles of IAS 17, "*Leases*" ("IAS 17"). Under the principles of the new standard these leases have been measured at the present value of the remaining lease payments, discounted using our incremental borrowing rates at January 1, 2019. Incremental borrowing rates as at January 1, 2019 range from 4.0 percent to 5.7 percent. Leases with a remaining term of less than twelve months and low-value leases were excluded. The associated ROU assets were measured at the amount equal to the lease liability on January 1, 2019 less any amount previously recognized under IAS 37 for onerous contracts with no impact on retained earnings.

The impact of the adoption of IFRS 16 as at January 1, 2019 is as follows:

- Recorded lease liabilities of $1.5 billion, of which $128 million was the current portion;
- Recorded ROU assets of $893 million, equal to the lease liabilities less the previously recognized onerous contract provisions and a $16 million net investment in finance leases;
- Decreased the onerous contract provisions by $585 million, offsetting the ROU asset; and
- Recognized certain subleases as a net investment in finance leases ($16 million) that were classified as operating leases under IAS 17.

The adoption of the new standard had the following impact to our year-to-date 2019 financial results compared with what would have occurred had we not adopted the new accounting policy:

- Decrease in purchased product of $34 million;
- Decrease to transportation and blending costs of $87 million;
- Decrease to operating costs of $5 million;
- Decrease to general and administrative expenses of $58 million;
- Increase to DD&A expense of $168 million; and
- Increase in finance expenses of $82 million.

Further information about changes to our accounting policies resulting from the adoption of IFRS 16 can be found in Note 4 of the Consolidated Financial Statements.

Uncertain Tax Positions

Effective January 1, 2019, we adopted International Financial Reporting Interpretation Committee ("IFRIC") 23, *"Uncertainty over Income Tax Treatments"* using the modified approach. The interpretation provides clarity on how

to account for a tax position when there is uncertainty over income tax treatments. In determining the likely resolution of the uncertain tax positions, a position may be considered separately or as a group. In addition, an assessment is required to determine the probability that the tax authority will accept the tax position taken in income tax filings. If the uncertain income tax treatment is unlikely to be accepted, the accounting tax position must reflect an appropriate level of uncertainty. An uncertain tax position may be reassessed if new information changes the original assessment. The adoption of IFRIC 23 did not have a material impact on the Consolidated Financial Statements.

New Accounting Standards and Interpretations not yet Adopted

A number of new standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2020 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2019. These standards and interpretations are not expected to have a material impact on the Company's Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of ICFR and disclosure controls and procedures ("DC&P") as at December 31, 2019. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2019.

The effectiveness of our ICFR was audited as at December 31, 2019 by PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, as stated in their Report of Independent Registered Public Accounting Firm, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2019.

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.

SUSTAINABILITY

At Cenovus, sustainability is essential to the way we do business. It means creating a safe and inclusive workplace, partnering with local and Indigenous communities, and innovating to minimize our impact on the environment. We believe striking the right balance among environmental, economic and social considerations creates long-term value.

We recognize that operating our business sustainably requires transparency with our stakeholders about our ESG performance. After conducting comprehensive research, we have identified four key ESG focus areas for the company: climate & GHG emissions, Indigenous engagement, land & wildlife and water stewardship. Supported by our leading safety practices and strong governance structure, we believe these four ESG focus areas are the most material to our company and are of the greatest importance to our stakeholders.

To support our sustainability performance, our Corporate Responsibility ("CR") policy guides our activities in the areas of: Leadership, Corporate Governance and Business Practices, People, Environmental Performance, Stakeholder and Aboriginal Engagement, and Community Involvement and Investment. We published our 2018 ESG report in July 2019 to report on our management efforts and performance across the areas within our CR policy, as well as other environment, social and governance topics that are important to our stakeholders. Our ESG report is available on our website at cenovus.com.

OUTLOOK

In 2020, we expect to see continued commodity price volatility and market access constraints for heavy oil exiting Alberta. Transportation challenges will continue to negatively impact heavy oil prices, demonstrating the need for increased rail export capabilities and approved pipeline projects to proceed as soon as possible. While our production levels have been impacted by the government mandated production curtailments, the resulting narrowing price differentials are anticipated to continue to have a positive impact on our cash flows. Curtailment restrictions are expected to remain in place until the end of 2020, with curtailment relief for crude volumes that are transported in the form of crude-by-rail and new conventional wells drilled. Increased crude-by-rail volumes and incremental pipeline space should help ease takeaway capacity constraints. In the first half of 2019 we achieved

first steam from Christina Lake phase G but subsequently deferred oil production ramp up to comply with the curtailment order. With the implementation of the SPA program Cenovus is well positioned to bring on Christina Lake phase G oil production in the first quarter of 2020 and ramp up towards its nameplate capacity of 50,000 barrels per day throughout 2020.

We continue to look for ways to increase our margins through strong operating performance and cost leadership, while focusing on safe and reliable operations. Proactively managing our market access commitments and opportunities assists with our goal of reaching a broader customer base to secure a higher sales price for our crude oil.

We have reduced the amount of capital needed to sustain our base business and expand our projects, through a continued focus on capital discipline and cost reduction, which we believe will further help support our financial resilience.

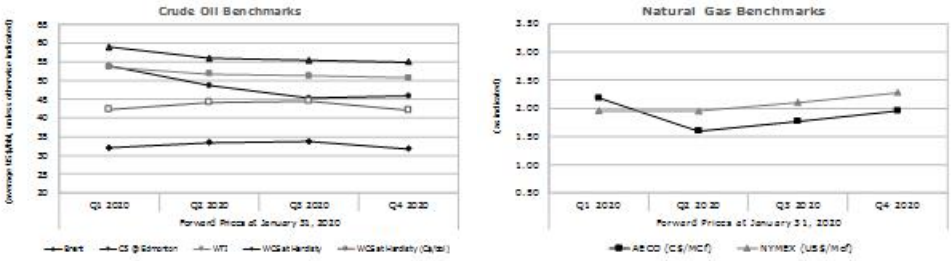
The following outlook commentary is focused on the next twelve months.

Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

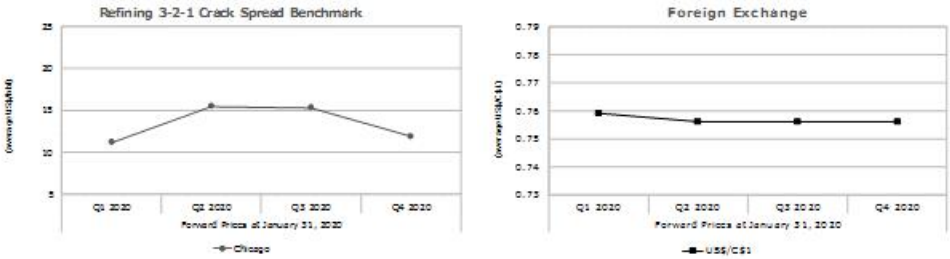
- We expect the general outlook for light crude oil prices will be tied primarily to the supply response to the current price environment, the impact of potential supply disruptions, and global demand impacts amid evolving trade conflicts;
- Crude oil price volatility is expected to increase slightly due to increased Middle East geopolitical risks and as global inventories draw down to OPEC stated target of the 2010-2014 average;
- Continuing OPEC supply cuts and U.S. led sanctions on Venezuela and Iran will be supportive of the narrowing of global light-heavy crude oil price differentials;
- We expect that the WTI-WCS differential in Alberta will remain largely tied to the extent to which production curtailments in Alberta remain in place, the completion of the Trans Mountain Expansion Project, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, and the level of crude-by-rail activity;
- We anticipate that the IMO regulations regarding high sulphur fuel oil will cause light-heavy crude oil price differentials to widen, although the magnitude and duration of the widening remains uncertain; and
- We expect refining crack spreads will likely continue to fluctuate, adjusting for seasonal trends, and will narrow and widen in tandem with the Brent-WTI differentials. Refining margins will also be impacted by the IMO regulations.

Natural gas and NGLs production associated with our Deep Basin assets provide improved upstream integration for the fuel, solvent and blending requirements at our Oil Sands operations.



Natural gas prices are anticipated to remain challenged with North American supply continuing to grow as a result of U.S. shale gas drilling and associated natural gas from oil plays. The AECO basis differential is expected to remain lower than NYMEX, reflecting transportation costs.

We expect the Canadian dollar to continue to be tied to crude oil prices, the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise or lower benchmark lending rates relative to each other, and emerging macro-economic factors.



Our exposure to the light-heavy crude oil price differentials is composed of both a global light-heavy component as well as Canadian transportation constraints. While we expect to see volatility in crude oil prices, we have the ability to partially mitigate the impact of light-heavy crude oil price differentials through the following:

- Transportation commitments and arrangements – supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets, as well as using our crude-by-rail terminal and entering into agreements with third parties to move additional rail volumes to alleviate a portion of near-term takeaway capacity constraints;
- Integration – having heavy oil refining capacity capable of processing Canadian heavy oil. From a value perspective, our refining business positions us to capture value from both the WTI-WCS differential for Canadian crude oil and the Brent-WTI differential from the sale of refined products;
- Marketing agreements – limiting the impact of fluctuations in upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners;
- Dynamic storage – our ability to use the significant storage capacity in our oil sands reservoirs provides us flexibility on timing of production and sales of our inventory. We will continue to manage our production well rates in response to pipeline capacity constraints, crude-by-rail export capacity, mandated production curtailments and crude oil price differentials; and
- Financial hedge transactions – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions related to our exposures.

Key Priorities For Our Five-Year Business Plan

We recently updated and shared our five-year business plan at our Investor Day on October 2, 2019. Our corporate strategy remains focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. The five-year business plan allows for disciplined production growth, subject to improved market access, and provides potential for significant Free Funds Flow generation through 2024 in a WTI price environment of US$45.00 per barrel. In 2020, we expect to be well positioned to increase shareholder returns while we continue to focus on deleveraging, remaining disciplined with our capital investment, improving market access, maintaining cost leadership, and advancing focused technology and innovation to achieve margin improvement and environmental benefits.

Deleveraging and Disciplined Capital Investment

Our commitment to balance sheet strength and capital discipline has allowed us to reduce our Net Debt down to $6.5 billion. Deleveraging continues to be a top priority and we continue to target $5 billion as our longer-term Net Debt target. Improving our financial resilience and flexibility while continuing to deliver safe and reliable operations will continue to be a top priority.

In 2020, we anticipate capital investment to be between $1.3 billion and $1.5 billion. Our oil sands production is expected to range between 390,000 and 410,000 barrels per day for 2020, with the SPA program and our crude-by-rail contracts already in place allowing us to produce from our oil sands facilities on an unconstrained basis in 2020 as we ramp up Christina Lake phase G.

In 2020, we will continue to be disciplined with our capital and focus on further strengthening our balance sheet. The majority of our 2020 capital budget will be directed towards sustaining oil sands production. We also plan to advance high-return projects to sanction-ready status for possible final investment decisions as early as the second half of 2020, conditional on improved market access.

As at December 31, 2019, our Net Debt position was $6.5 billion. Through a combination of cash on hand and available capacity on our committed credit facility, we have approximately $4.4 billion of liquidity as at December 31, 2019.

Over the long-term, we continue to target a Net Debt to Adjusted EBITDA ratio of less than 2.0 times. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure sufficient liquidity through all stages of the economic cycle.

We remain committed to increasing shareholder value through cost leadership, capital discipline and safe and reliable operations. These commitments, in combination with our high-quality upstream assets and joint ownership in strong refining assets, are expected to strengthen our ability to generate Free Funds Flow and continue to deleverage our balance sheet.

Shareholder Returns

While deleveraging remains a top priority for Cenovus, we believe we have built significant financial resilience into our business. Our updated five-year business plan is expected to provide the capacity to fund opportunistic share repurchases and sustainably grow our dividend.

We believe we will have capacity for further dividend increases at a potential growth rate of between five percent and 10 percent annually, even in a WTI price environment of US$45.00 per barrel.

Market Access

Market access constraints for Canadian crude oil production continue to be a challenge. Our strategy is to maintain firm transportation commitments through a combination of pipelines, rail and marine access to support our growth plans, but leave capacity for optimization. We expect to supplement firm capacity with active blending, storage, sourcing and destination optimization to ensure we are maximizing the margin on every barrel we produce.

Cost Leadership

Over the past four years, we have achieved significant improvements in our operating and sustaining capital costs. In 2020, we will continue to look for ways to improve efficiencies across Cenovus to drive incremental capital, operating and general and administrative cost reductions. We expect to realize additional savings through improvements in areas such as drilling performance, development planning and optimized scheduling of oil sands well start-ups. Our ability to drive structural and sustainable cost and margin improvements will further support our business plan, financial resilience and our ability to generate shareholder value.

We believe growth in cash flows and further cost reductions will help us reach our Net Debt to Adjusted EBITDA target.

Advance Focused Technology and Innovation to Achieve Margin Improvement

We have always believed that technology and innovation are differentiating factors in our industry. We focus our innovation efforts on accelerating the adoption of technology solutions and methods of operating to enhance safety, reduce costs, improve margins and lower emissions. We expect innovation at Cenovus to mean significant improvements and game-changing developments that are implemented to generate value. We aim to complement our internal technology development activities with external collaboration in an effort to leverage our technology spend.

ADVISORY

Oil and Gas Information

The estimates of reserves were prepared effective December 31, 2019 by independent qualified reserves evaluators, based on the COGE Handbook and in compliance with the requirements of NI 51-101. Estimates are presented using an average of three IQREs January 1, 2020 price forecasts. For additional information about our reserves and other oil and gas information, see “Reserves Data and Other Oil and Gas Information” in our AIF for the year ended December 31, 2019.

Barrels of Oil Equivalent – natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Forward-looking Information

This document contains certain forward-looking statements and forward-looking information (collectively referred to as “forward-looking information”) within the meaning of applicable securities legislation, including the *U.S. Private Securities Litigation Reform Act of 1995*, about our current expectations, estimates and projections about the future, based on certain assumptions made by us in light of our experience and perception of historical trends. Although we believe that the expectations represented by such forward looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking information in this document is identified by words such as “aim”, “anticipate”, “believe”, “can be”, “capacity”, “committed”, “commitment”, “continuing”, “could”, “drive”, “expect”, “estimate”, “focus”, “forecast”, “forward”, “future”, “guide”, “guidance”, “may”, “outlook”, “plan”, “position”, “potential”, “priority”, “projection”,

“schedule”, “strategy”, “should”, “target”, “will”, or similar expressions and includes suggestions of future outcomes, including statements about: strategy and related milestones; schedules and plans; focus on maximizing shareholder value through cost leadership; focus on integrating ESG considerations into our business plan; desire to realize the best margins for our products; potential for significant Free Funds Flow generation through 2024 in a WTI price environment of US$45.00 per barrel; plans to maintain and demonstrate financial discipline while balancing growth and shareholder return; our targeted five percent to 10 percent annual dividend growth; our willingness to consider opportunistic share repurchases, including supporting a potential sale of ConocoPhillips’ ownership of our common shares; continuing to advance our operational performance and upholding our trusted reputation; expected timing for oil sands expansion phases and associated expected production capacities; expected production on unconstrained basis; projections for 2020 and future years and our plans and strategies to realize such projections; forecast exchange rates and trends; future opportunities for oil and natural gas development; forecast operating and financial results, including forecast sales prices, costs and cash flows; our commitment to continue reducing debt, including our long-term target Net Debt to Adjusted EBITDA ratio; our ability to satisfy payment obligations as they become due; priorities for and approach to capital investment decisions or capital allocation; planned capital expenditures, including the amount, timing and funding sources thereof; all statements with respect to our 2020 guidance estimates; expected future production, including the timing, stability or growth thereof; the impact of the Government of Alberta’s mandatory production curtailment; our ability to take steps to partially mitigate against wider WTI and WCS price differentials; our expectation that our capital investment and any cash dividends for 2020 will be funded from internally generated cash flows and cash balance on hand; expected reserves; capacities, including for projects, transportation and refining; impact on alignment of transportation and storage commitments and production growth; all statements related to government royalty regimes applicable to Cenovus, which regimes are subject to change; our ability to preserve our financial resilience and various plans and strategies with respect thereto; forecast cost reductions and sustainability thereof; our priorities, including for 2020; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact; potential impacts of various risks, including those related to commodity prices and climate change; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof, and anticipated impact on the Consolidated Financial Statements; the availability and repayment of our credit facilities; potential asset sales; expected impacts of the contingent payment; future investment, use and development of technology and equipment and associated future outcomes; our ability to access and implement all technology necessary to efficiently and effectively operate our assets and achieve expected future results; planned capital expenditures; and projected growth and projected shareholder return. 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 our forward-looking information is based include, but are not limited to: forecast oil and natural gas, natural gas liquids, condensate and refined products prices, light-heavy crude oil price differentials and other assumptions identified in Cenovus’s 2020 guidance, available at cenovus.com; bottom of the cycle commodity prices of about US$45/bbl WTI and C$44/bbl WCS; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to our share price and market capitalization over the long term; opportunities to repurchase shares for cancellation at prices acceptable to us; cash flows and cash balances on hand being sufficient to fund capital investments and dividends, including any increase thereto; future narrowing of crude oil differentials; realization of expected capacity to store within our oil sands reservoirs barrels not yet produced, including that we will be able to time production and sales of our inventory at later dates when pipeline capacity has improved and crude oil differentials have narrowed; the Government of Alberta’s mandatory production curtailment will continue to maintain a relatively narrow differential between WTI and WCS crude oil prices thereby positively impacting cash flows for Cenovus; the ability of our refining capacity, dynamic storage, existing pipeline commitments, financial hedge transactions and plans to ramp up crude-by-rail loading capacity to partially mitigate a portion of our WCS crude oil volumes against wider differentials; our ability to produce from our Oil Sands facilities on an unconstrained basis; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; accounting estimates and judgments; future use and development of technology and associated expected future results; 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 to meet our current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; our ability to complete asset sales, including with desired transaction metrics and within the timelines we expect; forecast inflation and other assumptions inherent in our current guidance set out below; expected impacts of the contingent payment to ConocoPhillips; alignment of realized WCS and WCS prices used to calculate the contingent payment to ConocoPhillips; our ability to access and implement all technology and equipment necessary to achieve expected future results and that such results are realized; our ability to implement capital projects or stages thereof in a successful and timely manner; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2020 guidance, as updated December 9, 2019, assumes: Brent prices of US$60.00/bbl, WTI prices of US$55.00/bbl; WCS of US$37.50/bbl; AECO natural gas prices of $1.80/Mcf; Chicago 3-2-1 crack spread of US$16.00/bbl; and an exchange rate of $0.76 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include, but are not limited to: our ability to access or implement some or all of the technology necessary to efficiently and effectively operate our assets and achieve expected future results; volatility of and other assumptions regarding commodity prices; our ability to realize the expected impacts of our capacity to store within our oil sands reservoirs barrels not yet produced, including possible inability to time production and sales at later dates when pipeline capacity and crude oil differentials have improved; failure of the Government of Alberta's mandatory production curtailment to cause the differential between the WTI and the WCS crude oil prices to narrow or to narrow sufficiently to positively impact our cash flows; unexpected consequences related to the Government of Alberta's mandatory production curtailment; the Government of Alberta may extend mandatory production curtailment beyond when takeaway capacity constraints have been sufficiently relieved; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; accuracy of our share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks, exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of our crude-by-rail terminal, including health, safety and environmental risks; our ability to maintain desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including potential dividend increases and the dividend reinvestment plan; accuracy of our reserves, future production and future net revenue estimates; accuracy of our accounting estimates and judgements; our ability to replace and expand oil and gas reserves; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of our assets or goodwill from time to time; our ability to maintain our relationship with our partners and to successfully manage and operate our integrated business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, including labour, materials, natural gas and other energy sources used in oil sands processes and increased insurance deductibles or premiums; potential failure of products to achieve or maintain acceptance in the market; risks associated with fossil fuel industry reputation and litigation related thereto; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and equipment and its application to our business, including potential cyberattacks; risks associated with climate change and our assumptions relating thereto; the timing and the costs of well and pipeline construction; our ability to secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; possible failure to obtain and retain qualified staff and equipment in a timely and cost efficient manner; changes in labour relationships; 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, climate change 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 general economic, market and business conditions; the political and economic conditions in the countries in which we operate or supply; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, shareholder proposals and regulatory actions against us.

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

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of our material risk factors, see "Risk Management and Risk Factors" in this MD&A.

ABBREVIATIONS

The following abbreviations have been used in this document:

Crude Oil		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
MMbbls	million barrels	Bcf	billion cubic feet
BOE	barrel of oil equivalent	MMBtu	million British thermal units
MMBOE	million barrel of oil equivalent	GJ	gigajoule
WTI	West Texas Intermediate	AECO	Alberta Energy Company
WCS	Western Canadian Select	NYMEX	New York Mercantile Exchange
CDB	Christina Dilbit Blend		
MSW	Mixed Sweet Blend		
WTS	West Texas Sour		

DEFINITIONS

Scope 1 emissions are direct emissions from owned or operated facilities. Cenovus accounts for emissions on a gross operatorship basis. This includes fuel combustion, venting, flaring and fugitive emissions. It does not include emissions from the 50% non-operated ownership in the company's refineries or emissions from non-operated Deep Basin assets.

Scope 2 emissions are indirect emissions from the generation of purchased energy for the company's operated facilities. For Cenovus, this is limited to electricity imports.

NETBACK RECONCILIATIONS

The following tables provide a reconciliation of the items comprising Netbacks to Operating Margin found in our Consolidated Financial Statements.

Total Production From Continuing Operations

Continuing Upstream Financial Results

Year Ended December 31, 2019 ($ millions)	Per Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	10,838	691	11,529	(4,021)	-	(222)	(64)	7,222
Royalties	1,143	29	1,172	-	-	-	1	1,173
Transportation and Blending	5,152	82	5,234	(4,021)	-	-	1	1,214
Operating	1,039	337	1,376	-	-	(222)	(33)	1,121
Production and Mineral Taxes	-	1	1	-	-	-	-	1
Netback	3,504	242	3,746	-	-	-	(33)	3,713
(Gain) Loss on Risk Management	23	-	23	-	-	-	-	23
Operating Margin	3,481	242	3,723	-	-	-	(33)	3,690

Year Ended December 31, 2018 ($ millions) [3]	Per Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	10,026	904	10,930	(4,993)	-	(179)	(69)	5,689
Royalties	473	72	545	-	-	-	-	545
Transportation and Blending	5,879	90	5,969	(4,993)	-	-	(4)	972
Operating	1,037	403	1,440	-	-	(179)	(37)	1,224
Production and Mineral Taxes	-	1	1	-	-	-	-	1
Netback	2,637	338	2,975	-	-	-	(28)	2,947
(Gain) Loss on Risk Management	1,551	26	1,577	-	-	-	-	1,577
Operating Margin	1,086	312	1,398	-	-	-	(28)	1,370

Year Ended December 31, 2017 ($ millions) [3]	Per Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	7,362	555	7,917	(3,050)	-	-	(45)	4,822
Royalties	230	41	271	-	-	-	-	271
Transportation and Blending	3,704	56	3,760	(3,050)	-	-	(1)	709
Operating	934	250	1,184	-	-	-	(77)	1,107
Production and Mineral Taxes	-	1	1	-	-	-	-	1
Netback	2,494	207	2,701	-	-	-	33	2,734
(Gain) Loss on Risk Management	307	-	307	-	-	-	-	307
Operating Margin	2,187	207	2,394	-	-	-	33	2,427

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Represents natural gas volumes produced by the Deep Basin segment used for internal consumption by the Oil Sands segment.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Polices section in this MD&A.

Three Months Ended December 31, 2019 ($ millions)	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands[4]	Deep Basin[4]	Continuing Operations	Condensate	Inventory	Internal Usage[5]	Other	Continuing Operations
Gross Sales	2,659	190	2,849	(1,060)	-	(82)	(13)	1,694
Royalties	316	9	325	-	-	-	1	326
Transportation and Blending	1,416	20	1,436	(1,060)	-	-	1	377
Operating	268	80	348	-	-	(82)	(6)	260
Production and Mineral Taxes	-	-	-	-	-	-	-	-
Netback	659	81	740	-	-	-	(9)	731
(Gain) Loss on Risk Management	(15)	-	(15)	-	-	-	-	(15)
Operating Margin	674	81	755	-	-	-	(9)	746

(4) Found in Note 1 of the Interim Consolidated Financial Statements.
(5) Represents natural gas volumes produced by the Deep Basin segment used for internal consumption by the Oil Sands segment.

Three Months Ended December 31, 2018 ($ millions) (3)	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands(1)	Deep Basin(1)	Continuing Operations	Condensate	Inventory	Internal Usage(2)	Other	Continuing Operations
Gross Sales	1,380	190	1,570	(1,026)	-	(48)	(20)	476
Royalties	(39)	10	(29)	-	-	-	-	(29)
Transportation and Blending	1,263	18	1,281	(1,026)	-	-	-	255
Operating	248	100	348	-	-	(48)	(9)	291
Production and Mineral Taxes	-	-	-	-	-	-	-	-
Netback	(92)	62	(30)	-	-	-	(11)	(41)
(Gain) Loss on Risk Management	86	-	86	-	-	-	-	86
Operating Margin	(178)	62	(116)	-	-	-	(11)	(127)

(1) Found in Note 1 of the Interim Consolidated Financial Statements.
(2) Represents natural gas volumes produced by the Deep Basin segment used for internal consumption by the Oil Sands segment.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Polices section in this MD&A.

Oil Sands

Year Ended December 31, 2019 ($ millions)	Basis of Netback Calculation				Adjustments			Per Consolidated Financial Statements(4)
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	3,295	3,511	6,806	-	4,021	-	11	10,838
Royalties	486	650	1,136	-	-	-	7	1,143
Transportation and Blending	674	458	1,132	-	4,021	-	(1)	5,152
Operating	526	505	1,031	-	-	-	8	1,039
Netback	1,609	1,898	3,507	-	-	-	(3)	3,504
(Gain) Loss on Risk Management	10	13	23	-	-	-	-	23
Operating Margin	1,599	1,885	3,484	-	-	-	(3)	3,481

Year Ended December 31, 2018 ($ millions) (5)	Basis of Netback Calculation				Adjustments			Per Consolidated Financial Statements (4)
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	2,531	2,489	5,020	1	4,993	-	12	10,026
Royalties	371	102	473	-	-	-	-	473
Transportation and Blending	495	391	886	-	4,993	-	-	5,879
Operating	532	492	1,024	2	-	-	11	1,037
Netback	1,133	1,504	2,637	(1)	-	-	1	2,637
(Gain) Loss on Risk Management	683	868	1,551	-	-	-	-	1,551
Operating Margin	450	636	1,086	(1)	-	-	1	1,086

Year Ended December 31, 2017 ($ millions) (5)	Basis of Netback Calculation				Adjustments			Per Consolidated Financial Statements (4)
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	1,945	2,345	4,290	8	3,050	-	14	7,362
Royalties	178	52	230	-	-	-	-	230
Transportation and Blending	387	266	653	-	3,050	-	1	3,704
Operating	465	403	868	9	-	-	57	934
Netback	915	1,624	2,539	(1)	-	-	(44)	2,494
(Gain) Loss on Risk Management	131	176	307	-	-	-	-	307
Operating Margin	784	1,448	2,232	(1)	-	-	(44)	2,187

(4) Found in Note 1 of the Consolidated Financial Statements.
(5) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Polices section in this MD&A

Three Months Ended December 31, 2019 ($ millions)	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements (1)
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	731	866	1,597	-	1,060	-	2	2,659
Royalties	130	179	309	-	-	-	7	316
Transportation and Blending	207	150	357	-	1,060	-	(1)	1,416
Operating	132	136	268	-	-	-	-	268
Netback	262	401	663	-	-	-	(4)	659
(Gain) Loss on Risk Management	(5)	(10)	(15)	-	-	-	-	(15)
Operating Margin	267	411	678	-	-	-	(4)	674

(1) Found in Note 1 of the Interim Consolidated Financial Statements.

Three Months Ended December 31, 2018 ($ millions) (2)	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements (1)
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	265	84	349	-	1,026	-	5	1,380
Royalties	(5)	(34)	(39)	-	-	-	-	(39)
Transportation and Blending	141	96	237	-	1,026	-	-	1,263
Operating	123	121	244	1	-	-	3	248
Netback	6	(99)	(93)	(1)	-	-	2	(92)
(Gain) Loss on Risk Management	45	41	86	-	-	-	-	86
Operating Margin	(39)	(140)	(179)	(1)	-	-	2	(178)

(1) Found in Note 1 of the Interim Consolidated Financial Statements.
(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Polices section in this MD&A

Deep Basin

Year Ended December 31, 2019 ($ millions)	Basis of Netback Calculation	Adjustments	Per Consolidated Financial Statements(3)
	Total	Other(4)	Total Deep Basin
Gross Sales	638	53	691
Royalties	29	-	29
Transportation and Blending	82	-	82
Operating	312	25	337
Production and Mineral Taxes	1	-	1
Netback	214	28	242
(Gain) Loss on Risk Management	-	-	-
Operating Margin	214	28	242

Year Ended December 31, 2018 ($ millions) (5)	Basis of Netback Calculation	Adjustments	Per Consolidated Financial Statements(3)
	Total	Other(4)	Total Deep Basin
Gross Sales	847	57	904
Royalties	72	-	72
Transportation and Blending	86	4	90
Operating	377	26	403
Production and Mineral Taxes	1	-	1
Netback	311	27	338
(Gain) Loss on Risk Management	26	-	26
Operating Margin	285	27	312

Year Ended December 31, 2017 ($ millions) (5)	Basis of Netback Calculation	Adjustments	Per Consolidated Financial Statements(3)
	Total	Other(4)	Total Deep Basin
Gross Sales	524	31	555
Royalties	41	-	41
Transportation and Blending	56	-	56
Operating	230	20	250
Production and Mineral Taxes	1	-	1
Netback	196	11	207
(Gain) Loss on Risk Management	-	-	-
Operating Margin	196	11	207

(3) Found in Note 1 of the Consolidated Financial Statements.
(4) Reflects operating margin from processing facility.
(5) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Polices section in this MD&A.

Three Months Ended December 31, 2019 ($ millions)	Basis of Netback Calculation Total	Adjustments Other(2)	Per Interim Consolidated Financial Statements(1) Total Deep Basin
Gross Sales	179	11	190
Royalties	9	-	9
Transportation and Blending	20	-	20
Operating	74	6	80
Production and Mineral Taxes	-	-	-
Netback	76	5	81
(Gain) Loss on Risk Management	-	-	-
Operating Margin	76	5	81

Three Months Ended December 31, 2018 ($ millions) (3)	Basis of Netback Calculation Total	Adjustments Other(2)	Per Interim Consolidated Financial Statements(1) Total Deep Basin
Gross Sales	175	15	190
Royalties	10	-	10
Transportation and Blending	18	-	18
Operating	94	6	100
Netback	53	9	62
(Gain) Loss on Risk Management	-	-	-
Operating Margin	53	9	62

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Reflects operating margin from processing facility.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Polices section in this MD&A.

The following table provides the sales volumes used to calculate Netback.

Sales Volumes

(barrels per day, unless otherwise stated)	Three Months Ended December 31, 2019	December 31, 2018	Year Ended December 31 2019	2018	2017
Oil Sands					
Foster Creek	**153,797**	143,928	**157,770**	162,685	121,806
Christina Lake	**207,399**	186,530	**188,910**	204,016	161,514
Total Oil Sands Crude Oil	**361,196**	330,458	**346,680**	366,701	283,320
Natural Gas (MMcf per day)	**-**	-	**-**	1	10
Total Oil Sands (BOE per day)	**361,196**	330,458	**346,680**	366,905	284,984
Deep Basin					
Total Liquids	**26,197**	28,111	**26,673**	32,454	20,850
Natural Gas (MMcf per day)	**403**	469	**424**	527	316
Total Deep Basin (BOE per day)	**93,317**	106,232	**97,423**	120,258	73,492
Less: Internal Consumption (4) (MMcf per day)	**(336)**	(310)	**(320)**	(306)	-
Sales From Continuing Operations (4) (BOE per day)	**398,457**	385,023	**390,813**	436,163	358,476

(4) Less natural gas volumes used for internal consumption by the Oil Sands segment.

Exhibit 99.3



Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2019

(Canadian Dollars)

CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2019

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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 five 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 met 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, 2019. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission framework in Internal Control – Integrated Framework (2013) 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, 2019.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2019, as stated in their Report of Independent Registered Public Accounting Firm dated February 11, 2020. PricewaterhouseCoopers LLP has provided such opinions.

/s/ Alexander J. Pourbaix

Alexander J. Pourbaix
President &
Chief Executive Officer
Cenovus Energy Inc.

/s/ Jonathan M. McKenzie

Jonathan M. McKenzie
Executive Vice-President &
Chief Financial Officer
Cenovus Energy Inc.

February 11, 2020



REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Cenovus Energy Inc.

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying Consolidated Balance Sheets of Cenovus Energy Inc. and its subsidiaries (together, the "Company") as of December 31, 2019 and 2018, and the related Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss), Shareholders' Equity, and Cash Flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and its financial performance and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"). Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in Internal Control – Integrated Framework (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 4 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019 due to the adoption of IFRS 16, Leases.

Basis for Opinions

The Company's Management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by Management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.



Definition and Limitations 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.

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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of reserves and resources on the recoverable amounts of Property, Plant and Equipment ("PP&E") for the Deep Basin Cash Generating Units ("CGUs") and on Depreciation, Depletion and Amortization ("DD&A") expense for the Oil Sands and Deep Basin segments

As described in Notes 1, 3, 5, 10 and 18 to the consolidated financial statements, the Company assesses its CGUs for indicators of impairment on a quarterly basis or when facts and circumstances suggest that the carrying amount which is net of accumulated DD&A and net impairment losses may exceed its recoverable amount. The Company calculates depletion on the costs accumulated within each area using the unit-of-production method based on estimated proved reserves determined using forward prices and costs. Costs subject to depletion include estimated future costs to be incurred in developing proved reserves. As at December 31, 2019, the Company had $2,433 million in Deep Basin PP&E assets net of accumulated DD&A and net impairment losses. In aggregate the Company recognized $1,735 million of DD&A expense for the Oil Sands and Deep Basin segments for the year ended December 31, 2019. Management determined the recoverable amounts of PP&E for the Deep Basin CGUs based on fair value less costs of disposal using discounted after-tax cash flows of reserves and resources requiring the use of significant estimates and judgments by Management related to forward commodity prices, expected production volumes, quantity of reserves and resources, royalty payments, and future development and operating expenses, as well as estimates over discount rates, and income tax rates. The Company's estimates of reserves and resources, as applicable, used for both the determination of the recoverable amounts of PP&E for the Deep Basin CGUs and the calculation of DD&A expense for the Oil Sands and Deep Basin segments have been developed by Management's specialists, specifically independent qualified reserve evaluators.

The principal considerations for our determination that performing procedures relating to the impact of reserves and resources on the recoverable amounts of PP&E for the Deep Basin CGUs and on DD&A expense for the Oil Sands and Deep Basin segments is a critical audit matter are (i) the significant amount of judgment required by Management, including the use of Management's specialists, when developing the estimates of reserves and resources and the recoverable amounts; (ii) there was a high degree of auditor judgment, subjectivity, and effort in performing procedures relating to Management's cash flow projections and significant assumptions including forward commodity prices, expected production volumes, quantity of reserves and resources, future development and operating expenses, as well as discount rates; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to Management's estimates of reserves and resources, the determination of the recoverable amounts of PP&E for the Deep Basin CGUs and the calculation of DD&A expense for the Oil Sands and Deep Basin segments. These procedures also included, among others, testing Management's process for determining the recoverable amounts of PP&E for the Deep Basin CGUs and DD&A expense for the Oil Sands and Deep Basin



segments, which included (i) evaluating the appropriateness of the methods used by Management in making these estimates; (ii) testing the completeness, accuracy and relevance of underlying data used in Management's analysis in developing these estimates; (iii) assessing the reasonability of the assumptions used by Management, including forward commodity prices, expected production volumes, quantity of reserves and resources, as well as future development and operating expenses; and (iv) testing the unit-of-production rates used to calculate DD&A expense. The work of Management's specialists was used in performing the procedures to evaluate the reasonableness of the reserves and resources used to determine the recoverable amounts of PP&E for the Deep Basin CGUs and DD&A expense for the Oil Sands and Deep Basin segments. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as their methods and assumptions. The procedures performed also included tests of data used by Management's specialists and an evaluation of their findings. Evaluating the assumptions used by Management's specialists also involved assessing whether the assumptions used were reasonable considering the current and past performance of the Company, consistency with industry pricing forecasts and consistency with evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were also used to assist in evaluating the reasonableness of the recoverability calculations, including the discount rate used within the models.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta, Canada

February 11, 2020

We have served as the Company's auditor since 2008.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

For the years ended December 31,
($ millions, except per share amounts)

	Notes	**2019**	2018	2017
Revenues	1			
Gross Sales		**21,353**	21,389	17,314
Less: Royalties		**1,172**	545	271
		20,181	20,844	17,043
Expenses	1			
Purchased Product		**8,427**	8,744	8,033
Transportation and Blending		**5,184**	5,942	3,748
Operating		**2,088**	2,184	1,949
Production and Mineral Taxes		**1**	1	1
(Gain) Loss on Risk Management	35	**156**	305	896
Depreciation, Depletion and Amortization	10,18,19	**2,249**	2,131	1,838
Exploration Expense	10,17	**82**	2,123	888
General and Administrative		**336**	391	300
Onerous Contract Provisions	26	**(5)**	629	8
Finance Costs	6	**511**	627	645
Interest Income		**(12)**	(19)	(62)
Foreign Exchange (Gain) Loss, Net	7	**(404)**	854	(812)
Revaluation (Gain)	9	**-**	-	(2,555)
Transaction Costs	9	**-**	-	56
Re-measurement of Contingent Payment	25	**164**	50	(138)
Research Costs		**20**	25	36
(Gain) Loss on Divestiture of Assets	8	**(2)**	795	1
Other (Income) Loss, Net		**(11)**	(12)	(5)
Earnings (Loss) From Continuing Operations Before Income Tax		**1,397**	(3,926)	2,216
Income Tax Expense (Recovery)	12	**(797)**	(1,010)	(52)
Net Earnings (Loss) From Continuing Operations		**2,194**	(2,916)	2,268
Net Earnings (Loss) From Discontinued Operations	11	**-**	247	1,098
Net Earnings (Loss)		**2,194**	(2,669)	3,366
Basic and Diluted Earnings (Loss) Per Share ($)	13			
Continuing Operations		**1.78**	(2.37)	2.06
Discontinued Operations		**-**	0.20	0.99
Net Earnings (Loss) Per Share		**1.78**	(2.17)	3.05

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31,
($ millions)

	Notes	**2019**	2018	2017
Net Earnings (Loss)		**2,194**	(2,669)	3,366
Other Comprehensive Income (Loss), Net of Tax	31			
Items That Will Not be Reclassified to Profit or Loss:				
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**5**	(3)	9
Change in the Fair Value of Equity Instruments at FVOCI (1)		**12**	1	(1)
Items That May be Reclassified to Profit or Loss:				
Foreign Currency Translation Adjustment		**(228)**	397	(275)
Total Other Comprehensive Income (Loss), Net of Tax		**(211)**	395	(267)
Comprehensive Income (Loss)		**1,983**	(2,274)	3,099

(1) Fair Value through Other Comprehensive Income ("FVOCI").

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31,
($ millions)

	Notes	2019	2018
Assets			
Current Assets			
Cash and Cash Equivalents	14	**186**	781
Accounts Receivable and Accrued Revenues	15	**1,551**	1,238
Income Tax Receivable		**10**	-
Inventories	16	**1,532**	1,013
Risk Management	35,36	**5**	163
Total Current Assets		**3,284**	3,195
Exploration and Evaluation Assets	1,17	**787**	785
Property, Plant and Equipment, Net	1,18	**27,834**	28,698
Right-of-Use Assets, Net	1,19	**1,325**	-
Income Tax Receivable		**-**	160
Other Assets	20	**211**	64
Goodwill	1,21	**2,272**	2,272
Total Assets		**35,713**	35,174
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	22	**2,210**	1,833
Long-Term Debt	23	**-**	682
Lease Liabilities	24	**196**	-
Contingent Payment	25	**79**	15
Onerous Contract Provisions	26	**17**	50
Income Tax Payable		**17**	17
Risk Management	35,36	**2**	3
Total Current Liabilities		**2,521**	2,600
Long-Term Debt	23	**6,699**	8,482
Lease Liabilities	24	**1,720**	-
Contingent Payment	25	**64**	117
Onerous Contract Provisions	26	**46**	613
Decommissioning Liabilities	27	**1,235**	875
Other Liabilities	28	**195**	158
Deferred Income Taxes	12	**4,032**	4,861
Total Liabilities		**16,512**	17,706
Shareholders' Equity		**19,201**	17,468
Total Liabilities and Shareholders' Equity		**35,713**	35,174
Commitments and Contingencies	38		

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board of Directors

/s/ Patrick D. Daniel

Patrick D. Daniel
Director
Cenovus Energy Inc.

/s/ Claude Mongeau

Claude Mongeau
Director
Cenovus Energy Inc.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions)

	Share Capital	Paid in Surplus	Retained Earnings	AOCI (1)	**Total**
	(Note 30)	(Note 30)		(Note 31)	
As at December 31, 2016	5,534	4,350	796	910	11,590
Net Earnings (Loss)	-	-	3,366	-	3,366
Other Comprehensive Income (Loss)	-	-	-	(267)	(267)
Total Comprehensive Income (Loss)	-	-	3,366	(267)	3,099
Common Shares Issued	5,506	-	-	-	5,506
Stock-Based Compensation Expense	-	11	-	-	11
Dividends on Common Shares	-	-	(225)	-	(225)
As at December 31, 2017	11,040	4,361	3,937	643	19,981
Net Earnings (Loss)	-	-	(2,669)	-	(2,669)
Other Comprehensive Income (Loss)	-	-	-	395	395
Total Comprehensive Income (Loss)	-	-	(2,669)	395	(2,274)
Stock-Based Compensation Expense	-	6	-	-	6
Dividends on Common Shares	-	-	(245)	-	(245)
As at December 31, 2018	11,040	4,367	1,023	1,038	17,468
Net Earnings (Loss)	-	-	2,194	-	2,194
Other Comprehensive Income (Loss)	-	-	-	(211)	(211)
Total Comprehensive Income (Loss)	-	-	2,194	(211)	1,983
Stock-Based Compensation Expense	-	10	-	-	10
Dividends on Common Shares	-	-	(260)	-	(260)
As at December 31, 2019	**11,040**	**4,377**	**2,957**	**827**	**19,201**

(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	2019	2018	2017
Operating Activities				
Net Earnings (Loss)		**2,194**	(2,669)	3,366
Depreciation, Depletion and Amortization	18,19	**2,249**	2,131	2,030
Exploration Expense	17	**82**	2,123	890
Deferred Income Tax Expense (Recovery)	12	**(814)**	(794)	583
Unrealized (Gain) Loss on Risk Management	35	**149**	(1,249)	729
Unrealized Foreign Exchange (Gain) Loss	7	**(827)**	649	(857)
Revaluation (Gain)	9	**-**	-	(2,555)
Re-measurement of Contingent Payment	25	**164**	50	(138)
(Gain) Loss on Discontinuance	11	**-**	(301)	(1,285)
(Gain) Loss on Divestiture of Assets	8	**(2)**	795	1
Unwinding of Discount on Decommissioning Liabilities	27	**58**	63	128
Onerous Contract Provisions, Net of Cash Paid	26	**(15)**	618	(8)
Realized Foreign Exchange (Gain) Loss on Non-Operating Items		**401**	206	(18)
Other		**85**	52	48
Net Change in Other Assets and Liabilities		**(84)**	(72)	(107)
Net Change in Non-Cash Working Capital		**(355)**	552	252
Cash From (Used in) Operating Activities		**3,285**	2,154	3,059
Investing Activities				
Acquisition, Net of Cash Acquired	9	**-**	-	(14,565)
Capital Expenditures – Exploration and Evaluation Assets	17	**(73)**	(55)	(147)
Capital Expenditures – Property, Plant and Equipment	18	**(1,110)**	(1,322)	(1,523)
Proceeds From Divestitures	8,11	**1**	1,050	3,210
Net Change in Investments and Other		**(133)**	9	-
Net Change in Non-Cash Working Capital		**(117)**	(295)	159
Cash From (Used in) Investing Activities		**(1,432)**	(613)	(12,866)
Net Cash Provided (Used) Before Financing Activities		**1,853**	1,541	(9,807)
Financing Activities	37			
Issuance of Long-Term Debt		**-**	-	3,842
(Repayment) of Long-Term Debt		**(2,279)**	(1,144)	-
Net Issuance (Repayment) of Revolving Term Debt		**276**	(20)	32
Issuance of Debt Under Asset Sale Bridge Facility		**-**	-	3,569
(Repayment) of Debt Under Asset Sale Bridge Facility		**-**	-	(3,600)
Principal Repayment of Leases		**(150)**	-	-
Common Shares Issued, Net of Issuance Costs		**-**	-	2,899
Dividends Paid on Common Shares		**(260)**	(245)	(225)
Other		**-**	(1)	(2)
Cash From (Used in) Financing Activities		**(2,413)**	(1,410)	6,515
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(35)**	40	182
Increase (Decrease) in Cash and Cash Equivalents		**(595)**	171	(3,110)
Cash and Cash Equivalents, Beginning of Year		**781**	610	3,720
Cash and Cash Equivalents, End of Year		**186**	781	610

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 developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and refining operations in the United States ("U.S.").

Cenovus is incorporated under the "*Canada Business Corporations Act*" and its shares are listed on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at 4100, 225 6 Avenue S.W., Calgary, Alberta, Canada, T2P 1N2. 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 margin. The Company's reportable segments are:

- **Oil Sands**, which includes the development and production of bitumen in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as other projects in the early stages of development. The Company's interest in certain of its operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, increased from 50 percent to 100 percent on May 17, 2017.
- **Deep Basin**, which includes approximately 2.8 million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and NGLs. The assets reside in Alberta and British Columbia and include interests in numerous natural gas processing facilities. These assets were acquired on May 17, 2017.
- **Refining and Marketing**, which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification. The marketing of crude oil and natural gas sourced from Canada, including physical product sales that settle in the U.S., is considered to be undertaken by a Canadian business. U.S. sourced crude oil and natural gas purchases and sales are attributed to the U.S.
- **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, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. Eliminations include adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Company's rail terminal, crude oil production used as feedstock by the Refining and Marketing segment, and unrealized intersegment profits in inventory. Eliminations are recorded at transfer prices based on current market prices. The Corporate and Eliminations segment is attributed to Canada, with the exception of unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

In 2017, the Company announced its intention to divest of its Conventional segment that included its heavy oil assets at Pelican Lake, the carbon dioxide ("CO_2") enhanced oil recovery project at Weyburn and conventional crude oil, NGLs and natural gas assets in the Suffield and Palliser areas in southern Alberta. As such, the associated results of operations have been reported as a discontinued operation (see Note 11). As at January 5, 2018, all of the Company's Conventional assets were sold.

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			Deep Basin			Refining and Marketing		
For the years ended December 31,	**2019**	2018	2017	**2019**	2018	2017	**2019**	2018	2017
Revenues									
Gross Sales	**10,838**	10,026	7,362	**691**	904	555	**10,513**	11,183	9,852
Less: Royalties	**1,143**	473	230	**29**	72	41	**-**	-	-
	9,695	9,553	7,132	**662**	832	514	**10,513**	11,183	9,852
Expenses									
Purchased Product	**-**	-	-	**-**	-	-	**8,844**	9,261	8,476
Transportation and Blending	**5,152**	5,879	3,704	**82**	90	56	**-**	-	-
Operating	**1,039**	1,037	934	**337**	403	250	**948**	927	772
Production and Mineral Taxes	**-**	-	-	**1**	1	1	**-**	-	-
(Gain) Loss on Risk Management	**23**	1,551	307	**-**	26	-	**(16)**	(1)	6
Operating Margin	**3,481**	1,086	2,187	**242**	312	207	**737**	996	598
Depreciation, Depletion and Amortization	**1,543**	1,439	1,230	**319**	412	331	**280**	222	215
Exploration Expense	**18**	6	888	**64**	2,117	-	**-**	-	-
Segment Income (Loss)	**1,920**	(359)	69	**(141)**	(2,217)	(124)	**457**	774	383

	Corporate and Eliminations			Consolidated		
For the years ended December 31,	**2019**	2018	2017	**2019**	2018	2017
Revenues						
Gross Sales	**(689)**	(724)	(455)	**21,353**	21,389	17,314
Less: Royalties	**-**	-	-	**1,172**	545	271
	(689)	(724)	(455)	**20,181**	20,844	17,043
Expenses						
Purchased Product	**(417)**	(517)	(443)	**8,427**	8,744	8,033
Transportation and Blending	**(50)**	(27)	(12)	**5,184**	5,942	3,748
Operating	**(236)**	(183)	(7)	**2,088**	2,184	1,949
Production and Mineral Taxes	**-**	-	-	**1**	1	1
(Gain) Loss on Risk Management	**149**	(1,271)	583	**156**	305	896
Depreciation, Depletion and Amortization	**107**	58	62	**2,249**	2,131	1,838
Exploration Expense	**-**	-	-	**82**	2,123	888
Segment Income (Loss)	**(242)**	1,216	(638)	**1,994**	(586)	(310)
General and Administrative	**336**	391	300	**336**	391	300
Onerous Contract Provisions	**(5)**	629	8	**(5)**	629	8
Finance Costs	**511**	627	645	**511**	627	645
Interest Income	**(12)**	(19)	(62)	**(12)**	(19)	(62)
Foreign Exchange (Gain) Loss, Net	**(404)**	854	(812)	**(404)**	854	(812)
Revaluation (Gain)	**-**	-	(2,555)	**-**	-	(2,555)
Transaction Costs	**-**	-	56	**-**	-	56
Re-measurement of Contingent Payment	**164**	50	(138)	**164**	50	(138)
Research Costs	**20**	25	36	**20**	25	36
(Gain) Loss on Divestiture of Assets	**(2)**	795	1	**(2)**	795	1
Other (Income) Loss, Net	**(11)**	(12)	(5)	**(11)**	(12)	(5)
	597	3,340	(2,526)	**597**	3,340	(2,526)
Earnings (Loss) From Continuing Operations Before Income Tax				**1,397**	(3,926)	2,216
Income Tax Expense (Recovery)				**(797)**	(1,010)	(52)
Net Earnings (Loss) From Continuing Operations				**2,194**	(2,916)	2,268

B) Revenues by Product

For the years ended December 31,	2019	2018	2017
Upstream			
Crude Oil	**9,790**	9,662	7,184
Natural Gas	**300**	321	235
NGLs	**202**	333	184
Other	**65**	69	43
Refined Product	**8,291**	9,032	7,312
Market Optimization	**2,222**	2,151	2,540
Corporate and Eliminations	**(689)**	(724)	(455)
Revenues From Continuing Operations	**20,181**	20,844	17,043

C) Geographical Information

	Revenues		
For the years ended December 31,	2019	2018	2017
Canada	**11,799**	11,695	9,723
United States	**8,382**	9,149	7,320
Consolidated	**20,181**	20,844	17,043

	Non-Current Assets (1)	
As at December 31,	2019	2018
Canada	**28,336**	27,644
United States	**4,093**	4,175
Consolidated	**32,429**	31,819

(1) Includes exploration and evaluation ("E&E") assets, property, plant and equipment ("PP&E"), right-of-use ("ROU") assets, other assets and goodwill.

Export Sales

Sales of crude oil, NGLs and natural gas produced or purchased in Canada that have been delivered to customers outside of Canada were $4,002 million (2018 – $2,500 million; 2017 – $1,713 million).

Major Customers

In connection with the marketing and sale of Cenovus's own and purchased crude oil, NGLs, natural gas and refined products for the year ended December 31, 2019, Cenovus had two customers (2018 – three; 2017 – 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 $6,922 million and $2,316 million, respectively (2018 – $7,840 million, $2,285 million, and $2,263 million; 2017 – $5,655 million, $1,964 million), which are included in all of the Company's operating segments.

D) Assets by Segment

	E&E Assets		PP&E		ROU Assets	
As at December 31,	2019	2018	2019	2018	2019	2018
Oil Sands	**703**	639	**20,924**	21,646	**768**	-
Deep Basin	**84**	146	**2,433**	2,482	**3**	-
Refining and Marketing	**-**	-	**4,131**	4,284	**77**	-
Corporate and Eliminations	**-**	-	**346**	286	**477**	-
Consolidated	**787**	785	**27,834**	28,698	**1,325**	-

	Goodwill		Total Assets	
As at December 31,	2019	2018	2019	2018
Oil Sands	**2,272**	2,272	**26,317**	25,373
Deep Basin	**-**	-	**2,640**	2,742
Refining and Marketing	**-**	-	**5,688**	5,621
Corporate and Eliminations	**-**	-	**1,068**	1,424
Discontinued Operations	**-**	-	**-**	14
Consolidated	**2,272**	2,272	**35,713**	35,174

E) Capital Expenditures [1]

For the years ended December 31,	**2019**	2018	2017
Capital Investment			
Oil Sands	**706**	887	973
Deep Basin	**53**	211	225
Refining and Marketing	**280**	208	180
Corporate and Eliminations	**137**	57	77
Discontinued Operations	**-**	-	206
	1,176	1,363	1,661
Acquisition Capital			
Oil Sands [2]	**2**	332	11,614
Deep Basin	**7**	9	6,774
Refining and Marketing	**4**	-	-
Total Capital Expenditures	**1,189**	1,704	20,049

(1) Includes expenditures on PP&E, E&E assets and assets held for sale.
(2) In connection with the acquisition discussed in Note 9, Cenovus was deemed to have disposed of its pre-existing interest in FCCL Partnership ("FCCL") and re-acquired it at fair value as required by International Financial Reporting Standard 3, "Business Combinations" ("IFRS 3"), which is not reflected in the table above. The carrying value of the pre-existing interest was $9,081 million and the estimated fair value was $11,605 million as at May 17, 2017.

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 on a historical cost basis, except as detailed in the Company's accounting policies disclosed in Note 3.

These Consolidated Financial Statements were approved by the Board of Directors on February 11, 2020.

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 control. 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's Refining activities are conducted through the joint operation WRB Refining LP ("WRB") and, accordingly, the accounts reflect the Company's share of the assets, liabilities, revenues and expenses. Prior to May 17, 2017, FCCL was accounted for as a joint operation. Subsequent to the acquisition discussed in Note 9, Cenovus controls FCCL, and accordingly, FCCL has been consolidated.

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 using average rates 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 (Loss).

C) Revenue Recognition

Policy Applicable From January 1, 2018

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. Cenovus recognizes revenue when it transfers control of the product or service to a customer, which is generally when title passes from the Company to its customer.

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 services provided as agent are recorded as the services are provided.

Cenovus recognizes revenue from the following major products and services:

- Sale of crude oil, NGLs and natural gas;
- Sale of petroleum and refined products;
- Natural gas processing revenue;
- Marketing and transportation services; and
- Fee-for-service hydrocarbon trans-loading services.

The Company satisfies its performance obligations in contracts with customers upon the delivery of crude oil, NGLs, natural gas and petroleum and refined products, which is generally at a point in time. Performance obligations for natural gas processing revenue, marketing, transportation services and trans-loading services are satisfied over time as the service is provided. Cenovus sells its production of crude oil, NGLs, natural gas and petroleum and refined products generally pursuant to variable price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period. Revenue associated with natural gas processing, marketing, transportation services and trans-loading services are based, generally on fixed price contracts.

Cenovus's revenue transactions do not contain significant financing components and payments are typically due within 30 days of revenue recognition. The Company does not adjust transaction prices for the effects of a significant financing component when the period between the transfer of the promised goods or services to the customer and payment by the customer is less than one year. The Company does not disclose or quantify information about remaining performance obligations that have an original expected duration of one year or less and it does not have any long-term contracts with unfulfilled performance obligations.

Policy Applicable Before January 1, 2018

Revenues associated with the sales of Cenovus's crude oil, NGLs, natural gas, 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 the production of crude oil, NGLs and natural gas represent the Company's share, net of royalty payments to governments and other mineral interest owners.

Natural gas processing revenue and revenue from fee-for-service hydrocarbon trans-loading services is recognized in the period the service is provided.

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.

D) Transportation and Blending

The costs associated with the transportation of crude oil, NGLs and natural gas, including the cost of diluent used in blending, are recognized when the product is sold.

E) 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 or if the Company decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense.

F) 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 recorded with pension benefit costs.
- 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 recorded with pension benefit costs in operating, and general and administrative expenses, as well as PP&E and E&E assets.
- 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 benefit 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.

From time-to-time, the Company may provide certain other long-term incentive benefits to employees. In 2019, a one-time incentive program was introduced whereby a cash award equivalent to the employee's base salary is payable if Cenovus achieves prior to February 12, 2024 a target share price of $20 per share for a period of 20 consecutive trading days on the TSX (the "Plan"). All employees, except for the President & Chief Executive Officer, are eligible and new employees are eligible for a pro-rated award based on start date provided they are employed on the payout date. The obligation related to this Plan is estimated as the probability of the payout being achieved multiplied by the expected payout amount. The obligation is recognized over the greater of (i) the time to earliest payout of February 13, 2022; and (ii) the estimated time until payout is achieved, prior to February 12, 2024 as general and administrative expense.

G) Income Taxes

Income taxes comprise current and deferred taxes. 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 or when distributions can be made without incurring income taxes.

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.

H) Net Earnings per Share Amounts

Basic net earnings per 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.

I) 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.

J) 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.

K) 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 field/project/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 or the future economic value has decreased. E&E costs are subject to regular technical, commercial and Management review to confirm the continued intent to develop the resources.

Once technical feasibility and commercial viability have been established, the carrying value of the E&E asset is tested for impairment. The carrying value, net of any impairment loss, is then reclassified as PP&E.

Any gains or losses from the divestiture of E&E assets are recognized in net earnings.

L) Property, Plant and Equipment

General

PP&E is stated at cost less accumulated depreciation, depletion and amortization ("DD&A"), and net of any impairment losses. 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 PP&E are recognized in net earnings.

Development and Production Assets

Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of crude oil and natural gas properties, as well as any E&E expenditures incurred in finding reserves of crude oil, NGLs 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 forward 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.

Other Upstream Assets

Other upstream assets include information technology assets used to support the upstream business. These assets are depreciated on a straight-line basis over their useful lives of three years.

Refining Assets

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.

Refining assets 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 15 years
- Refining equipment 10 to 60 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 the crude-by-rail terminal, infrastructure, 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 years to 60 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.

M) Impairment of Non-Financial Assets

PP&E, E&E assets and ROU assets are reviewed separately for indicators of impairment quarterly or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Goodwill is tested for impairment at least annually.

If indicators of impairment exist, the recoverable amount of the asset or cash-generating unit ("CGU") is estimated as the greater of value-in-use ("VIU") and fair value less costs of disposal ("FVLCOD"). VIU is estimated as the present value of the future cash flows expected to arise from the continuing use of a CGU or an asset. FVLCOD is determined by estimating the discounted after-tax future net cash flows. For Cenovus's upstream assets, FVLCOD is based on the discounted after-tax cash flows of reserves and resources using forward prices and costs, consistent with Cenovus's independent qualified reserves evaluators ("IQREs") and may consider an evaluation of comparable asset transactions.

E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. ROU assets may be tested as part of a CGU, as a separate CGU or as an individual asset. Goodwill is allocated to the CGUs to which it contributes to the future cash flows.

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 on PP&E and ROU assets are recognized in the Consolidated Statements of Earnings (Loss) as additional DD&A and E&E asset impairments or write-downs are recognized as exploration expense.

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.

N) Leases

Policy Applicable From January 1, 2019

Leases

The Company assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration. The Company allocates the consideration in the contract to each lease component on the basis of their relative stand-alone prices. However, for the leases of storage tanks, the Company has elected not to separate non-lease components.

As Lessee

Leases are recognized as a ROU asset and a corresponding lease liability at the date on which the leased asset is available for use by the Company. Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of fixed payments, variable lease payments that are based on an index or a rate, amounts expected to be paid by the lessee under residual value guarantees, the

exercise price of purchase options if the lessee is reasonably certain to exercise that option, and payments of penalties for terminating the lease, less any lease incentives receivable. These payments are discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of leases with reasonably similar characteristics.

Lease payments are allocated between the liability and finance costs. The finance cost is charged to net earnings over the lease term.

The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in the future lease payments arising from a change in an index or rate, if there is a change in the amount expected to be payable under a residual value guarantee or if there is a change in the assessment of whether the Company will exercise a purchase, extension or termination option that is within the control of the Company.

When the lease liability is remeasured, a corresponding adjustment is made to the carrying amount of the ROU asset or is recorded in the Consolidated Statement of Earnings if the carrying amount of the ROU asset has been reduced to zero.

The ROU asset is initially measured at cost, which comprises the initial amount of the lease liability any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or site on which it is located less any lease payments made at or before the commencement date.

The ROU asset is depreciated, on a straight-line basis, over the shorter of the estimated useful life of the asset or the lease term. The ROU asset may be adjusted for certain remeasurements of the lease liability and impairment losses.

Leases that have terms of less than twelve months or leases on which the underlying asset is of low value are recognized as an expense in the Consolidated Statement of Earnings on a straight-line basis over the lease term.

A lease modification will be accounted for as a separate lease if the modification increases the scope of the lease and if the consideration for the lease increases by an amount commensurate with the stand-alone price for the increase in scope. For a modification that is not a separate lease or where the increase in consideration is not commensurate, at the effective date of the lease modification, the Company will remeasure the lease liability using the Company's incremental borrowing rate, when the rate implicit to the lease is not readily available, with a corresponding adjustment to the ROU asset. A modification that decreases the scope of the lease will be accounted for by decreasing the carrying amount of the ROU asset, and recognizing a gain or loss in net earnings that reflects the proportionate decrease in scope.

As Lessor

As a lessor, the Company assesses at inception whether a lease is a finance or operating lease. Leases where the Company transfers substantially all of the risk and rewards incidental to ownership of the underlying asset are classified as financing leases. Under a finance lease, the Company recognizes a receivable at an amount equal to the net investment in the lease which is the present value of the aggregate of lease payments receivable by the lessor. If substantially all the risks and rewards of ownership of an asset are not transferred the lease is classified as an operating lease. The Company recognizes lease payments received under operating leases as income on a straight-line basis over the lease term as other income.

When the Company is an intermediate lessor, it accounts for its interest in the head lease and the sublease separately. It assesses the lease classification of a sublease with reference to the ROU asset from the head lease not with reference to the underlying assets. If the head lease is a short-term lease to which the Company applies the exemption for lease accounting, the sublease is classified as an operating lease.

Policy Applicable Before January 1, 2019

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. At inception, a leased asset within PP&E and a corresponding lease obligation are recognized. The leased asset is depreciated over the shorter of the estimated useful life of the asset or the lease term.

O) Intangible Assets

Intangible assets acquired separately are initially measured at cost. Following initial recognition, intangible assets are recognized at cost less any accumulated amortization and accumulated impairment losses. Intangible assets with finite lives are amortized over the useful life and assessed for impairment whenever there is an indication that the intangible asset may be impaired. The amortization expense on intangible assets is recognized in the Consolidated Statement of Earnings (Loss) in the expense category consistent with the function of the intangible asset.

P) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and non-controlling interest, if any, 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.

Contingent consideration transferred in a business combination is measured at fair value on the date of acquisition and classified as a financial liability or equity. Contingent consideration classified as a liability is re-measured at fair value at each reporting date, with changes in fair value recognized in net earnings. Payments are classified as cash used in investing activities until the cumulative payments exceed the acquisition date fair value of the liability. Cumulative payments in excess of the acquisition date fair value are classified as cash used in operating activities. Contingent consideration classified as equity are not re-measured and settlements are accounted for within equity.

When a business combination is achieved in stages, the Company re-measures its pre-existing interest at the acquisition date fair value and recognizes the resulting gain or loss, if any, in net earnings.

Q) 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 (Loss).

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, upstream processing facilities, refining facilities and the crude-by-rail terminal. 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.

Actual expenditures incurred are charged against the accumulated liability.

Onerous Contract Provisions

Onerous contract provisions are recognized when the unavoidable costs of meeting the obligation exceed the economic benefit derived from the contract. The provision for onerous contracts is measured at the present value of estimated future cash flows underlying the obligations less any estimated recoveries, discounted at the credit-adjusted risk-free rate. Changes in the underlying assumptions are recognized in the Consolidated Statements of Earnings (Loss).

R) 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.

S) Stock-Based Compensation

Cenovus has a number of stock-based compensation plans which include stock options with associated net settlement rights (“NSRs”), performance share units (“PSUs”), restricted share units (“RSUs”), tandem stock appreciation rights (“TSARs”) and deferred share units (“DSUs”). Stock-based compensation costs are recorded in general and administrative expense, or E&E assets and PP&E when directly related to exploration or development activities.

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 stock-based 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 stock-based 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, Restricted and Deferred Share Units

PSUs, RSUs 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 stock-based compensation costs over the vesting period. Fluctuations in the fair values are recognized as stock-based compensation costs in the period they occur.

T) Financial Instruments

The Company's financial assets include cash and cash equivalents, accounts receivable and accrued revenues, risk management assets, investments in the equity of private companies and long-term receivables. The Company's financial liabilities include accounts payable and accrued liabilities, short-term borrowings, lease liabilities, contingent payment, risk management liabilities and long-term debt.

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.

The Company characterizes its fair value measurements into a three-level hierarchy depending on the degree to which the inputs are observable, as follows:

- Level 1 inputs are quoted prices in active markets for identical assets and liabilities;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

Classification and Measurement of Financial Assets

Policy Applicable From January 1, 2018

The initial classification of a financial asset depends upon the Company's business model for managing its financial assets and the contractual terms of the cash flows. There are three measurement categories into which the Company classified its financial assets:

- Amortized Cost: Includes assets that are held within a business model whose objective is to hold assets to collect contractual cash flows and its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest;
- FVOCI: Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, where its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest; or
- Fair Value through Profit and Loss ("FVTPL"): Includes assets that do not meet the criteria for amortized cost or FVOCI and are measured at fair value through profit or loss. This includes all derivative financial assets.

On initial recognition, the Company may irrevocably designate a financial asset that meets the amortized cost or FVOCI criteria as measured at FVTPL if doing so eliminates or significantly reduces an accounting mismatch. On initial recognition of an equity investment that is not held-for-trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in OCI. There is no subsequent reclassification of fair value changes to earnings following the derecognition of the investment. However, dividends that reflect a return on investment continue to be recognized in net earnings. This election is made on an investment-by-investment basis.

At initial recognition, the Company measures a financial asset at its fair value and, in the case of a financial asset not at FVTPL, including transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are recorded as an expense in net earnings.

Financial assets are reclassified subsequent to their initial recognition only if the business model for managing those financial assets changes. The affected financial assets will be reclassified on the first day of the first reporting period following the change in the business model.

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.

Policy Applicable Before January 1, 2018

Prior to the adoption of IFRS 9, "*Financial Instruments*" ("IFRS 9") on January 1, 2018, the Company classified and measured financial assets under IAS 39, *"Financial Instruments: Recognition and Measurement*" ("IAS 39"). There were three measurement categories into which the Company classified its financial assets:

- FVTPL: Assets were either 'held-for-trading' or had been 'designated at FVTPL'. The assets were measured at fair value with changes in fair value recognized in net earnings;
- Loans and Receivables: Included assets with fixed or determinable payments that are not quoted in an active market. After initial measurements, these assets were measured at amortized cost at the settlement date using the effective interest rate method of amortization; and
- Available for Sale Financial Assets: Included investments in the equity of private companies that the Company did not have control or had significant influence over. These assets were measured at fair value, with changes in fair value recognized in OCI. When an active market was non-existent, fair value was determined using valuation techniques. When the fair value could not be reliably measured, such assets were carried at cost.

Impairment of Financial Assets

Policy Applicable From January 1, 2018

The Company recognizes loss allowances for expected credit losses ("ECLs") on its financial assets measured at amortized cost. Due to the nature of its financial assets, Cenovus measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e. the difference between the cash flows due to the entity in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the related financial asset. The Company does not have any financial assets that contain a financing component.

Policy Applicable Before January 1, 2018

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 flows 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.

Classification and Measurement of Financial Liabilities

A financial liability is initially classified as measured at amortized cost or FVTPL. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. The classification of a financial liability is irrevocable.

Financial liabilities at FVTPL (other than financial liabilities designated at FVTPL) are measured at fair value with changes in fair value, along with any interest expense, recognized in net earnings. Other financial liabilities are initially measured at fair value less directly attributable transaction costs and are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in net earnings. Any gain or loss on derecognition is also recognized in net earnings.

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, it is treated as a derecognition of the original liability and the recognition of a new liability. When the terms of an existing financial liability are altered, but the changes are considered non-substantial, it is accounted for as a modification to the existing financial liability. Where a liability is substantially modified it is considered to be extinguished and a gain or loss is recognized in net earnings based on the difference between the carrying amount of the liability derecognized and the fair value of the revised liability. Where a liability is modified in a non-substantial way, the amortized cost of the liability is remeasured based on the new cash flows and a gain or loss is recorded in net earnings.

Derivatives

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. 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.

Risk management assets and liabilities are derivative financial instruments classified as measured at FVTPL 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 or 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.

U) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2019.

V) Recent Accounting Pronouncements

New Accounting Standards and Interpretations not yet Adopted

A number of new standards, amendments to accounting standards and interpretations are effective for annual periods beginning or after January 1, 2020 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2019. These standards and interpretations are not expected to have a material impact on the Company's Consolidated Financial Statements.

4. CHANGES IN ACCOUNTING POLICIES

A) Adoption of IFRS 16, "*Leases*"

Effective January 1, 2019, the Company adopted IFRS 16, "*Leases*" ("IFRS 16"). The Company has applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Therefore, the comparative information in the Company's consolidated balance sheet, consolidated statements of earnings, other comprehensive income, shareholders' equity and cash flows has not been restated.

On adoption, Management elected to use the following practical expedients permitted under the standard:

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a ROU asset if the underlying asset is of a low dollar value (less than US$5 thousand);
- The use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease;
- Account for lease and non-lease components as a single lease component for lease liabilities related to storage tanks; and
- Use the Company's previous assessment under IAS 37, "*Provisions, Contingent Liabilities and Contingent Assets*" ("IAS 37") for onerous contracts instead of reassessing the ROU assets for impairment on January 1, 2019.

The impacts of the adoption of IFRS 16 as at January 1, 2019 are as follows:

	Notes	As Reported at December 31, 2018	Adjustments	**Balance on Adoption as at January 1, 2019**
Assets				
Accounts Receivable and Accrued Revenues	iv	1,238	2	**1,240**
Property, Plant and Equipment, Net	v	28,698	(3)	**28,695**
Right-of-Use Assets, Net	ii	-	1,491	
	iii	-	(585)	
	iv	-	(16)	
	v	-	3	**893**
Other Assets	iv	64	14	**78**
Liabilities and Shareholders' Equity				
Current Portion of Lease Liabilities	i	-	(128)	**(128)**
Current Portion of Onerous Contract Provisions	iii	(50)	37	**(13)**
Non-Current Lease Liabilities	i	-	(1,363)	
	v	-	(3)	**(1,366)**
Non-Current Onerous Contract Provisions	iii	(613)	548	**(65)**
Other Liabilities	v	(158)	3	**(155)**
Total		29,179	-	**29,179**

Notes:

i) Lease Liabilities

On adoption of IFRS 16, the Company recognized lease liabilities in relation to leases which had previously been classified as operating leases under the principles of IAS 17, "*Leases*" ("IAS 17"). Under the principles of the new standard these leases have been measured at the present value of the remaining lease payments, discounted using the Company's incremental borrowing rates at January 1, 2019. Incremental borrowing rates as at January 1, 2019 range from 4.0 percent to 5.7 percent. Leases with a remaining term of less than twelve months and low-value leases were excluded. Total lease liabilities of $1.5 billion were recorded as at January 1, 2019, of which $128 million was the current portion.

ii) ROU Assets

The associated ROU assets were measured at the amount equal to the lease liability on January 1, 2019 less any amount previously recognized under IAS 37 for onerous contract provisions with no impact on retained earnings.

iii) Onerous Contract Provisions

On initial adoption, Management has applied the practical expedient to use the Company's previous assessment under IAS 37 for onerous contracts. This resulted in a reduction of $585 million to the December 31, 2018 onerous contract provisions.

iv) Sublease Contracts

On transition, the Company reassessed the classification of its sublease contracts previously classified as operating leases under IAS 17. The Company concluded certain of these subleases were finance leases under IFRS 16 and as a result a $16 million net investment in finance leases was recognized on adoption of IFRS 16, of which, the current portion was $2 million.

v) Reclassify Previously Recognized Finance Leases

Leases accounted for as finance leases under IAS 17 was reclassified to ROU assets and lease liabilities from PP&E and other liabilities, respectively.

vi) Reconciliation of Commitments to Lease Liability

The following table provides a reconciliation of the commitments as at December 31, 2018 to the Company's lease liabilities as at January 1, 2019:

	Total
Transportation and Storage	23,341
Real Estate	1,831
Capital Commitments	24
Other Long-Term Commitments	490
Commitments as at December 31, 2018	25,686
Less:	
Non-Lease Components	(1,143)
Agreements that do not Contain a Lease	(22,811)
Lease Agreements with Assets not yet Available for Use	(507)
Short-Term Leases	(8)
Add:	
Provision Previously Recognized under IAS 37	1,064
Finance Lease Liabilities under IAS 17	4
Lease Liabilities Commitments as at December 31, 2018	2,285
Impact of Discounting	(791)
Lease Liability as at January 1, 2019	**1,494**

B) Uncertain Tax Positions

Effective January 1, 2019, the Company adopted International Financial Reporting Interpretation Committee ("IFRIC") 23, *"Uncertainty over Income Tax Treatments"* using the modified approach. The interpretation provides clarity on how to account for a tax position when there is uncertainty over income tax treatments. In determining the likely resolution of the uncertain tax positions, a position may be considered separately or as a group. In addition, an assessment is required to determine the probability that the tax authority will accept the tax position taken in income tax filings. If the uncertain income tax treatment is unlikely to be accepted, the accounting tax position must reflect an appropriate level of uncertainty. An uncertain tax position may be reassessed if new information changes the original assessment. The adoption of IFRIC 23 did not have a material impact on the Consolidated Financial Statements.

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 recorded in the Company's Consolidated Financial Statements.

Joint Arrangements

The classification of a joint arrangement as either a joint operation or a joint venture requires judgment. Cenovus holds a 50 percent interest in WRB, a jointly controlled entity. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of WRB. As a result, the joint arrangement is classified as a joint operation and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

Prior to May 17, 2017, Cenovus held a 50 percent interest in FCCL, which was jointly controlled with ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") and met the definition of a joint operation under IFRS 11, *"Joint Arrangements"*. As such, Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the acquisition (see Note 9), Cenovus controls FCCL, as defined under IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10") and, accordingly, FCCL has been consolidated.

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 partnerships. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans.
- FCCL operated 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 expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's internal approval process.

Identification of Cash-Generating Units

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 interpretation. 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, crude-by-rail, railcars, storage tanks and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses and reversals.

Determining the Lease Term

In determining the lease term, Management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option. The assessment is reviewed if a significant event or a significant change in circumstances occurs which affects this assessment.

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 recorded 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.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas 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 affect the impairment test fair value less costs to sell and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands and Deep Basin segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses, and income tax rates. Recoverable amounts for the Company's refining assets and crude-by-rail terminal use assumptions such as throughput, forward commodity prices, operating expenses, transportation capacity, supply and demand conditions and income tax rates. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration 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.

Onerous Contract Provisions

A contract is considered to be onerous when the unavoidable cost of meeting the obligations of the contract exceed the economic benefits expected to be derived from the contract. Determining when to record a provision for an onerous contract requires Management judgment and the use of estimates and assumptions, including the nature, extent and timing of future cash flows and discount rates related to the contract.

Fair Value of Assets Acquired and Liabilities Assumed in a Business Combination

The fair value of assets acquired and liabilities assumed in a business combination, including contingent consideration and goodwill, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparables and discounted cash flows which rely on assumptions such as forward commodity prices, reserves and resources estimates, production costs, volatility, Canadian-U.S. foreign exchange rates and discount rates. Changes in these variables could significantly impact the carrying value of the net assets.

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 recorded 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,	2019	2018	2017
Interest Expense – Short-Term Borrowings and Long-Term Debt	**407**	516	571
Net (Discount) Premium on Redemption of Long-Term Debt (Note 23)	**(63)**	17	-
Interest Expense – Lease Liabilities (Note 24)	**82**	-	-
Unwinding of Discount on Decommissioning Liabilities (Note 27)	**58**	62	48
Other	**27**	32	26
	511	627	645

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	2019	2018	2017
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued From Canada	**(800)**	602	(665)
Other	**(27)**	47	(192)
Unrealized Foreign Exchange (Gain) Loss	**(827)**	649	(857)
Realized Foreign Exchange (Gain) Loss	**423**	205	45
	(404)	854	(812)

8. DIVESTITURES

On September 6, 2018, the Company completed the sale of Cenovus Pipestone Partnership ("CPP"), a wholly-owned subsidiary, for cash proceeds of $625 million, before closing adjustments. CPP held the Company's Pipestone and Wembley natural gas and liquids business in northwestern Alberta and included the Company's 39 percent operated working interest in the Wembley gas plant. A before-tax loss of $797 million was recorded on the sale (after-tax – $557 million).

9. ACQUISITION

FCCL and Deep Basin Acquisition

A) Summary of the Acquisition

On May 17, 2017, Cenovus acquired from ConocoPhillips a 50 percent interest in FCCL and the majority of ConocoPhillips' western Canadian conventional crude oil and natural gas assets (the "Acquisition").

B) Total Consideration

Total consideration for the Acquisition consisted of US$10.6 billion in cash and at closing, the Company issued 208 million Cenovus common shares that were accounted for at $12.40 per share, the estimated fair value for accounting purposes. At the same time, Cenovus agreed to make certain quarterly contingent payments to ConocoPhillips during the five years subsequent to May 17, 2017 if crude oil prices exceed a specific threshold (see Note 25). The following table summarizes the fair value of the considerations:

Common Shares	**2,579**
Cash	**15,005**
	17,584
Estimated Contingent Payment (Note 25)	**361**
Total Consideration	**17,945**

C) Revaluation Gain

Prior to the Acquisition, Cenovus's 50 percent interest in FCCL was jointly controlled with ConocoPhillips and met the definition of a joint operation under IFRS 11 and as such Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the Acquisition, Cenovus controls FCCL, as defined under IFRS 10 and, accordingly, FCCL has been consolidated from the date of acquisition. As required by IFRS 3, when an acquirer achieves control in stages, the previously held interest is re-measured to fair value at the acquisition date with any gain or loss recognized in net earnings. The acquisition-date fair value of the previously held interest was $12.3 billion and has been included in the measurement of the total consideration transferred.

The carrying value of the FCCL assets was $9.7 billion. As a result, Cenovus recognized a non-cash revaluation gain of $2.6 billion ($1.9 billion, after-tax) on the re-measurement to fair value of its existing interest in FCCL.

D) Goodwill

Goodwill arising from the Acquisition has been recognized as follows:

Total Purchase Consideration	**17,945**
Fair Value of Pre-Existing 50 Percent Ownership Interest in FCCL	**12,347**
Fair Value of Identifiable Net Assets	**(28,262)**
Goodwill	**2,030**

E) Transaction Costs

In 2017, the Company incurred $56 million of Acquisition-related costs, excluding common share and debt issuance costs. These costs have been included in transaction costs in the Consolidated Statements of Earnings.

F) Transitional Services

Under the purchase and sales agreement, Cenovus and ConocoPhillips agreed to certain transitional services where ConocoPhillips provided certain day-to-day services required by Cenovus for a period of approximately nine months. These transactions were in the normal course of operations and have been measured at the exchange amounts. In 2017, costs related to the transitional services of approximately $40 million were recorded in general and administrative expenses.

10. IMPAIRMENT CHARGES AND REVERSALS

A) Cash-Generating Unit Net Impairments

On a quarterly basis, the Company assesses its CGUs for indicators of impairment or when facts and circumstances suggest the carrying amount may exceed its recoverable amount. Goodwill is tested for impairment at least annually. For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates.

2019 Upstream Impairments

As indicators of impairment were noted due to a decline in forward natural gas prices since December 31, 2018, the Company tested its Deep Basin CGUs for impairment. As at December 31, 2019, there was no impairment of goodwill or the Company's CGUs.

Key Assumptions

The recoverable amounts of Cenovus's upstream CGUs were determined based on FVLCOD or an evaluation of comparable asset transactions. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs (Level 3). Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves have been evaluated as at December 31, 2019 by the Company's IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2019, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2020	2021	2022	2023	2024	Average Annual Increase Thereafter
WTI (US$/barrel) (1)	61.00	63.75	66.18	67.91	69.48	2.0%
WCS (C$/barrel) (2)	57.57	62.35	64.33	66.23	67.97	2.1%
Edmonton C5+ (C$/barrel)	76.83	79.82	82.30	84.72	86.71	2.0%
AECO (C$/Mcf) (3)(4)	2.04	2.32	2.62	2.71	2.81	2.1%

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Alberta Energy Company ("AECO") natural gas.
(4) Assumes gas heating value of one million British thermal units per thousand cubic feet.

Discount and Inflation Rates

Discounted future cash flows are determined by applying a discount rate between 10 percent and 15 percent based on the individual characteristics of the CGU, and other economic and operating factors. Inflation is estimated at two percent.

2018 Net Upstream Impairments

As at December 31, 2018, the book value of the Company's net assets was greater than its market capitalization; therefore, the Company tested its upstream CGUs for impairment. As at December 31, 2018, there was no impairment of goodwill or the Company's CGUs. However, the impairment test provided evidence that previously recognized impairment losses should be reversed.

As at December 31, 2018, the recoverable amount of the Clearwater CGU was estimated to be $761 million. Earlier in 2018 and 2017, impairment losses of $100 million and $56 million, respectively, were recorded due to a decline in forward prices. The impairment was recorded as additional DD&A in the Deep Basin segment. In the fourth quarter of 2018, the Company reversed $132 million of impairment losses, net of the DD&A that would have been recorded had no impairments been recorded. The reversal was due to improved recovery, extensions, and well performance and changes to the development plan.

There were no goodwill impairments for the twelve months ended December 31, 2018.

Key Assumptions

The recoverable amounts of Cenovus's upstream CGUs were determined based on FVLCOD or an evaluation of comparable asset transactions. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs (Level 3). Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves were evaluated as at December 31, 2018 by the IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2018, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2019	2020	2021	2022	2023	Average Annual Increase Thereafter
WTI (US$/barrel)	58.58	64.60	68.20	71.00	72.81	2.0%
WCS (C$/barrel)	51.55	59.58	65.89	68.61	70.53	2.1%
Edmonton C5+ (C$/barrel)	70.10	79.21	83.33	86.20	88.16	2.0%
AECO (C$/Mcf)	1.88	2.31	2.74	3.05	3.21	2.0%

2017 Upstream Impairments

As at December 31, 2017, the Company tested its Clearwater CGU for impairment due to a decline in forward commodity prices. As a result, an impairment loss of $56 million on the Clearwater CGU was recorded. The impairment was recorded as additional DD&A in the Deep Basin segment. As at December 31, 2017, the recoverable amount of the Clearwater CGU was estimated to be approximately $295 million, which excludes the Clearwater assets reclassified to assets held for sale.

There were no goodwill impairments for the twelve months ended December 31, 2017.

B) Asset Impairments and Write-downs

Exploration and Evaluation Assets

For the year ended December 31, 2019, $82 million of previously capitalized E&E costs were written off as thecarrying value was not considered to be recoverable and recorded as exploration expense. Write-downs of $64 million and $18 million were recorded in the Deep Basin and Oil Sands segments, respectively.

In 2018, Management completed a comprehensive review of the Deep Basin development plan considering factors such as well inventory, pace of development, infrastructure constraints, economic thresholds and limited capital spending on the assets going forward. As such, previously capitalized E&E costs of $2.1 billion were written off as exploration expense in the Elmworth, Wapiti, Kaybob, Edson and Clearwater areas within the Deep Basin segment.

In 2017, Management wrote off certain E&E assets, as their carrying values were not considered to be recoverable. As a result, $888 million of previously capitalized E&E costs were written off and recorded as exploration expense. These assets reside primarily in the Borealis CGU within the Oil Sands segment.

Property, Plant and Equipment, Net

For the year ended December 31, 2019, the Company recorded an impairment loss of $20 million mainly in the Oil Sands segment related to a natural gas property that was written down to its recoverable amount. In addition, $10 million of corporate assets primarily related to leasehold improvements were written off. These impairment losses were recorded as additional DD&A in the Oil Sands segment and Corporate and Eliminations segment.

In 2018, the Company recorded an impairment loss of $6 million in the Oil Sands segment for information technology assets that were written down to their recoverable amounts.

In 2017, the Company recorded an impairment loss of $21 million related to equipment that was written down to its recoverable amount. The impairment loss relates to the Oil Sands segment.

11. DISCONTINUED OPERATIONS

In 2017, the Company announced its intention to divest of its Conventional segment. The Conventional segment included the Company's heavy oil assets at Pelican Lake, the CO_2 enhanced oil recovery project at Weyburn and conventional crude oil, NGLs and natural gas assets in the Suffield and Palliser areas in southern Alberta. The associated assets and liabilities were reclassified as held for sale. The results of operations from the Conventional segment have been reported as a discontinued operation.

In 2017, the Company sold the majority of its Conventional segment assets for total gross cash proceeds of $3.2 billion before closing adjustments. A before-tax gain on discontinuance of $1.3 billion was recorded on the sale.

On January 5, 2018, the Company completed the sale of its Suffield crude oil and natural gas operations in southern Alberta for cash proceeds of $512 million, before closing adjustments. A before-tax gain on discontinuance of $343 million was recorded on the sale.

The following table presents the results of discontinued operations, including asset sales:

For the years ended December 31,	2018	2017
Revenues		
Gross Sales	14	1,309
Less: Royalties	3	174
	11	1,135
Expenses		
Transportation and Blending	1	167
Operating	(28)	426
Production and Mineral Taxes	1	18
(Gain) Loss on Risk Management	-	33
Operating Margin	37	491
Depreciation, Depletion and Amortization	-	192
Exploration Expense	-	2
Finance Costs	1	80
Earnings (Loss) From Discontinued Operations Before Income Tax	36	217
Current Tax Expense (Recovery)	-	24
Deferred Tax Expense (Recovery)	9	33
After-tax Earnings (Loss) From Discontinued Operations	27	160
After-tax Gain (Loss) on Discontinuance (1)	220	938
Net Earnings (Loss) From Discontinued Operations	247	1,098

(1) Net of deferred tax expense of $81 million in 2018 (2017 – $347 million).

Cash flows from discontinued operations reported in the Consolidated Statement of Cash Flows are:

For the years ended December 31,	2018	2017
Cash From Operating Activities	36	448
Cash From Investing Activities	404	2,993
Net Cash Flow	440	3,441

12. INCOME TAXES

The provision for income taxes is:

For the years ended December 31,	2019	2018	2017
Current Tax			
Canada	**14**	(128)	(217)
United States	**3**	2	(38)
Total Current Tax Expense (Recovery)	**17**	(126)	(255)
Deferred Tax Expense (Recovery)	**(814)**	(884)	203
Tax Expense (Recovery) From Continuing Operations	**(797)**	(1,010)	(52)

For the year ended December 31, 2019, a current tax expense was recorded compared with a recovery in 2018 and 2017 due to the carry back of losses to recover tax paid in previous years. The maximum recovery was reached in 2018.

In 2019, the Government of Alberta enacted a reduction in the provincial corporate tax rate from 12 percent to eight percent over four years. As a result, the Company recorded a deferred income tax recovery of $671 million for the year ended December 31, 2019. In addition, the Company has recorded a deferred income tax recovery of $387 million due to an internal restructuring of the Company's U.S. operations resulting in a step-up in the tax basis of the Company's refining assets.

In 2018, the Company recorded a deferred tax recovery related to current period losses, including the write-down of the Deep Basin E&E assets and a $78 million recovery arising from an adjustment to the tax basis of the Company's refining assets. The increase in tax basis was a result of the Company's partner recognizing a taxable gain on its interest in WRB, which due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. A deferred tax expense was recorded in 2017 due to the revaluation gain of our pre-existing interest in connection with the Acquisition, net of a reduction of the U.S. federal corporate income tax rate from 35 percent to 21 percent reducing the Company's deferred income tax liability and the impact of E&E asset write-downs.

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

For the years ended December 31,	2019	2018	2017
Earnings (Loss) From Continuing Operations Before Income Tax	**1,397**	(3,926)	2,216
Canadian Statutory Rate	**26.5%**	27.0%	27.0%
Expected Income Tax Expense (Recovery) From Continuing Operations	**370**	(1,060)	598
Effect on Taxes Resulting From:			
Foreign Tax Rate Differential	**(52)**	(57)	(17)
Non-Taxable Capital (Gains) Losses	**(38)**	89	(148)
Non-Recognition of Capital (Gains) Losses	**(39)**	87	(118)
Adjustments Arising From Prior Year Tax Filings	**4**	3	(41)
Recognition of Previously Unrecognized Capital Losses	**-**	-	(68)
Recognition of U.S. Tax Basis	**(387)**	(78)	-
Change in Statutory Rates	**(671)**	-	(275)
Non-Deductible Expenses	**-**	3	(5)
Other	**16**	3	22
Total Tax Expense (Recovery) From Continuing Operations	**(797)**	(1,010)	(52)
Effective Tax Rate	**(57.1)%**	25.7%	(2.3)%

The analysis of deferred income tax liabilities and deferred income tax assets is as follows:

For the years ended December 31,	2019	2018
Deferred Income Tax Liabilities		
Deferred Income Tax Liabilities to be Settled Within 12 Months	**3**	47
Deferred Income Tax Liabilities to be Settled After More Than 12 Months	**4,540**	5,498
	4,543	5,545
Deferred Income Tax Assets		
Deferred Income Tax Assets to be Recovered Within 12 Months	**(113)**	(57)
Deferred Income Tax Assets to be Recovered After More Than 12 Months	**(398)**	(627)
	(511)	(684)
Net Deferred Income Tax Liability	**4,032**	4,861

The deferred income tax assets and liabilities to be settled within 12 months represents Management's estimate of the timing of the reversal of temporary differences and may 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	PP&E	Timing of Partnership Items	Risk Management	Other	Total
As at December 31, 2017	6,232	164	17	2	6,415
Charged (Credited) to Earnings	(836)	(164)	27	49	(924)
Charged (Credited) to OCI	54	-	-	-	54
As at December 31, 2018	5,450	-	44	51	5,545
Charged (Credited) to Earnings	(927)	-	(43)	(7)	(977)
Charged (Credited) to OCI	(25)	-	-	-	(25)
As at December 31, 2019	**4,498**	**-**	**1**	**44**	**4,543**

Deferred Income Tax Assets	Unused Tax Losses	Timing of Partnership Items	Risk Management	Other	Total
As at December 31, 2017	(191)	-	(283)	(328)	(802)
Charged (Credited) to Earnings	(159)	-	282	8	131
Charged (Credited) to OCI	(7)	-	-	(6)	(13)
As at December 31, 2018	(357)	-	(1)	(326)	(684)
Charged (Credited) to Earnings	129	-	-	34	163
Charged (Credited) to OCI	3	-	-	7	10
As at December 31, 2019	**(225)**	**-**	**(1)**	**(285)**	**(511)**

Net Deferred Income Tax Liabilities	Total
Net Deferred Income Tax Liabilities as at December 31, 2017	5,613
Charged (Credited) to Earnings	(793)
Charged (Credited) to OCI	41
Net Deferred Income Tax Liabilities as at December 31, 2018	4,861
Charged (Credited) to Earnings	(814)
Charged (Credited) to OCI	(15)
Net Deferred Income Tax Liabilities as at December 31, 2019	**4,032**

No deferred tax liability has been recognized as at December 31, 2019 and 2018 on temporary differences associated with investments in subsidiaries and joint arrangements where the Company can control the timing of the reversal of the temporary difference and the reversal is not probable in the foreseeable future.

The approximate amounts of tax pools available, including tax losses, are:

As at December 31,	2019	2018
Canada	**6,113**	7,935
United States	**2,648**	1,391
	8,761	9,326

As at December 31, 2019, the above tax pools included $696 million (2018 – $1,375 million) of Canadian federal non-capital losses and $188 million (2018 – $nil) of U.S. federal net operating losses. These losses expire no earlier than 2033.

Also included in the December 31, 2019 tax pools are Canadian net capital losses totaling $188 million (2018 –$8 million), which are available for carry forward to reduce future capital gains. Net capital losses totaling $100 million have been recognized as a deferred income tax asset as at December 31, 2019 based on past and future capital gains. The Company has not recognized $262 million (2018 – $661 million) of net capital losses associated with unrealized foreign exchange losses on its U.S. denominated debt.

13. PER SHARE AMOUNTS

A) Net Earnings (Loss) Per Share — Basic and Diluted

For the years ended December 31,	**2019**	2018	2017
Earnings (Loss) From:			
Continuing Operations	**2,194**	(2,916)	2,268
Discontinued Operations	**-**	247	1,098
Net Earnings (Loss)	**2,194**	(2,669)	3,366
Basic – Weighted Average Number of Shares (millions)	**1,228.8**	1,228.8	1,102.5
Dilutive Effect of Cenovus NSRs	**0.6**	0.4	-
Diluted – Weighted Average Number of Shares	**1,229.4**	1,229.2	1,102.5
Basic and Diluted Earnings (Loss) Per Share From: ($)			
Continuing Operations	**1.78**	(2.37)	2.06
Discontinued Operations	**-**	0.20	0.99
Net Earnings (Loss) Per Share	**1.78**	(2.17)	3.05

As at December 31, 2019, 32 million NSRs (2018 – 34 million; 2017 – 43 million) and no TSARs (2018 – nil; 2017 – 81 thousand) were excluded from the diluted weighted average number of shares as their effect would have been anti-dilutive or their exercise prices exceed the market price of Cenovus's common shares. These instruments could potentially dilute earnings per share in the future. For further information on the Company's stock-based compensation plans, see Note 32.

B) Dividends Per Share

For the year ended December 31, 2019, the Company paid dividends of $260 million or $0.2125 per share, all of which were paid in cash (2018 – $245 million or $0.20 per share; 2017 – $225 million or $0.20 per share). The Cenovus Board of Directors declared a first quarter dividend of $0.0625 per share, payable on March 31, 2020, to common shareholders of record as of March 13, 2020.

14. CASH AND CASH EQUIVALENTS

As at December 31,	**2019**	2018
Cash	**108**	155
Short-Term Investments	**78**	626
	186	781

15. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at	**December 31, 2019**	January 1, 2019 (1)
Accruals	**1,185**	614
Prepaids and Deposits	**54**	45
Partner Advances	**16**	237
Trade	**206**	251
Joint Operations Receivables	**36**	37
Net Investment in Finance Leases	**-**	2
Other	**54**	54
	1,551	1,240

(1) See Note 4.

16. INVENTORIES

As at December 31,	2019	2018
Product		
Refining and Marketing	**874**	703
Oil Sands	**570**	223
Deep Basin	**1**	-
Parts and Supplies	**87**	87
	1,532	1,013

During the year ended December 31, 2019, approximately $14,285 million of produced and purchased inventory was recorded as an expense (2018 – $15,664 million; 2017 – $12,856 million).

As at December 31, 2019, as a result of a decline in refined product prices, Cenovus recorded a write-down of its product inventory of $25 million from cost to net realizable value (2018 – $47 million).

17. EXPLORATION AND EVALUATION ASSETS

	Total
As at December 31, 2017	3,673
Additions	374
Transfers to Assets Held for Sale	(1)
Transfers From Assets Held for Sale	46
Exploration Expense (Note 10)	(2,123)
Change in Decommissioning Liabilities	(8)
Divestitures	(1,176)
As at December 31, 2018	785
Additions	73
Exploration Expense (Note 10)	(82)
Change in Decommissioning Liabilities	9
Exchange Rate Movements and Other	2
As at December 31, 2019	**787**

18. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other (1)	Total
COST					
As at December 31, 2017	27,441	333	5,061	1,167	34,002
Additions	1,065	-	204	61	1,330
Transfers From Assets Held for Sale	469	-	-	-	469
Change in Decommissioning Liabilities	(279)	-	(3)	(3)	(285)
Exchange Rate Movements and Other	(6)	-	370	-	364
Divestitures (Note 8)	(644)	-	-	(12)	(656)
As at December 31, 2018	28,046	333	5,632	1,213	35,224
Adjustment for Change in Accounting Policy (Note 4)	-	-	(4)	-	(4)
As at January 1, 2019	28,046	333	5,628	1,213	35,220
Additions	695	-	228	193	1,116
Change in Decommissioning Liabilities	340	-	9	5	354
Exchange Rate Movements and Other	(9)	-	(288)	3	(294)
Divestitures	(40)	-	-	-	(40)
As at December 31, 2019	**29,032**	**333**	**5,577**	**1,414**	**36,356**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2017	2,104	331	1,193	778	4,406
Depreciation, Depletion and Amortization	1,874	2	217	64	2,157
Transfers From Assets Held for Sale	35	-	-	-	35
Impairment Losses (Note 10)	106	-	-	-	106
Impairment Reversals (Note 10)	(132)	-	-	-	(132)
Exchange Rate Movements and Other	(31)	-	32	-	1
Divestitures (Note 8)	(38)	-	-	(9)	(47)
As at December 31, 2018	3,918	333	1,442	833	6,526
Adjustment for Change in Accounting Policy (Note 4)	-	-	(1)	-	(1)
As at January 1, 2019	3,918	333	1,441	833	6,525
Depreciation, Depletion and Amortization	1,735	-	241	75	2,051
Impairment Losses (Note 10)	20	-	-	10	30
Exchange Rate Movements and Other	31	-	(86)	-	(55)
Divestitures	(29)	-	-	-	(29)
As at December 31, 2019	**5,675**	**333**	**1,596**	**918**	**8,522**
CARRYING VALUE					
As at December 31, 2017	25,337	2	3,868	389	29,596
As at December 31, 2018	24,128	-	4,190	380	28,698
As at January 1, 2019 (Note 4)	24,128	-	4,187	380	28,695
As at December 31, 2019	**23,357**	**-**	**3,981**	**496**	**27,834**

(1) Includes crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft.

PP&E includes the following amounts in respect of assets under construction and not subject to DD&A:

As at December 31,	**2019**	2018
Development and Production	**1,836**	1,818
Refining Equipment	**172**	181
	2,008	1,999

19. RIGHT-OF-USE ASSETS, NET

	Real Estate	Railcars & Barges	Storage Assets	Refining Equipment	Other	Total
COST						
As at January 1, 2019 (Note 4)	517	63	292	13	9	894
Additions	10	436	172	-	6	624
Terminations	-	-	(11)	-	-	(11)
Reclassifications	(8)	-	-	-	-	(8)
Re-measurement	-	(2)	18	(2)	-	14
Exchange Rate Movements and Other	(10)	(2)	(7)	(1)	(1)	(21)
As at December 31, 2019	**509**	**495**	**464**	**10**	**14**	**1,492**
ACCUMULATED DEPRECIATION						
As at January 1, 2019 (Note 4)	-	-	-	1	-	1
Depreciation	29	55	75	2	4	165
Impairment Losses	3	-	-	-	-	3
Terminations	-	-	(1)	-	-	(1)
Exchange Rate Movements and Other	-	-	(1)	-	-	(1)
As at December 31, 2019	**32**	**55**	**73**	**3**	**4**	**167**
CARRYING VALUE						
As at January 1, 2019 (Note 4)	517	63	292	12	9	893
As at December 31, 2019	**477**	**440**	**391**	**7**	**10**	**1,325**

In 2019, Cenovus recognized $17 million of lease income. Lease income is earned on operating leases related to the Company's real estate ROU assets in which Cenovus is the lessor, and from the recovery of non-lease components for operating costs and unreserved parking related to the Company's net investment in finance leases. Finance leases are included in other assets as net investment in finance leases.

20. OTHER ASSETS

As at	December 31, 2019	January 1, 2019 (1)
Intangible Assets	**101**	6
Equity Investments (Note 35)	**52**	38
Net Investment in Finance Leases	**30**	14
Long-Term Receivables	**21**	12
Prepaids	**7**	8
	211	78

(1) See Note 4.

In 2019, Cenovus entered into an agreement to assume a firm capacity shipper position in a pipeline transportation services agreement from a third party. The fee was recorded as an intangible asset at cost and will be amortized over the life of the contract of approximately 10 years.

21. GOODWILL

As at December 31, 2019 and 2018, the carrying amount of goodwill was associated with the Company's Primrose (Foster Creek) CGU and Christina Lake CGU was $1,171 million and $1,101 million, respectively.

For the purposes of impairment testing, goodwill is allocated to the CGU to which it relates. The assumptions used to test Cenovus's goodwill for impairment as at December 31, 2019 are consistent to those disclosed in Note 10.

22. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	2019	2018
Accruals	**1,100**	675
Trade	**939**	767
Interest	**49**	80
Partner Advances	**16**	237
Employee Long-Term Incentives	**60**	36
Joint Operations Payable	**2**	3
Other	**44**	35
	2,210	1,833

23. LONG-TERM DEBT AND CAPITAL STRUCTURE

As at December 31,	Notes	2019	2018
Revolving Term Debt	A	**265**	-
U.S. Dollar Denominated Unsecured Notes	B	**6,492**	9,241
Total Debt Principal		**6,757**	9,241
Debt Discounts and Transaction Costs		**(58)**	(77)
Long-Term Debt		**6,699**	9,164
Less: Current Portion		**-**	682
Long-Term Portion		**6,699**	8,482

The weighted average interest rate on outstanding debt for the year ended December 31, 2019 was 5.1 percent (2018 – 5.1 percent).

As at December 31, 2019, the Company is in compliance with all of the terms of its debt agreements.

A) Revolving Term Debt

Cenovus has in place a committed credit facility that consists of a $1.2 billion tranche and a $3.3 billion tranche. On October 23, 2019, the Company extended the maturity date of the $1.2 billion tranche from November 30, 2021 to November 30, 2022 and the maturity date of the $3.3 billion tranche from November 30, 2022 to November 30, 2023. Borrowings are available by way of Bankers' Acceptances, London Interbank Offered Rate based loans, prime rate loans or U.S. base rate loans.

B) Unsecured Notes

Unsecured notes are composed of:

	2019		2018	
As at December 31,	**US$ Principal Amount**	**Total C$ Equivalent**	US$ Principal Amount	Total C$ Equivalent
5.70% due October 15, 2019	**-**	**-**	500	682
3.00% due August 15, 2022	**500**	**650**	500	682
3.80% due September 15, 2023	**450**	**585**	450	614
4.25% due April 15, 2027	**962**	**1,249**	1,171	1,597
5.25% due June 15, 2037	**641**	**833**	700	955
6.75% due November 15, 2039	**1,400**	**1,818**	1,400	1,910
4.45% due September 15, 2042	**155**	**202**	744	1,015
5.20% due September 15, 2043	**58**	**75**	350	477
5.40% due June 15, 2047	**832**	**1,080**	959	1,309
	4,998	**6,492**	6,774	9,241

At maturity, on October 15, 2019, the Company repaid, in full the 5.70 percent unsecured notes with a remaining principal of US$500 million.

In addition, during the year ended December 31, 2019, the Company paid US$1,214 million to repurchase a portion of its unsecured notes with a principal amount of US$1,276 million. A gain on the repurchase of $63 million was recorded in finance costs.

The Company has in place a base shelf prospectus that allows the Company to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus also allows ConocoPhillips to offer for sale, should they so choose from

time to time, the common shares they acquired in connection with the Acquisition (see Note 9). The base shelf prospectus will expire in October 2021. Offerings under the base shelf prospectus are subject to market conditions. As at December 31, 2019, US$5.0 billion remains available under the base shelf prospectus.

C) Mandatory Debt Payments as at December 31, 2019

	US$ Principal Amount	Total C$ Equivalent
2020	**-**	**-**
2021	**-**	**-**
2022	**500**	**650**
2023	**450**	**585**
2024	**-**	**-**
Thereafter	**4,048**	**5,257**
	4,998	**6,492**

D) Capital Structure

Cenovus's capital structure objectives remain unchanged from previous periods. Cenovus's capital structure consists of shareholders' equity plus Net Debt. Net Debt includes the Company's short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. Cenovus conducts its business and makes decisions consistent with that of an investment grade company. The Company'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. To ensure financial resilience, Cenovus may, among other actions, adjust capital and operating spending, draw down on its credit facility or repay existing debt, adjust dividends paid to shareholders, purchase the Company's common shares for cancellation, issue new debt, or issue new shares.

Cenovus monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Net Debt to Adjusted Earnings Before Interest, Taxes and DD&A ("Adjusted EBITDA") and Net Debt to Capitalization. These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength.

Cenovus targets a Net Debt to Adjusted EBITDA ratio of less than 2.0 times over the long-term. This ratio may periodically be above the target due to factors such as persistently low commodity prices. Cenovus also manages its Net Debt to Capitalization ratio to ensure compliance with the associated covenant as defined in its committed credit facility agreement.

Net Debt to Adjusted EBITDA *(1)*

As at December 31,	**2019**	2018	2017
Current Portion of Long-Term Debt	**-**	682	-
Long-Term Debt	**6,699**	8,482	9,513
Less: Cash and Cash Equivalents	**(186)**	(781)	(610)
Net Debt	**6,513**	8,383	8,903
Net Earnings (Loss)	**2,194**	(2,669)	3,366
Add (Deduct):			
Finance Costs	**511**	628	725
Interest Income	**(12)**	(19)	(62)
Income Tax Expense (Recovery)	**(797)**	(920)	352
Depreciation, Depletion and Amortization	**2,249**	2,131	2,030
E&E Write-down	**82**	2,123	890
Unrealized (Gain) Loss on Risk Management	**149**	(1,249)	729
Foreign Exchange (Gain) Loss, Net	**(404)**	854	(812)
Revaluation (Gain)	**-**	-	(2,555)
Re-measurement of Contingent Payment	**164**	50	(138)
(Gain) Loss on Discontinuance	**-**	(301)	(1,285)
(Gain) Loss on Divestitures of Assets	**(2)**	795	1
Other (Income) Loss, Net	**(11)**	(12)	(5)
Adjusted EBITDA	**4,123**	1,411	3,236
Net Debt to Adjusted EBITDA	**1.6x**	5.9x	2.8x

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated.

Net Debt to Capitalization

As at December 31,	**2019**	2018	2017
Net Debt	**6,513**	8,383	8,903
Shareholders' Equity	**19,201**	17,468	19,981
	25,714	25,851	28,884
Net Debt to Capitalization	**25%**	32%	31%

Under the terms of Cenovus's committed credit facility, the Company is required to maintain a debt to capitalization ratio, as defined in the agreement, not to exceed 65 percent. The Company is well below this limit.

24. LEASE LIABILITIES

	Total
As at January 1, 2019 (Note 4)	1,494
Additions	590
Interest Expense (Note 6)	82
Lease Payments	(232)
Terminations	(11)
Re-measurement	15
Exchange Rate Movements and Other	(22)
As at December 31, 2019	**1,916**
Less: Current Portion	**196**
Long-Term Portion	**1,720**

The Company has lease liabilities for contracts related to office space, railcars, barges, storage assets, drilling rigs, and other refining and field equipment. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Discount rates during the year ended December 31, 2019 were between 2.7 percent and 5.7 percent, depending on the duration of the lease term.

For the years ended December 31,	**2019**
Variable Lease Payments	**19**
Short-Term Lease Payments	**13**

The Company has variable lease payments related to property taxes for real estate contracts. Short-term leases are leases with terms of twelve months or less.

The Company has included extension options in the calculation of finance lease liabilities where the Company has the right to extend a lease term at its discretion and is reasonably certain to exercise the extension option. The Company does not have any significant termination options and the residual amounts are not material.

25. CONTINGENT PAYMENT

	2019	2018
Contingent Payment, Beginning of Year	**132**	206
Re-measurement (1)	**164**	50
Liabilities Settled or Payable	**(153)**	(124)
Contingent Payment, End of Year	**143**	132
Less: Current Portion	**79**	15
Long-Term Portion	**64**	117

(1) Contingent payment is carried at fair value. Changes in fair value are recorded in net earnings.

In connection with the Acquisition, Cenovus agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52.00 per barrel during the quarter. The quarterly payment will be $6 million for each dollar that the WCS price exceeds $52.00 per barrel. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment. There are no maximum payment terms.

The contingent payment is accounted for as a financial option. The fair value is estimated by calculating the present value of the future expected cash flows using an option pricing model, which assumes the probability distribution for WCS is based on the volatility of WTI options, volatility of Canadian-U.S. foreign exchange rate options and both WTI and WCS futures pricing, and discounted at a credit-adjusted risk-free rate. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. As at December 31, 2019, $14 million was payable under this agreement (2018 – $nil).

26. ONEROUS CONTRACT PROVISIONS

	2019	2018
Onerous Contract Provisions, Beginning of Year	**663**	45
Adjustment for Change in Accounting Policy (Note 4)	**(585)**	-
As at January 1,	**78**	45
Liabilities Incurred	**-**	684
Liabilities Settled	**(13)**	(21)
Change in Assumptions	**(9)**	2
Change in Discount Rate	**4**	(57)
Unwinding of Discount on Onerous Contract Provisions	**3**	10
Onerous Contract Provisions, End of Year	**63**	663
Less: Current Portion	**17**	50
Long-Term Portion	**46**	613

In 2019, the provision for onerous contracts relates to the non-lease components of the Company's real estate contracts consisting of operating costs and unreserved parking. The provision represents the present value of the difference between the future payments that Cenovus is obligated to make under the non-cancellable contracts and the estimated sublease recoveries, discounted at a credit-adjusted risk-free rate of between 2.8 percent and 4.1 percent (2018 – 4.0 percent and 5.7 percent). The onerous contract provision is expected to be settled in periods up to and including the year 2040. The estimate may vary as a result of changes in the use of the leased office space and sublease arrangements, where applicable. In 2018, prior to the adoption of IFRS 16, the provision for onerous contracts related to base rent, operating costs and parking for office space in Calgary, Alberta.

Sensitivities

Changes to the credit-adjusted risk-free rate or the estimated sublease recoveries would have the following impact on the provision:

		2019		2018	
As at December 31,	**Sensitivity Range**	**Increase**	**Decrease**	Increase	Decrease
Credit-Adjusted Risk-Free Rate	± one percent	**(2)**	**2**	(46)	52
Estimated Sublease Recovery	± five percent	**(17)**	**17**	(40)	40

27. 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, refining facilities and the crude-by-rail terminal.

The aggregate carrying amount of the obligation is:

	2019	2018
Decommissioning Liabilities, Beginning of Year	**875**	1,029
Liabilities Incurred	**3**	8
Liabilities Settled	**(52)**	(44)
Liabilities Disposed	**(8)**	(30)
Transfers (to) From Liabilities Related to Assets Held for Sale	**-**	149
Change in Estimated Future Cash Flows	**21**	(136)
Change in Discount Rate	**339**	(165)
Unwinding of Discount on Decommissioning Liabilities (Note 6)	**58**	63
Foreign Currency Translation	**(1)**	1
Decommissioning Liabilities, End of Year	**1,235**	875

As at December 31, 2019, the undiscounted amount of estimated future cash flows required to settle the obligation is $5,173 million (2018 – $5,163 million), which has been discounted using a credit-adjusted risk-free rate of 4.9 percent (2018 – 6.5 percent) and an inflation rate of two percent (2018 – two 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. The Company expects to settle approximately $55 million to $60 million of decommissioning liabilities over the next year. Revisions in estimated future cash flows resulted from a change in the timing of decommissioning liabilities over the estimated life of the reserves and an increase in cost estimates.

Sensitivities

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

	2019		2018	
As at December 31,	**Credit-Adjusted Risk-Free Rate**	**Inflation Rate**	Credit-Adjusted Risk-Free Rate	Inflation Rate
One Percent Increase	**(236)**	**340**	(138)	196
One Percent Decrease	**332**	**(243)**	188	(145)

28. OTHER LIABILITIES

As at	**December 31, 2019**	January 1, 2019 (1)
Employee Long-Term Incentives	**103**	41
Pension and Other Post-Employment Benefit Plan (Note 29)	**73**	75
Other	**19**	39
	195	155

(1) See Note 4.

29. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension that includes either a defined contribution or defined benefit component and other post-employment benefit plan. Most of the employees participate in the defined contribution pension. Employees who meet certain criteria may elect to 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 December 31, 2017 and the next required actuarial valuation will be as at December 31, 2020.

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,	**2019**	2018	**2019**	2018
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**167**	181	**21**	22
Current Service Costs	**11**	13	**1**	1
Interest Costs (1)	**6**	6	**1**	1
Benefits Paid	**(36)**	(33)	**(2)**	(2)
Plan Participant Contributions	**2**	2	**-**	-
Past Service Costs – Curtailments	**-**	(2)	**-**	-
Re-measurements:				
(Gains) Losses From Experience Adjustments	**(4)**	-	**-**	-
(Gains) Losses From Changes in Financial Assumptions	**12**	-	**1**	(1)
Defined Benefit Obligation, End of Year	**158**	167	**22**	21
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**113**	141	**-**	-
Employer Contributions	**9**	6	**-**	-
Plan Participant Contributions	**2**	2	**-**	-
Benefits Paid	**(35)**	(33)	**-**	-
Interest Income (1)	**3**	4	**-**	-
Re-measurements:				
Return on Plan Assets (Excluding Interest Income)	**15**	(7)	**-**	-
Fair Value of Plan Assets, End of Year	**107**	113	**-**	-
Pension and OPEB (Liability) (2)	**(51)**	(54)	**(22)**	(21)

(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 16.6 years and 12.0 years, respectively.

B) Pension and OPEB Costs

	Pension Benefits			OPEB		
For the years ended December 31,	**2019**	2018	2017	**2019**	2018	2017
Defined Benefit Plan Cost						
Current Service Costs	**11**	13	14	**1**	1	2
Past Service Costs – Curtailments	**-**	(2)	(6)	**-**	-	(1)
Net Interest Costs	**3**	3	3	**1**	1	1
Re-measurements:						
Return on Plan Assets (Excluding Interest Income)	**(15)**	7	(9)	**-**	-	-
(Gains) Losses From Experience Adjustments	**(4)**	-	1	**-**	-	-
(Gains) Losses From Changes in Demographic Assumptions	**-**	-	-	**-**	-	(1)
(Gains) Losses From Changes in Financial Assumptions	**12**	-	(2)	**1**	(1)	(1)
Defined Benefit Plan Cost (Recovery)	**7**	21	1	**3**	1	-
Defined Contribution Plan Cost	**21**	22	27	**-**	-	-
Total Plan Cost	**28**	43	28	**3**	1	-

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 regularly and is re-balanced monthly, if necessary. The asset allocation structure targets an investment of 25 percent to 70 percent in equity securities, 25 percent to 35 percent in fixed income assets, zero percent to 15 percent in real estate assets, zero percent to 10 percent in listed infrastructure assets, zero percent to 10 percent in emerging market debts and zero percent to 10 percent in cash and cash equivalents.

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,	**2019**	2018
Equity Funds	**59**	70
Fixed Income Funds	**35**	29
Listed Infrastructure Funds	**9**	-
Non-Invested Assets	**2**	12
Cash and Cash Equivalents	**2**	2
	107	113

Fair value of the equity, fixed income and listed infrastructure assets 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 defined benefit plan does not hold any direct investment 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 December 31, 2017, and direction of 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, 2020 are $7 million for the defined benefit pension plan. 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,	**2019**	2018	2017	**2019**	2018	2017
Discount Rate	**3.00%**	3.50%	3.50%	**3.00%**	3.50%	3.25%
Future Salary Growth Rate	**3.94%**	3.88%	3.81%	**5.08%**	5.08%	5.08%
Average Longevity (years)	**88.2**	88.2	88.0	**88.2**	88.1	88.0
Health Care Cost Trend Rate	**N/A**	N/A	N/A	**6.00%**	6.00%	6.00%

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 is:

	2019		2018	
As at December 31,	**Increase**	**Decrease**	Increase	Decrease
One Percent Change:				
Discount Rate	**(25)**	**32**	(25)	31
Future Salary Growth Rate	**3**	**(3)**	3	(2)
Health Care Cost Trend Rate	**1**	**(1)**	1	(1)
One Year Change in Assumed Life Expectancy	**3**	**(3)**	3	(3)

The 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 recorded 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.

30. SHARE CAPITAL

A) Authorized

Cenovus is authorized to issue an unlimited number of common shares and first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common 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

	2019		2018	
As at December 31,	**Number of Common Shares** (thousands)	**Amount**	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**1,228,790**	**11,040**	1,228,790	11,040
Common Shares Issued Under Stock Option Plan (Note 32)	**38**	**-**	-	-
Outstanding, End of Year	**1,228,828**	**11,040**	1,228,790	11,040

As at December 31, 2019, ConocoPhillips continued to hold 208 million common shares. ConocoPhillips is restricted from nominating new members to Cenovus's Board of Directors and must vote its Cenovus common shares in accordance with Management's recommendations or abstain from voting until such time ConocoPhillips owns 3.5 percent or less of the then outstanding common shares of Cenovus.

There were no preferred shares outstanding as at December 31, 2019 (2018 – nil).

As at December 31, 2019, there were 26 million (2018 – 23 million) common shares available for future issuance under the stock option plan.

C) Paid in Surplus

Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana Corporation ("Encana") under the plan of arrangement into two independent energy companies, Encana (now known as Ovintiv Inc.) and Cenovus (pre-arrangement earnings). In addition, paid in surplus includes stock-based compensation expense related to the Company's NSRs discussed in Note 32A.

	Pre-Arrangement Earnings	Stock-Based Compensation	Total
As at December 31, 2017	4,086	275	4,361
Stock-Based Compensation Expense	-	6	6
As at December 31, 2018	4,086	281	4,367
Stock-Based Compensation Expense	-	10	10
As at December 31, 2019	**4,086**	**291**	**4,377**

31. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Pension Plan	Foreign Currency Translation Adjustment	Private Equity Instruments	Total
As at December 31, 2017	(4)	633	14	643
Other Comprehensive Income (Loss), Before Tax	(5)	397	1	393
Income Tax	2	-	-	2
As at December 31, 2018	(7)	1,030	15	1,038
Other Comprehensive Income (Loss), Before Tax	6	(228)	14	(208)
Income Tax	(1)	-	(2)	(3)
As at December 31, 2019	**(2)**	**802**	**27**	**827**

32. 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 value 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 expire after seven years.

Options issued by the Company on or after February 24, 2011 have associated NSRs. The NSRs, 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. Alternatively, the holder may elect to exercise the option and receive a net cash payment equal to the excess of the market price received from the sale of the common shares over the exercise price of the option.

The NSRs vest and expire under the same terms and conditions as the underlying options.

NSRs

The weighted average unit fair value of NSRs granted during the year ended December 31, 2019 was $2.93 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	**1.78%**
Expected Dividend Yield	**1.70%**
Expected Volatility (1)	**31.00%**
Expected Life (years)	**4.52**

(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:

For the year ended December 31, 2019	Number of NSRs (thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	34,484	26.29
Granted	3,867	11.57
Exercised	(164)	9.48
Forfeited	(1,450)	26.25
Expired	(5,209)	38.14
Outstanding, End of Year	**31,528**	**22.61**

	Outstanding NSRs			Exercisable NSRs	
As at December 31, 2019 **Range of Exercise Price** ($)	**Number of NSRs** (thousands)	**Weighted Average Remaining Contractual Life** (years)	**Weighted Average Exercise Price** ($)	**Number of NSRs** (thousands)	**Weighted Average Exercise Price** ($)
5.00 to 9.99	**2,903**	**5.2**	**9.48**	**756**	**9.48**
10.00 to 14.99	**7,189**	**5.5**	**12.69**	**1,785**	**14.34**
15.00 to 19.99	**2,714**	**3.3**	**19.47**	**2,714**	**19.47**
20.00 to 24.99	**3,104**	**2.2**	**22.26**	**3,104**	**22.26**
25.00 to 29.99	**8,787**	**1.1**	**28.39**	**8,787**	**28.39**
30.00 to 34.99	**6,831**	**0.3**	**32.61**	**6,831**	**32.61**
	31,528	**2.6**	**22.61**	**23,977**	**26.15**

B) Performance Share Units

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 PSUs issued prior to 2018, 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. The number of PSUs eligible for payment on and after 2018 is based on four performance periods over three years and the units granted are multiplied by 20 percent after year one, 20 percent after year two, 20 percent after year three and 40 percent after the fourth performance period through years one to 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 $53 million as at December 31, 2019 (2018 – $32 million) in the Consolidated Balance Sheets for PSUs based on the market value of Cenovus's common shares at the end of the year. As PSUs are paid out upon vesting, the intrinsic value of vested PSUs was $nil as at December 31, 2019 and 2018.

The following table summarizes the information related to the PSUs held by Cenovus employees:

For the year ended December 31, 2019	Number of PSUs (thousands)
Outstanding, Beginning of Year	6,063
Granted	2,604
Cancelled	(1,873)
Units in Lieu of Dividends	118
Outstanding, End of Year	**6,912**

C) Restricted Share Units

Cenovus has granted RSUs to certain employees under its Restricted Share Unit Plan for Employees. RSUs 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. RSUs generally vest after three years.

RSUs 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 stock-based compensation costs over the vesting period. Fluctuations in the fair value are recognized as stock-based compensation costs in the period they occur.

The Company has recorded a liability of $63 million as at December 31, 2019 (2018 – $32 million) in the Consolidated Balance Sheets for RSUs based on the market value of Cenovus's common shares at the end of the year. As RSUs are paid out upon vesting, the intrinsic value of vested RSUs was $nil as at December 31, 2019 and 2018.

The following table summarizes the information related to the RSUs held by Cenovus employees:

For the year ended December 31, 2019	Number of RSUs (thousands)
Outstanding, Beginning of Year	7,461
Granted	2,742
Vested and Paid Out	(1,568)
Cancelled	(415)
Units in Lieu of Dividends	152
Outstanding, End of Year	**8,372**

D) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and certain employees may receive DSUs, which are equivalent in value to a common share of the Company. Eligible 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 $16 million as at December 31, 2019 (2018 – $13 million) in the Consolidated Balance Sheets for DSUs based on the market value of Cenovus's common shares at the end of the year. 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:

For the year ended December 31, 2019	Number of DSUs (thousands)
Outstanding, Beginning of Year	1,360
Granted to Directors	235
Granted	106
Units in Lieu of Dividends	24
Redeemed	(488)
Outstanding, End of Year	**1,237**

E) Total Stock-Based Compensation

For the years ended December 31,	**2019**	2018	2017
NSRs	**9**	6	9
PSUs	**15**	(6)	(7)
RSUs	**34**	9	3
DSUs	**9**	-	(11)
Stock-Based Compensation Expense (Recovery)	**67**	9	(6)
Stock-Based Compensation Costs Capitalized	**20**	4	3
Total Stock-Based Compensation	**87**	13	(3)

33. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	**2019**	2018	2017
Salaries, Bonuses and Other Short-Term Employee Benefits	**567**	580	606
Post-Employment Benefits	**29**	30	27
Stock-Based Compensation Expense	**67**	9	(6)
Other Long-Term Incentive Benefits	**31**	-	-
Termination Benefits	**6**	63	19
	700	682	646

Stock-based compensation includes the costs recorded during the year associated with stock options, NSRs, PSUs, RSUs and DSUs.

34. 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,	**2019**	2018	2017
Salaries, Director Fees and Short-Term Benefits	**24**	20	26
Post-Employment Benefits	**2**	3	4
Stock-Based Compensation	**22**	5	6
Other Long-Term Incentive Benefits	**1**	-	-
Termination Benefits	**-**	9	4
	49	37	40

Post-employment benefits represent the present value of future pension benefits earned during the year.

35. FINANCIAL INSTRUMENTS

Cenovus's financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, net investment in finance leases, accounts payable and accrued liabilities, risk management assets and liabilities, private equity investments, long-term receivables, lease liabilities, contingent payment, 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 these instruments.

The fair values of long-term receivables and net investment in finance leases 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, 2019, the carrying value of Cenovus's debt was $6,699 million and the fair value was $7,610 million (2018 carrying value – $9,164 million; fair value – $8,431 million).

Equity investments classified at FVOCI comprise equity investments in private companies. The Company classifies certain private equity instruments at FVOCI as they are not held for trading and fair value changes are not reflective of the Company's operations. 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.

The following table provides a reconciliation of changes in the fair value of private equity investments classified at FVOCI:

	2019	2018
Fair Value, Beginning of Year	**38**	37
Change in Fair Value (1)	**14**	1
Fair Value, End of Year	**52**	38

(1) Changes in fair value are recorded in OCI.

B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil swaps, futures and options, as well as condensate futures and swaps, foreign exchange and interest rate swaps. Crude oil, condensate and, if entered into, 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 foreign exchange swaps are calculated using external valuation models which incorporate observable market data, including foreign exchange forward curves (Level 2) and the fair value of interest rate swaps are calculated using external valuation models which incorporate observable market data, including interest rate yield curves (Level 2).

Summary of Unrealized Risk Management Positions

	2019			2018		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Crude Oil	**5**	**2**	**3**	156	2	154
Foreign Exchange	**-**	**-**	**-**	-	1	(1)
Interest Rate	**-**	**-**	**-**	7	-	7
Total Fair Value	**5**	**2**	**3**	163	3	160

The following table presents the Company's fair value hierarchy for risk management assets and liabilities carried at fair value:

As at December 31,	**2019**	2018
Level 2 – Prices Sourced From Observable Data or Market Corroboration	**3**	160

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.

The following table provides a reconciliation of changes in the fair value of Cenovus's risk management assets and liabilities:

	2019	2018
Fair Value of Contracts, Beginning of Year	**160**	(986)
Fair Value of Contracts Realized During the Year	**7**	1,554
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year	**(156)**	(305)
Unamortized (Amortized) Premium on Put Options	**-**	(16)
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**(8)**	(87)
Fair Value of Contracts, End of Year	**3**	160

Financial assets and liabilities are offset only 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:

	2019			2018		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	**13**	**10**	**3**	277	117	160
Amount Offset	**(8)**	**(8)**	**-**	(114)	(114)	-
Net Amount per Consolidated Financial Statements	**5**	**2**	**3**	163	3	160

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. There were no amounts pledged as collateral as at December 31, 2019 (2018 – $nil).

C) Fair Value of Contingent Payment

The contingent payment is carried at fair value on the Consolidated Balance Sheets. Fair value is estimated by calculating the present value of the future expected cash flows using an option pricing model (Level 3), which assumes the probability distribution for WCS is based on the volatility of WTI options, volatility of Canadian-U.S. foreign exchange rate options and both WTI and WCS futures pricing, and discounted at a credit-adjusted risk-free rate of 2.6 percent. Fair value of the contingent payment has been calculated by Cenovus's internal valuation team which consists of individuals who are knowledgeable about and have experience in fair value techniques. As at December 31, 2019, the fair value of the contingent payment was estimated to be $143 million.

As at December 31, 2019, average WCS forward pricing for the remaining term of the contingent payment is $46.57 per barrel. The average volatility of WTI options and the Canadian-U.S. foreign exchange rate options used to value the contingent payment was 24 percent and five percent, respectively. Changes in the following inputs to the option pricing model, with fluctuations in all other variables held constant, could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

As at December 31, 2019	Sensitivity Range	Increase	Decrease
WCS Forward Prices	± $5.00 per bbl	**(129)**	**80**
WTI Option Volatility	± five percent	**(45)**	**42**
Canadian to U.S. Dollar Foreign Exchange Rate Option Volatility	± five percent	**10**	**(19)**

As at December 31, 2018	Sensitivity Range	Increase	Decrease
WCS Forward Prices	± $5.00 per bbl	(104)	71
WTI Option Volatility	± five percent	(57)	51
Canadian to U.S. Dollar Foreign Exchange Rate Option Volatility	± five percent	1	(12)

D) Earnings Impact of (Gains) Losses From Risk Management Positions

For the years ended December 31,	2019	2018	2017
Realized (Gain) Loss (1)	**7**	1,554	167
Unrealized (Gain) Loss (2)	**149**	(1,249)	729
(Gain) Loss on Risk Management From Continuing Operations	**156**	305	896

(1) Realized gains and losses on risk management are recorded in the reportable segment to which the derivative instrument relates. Excludes realized risk management loss of $nil in 2019 (2018 – $nil; 2017 – $33 million loss) that were classified as discontinued operations.

(2) Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.

36. RISK MANAGEMENT

Cenovus 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.

To manage exposure to interest rate volatility, the Company may periodically enter into interest rate swap contracts. To mitigate the Company's exposure to foreign exchange rate fluctuations, the Company periodically enters into foreign exchange contracts. There were no interest rate or foreign exchange contracts outstanding as at December 31, 2019.

In addition, the Company may periodically enter into other financial positions as a part of ongoing operations to market the Company's production. As at December 31, 2019, the fair value of other financial positions was an asset of $3 million, and consisted of WCS, WTI and condensate instruments.

A) Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of forward 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 does not allow the use of derivative instruments for speculative purposes.

Crude Oil – The Company has used fixed price and basis swaps, put options and costless collars to partially mitigate its exposure to the commodity price risk on its crude oil sales. In addition, Cenovus has entered into a number of transactions to help protect against widening light/heavy crude oil price differentials.

Condensate – The Company has used fixed price and basis swaps to partially mitigate its exposure to the commodity price risk on its condensate purchases.

Natural Gas – The Company may enter into transactions to partially mitigate its natural gas commodity price risk.

Sensitivities

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to independent fluctuations in commodity prices, with all other variables held constant. Management believes the 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 could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

As at December 31, 2019	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00 per bbl Applied to WTI and Condensate Hedges	**3**	**(3)**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**5**	**(5)**

As at December 31, 2018	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00 per bbl Applied to WTI and Condensate Hedges	(78)	80
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	4	(4)

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 dollar can have a significant effect on reported results.

As disclosed in Note 7, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada. As at December 31, 2019, Cenovus had US$4,998 million in U.S. dollar debt issued from Canada (2018 – US$6,774 million). In respect of these financial instruments, the impact of changes in the Canadian per U.S. dollar exchange rate would have resulted in a change to the foreign exchange (gain) loss as follows:

For the years ended December 31,	2019	2018
$0.05 Increase in the Canadian per U.S. Dollar Foreign Exchange Rate	**250**	339
$0.05 Decrease in the Canadian per U.S. Dollar Foreign Exchange Rate	**(250)**	(339)

As at December 31, 2019, the increase or decrease in net earnings for a $0.05 change in the U.S. per Canadian dollar foreign exchange rate on the Company's foreign exchange contracts amounts to $nil (2018 – $4 million).

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. In addition, to manage exposure to interest rate volatility, the Company periodically enters into interest rate swap contracts. In 2018, the Company unwound US$250 million of interest rate swaps, resulting in a risk management gain of $23 million. In 2019, the Company unwound the remaining US$150 million of its interest swaps, resulting in a risk management loss of $1 million. As at December 31, 2019, Cenovus had no interest rate swap contracts outstanding (2018 notional amount – US$150 million). In respect of these financial instruments, the impact of changes in the interest rate would have resulted in a change to unrealized gains (losses) impacting earnings before income tax as follows:

For the years ended December 31,	2019	2018
50 Basis Points Increase	**-**	12
50 Basis Points Decrease	**-**	(13)

As at December 31, 2019, the increase or decrease in net earnings for a one percent change in interest rates on floating rate debt amounts to $3 million (2018 – $nil; 2017 – $nil). This assumes the amount of fixed and floating debt remains unchanged from respective balance sheet dates.

D) Credit Risk

Credit risk arises from the potential that the Company may incur a financial loss if a counterparty to a financial instrument fails to meet its financial or performance obligations in accordance with agreed terms. Cenovus has in place a Credit Policy approved by the Audit Committee of the Board of Directors designed to ensure that its credit exposures are within an acceptable risk level as determined by the Company's Enterprise Risk Management Policy. The Credit Policy outlines the roles and responsibilities related to credit risk, sets a framework for how credit exposures will be measured, monitored and mitigated, and sets parameters around credit concentration limits.

Cenovus assesses the credit risk of new counterparties and continues risk-based monitoring of all counterparties on an ongoing basis. 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. Cenovus's exposure to its counterparties is within credit policy tolerances. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, and long-term receivables is the total carrying value.

As at December 31, 2019, approximately 97 percent of the Company's accruals, joint operations, trade receivables and net investment in finance leases were investment grade (2018 – 90 percent), and as at December 31, 2019 and 2018, substantially all of the Company's accounts receivable were outstanding less than 60 days. The average expected credit loss on the Company's accruals, joint operations, trade receivables and net investment in finance leases was 0.3 percent as at December 31, 2019 (2018 – 0.4 percent). As at December 31, 2019, Cenovus had one counterparty (2018 – one counterparty) whose net settlement position individually accounted for more than 10 percent of the fair value of the Company's accruals, joint operations, trade receivables and net investment in finance leases.

E) Liquidity Risk

Liquidity risk is the risk that the Company 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, which may be impacted by the Company's credit ratings. As disclosed in Note 23, over the long term, Cenovus targets a Net Debt to Adjusted EBITDA of less than 2.0 times to manage the Company's overall debt position.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facility capacity and availability under its shelf prospectus. As at December 31, 2019, Cenovus had $186 million in cash and cash equivalents, and $4.2 billion available on its committed credit facility. In addition, Cenovus has unused capacity of US$5.0 billion under a base shelf prospectus, the availability of which is dependent on market conditions.

Undiscounted cash outflows relating to financial liabilities are:

As at December 31, 2019	Less than 1 Year	Years 2 and 3	Years 4 and 5	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	**2,210**	**-**	**-**	**-**	**2,210**
Risk Management Liabilities (1)	**2**	**-**	**-**	**-**	**2**
Long-Term Debt (2)	**344**	**1,338**	**1,465**	**9,326**	**12,473**
Contingent Payment (3)	**79**	**69**	**-**	**-**	**148**
Lease Liabilities (2)	**277**	**466**	**410**	**1,544**	**2,697**

As at December 31, 2018	Less than 1 Year	Years 2 and 3	Years 4 and 5	Thereafter	Total
Accounts Payable and Accrued Liabilities	1,833	-	-	-	1,833
Risk Management Liabilities (1)	3	-	-	-	3
Long-Term Debt (2)	1,152	862	2,138	13,256	17,408
Contingent Payment (3)	15	113	15	-	143
Other (4)	-	1	1	2	4

(1) Risk management liabilities subject to master netting agreements.
(2) Principal and interest, including current portion.
(3) Refer to Note 35C for fair value assumptions.
(4) Includes finance leases under IAS 17.

37. SUPPLEMENTARY CASH FLOW INFORMATION

For the years ended December 31,	**2019**	2018	2017
Interest Paid	**511**	564	538
Interest Received	**12**	19	31
Income Taxes Paid	**17**	116	12

The following table provides a reconciliation of cash flows arising from financing activities:

	Dividends Payable	Long-Term Debt	Lease Liabilities
As at December 31, 2016	-	6,332	-
Changes From Financing Cash Flows:			
Issuance of Long-Term Debt	-	3,842	-
Net Issuance (Repayment) of Revolving Long-Term Debt	-	32	-
Issuance of Debt Under Asset Sale Bridge Facility	-	3,569	-
(Repayment) of Debt Under Asset Sale Bridge Facility	-	(3,600)	-
Dividends Paid	(225)	-	-
Non-Cash Changes:			
Dividends Declared	225	-	-
Foreign Exchange (Gain) Loss	-	(697)	-
Finance Costs	-	36	-
Other	-	(1)	-
As at December 31, 2017	-	9,513	-
Changes From Financing Cash Flows:			
(Repayment) of Long-Term Debt	-	(1,144)	-
Net Issuance (Repayment) of Revolving Long-Term Debt	-	(20)	-
Dividends Paid	(245)	-	-
Non-Cash Changes:			
Dividends Declared	245	-	-
Foreign Exchange (Gain) Loss	-	817	-
Finance Costs	-	(2)	-
As at December 31, 2018	-	9,164	-
Adjustment for Change in Accounting Policy (Note 4)	-	-	1,494
As at January 1, 2019 (Note 4)	-	9,164	1,494
Changes From Financing Cash Flows:			
Dividends Paid	(260)	-	-
Net Issuance (Repayment) of Long-Term Debt	-	(2,279)	-
Net Issuance (Repayment) of Revolving Long-Term Debt	-	276	-
Principal Repayment of Leases	-	-	(150)
Non-Cash Changes:			
Dividends Declared	260	-	-
Foreign Exchange (Gain) Loss	-	(399)	(23)
Gain on Repurchase of Debt and Amortization of Debt Issuance Costs	-	(63)	-
Lease Additions	-	-	590
Re-measurement of Lease Liabilities	-	-	15
Lease Terminations	-	-	(11)
Other	-	-	1
As at December 31, 2019	**-**	**6,699**	**1,916**

38. COMMITMENTS AND CONTINGENCIES

A) Commitments

Future payments for the Company's commitments are below. A commitment is an enforceable and legally binding agreement to make a payment in the future for the purchase of goods and services. These items exclude amounts recorded in the Consolidated Balance Sheets.

As at December 31, 2019	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Transportation and Storage (1)	**1,005**	**959**	**1,026**	**1,456**	**1,381**	**15,672**	**21,499**
Real Estate (2) (3)	**35**	**36**	**38**	**39**	**42**	**662**	**852**
Other Long-Term Commitments	**104**	**44**	**36**	**34**	**28**	**108**	**354**
Total Payments (4)	**1,144**	**1,039**	**1,100**	**1,529**	**1,451**	**16,442**	**22,705**

As at December 31, 2018	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Transportation and Storage (1)	1,040	1,104	1,335	1,491	1,562	16,809	23,341
Real Estate (2) (3)	104	73	78	74	77	1,425	1,831
Capital Commitments	21	2	1	-	-	-	24
Other Long-Term Commitments	148	81	45	37	32	147	490
Total Payments (4)	1,313	1,260	1,459	1,602	1,671	18,381	25,686

(1) Includes transportation commitments of $13 billion (2018 – $14 billion) that are subject to regulatory approval or have been approved, but are not yet in service.
(2) Relates to the non-lease components of lease liabilities consisting of operating costs and unreserved parking for office space in 2019. Includes both the lease and non-lease component of the Company's real estate contracts for 2018.
(3) Excludes committed payments for which a provision has been provided.
(4) Contracts undertaken on behalf of WRB are reflected at Cenovus's 50 percent interest.

On January 1, 2019, the Company adopted IFRS 16 which resulted in the recognition of lease liabilities related to operating leases on the balance sheet. These liabilities were previously reported as commitments. For a reconciliation of the Company's commitments as at December 31, 2018 to its lease liabilities as at January 1, 2019, see Note 4.

Transportation and storage commitments include future commitments relating to railcar and storage tank leases of $31 million and $11 million, respectively, that have not yet commenced. The railcar leases are expected to commence in 2020 with lease terms of between six years and eight years and the storage tank leases are expected to commence in 2020 with lease terms of five years.

As at December 31, 2019, there were outstanding letters of credit aggregating $364 million issued as security for performance under certain contracts (2018 – $336 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 36.

B) Contingencies

Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on its Consolidated Financial Statements.

Decommissioning Liabilities

Cenovus is responsible for the retirement of long-lived assets at the end of their useful lives. Cenovus has recorded a liability of $1,235 million, based on current legislation and estimated costs, related to its upstream 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.

Contingent Payment

In connection with the Acquisition, Cenovus agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52.00 per barrel during the quarter. As at December 31, 2019, the estimated fair value of the contingent payment was $143 million (see Note 25).

Exhibit 99.4

Cenovus Energy Inc.

Supplementary Information – Oil and Gas Activities (unaudited)

For the Year Ended December 31, 2019

(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 and 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 dollars are in millions of Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

RESERVES DATA

The SEC Modernization of Oil and Gas Reporting final rules require that proved after royalty 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 twelve-month period. This same twelve-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 disclosed are effective December 31, 2019, and were prepared by the independent, qualified reserves evaluators McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. There are significant differences between reserves evaluated under the SEC requirements and those presented in the Company's Annual Information Form filed under National Instrument 51-101 "*Standards of Disclosure for Oil and Gas Activities*" ("NI 51-101"). NI 51-101 requires disclosure of before royalties reserves and the associated values using forecasted prices and costs.

The reserves presented in this supplemental information are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the Company's control. In general, estimates of economically recoverable bitumen, crude oil, natural gas liquids 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 environmental regulations, 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 bitumen, crude oil, natural gas liquids 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. Cenovus's actual production, sales, royalty payments, taxes and development and operating expenditures with respect to its reserves may vary from current estimates and such variances may be material. Actual reserves may be greater than or less than the estimates disclosed. For a full discussion of Cenovus's material risk factors refer to "Risk Management and Risk Factors" in the Company's annual 2019 Management's Discussion and Analysis included in the annual report on Form 40-F of which this document forms a part.

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 rates. Canadian reserves, as presented on a net basis, assume royalty rates in existence at the time the estimates were made.

The reserves data contained herein is dated February 11, 2020 with an effective date of December 31, 2019.

OIL AND GAS RESERVES INFORMATION

All of Cenovus's reserves are located in Alberta and British Columbia, Canada.

Net Proved Reserves (Cenovus Share After Royalties) (1)(2)
Average Fiscal-Year Prices

	Bitumen	Crude Oil	Natural Gas Liquids	Natural Gas	Total
	(MMbbls) (3)	(MMbbls) (3)	(MMbbls) (3)	(Bcf) (3)	(MMBOE) (3)
2018					
Beginning of year	3,966	24	80	1,794	4,369
Revisions and improved recovery	155	(2)	(10)	(170)	116
Extensions and discoveries	112	6	11	175	158
Sale of reserves in place	-	(14)	(27)	(553)	(133)
Production	(118)	(2)	(8)	(187)	(160)
End of year	4,115	12	46	1,059	4,350
Developed	667	8	37	860	856
Undeveloped	3,448	4	9	199	3,494
Total	4,115	12	46	1,059	4,350
2019					
Beginning of year	**4,115**	**12**	**46**	**1,059**	**4,350**
Revisions and improved recovery	**(212)**	**-**	**1**	**3**	**(211)**
Extensions and discoveries	**14**	**2**	**2**	**32**	**22**
Purchase of reserves in place	**-**	**-**	**-**	**1**	**-**
Sale of reserves in place	**-**	**-**	**-**	**(1)**	**-**
Production	**(103)**	**(2)**	**(8)**	**(158)**	**(139)**
End of year	**3,814**	**12**	**41**	**936**	**4,022**
Developed	**764**	**8**	**32**	**761**	**930**
Undeveloped	**3,050**	**4**	**9**	**175**	**3,092**
Total	**3,814**	**12**	**41**	**936**	**4,022**

(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) "Million barrels" is abbreviated as MMbbls, "billion cubic feet" is abbreviated as Bcf, and "million barrel of oil equivalent" is abbreviated as MMBOE.

Changes to Reserves

The explanation of significant year-over-year changes in the Company's net proved reserves for the year ended December 31, 2018 and December 31, 2019 is set forth below.

Year ended December 31, 2018

The changes to the Company's net proved bitumen reserves in 2018 are explained as follows:

- *Revisions and improved recovery:* Improved performance for the Christina Lake, Foster Creek, and Narrows Lake properties, increased net proved reserves by 69 million barrels. In addition, lower bitumen prices decreased royalties payable for the Company's Christina Lake, Foster Creek and Narrows Lake properties and resulted in increased net proved reserves of 86 million barrels.
- *Extensions and discoveries:* The recognition of lower continuous net pay thickness cut-offs for the Christina Lake, Foster Creek and Narrows Lake properties increased reserves by 98 million barrels. In 2018, the Alberta Energy Regulator approved an area expansion at the Foster Creek property, increasing the Company's net proved reserves by 14 million barrels.

The changes to the Company's net proved reserves of crude oil, natural gas liquids and natural gas in 2018 are explained as follows:

- *Sale of reserves in place:* The Company sold its Suffield property and Cenovus Pipestone Partnership, reducing its net proved reserves of crude oil, natural gas liquids and natural gas by 14 million barrels, 27 million barrels and 553 billion cubic feet, respectively.
- *Revisions and improved recovery:* The year-over-year decrease in natural gas price decreased reserves of natural gas liquids and natural gas by three million barrels and 82 billion cubic feet, respectively. Technical revisions attributable to the re-allocation of Deep Basin development spend decreased net proved reserves of natural gas liquids and natural gas of seven million barrels and 88 billion cubic feet, respectively.
- *Extensions and discoveries:* Successful Deep Basin development identified net proved reserves of natural gas liquids and natural gas of 11 million barrels and 175 billion cubic feet, respectively.

Year ended December 31, 2019

The changes to the Company's net proved bitumen reserves in 2019 are explained as follows:

- *Revisions and improved recovery:* Increased bitumen prices resulted in higher royalties payable for the Company's Christina Lake and Foster Creek properties which resulted in a decrease in net proved reserves of 212 million barrels.
- *Extensions and discoveries:* Recognition of a phase expansion at Christina Lake increased the Company's net proved reserves by 14 million barrels.

The changes to the Company's net proved reserves of crude oil, natural gas liquids and natural gas in 2019 are explained as follows:

- *Extensions and discoveries:* The Marten Hills development identified two million barrels of net proved crude oil reserves. Deep Basin development identified net proved reserves of natural gas liquids and natural gas of two million barrels and 32 billion cubic feet, respectively.

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 twelve-month period and cost assumptions were applied to Cenovus's annual future production from net 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 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, natural gas liquids 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 twelve-month period before the end of the year:

	Crude Oil and Natural Gas Liquids				Natural Gas	
	WTI (1) Cushing Oklahoma	**WCS (2)**	**Edmonton MSW (3)**	**Edmonton C5+**	**Henry Hub Louisiana**	**AECO (4)**
	(US$/bbl)	(C$/bbl)	(C$/bbl)	(C$/bbl)	(US$/MMBtu)	(C$/MMBtu)
2019	**55.69**	**55.65**	**67.09**	**69.19**	**2.58**	**1.76**
2018	65.56	48.59	68.92	79.61	3.10	1.67

(1) WTI is an abbreviation for West Texas Intermediate.
(2) WCS is an abbreviation for Western Canadian Select.
(3) MSW is an abbreviation for Mixed Sweet Blend.
(4) AECO is an abbreviation for Alberta Energy Company.

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

($ millions)	**2019**	2018
Future cash inflows	**164,640**	106,744
Less future:		
Production costs	**38,880**	42,399
Development costs	**22,625**	24,895
Asset retirement obligation payments (1)	**3,524**	3,504
Income taxes (2)	**22,031**	8,040
Future net cash flows	**77,580**	27,906
Less 10 percent annual discount for estimated timing of cash flow	**50,370**	17,123
Discounted future net cash flow	**27,210**	10,783

(1) Includes future abandonment and reclamation costs associated with existing and future wells having attributed reserves, non-reserves wells and gathering systems, batteries, plants and processing facilities. The Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves ("SMOG") for 2018 has been re-presented to include abandonment and reclamation costs of $213 million on a discounted basis and $1,604 million on an undiscounted basis relating to non-reserves wells and gathering systems, batteries, plants and processing facilities.
(2) Income taxes for 2018 have been updated to reflect the change in abandonment and reclamation costs noted above.

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

($ millions)	**2019**	2018 (1)
Balance, beginning of year	**10,783**	19,372
Changes resulting from:		
Sales of oil and gas produced during the period (2)	**(3,723)**	(1,435)
Extensions, discoveries and improved recovery, net of related cost	**153**	475
Purchases of proved reserves in place	**1**	-
Sales of proved reserves in place	**(1)**	(411)
Net change in prices and production costs (2)	**24,360**	(12,993)
Revisions to quantity estimates	**(454)**	266
Accretion of discount	**1,325**	2,505
Previously estimated development costs incurred net of change in future development costs	**75**	405
Other	**(425)**	(607)
Net change in income taxes	**(4,884)**	3,206
Balance, end of year	**27,210**	10,783

(1) Updated due to the re-presentation of SMOG to include abandonment and reclamation costs associated with non-reserves wells and gathering systems, batteries, plants and processing facilities.
(2) On January 1, 2019, Cenovus adopted IFRS 16,"Leases" ("IFRS 16"), which prescribes a different accounting treatment for operating leases than U.S. Generally Accepted Accounting Principles ("US GAAP"). Under US GAAP, the amortization of a right-of-use asset and interest expense related to an operating lease are recorded by nature of the expense on the income statement (production costs). Under IFRS 16, amortization of a right-of-use asset and interest expense are classified as depreciation expense and finance costs, respectively. As a result, changes in SMOG due to the amortization of right-of-use assets and interest payments have been included by Cenovus in "Net change in prices and production costs".

OTHER FINANCIAL INFORMATION

Results of Operations

($ millions)	2019	2018
Oil and gas sales to external customers, net of royalties, transportation and blending and realized risk management	**4,683**	2,332
Intersegment sales	**417**	517
	5,100	2,849
Less:		
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	**1,434**	1,474
Depreciation, depletion and amortization	**1,862**	1,851
Exploration expense	**82**	2,123
Operating income	**1,722**	(2,599)
Income taxes	**456**	(702)
Results of operations	**1,266**	(1,897)

Capitalized Costs

($ millions)	2019	2018
Proved oil and gas properties	**29,365**	28,379
Unproved oil and gas properties (1)	**787**	785
Total capital cost	**30,152**	29,164
Accumulated depreciation, depletion and amortization	**6,008**	4,251
Net capitalized costs	**24,144**	24,913

(1) Unproved oil and gas properties include exploration and evaluation assets for which no proved reserves have been recognized.

Costs Incurred

($ millions)	2019	2018
Acquisitions		
Unproved (1)	**4**	16
Proved (2) (3)	**5**	325
Total acquisitions	**9**	341
Exploration costs	**73**	55
Development costs	**686**	1,043
Total costs incurred	**768**	1,439

(1) An unproved property is a property to which no proved or probable reserves have been specifically attributed.
(2) A proved property is a property to which proved and probable reserves have been specifically attributed.
(3) Asset retirement costs are included in the year of acquisition.

Exhibit 99.5

Certification of Chief Executive Officer
Pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934

I, Alex J. Pourbaix, 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 12, 2020

/s/ Alex J. Pourbaix

Alex J. Pourbaix
President & Chief Executive Officer
(Principal Executive Officer)

Exhibit 99.6

Certification of Chief Financial Officer
Pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934

I, Jonathan M. McKenzie, 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 12, 2020

/s/ Jonathan M. McKenzie

Jonathan M. McKenzie
Executive Vice-President & Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.7

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, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Alex J. Pourbaix, 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.

Date: February 12, 2020

By: /s/ Alex J. Pourbaix
Alex J. Pourbaix
President & Chief Executive Officer

Exhibit 99.8

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, 2019, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jonathan M. McKenzie, 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.

Date: February 12, 2020

By: /s/ Jonathan M. McKenzie
Jonathan M. McKenzie
Executive Vice-President & Chief Financial Officer

Exhibit 99.9

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in this Annual Report on Form 40-F for the year ended December 31, 2019 of Cenovus Energy Inc. of our report dated February 11, 2020, relating to the consolidated financial statements, and the effectiveness of internal control over financial reporting, which appears in the Exhibit 99.3 to this Annual Report on Form 40-F.

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. 333-202165), and Form F-10 (File No. 333-233702) of Cenovus Energy Inc. of our report dated February 11, 2020 referred to above. We also consent to reference to us under the heading “Interests of Experts”, which appears in the Annual Information Form included in Exhibit 99.1 to this Annual Report on Form 40-F, which is incorporated by reference in such Registration Statements.

/s/ PricewaterhouseCoopers LLP

Calgary, Alberta, Canada
February 12, 2020

Exhibit 99.10

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.'s oil and gas reserves data, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs, and the information derived from our report, as described or incorporated by reference in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2019 and Cenovus Energy Inc.'s registration statements on Form S-8 (File No. 333-163397), Form F-3D (File No. 333-202165) and Form F-10 (File No. 333-233702), 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/ Michael J. Verney

Michael J. Verney, P. Eng.
Executive Vice President

Calgary, Alberta
February 12, 2020

2200, Bow Valley Square 3, 255 - 5 Avenue SW, Calgary AB T2P 3G6 Tel: (403) 262-5506 Fax: (403) 233-2744 www.mcdan.com

Exhibit 99.11

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.'s oil and gas reserves data, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs, and the information derived from our report, as described or incorporated by reference in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2019 and Cenovus Energy Inc.'s registration statements on Form S-8 (File No. 333-163397), Form F-3D (File No. 333-202165) and Form F-10 (File No. 333-233702), 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.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Jodi L. Anhorn

Jodi L. Anhorn, P. Eng.
President and Chief Executive Officer

Calgary, Alberta
February 12, 2020

Exhibit 99.12

Code of Business Conduct & Ethics



cenovus ENERGY

July 24, 2019

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About Our Code

The Code of Business Conduct & Ethics ("Code") is designed to provide staff with tools and guidance needed to make good decisions on behalf of Cenovus, to help us conduct our business legally, ethically and safely while we pursue progressive and innovative approaches to developing energy resources.

Although the Code provides the basic principles needed to help staff conduct themselves appropriately, ethical situations can be challenging and the Code may not address every situation you encounter in your daily work. When in doubt, ask for guidance.

Who must follow the Code?
The Code applies to all of us - directors, officers, employees, contractors and others working on behalf of Cenovus in all locations where Cenovus conducts business. The Code is an expression of our company values, and is endorsed by the highest level of governance in our company – the Board of Directors. Cenovus directors, employees, contractors, service providers and suppliers are expected to be familiar with and uphold Cenovus's values and the expectation of the Code at all times.

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Message from Alex Pourbaix

Conducting Cenovus's business with integrity is fundamental to our success. This means that the choices we make and the things we do have impact and real consequences. Making the right choices and doing the right thing matters.

Our values lay the foundation to our business, and our Code of Business Conduct & Ethics ("Code") puts those values into practice. The Code sets out Cenovus's expectations for ethical behaviour and decision-making as well as compliance with the law, which in turn reflects and guides our culture.

It's important that every individual understands not only the requirements, but the spirit of the Code. We expect everyone who works for Cenovus or on its behalf to adhere to the guidance that the Code provides.

Our commitment to the values enshrined in the Code reflects our commitment to our shareholders – and also to our employees, our third-party stakeholders and the communities in which we operate, to do what we say we will do. By demonstrating our values and reflecting the expectations of the Code, you will inspire others to do the same. Our reputation and success requires that we are all committed to making the right decisions on Cenovus's behalf.



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OUR VALUES AND REPUTATION

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Protection from Retaliation
Integrity and Leadership
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Values

Cenovus's Code reflects the values and behaviours we expect, aligns with our strategic direction and reflects the culture we strive to achieve.

- Safety: Safety before all else
- Integrity: We are transparent, honest and treat everyone with respect
- Performance: We work as one team to make smart decisions that deliver results
- Accountability: We do what we say we will do

Compliance with the Law

This Code is not meant to outline all laws to which we must comply, nor provide an expectation that staff understand all details of laws and regulations to which Cenovus is subject. Rather, it is a resource to help staff live Cenovus's values while conducting business on its behalf. Everyone must personally commit to follow the expectations of the Code.

However, we must be aware of Cenovus's compliance obligations under applicable legal and regulatory frameworks while still upholding our commitment to our values. The Code is not a substitute for complying with Cenovus's specific standards, policies and procedures, which describe our expectations and support our values. Any individual performing work on behalf of Cenovus is expected to comply with company policies, procedures and rules as well as applicable laws, rules and regulations that apply to their role.

Reporting Violations of the Code

It's important that we feel comfortable speaking up about potential violations of all our policies, including the Code, without fear of retaliation. To report concerns, including violations of this Code, refer to the resources listed in the Resources section.

Not sure where to turn? Call the Integrity Helpline for an anonymous way to report concerns about any potential ethical issue in the workplace or at our operations. Use the online intake form or call 1-877-760-6766 (available 24/7).

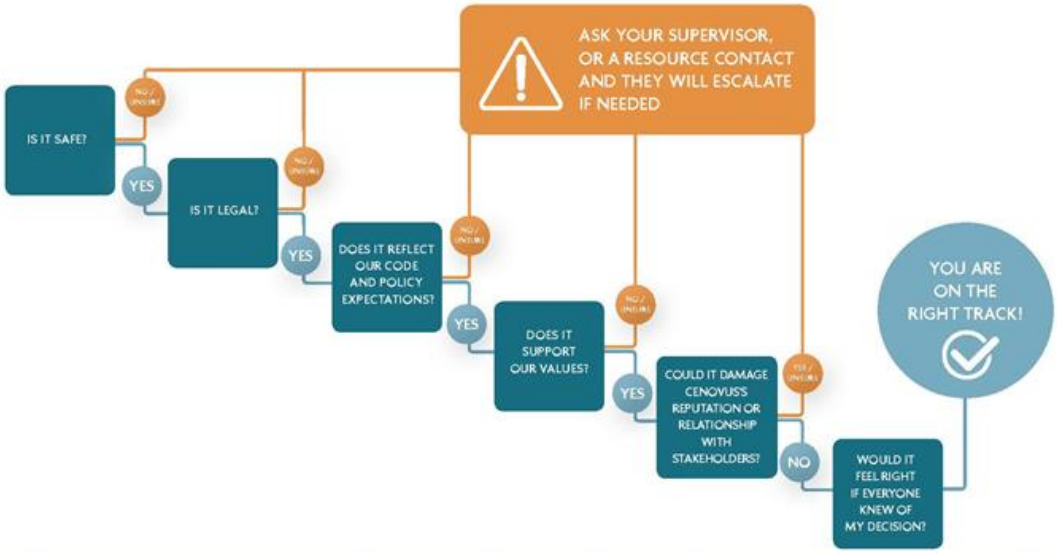
RESOURCES

If you are unsure if, how or when a law may apply, or if you're unsure how to make the right choices or do the right thing, contact your supervisor or another resource such as:

- Enterprise Compliance
- Human Resources Business Partner (HRBP)
- Investigations Committee
- Integrity Helpline
- Legal
- Privacy Officer

Making the Right Decision

Ethical decision-making may be complicated and requires good judgment, experience and expertise. Consider the following questions:



ETHICAL DECISION-MAKING

It's sometimes difficult to anticipate what, if any, impact there could be on Cenovus's reputation. When making business decisions, assume that your decision could be shared with our community and industry stakeholders through traditional or social media avenues. This is not to limit your right to engage in respectful discussions or activities about the workplace – rather, it's a reminder to be aware of your conduct while associated with Cenovus.

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Protection from Retaliation

Retaliation against individuals who ask questions, who report concerns or suspected violations of company policies, laws or regulations, or who participate in reviews or investigations of the same, will not be tolerated. We protect whistleblowers from retaliation where there's a breach of any policy, not just the Code.

No adverse or disciplinary action will be taken against individuals making a good faith report of a concern about business conduct, including cooperating with an investigation of an alleged violation, or a violation of policy or law, whether or not the report ultimately proves to be founded. Good faith does not mean that the individual reporting the concern or violation needs to be right; but it does mean that the individual believes he/she is providing truthful and accurate information.

If you think you or someone you know has been retaliated against for raising an issue, you should contact the Integrity Helpline or Investigations Committee immediately.

RETALIATION

Retaliation may present itself in different ways. It may include withholding information, prying questions, veiled threats, avoidance, excluding individuals from relevant meetings, not providing development opportunities provided to others, etc. If you're in a position of influence, be mindful of what could be perceived as intimidating words or behaviours, or where you might be causing someone to have a negative experience.

Retaliation is considered a violation of the Code and allegations will be investigated in accordance with the Investigations Standard. For more details on retaliation, see the Investigations Process.

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Integrity and Leadership

Cenovus leaders are expected to demonstrate integrity in their day-to-day actions and decision-making, and to foster a culture that encourages integrity and accountability. Staff are most likely to discuss their concerns with a trusted supervisor, and therefore leaders have a duty to model Cenovus's values by acting with integrity every day.

Leaders should provide a positive role model and reinforce Code expectations through demonstrated words and actions. One of the best ways to foster an ethical culture is to set and maintain an environment where staff feel comfortable raising concerns without fear of retaliation, by responding quickly to questions or reports of violations, and escalating issues swiftly when required.

Leaders aren't expected to solve issues on their own, but are expected to leverage the resources available to help them address concerns, as well as report observed or suspected violations.

VIRTUES OF GREAT LEADERS

- Set a great example
- Be open and approachable and respond quickly to questions and requests for guidance
- Never retaliate or punish those who speak up
- Report suspected violations
- Leverage resources for questions and support

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Safety Before All Else

Cenovus is committed to providing a healthy and safe work environment. This includes physical and psychological health and safety.

Workers have the right to know and understand the hazards and potential hazards impacting their immediate workplace or role, the right to participate in any determination impacting their own safety and the safety of others, and the right to refuse unsafe work as it relates to their health and safety.

All work should be conducted in accordance with:

- Cenovus Safety Commitments
- Cenovus Life Saving Rules
- Cenovus health and safety standards, programs and processes, and
- Applicable health and safety legislation

Cenovus works with its staff to provide the time, tools and resources they need to plan and execute work safely. Work does not commence until hazards are identified, and hazard mitigations are in place and have been communicated to individuals conducting the work.

Cenovus has established Joint Work Site Health & Safety Committees at all its work sites to bring supervisors and workers together to discuss and address health and safety-related concerns in the workplace.

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Cenovus Safety Commitments
Our eight safety commitments define the attitude and behaviours we expect from anyone who works with us and for us, and empowers workers to speak up if they see an unsafe situation or feel the work they're asked to do is unsafe.

The commitments are a promise from every leader at Cenovus to workers at all levels that we value safety above all else. Our commitment to workers and their families is that they return home safely - every day. Working at Cenovus means working safely.

Our Life Saving Rules
By following life-saving rules for high-risk work activities, workers reduce the likelihood of injuries and prevent incidents that could have life-altering or fatal outcomes.

Our ten life-saving rules help us manage the risks associated with these activities on a day-to-day basis

IF YOU SEE IT, REPORT IT!

- We require reporting of all safety hazards, potential hazards, incidents and near-misses. We take all reports seriously and will investigate to identify facts and root causes. Report in the incident reporting system, or contact the Integrity Helpline.
- Being fit for duty means, among other things, that our workers are free from the influence of drugs, alcohol, fatigue or other circumstances that may impede judgment or productivity. See the Fit for Duty Policy for more information.

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Environmental Commitment

We are committed to protecting and preserving the environment while delivering energy in a responsible way. Our goal is to continuously improve our environmental performance in order to live up to the responsibility that goes with being a developer of some of Canada's most valuable resources.

As part of this commitment, we strive to minimize impacts on the environment such as on the wildlife in our operating areas, the soil and its vegetation, air quality, and working to help ensure our operation don't affect nearby lakes or streams.

Our environmental commitments reflect our thinking by demonstrating how we consider the environment when planning and guiding our work.

ENVIRONMENTAL IMPACT

- We think about potential environmental impacts at the project planning stage. That helps Cenovus make choices that can improve our overall environmental performance. For example, avoiding wetlands while planning access to a development location minimizes our impact to both water and wildlife resources.
- Cenovus is committed to the reduction of our greenhouse gas emissions intensity. This focus is driving actions at our facilities, and limiting unnecessary flaring and venting.

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Community Engagement

Cenovus values positive outcomes for our stakeholders, including the landowners and communities in which we operate. We work to better understand our neighbours' interests in our projects so we can minimize negative impacts while also creating opportunities. Cenovus engages with local communities, including Indigenous communities, to develop long term relationships that are mutually beneficial and trusting.

To achieve this, in alignment with our values, we help provide business, employment and community investment opportunities and other benefits so that our local community partners can experience positive impacts from our operations.

COMMUNITY INVOLVEMENT

- When evaluating opportunities for local community involvement – whether contracts for work or funding educational endeavors - consider whether a local Indigenous company can provide the product or service, or could benefit from Cenovus's assistance. Consult with Cenovus's Community and Indigenous Affairs team for assistance.
- Staff are encouraged to volunteer and get involved in community-based organizations and contribute to charities of their choice. Charitable donations, however, should not be provided in such a way that they could influence public officials. See Giving Program and the Staff Fundraising Guideline for details.

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Diversity and Inclusion

At Cenovus, we embrace diversity of thought, experience and backgrounds. We believe that, through diversity and inclusion, Cenovus has the ability to solve its challenges, seize its opportunities and unlock innovative solutions.

What is diversity and inclusion?

- Diversity is the variety of people and ideas within an organization. It's all of the ways in which individuals differ – both seen and unseen attributes that make us each unique.
- Inclusion is 'diversity in action' - creating an environment of involvement, respect and connection, where various ideas, backgrounds and perspectives are harnessed to create business value. It's about creating an environment where all individuals feel valued and connected regardless of their differences.

Cenovus prohibits discrimination on any unlawful grounds. Accommodating differences may require us to make reasonable adjustments to maintain fairness. This means that in some cases, treating people equitably may include providing accommodations such as adapting facilities, services or employment conditions.

RESPECT IN THE WORKPLACE

- Always treat others with respect, in the workplace and when working with stakeholders and other third-party suppliers
- Keep an open mind to others' ideas and points of view
- Be aware of your own unconscious biases and how they may influence your behaviour
- Speak up if you have a concern

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Violence and Harassment Free Workplace

Everyone has the right to feel safe at work. Cenovus is committed to providing a safe and healthy work environment, free from violence and harassment. We do not tolerate any form of violence, harassment or bullying. Staff are expected to report all incidents of violence or harassment they experience or witness.

Harassment is any unwelcome or objectionable conduct, whether intentional or not, that negatively affects someone or creates an uncomfortable working environment. Harassment is behaviour that could be perceived as intimidating, hostile, offensive, demeaning, humiliating, embarrassing, or that is of a sexual nature. Harassment can be verbal or visual, and can include jokes, comments or images. It can take place in person, be presented visually in a work environment, or even online through inappropriate emails, texts or social media posts.

Violence includes behaviour that may cause physical or psychological harm, including physical acts, threatening behaviour, or innuendo. Violence isn't just physical (touching, hitting, poking, grabbing, etc.), but can include behaviours such as threats or displays of extreme anger.

WORKPLACE VIOLENCE & HARASSMENT PREVENTION

- Harassment may be perceived differently by different individuals. If you feel that harassment has taken place, speak up. If you feel comfortable, talk to the person - they might not realize that their comment could be perceived as offensive. If needed, report harassment to the Investigations Committee, Integrity Helpline, or talk to your supervisor or HRBP.
- Did you know that harassment and violence are considered workplace hazards, just like other health & safety hazards? To know the expectations under the law, see the Cenovus Workplace Violence & Harassment Prevention Standard and related Process.



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Responsible Information Use

Information is one of Cenovus's most valuable corporate assets. The security and protection of information is the responsibility of every Cenovus employee and contractor. We are committed to protecting Cenovus's sensitive information from improper use or disclosure.

Protecting Sensitive Information

For purposes of the Code, sensitive Cenovus information includes all non-public information, including all Cenovus internal information. If sensitive information is disclosed externally or otherwise compromised, it could be harmful to Cenovus, our staff, or its customers, suppliers and stakeholders. Sensitive information may relate to Cenovus sites, assets, projects, operations, financial or legal matters, planning and strategic activities, possible or actual acquisition & divestiture transactions, other commercial activities, personal information, new or innovative technologies and other intellectual property.

Everyone is obligated to maintain the confidentiality of Cenovus information. Protect Cenovus's information through proper controls including secure storage, passwords and codes, secure transmission and physical safeguarding of devices. Sensitive information should be destroyed securely, including deletion or shredding.

Suppliers and stakeholders regularly provide Cenovus with their sensitive information, and we must not personally benefit from that information. It's important to observe any legal or contractual limitations of using non-Cenovus confidential information and protect this information as you would Cenovus's.

ENSURE INFORMATION PROTECTION

- Thinking about forwarding a memo or email outside of Cenovus? Think again – make sure that you have been authorized, that the individual receiving is subject to a confidentiality agreement, and that the information is properly secured and labeled.
- Always be mindful who can see your on-screen content or overhear your phone conversations. Always lock your computer screen when leaving your workspace and secure your device if left unattended.
- Collaborating on a sensitive Cenovus document with an individual outside of Cenovus or using a non-Cenovus online file storage system? Protect the document through secure transmission and make sure the site or system applies similar or enhanced controls to those required by Cenovus.
- Know the classification of the information you are handling and act accordingly. Find out more on how to classify, secure and properly destroy Cenovus's information in the Information Security Classification Standard and the Records Management Standard.

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Recordkeeping

Accurate and complete records are necessary for the management of our business. They are vital for good decision-making; let us effectively conduct our activities and operations; allow us to understand and manage our rights and responsibilities in our relationships with staff, stakeholders, customers & the government; and provide evidence of our compliance to our obligations.

It's not just financial records that need to be accurate and complete - information related to our assets, activities, transactions, rights, obligations, operations, marketing, the environment, health & safety, training, human resources and other matters, must be recorded honestly, accurately and with care. See the Information Management Policy and Records Management Standard for details.

DOCUMENTING BUSINESS DATA

- Write it down! Whether you create a document, an email or a memo, business decisions must be recorded. Did someone give you verbal approval? Follow up with a confirmation with the details.
- Know the retention rules that apply to the information you keep
- Never destroy records that may be needed to respond to a pending or ongoing investigation, audit or litigation

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Privacy and Personal Information

Cenovus collects, uses, stores and discloses personal information about our employees, contractors, customers, suppliers and other third-parties, in compliance with all legal requirements.

Personal information is any information about an identifiable individual. It includes, but is not limited to, phone numbers, birthdate, address, identifying numbers (e.g. SIN number), health information or financial information. If you have access to employee personal information or personal information of others in the course of work, it is your responsibility to protect it through appropriate means.

We protect the confidentiality of personal information and only collect, store, use it and disclose it accordance with Cenovus's policies and applicable laws.

PROTECTING PERSONAL INFORMATION

- Personal information of others cannot be shared within or outside Cenovus unless you are authorized to do so by virtue of your job duties
- Personal information belongs to the person it is about. Be mindful and professional when handling personal information, for example when emailing employee data or when discussing or capturing information about others
- Our Privacy Policy and related standards and processes provide further details on our commitment to maintaining staff and stakeholder privacy

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Communicating with the Public

Cenovus regularly communicates with the public, and the purpose of those communications varies from being transparent about our vision, mission and values, to meeting our public disclosure obligations such as our quarterly financial statements. Regardless of the type of communication, information must be purposeful, contextual, appropriate to the circumstances and, where appropriate, meet legal and regulatory requirements.

Only a few designated staff have been identified to communicate on behalf of Cenovus, whether to the media, members of the investment community or members of the general public. Unless you are an authorized spokesperson, avoid communicating non-public Cenovus matters in any public environment.

Communicating with the public isn't limited to Cenovus's official communications. If your personal activities and comments outside of work could reasonably be confused with your Cenovus role or function, always make it clear which interests you are representing.

If you are contacted by the media or the public about Cenovus, or if you have been asked to present in public (such as in person, remotely, via social media, on a website or through a published article), contact Communications for approval and further details.

CENOVUS SPOKESPERSONS

- If you participate in any non-Cenovus endorsed political activity, especially if it's related to the energy industry, use your personal email and contact information
- Only certain individuals are authorized to speak on Cenovus's behalf - including on social media. If you receive an inquiry from the media, a financial analyst or another external party, even if you know them personally, you must refer them to authorized spokespersons.
- Did you know that the Policy on Disclosure & Employee Trading identifies members of Cenovus's Disclosure Committee and designates authorized spokespersons?

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Social Media

Social media is pervasive throughout our personal lives and is used by Cenovus as part of our communications strategy with our stakeholders. While we encourage staff to share their pride in where they work and in our industry online, you should avoid discussing company matters on social platforms and must never represent your views as those of Cenovus.

Your online activities and communications may reflect on Cenovus and its reputation. If you do participate in a discussion regarding Cenovus or our industry, consider identifying yourself as Cenovus staff while continuing to be clear that your views are your own, be respectful and professional, and don't disclose any Cenovus information that is not available in the public realm, including content from our intranet.

ONLINE ETIQUETTE

- Participate in Cenovus's social media presence through the approved channels. See the Social Media Standard for more information.
- Don't post messages on social media that could harm Cenovus's reputation or any of its staff.
- Don't use your Cenovus email on social media or websites when posting personal observations or when creating personal online accounts.
- Don't post or share non-public information about Cenovus, including incidents, announcements or bulletins, or images of Cenovus assets or sites. Posting anonymously or asking someone else to post on your behalf is inappropriate and contrary to the expectations of the Code.
- Making disparaging comments on social media about Cenovus is not permitted.



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Acting with Integrity

At Cenovus, acting with integrity is an important aspect of Cenovus's culture as it improves our business and reputation, supports employee performance and reduces staff misconduct.

Conflicts of Interest

Conflicts of interest, or even the appearance of a conflict of interest, can negatively affect Cenovus's business and reputation. A conflict of interest is a situation where a personal interest influences, or has the potential to influence, the ability of an individual to act in Cenovus's best interests.

Staff and directors must be aware of situations that could result in, or could be perceived to result in, a conflict of interest. Conflicts may exist when:

- The individual (or their relative, family member or close personal friend) receives, or has the potential to receive, financial or some other benefit as a result of the individual's position with Cenovus
- The individual has the opportunity to influence Cenovus's decision-making in a manner that results in, or may result in, personal gain or advantage for themselves, a relative, family member or close personal friend
- The individual has an existing or potential financial or other interest which impairs, or might appear to impair, the individual's judgment in carrying out their responsibilities to Cenovus

Staff and directors must immediately disclose conflicts of interest, update any declarations on an annual basis, and adhere to required and documented mitigation measures.

CONFLICTS OF INTEREST

- Personal or family ownership (or a stake in) another company that is a vendor or supplier to Cenovus
- Working relationships with relatives or close personal friends
- Being on the Board of Directors of a company or organization where Cenovus business could be discussed
- Spending time on outside business to the point where it interferes with our job duties

Unsure if you have a conflict? Read the Conflicts of Interest Standard and discuss it with your supervisor or Cenovus representative. Disclosure of potential conflicts creates an opportunity for transparency.

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Using and Protecting Cenovus's Assets

Employees, contractors and directors are provided company assets, including physical, digital and other company assets, to support them in conducting their job efficiently and effectively. These assets include facilities, equipment, tools, computers, mobile devices, supplies, credit cards, and other tangible resources - as well as nonphysical assets such as information, data & information systems, network environments, cloud services, staff time, corporate opportunities and company funds.

Everyone is expected to properly steward the use of Cenovus's assets through cost-effective management, including protection from theft, damage, loss or misuse.

Cenovus's assets, including the use of staff time, company meeting rooms, email or other technology tools, must never be used for personal commercial ventures.

Q&A: I have a side business selling cosmetics. Can I sell to my colleagues?

The most effective forum is through the Classifieds on INC. However, you cannot solicit business using your Cenovus email and you can't use Cenovus meeting rooms. Consider using mixed-use or public spaces for in-person connections, and make sure you aren't pressuring people to buy, especially if you're in a position of authority.

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Acceptable Use
Although Cenovus provides resources for business purposes, reasonable personal use of some assets such as computers, phones, mobile devices, copiers, printers, email and the Internet, is permitted. Employees should not have an expectation of privacy when using Cenovus's resources.

Cenovus reserves the right to monitor, inspect or search Cenovus information systems and devices, including all information and communications accessed, created, transmitted or stored using Cenovus systems, assets or information resources.

EMAIL & INTERNET

- Email and the Internet are uncontrolled environments that can transmit or disseminate information about you and the company. An email could be purposely or inadvertently forwarded, or you could expose your Cenovus IP address through a website cookie. Even if the use is acceptable, make sure all your communications are appropriate and professional, and do not reflect poorly on the company.
- Keep equipment and company information accessed on any device, safe and secure - lock your devices and follow best practices for passwords and codes
- Do not use Cenovus's corporate assets or systems in a way that could put Cenovus at risk

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Fair Dealing and Competition

Cenovus competes fairly and honestly in the markets in which it operates. We do not interfere or attempt to interfere with the normal operation of markets through any means, such as agreements that restrict competition, via collusion, manipulation, concealment, abuse of privileged information, misrepresentation of material facts, or using any other unfair-dealing or deceptive practices.

The sharing of competitively sensitive information such as prices, suppliers, or marketing or production objectives, can result in accusations of anti-competitive behaviour. Competitively sensitive information about Cenovus must be guarded carefully, and staff must avoid obtaining competitively sensitive information about our competitors, unless done legally and ethically and for approved purposes.

Staff must never misrepresent themselves or Cenovus in order to obtain competitors' sensitive information, and even if obtained in error, must not use this information.

SHARING INFORMATION

- Sharing competitively sensitive information in collaborative forums should be avoided as it could result in accusations of market manipulation or interference
- Violations of competition and anti-trust laws are serious violations of the law and the Code and in certain circumstances can lead to criminal charges against Cenovus and the individuals involved. For more information see the Competition & Antitrust Law Compliance Standard.

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Third-Party Engagement

Cenovus's relationships with its customers, suppliers, stakeholders and other third-parties is an important part of our business. When we conduct business, we behave ethically, honestly and with respect and integrity - and we work with suppliers and service providers who uphold these values.

Our suppliers and service providers enhance our competitiveness, resiliency and sustainability, but never at the expense of our values and reputation.

We purchase goods and services from qualified suppliers based on fair, objective criteria such as price, quality and service offerings. Our commercial strategies and associated agreements are driven by our need to manage our risks, achieve security of supply, and maximize value for Cenovus, while being true to our values and commitments.

Cenovus supports the principle of diversity and encourages Indigenous and local business participation in order to share the benefits created by our business presence and contribute positively to the communities in which we operate.

PUBLIC OFFICIALS

- Be aware that when dealing with public officials, including Indigenous groups, that additional rules may apply. See the Trade Compliance & Integrity Standard or contact Legal or Government Affairs.

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Securities Trading and Public Disclosure

Securities laws require timely and accurate disclosure of certain information and events, including but not limited to financial results, future business plans, acquisition or divestiture activities and changes in our operations or plans that have the potential to impact investment decisions.

For staff in possession of non-public material information or knowledge, trading in Cenovus securities may only occur after material information (such as our quarterly or annual financial results) is fully disclosed to the public and a reasonable period of time has elapsed. Employees, contractors, their relatives, friends or associates are prohibited from taking advantage of, or benefiting from, potentially material non-public information obtained at work.

BLACKOUT PERIODS

- Did you know about Cenovus's blackout periods? They start 2 weeks before financial results or budget release are disseminated and end 2 days after. For more information see the Policy on Disclosure & Employee Trading.
- If you inadvertently come into possession of non-public material information or knowledge, do not share it and consult your supervisor

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Financial Reporting and Internal Controls

Financial integrity is fundamental to our business and helps us maintain the trust and confidence we have built with shareholders, governments, suppliers, employees and other stakeholders. Cenovus is committed to providing fair, accurate, complete, timely and understandable financial disclosure in the reports we create and the documents we disclose publicly and file with regulatory authorities.

Ensuring accurate and complete financial records is everyone's responsibility, not just the role of accounting and finance staff. Accurate recordkeeping and reporting reflects on our reputation and credibility, ensures we meet our legal and regulatory obligations and is critical for making strategic decisions.

- We ensure financial documents and records are prepared in compliance with legal and regulatory requirements and in accordance with generally accepted accounting principles
- We adhere to spending limits, deadlines, documented approval and decision rights and process requirements
- We record financial transactions in a timely, complete and accurate manner
- We never knowingly falsify records, accrue to meet budget, or distort the nature of a transaction Staff responsible for preparing or providing information for Cenovus's public disclosures must do so honestly, accurately and in compliance with Cenovus disclosure controls and procedures.

Subject to legal considerations, staff are expected to cooperate with all requests for financial information from government or regulatory agencies and cooperate fully with government and compliance audits or investigations. If you learn of a pending investigation or audit, contact Legal.

Upon request, staff must make relevant information fully available to Cenovus auditors, the Board of Directors or the Audit Committee of the Board of Directors.

DID YOU KNOW

- Staff and directors should submit any good faith questions and concerns regarding questionable accounting, auditing or disclosure matters or controls. See the Resources section for contacts.
- **Q&A:** Year-end is approaching, and I received an invoice for work performed in December. If I submit the invoice in December I will not meet budget which is a measure of my performance. Can I defer the recording of the invoice until January?

  No, we do not delay or accelerate the recording of revenue or expenses to meet budgetary goals.

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Fraud and Other Irregularities

Fraud is any act that results in an actual benefit, or an attempt to gain a benefit, through deceit, dishonesty, concealment or violation of trust. It includes any misuse, or attempt to misuse, your role in the company or of a company asset, for personal gain or purposes unrelated to company business. This can include theft, misappropriation of funds, supplies, resources, time, equipment or other assets, or a misstatement of information or records for gain or benefit.

Employees, contractors, suppliers, service providers and directors must not, under any circumstances, falsify information including expenditures or worktime, misappropriate funds, misuse property, information or other Cenovus assets for personal benefit, or knowingly assist other individuals to do so.

FRAUD PREVENTION

Examples of fraud include:

- Billing for non-existent work or equipment
- Inappropriate or unapproved standby charges
- Falsely claiming mileage, time or expenses
- Theft of materials
- Destruction, removal or inappropriate use of company assets
- Hiding or falsifying relationships to gain a benefit (financial or otherwise)

Suspected incidents of fraud or theft should be immediately reported to the Integrity Helpline or the Investigations Committee.

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Bribery, Corruption and Sanctions

Fostering positive business relationships is important to Cenovus's success, but we must be mindful of the legal and ethical boundaries of what's appropriate with respect to where, what and who we do business with. We do not tolerate soliciting, accepting or paying bribes, kickbacks or other illicit or improper payments for any purpose, particularly when public officials are involved. We also do not do business with individuals or entities or within jurisdictions or acquire products or services that are prohibited under sanction or embargo laws.

DID YOU KNOW?

- Public officials are more than elected officials and government employees - they also include staff of regulatory boards or commissions, and may also include Indigenous groups. Need more information?

  See the Trade Compliance & Integrity Standard or contact Legal for more information.

Gifts

When receiving or offering gifts, entertainment or other personal benefits, staff must be aware of the line between ethical and unethical giving and acceptance of gifts where we may be influenced, or appear to be influenced, due to the value of a gift. See the Gift Guideline.

GIFTS & FAVOURS

- Cenovus is committed to supporting the communities in which we operate. However, gifts or favours must not be given to public officials or community leaders directly in exchange for support of a Cenovus permit, approval, business or other initiatives.

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Political and Lobbying Activities

Cenovus engages in political and lobbying activities that are legal and transparent, and in compliance with lobbying and election laws and reporting requirements. The company respects the political process and does not make financial contributions or contributions in kind (e.g. properties, materials or services) to political parties, committees or their representatives.

Lobbying is an important part of our business and ensures that public officials are given the information necessary to make balanced decisions. It's important that Government Affairs is made aware of any communication staff have, in their business capacity, or plan to have with public officials so they can determine whether or not lobbying is taking place.

POLITICAL ACTIVITIES

- Cenovus allows employees, contractors and directors to be individually involved in political activities, as long as they undertake these activities on their own behalf, on their own time, not using any company resources (including email) and that contributions made to a political party or candidate are not reimbursed by Cenovus. If in doubt, contact Government Affairs or Legal for requirements.
- Never make political or charitable donations on Cenovus's behalf outside of our donation process



COMPLIANCE

Waivers and Amendments

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Cenovus reviews all ethical, legal or safety issues and protects the confidentiality of those involved to the extent possible.

Violations of the Code may result in disciplinary action up to and including termination of employment or service contract. Where a related Cenovus policy or standard exists and provides further details or definition, this Code and the policy or standard shall be interpreted together, and the highest standard shall prevail.

In cases where local or international law is violated, Cenovus may have a responsibility to involve appropriate legal or regulatory agencies.

Waivers and Amendments

Waivers of the Code for employees or contractors may be granted 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 the Code will be publicly disclosed to the extent required by law, rule, regulation or stock exchange requirement.

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Speak Up

To report a concern or suspected violation, talk to you supervisor, or leverage one of the Resources listed below.

To suggest improvements to our compliance & ethics program and activities, please contact Enterprise.Compliance@Cenovus.com.

Resources

If you are unsure if, how or when a law may apply, or if you're unsure how to make the right choices or do the right thing, contact your supervisor or another resource such as:

- Enterprise Compliance
- Human Resources Business Partner (HRBP)
- Investigations Committee
- Integrity Helpline
- Legal
- Privacy Officer

Resources will engage the right Cenovus experts to answer your question or to address your concern.

Cenovus's Integrity Helpline is operated by a third-party company and provides an anonymous and confidential option for staff and stakeholders to submit any concerns or questions they have about potential ethical, policy or workplace behaviour issues. The Integrity Helpline is available 24/7 and is a resource for staff and stakeholders who prefer not to use other channels, or who feel their concern raised through other channels was not properly addressed.

Concerns that are made anonymously or confidentially will be protected to the extent possible. Information will be shared with a very limited number of individuals, and only when necessary to review and investigate the issues raised.

In emergency situations or where someone's physical safety or security may be threatened, Enterprise Security or site-security should be contacted immediately.

If in doubt, err on the side of caution and raise your concern - we treat all reports seriously - and will review issues and incidents to the fullest extent possible.

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