cenovus ENERGY

# 2016 ANNUAL REPORT

Rising to the challenge

**Reducing our cost structure** – Our staff have worked diligently to reduce our cost structure over the past two years. We reduced our oil sands per unit operating costs by 12 percent in 2016, achieving a 34 percent reduction since 2014. Our overall per unit conventional operating costs have come down by nine percent from 2015 levels. And, our per unit oil sands sustaining capital in 2016 was down 33 percent from 2015 levels and 50 percent from 2014 by changing the way we work, eliminating duplication and implementing efficiencies across our operations. Lowering our cost structure remains a focus for Cenovus in 2017.

**Implementing a new well pad design** – In 2016, we began field implementation of a new design for our oil sands well pads that is expected to reduce the well pad footprint and result in cost savings of 35 to 50 percent when compared to how we've traditionally built well pads. The new well pads, like the one under construction at Christina Lake in the picture above, have a streamlined design, use less equipment and eliminate the buildings that cover the well pair modules. Innovations like this help us improve our cost structure, our construction cycle times and our environmental performance.

## ON THE COVER

At Cenovus, we don't mine the oil sands. We use a drilling method at our oil sands projects called steam-assisted gravity drainage (SAGD) to get the oil out of the ground. Since the oil in the oil sands can at times be as hard as a hockey puck and embedded in tonnes of sand, it needs to be liquefied so it comes away from the sand, all while it's deep below the surface. We use steam to do that. To create the steam, we use steam generators, like the ones at our Christina Lake facility pictured on the cover. The generators use natural gas to heat water that's too salty to drink or for use in agriculture. The steam is injected deep underground to help liquefy the thick oil so it can be pumped to the surface. Once the oil and water from the steam have been pumped to the surface, we separate them. The water gets used over and over again to make new steam and the oil gets sent to refineries.

**Restarting oil sands expansion** – Our 2017 budget includes capital to resume construction of the phase G expansion at our Christina Lake oil sands project pictured above. The expansion was deferred in late 2014 due to declining oil prices. Since deferring phase G, Cenovus has optimized the design, reworked the construction plan and rebid contracts, reducing project costs by more than $500 million. Phase G has a design capacity of 50,000 barrels per day gross. First oil from the expansion is expected in the second half of 2019. We also have plans to progress engineering work on deferred projects at Foster Creek and Narrows Lake.

**Investing in conventional oil** – A significant amount of work was done in 2016 to evaluate our large inventory of attractive conventional oil drilling opportunities on the Palliser Block in southern Alberta. In 2017, we intend to invest in these opportunities for the purpose of generating short-cycle cash flow to support the continued growth of our oil sands assets, which is consistent with our long-standing conventional strategy.

# TABLE OF CONTENTS



For additional information about the forward-looking statements, non-GAAP measures, and reserves and resources estimates contained in this annual report, see the Advisory on page 7 and the Advisory on page 98.

MESSAGE FROM OUR

# PRESIDENT & CHIEF EXECUTIVE OFFICER

As I reflect on the business environment we've faced over the past two years, I am extremely proud of the way our staff have risen to the challenge.

In 2016 we saw continued uncertainty in the macro business environment, particularly in the first three months of the year when oil prices fell below $30 a barrel. We once again took a number of decisive actions to help maintain our financial resilience. We reduced our capital, operating, and general and administrative (G&A) budgets; we made the difficult but necessary decision to further reduce our workforce; we cut or adjusted a number of employee programs; and we further reduced our dividend. While we saw some recovery in the price of oil over the last nine months of the year, we did not waver from our plan to preserve our financial resilience.

I am confident that the deliberate actions we have taken over the past 24 months have made us a stronger, more resilient company. We are well-positioned for what we anticipate will be another year of market and commodity price volatility, and are focused on delivering disciplined growth and value creation for you, our shareholders.

## LOOKING BACK ON 2016

Overall, 2016 was a year of significant accomplishment for Cenovus and I am pleased that we were once again able to deliver on the things within our control – production and costs. We brought on two oil sands expansion phases, increasing our oil sands production capacity and providing clear line of sight to the next two years of oil sands production growth. And, the progress we've made in lowering our cost structure will allow us to take advantage of the deflationary environment and resume investment in our top tier assets.

### Delivered strong operational performance

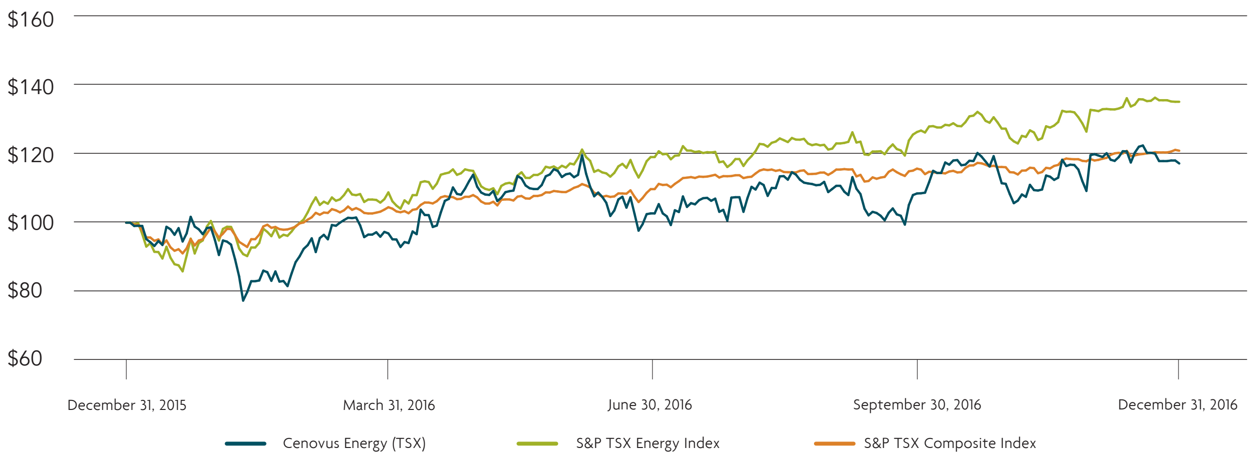
In 2016, we delivered strong, reliable operational performance across all areas of our business.

In the oil sands, we grew production by seven percent, due to a focus on operational improvements and Foster Creek phase G and Christina Lake phase F coming on stream in the second half of the year. I am pleased to report that the ramp up of both phases is proceeding well. At Foster Creek, the process improvements we put in place over the last few years have increased operating efficiency and reliability at the project, which allowed us to deliver on our 2016 plan. Christina Lake also had exceptionally strong performance and we successfully started up our largest expansion phase to date. Additionally, we successfully commissioned a natural gas fired 100 megawatt cogeneration plant at Christina Lake. The electricity generated at Christina Lake supplies power to the project with any surplus being sold to the Alberta grid.

In the conventional side of our business, our oil and natural gas production volumes continued to be a key free funds flow contributor to the company. And in refining, our Wood River Refinery in Illinois and Borger Refinery in Texas, which we jointly own with the operator, Phillips 66, continued to deliver strong operating performance. These refineries are important components of our integrated strategy because they allow us to capture the full value chain for our products and provide resilience through market fluctuations.

It was also a solid year for workplace safety. We had strong process safety performance, and on the personal safety side, had our best safety record from a recordable injury perspective through the summer months. Although we had some safety incidents over the fall and winter, no one was seriously hurt.

## 2016 TOTAL SHAREHOLDER RETURN




This chart shows cumulative total shareholder return for $100 invested (assuming quarterly reinvestment of dividends), over the period December 31, 2015 to December 31, 2016. Cenovus's total shareholder return for 2016 was 17 percent. We finished the year in line with the S&P TSX Composite Index, which was up by 21 percent for the same period, but underperformed the S&P TSX Energy Index, which was up by 35 percent.

Workplace safety is and will always be a top priority at Cenovus. We remain committed to the health and safety of our staff, and to continually improving our safety performance.

### Achieved a lower cost structure

We have done a tremendous amount of work to reduce our cost structure over the past two years. In 2016, we lowered our operating costs further and made significant progress in reducing our sustaining capital.

Our 2016 oil sands per unit operating costs were 12 percent below 2015 levels. Our overall per unit conventional operating costs were reduced by nine percent from 2015 levels, despite lower production.

Our per unit oil sands sustaining capital in 2016 was down 33 percent from 2015 levels and 50 percent from 2014 by changing the way we work, eliminating duplication and implementing efficiencies across our operations. While we've already made great strides, we believe we can further improve the efficiency of our operations and further reduce our costs. For example, we will be looking at additional improvements to our drilling and completion times, well pad designs and well conformance, and the use of wider well spacing and longer horizontal well lengths at our oil sands operations.

## LOOKING AHEAD – 2017 AND BEYOND

I am optimistic about what's ahead for Cenovus. While we've seen some recovery in oil prices, we cannot rely on price alone to drive value for us. We've set the bar high for ourselves and will look for ways to demonstrate cost leadership in everything we do, to increase our margins, and to excel at operating performance. We are now well-positioned to create value and grow at a mid-cycle West Texas Intermediate oil price of US$55 per barrel, and to remain resilient when prices are lower.

As I mentioned earlier, we have been very successful in reducing the amount of capital we need to sustain our base business and expand our projects, and we continue to have one of the strongest balance sheets in the industry. This performance puts us in a position to reactivate growth in a disciplined manner – to invest in new projects that have the greatest potential to drive shareholder value in the near-to-medium term.

In 2017, we are resuming construction of phase G of our Christina Lake oil sands project and plan to progress engineering work on deferred projects at Foster Creek and Narrows Lake. We are investing in a targeted tight oil drilling program in the Palliser Block in southern Alberta. And we have the financial strength to reinvest in Foster Creek phase H and Narrows Lake phase A once we're confident we've defined the appropriate development plans. These projects have the potential to provide five years of growth and take our oil sands production to more than half a million barrels per day gross.

We will continue to proactively manage our portfolio of market access commitments and opportunities to achieve our goal of reaching a broader customer base to secure the highest sale price for our oil. We are encouraged by the federal government's recent conditional approval of Kinder Morgan's Trans Mountain and Enbridge's Line 3 expansion projects, and by the renewed optimism around TransCanada's Keystone XL pipeline. While these are positive steps, market access constraints will increase unless more proposed projects are approved and built – many of which have faced opposition because of concerns around potential environmental impacts.

We take our stewardship of the environment very seriously. As an oil producer, we're committed to doing our part and working with peers, other industries, academics, entrepreneurs and governments to address climate change. We see a role for us in advancing technology with the potential to significantly reduce or capture greenhouse gas (GHG) emissions from the well to end use and in catalyzing others to take on this challenge.

Addressing environmental concerns is an ambitious but vitally important undertaking, and it's why we're a member of Canada's Oil Sands Innovation Alliance (COSIA). It's also why we co-founded Evok Innovations with Suncor Energy and the BC Cleantech CEO Alliance. Evok is an entrepreneur-run cleantech fund that accelerates the development and commercialization of solutions to the most pressing environmental and economic challenges facing the oil and gas sector today.

A lower carbon future is inevitable. So, too, are policies that will increasingly focus on reduced emissions. Cenovus is preparing for that future – a future where we must compete on both a cost and carbon basis with other global sources of energy. Since 2004, we've reduced our carbon emissions per barrel by about one-third. Further to that, we've set an upstream operations GHG emissions intensity reduction target of another one-third, from our January 2016 levels, by the end of 2026.

Last April, we welcomed Kieron McFadyen to our Leadership Team as Executive Vice-President and President of our upstream operations. I'd like to thank him, and the other members of the Leadership Team, for their guidance and expertise over the last year. We also welcomed Richard Marcogliese, Claude Mongeau and Rhonda Zygocki as new members to our Board of Directors.

Michael Grandin, who has been our Board Chair since our inception, will be retiring at the conclusion of our Annual General Meeting on April 26. At that time, longstanding Board member Patrick Daniel will take over as Board Chair. Patrick knows our company well and has a wealth of business experience, and I look forward to working with him in his new capacity. Additionally, Valerie Nielsen who has served as a Director on the Board since Cenovus's inception in 2009 will also be stepping down.

I'd like to extend my sincere thanks to Valerie for her dedicated service to our company, and a special thank you to Michael for his steadfast guidance over the years. Michael has positioned the Board and the company well as we continue our journey, and I wish him an equally rewarding retirement.

I would also like to thank our staff for their great work in 2016. Collectively, we remain focused on financial resilience and capital discipline, investing in disciplined growth, continuing to be a cost leader, and on developing new ways and technologies to improve our performance.

We have proven that we are a company that can rise to challenges and I'm confident that we are prepared to do exactly that in 2017.

/s/ Brian C. Ferguson

***BRIAN C. FERGUSON***

President & Chief Executive Officer

MESSAGE FROM OUR

# BOARD CHAIR

As 2017 begins, the essential requirements for growth appear to be in place. Oil price has almost doubled from its 2016 low; unit operating costs are down roughly 30 percent from 2014 levels; capital costs, for projects of similar scope, are down approximately 50 percent from 2014 levels; the company has significant cash and debt capacity on hand for reinvestment; essential core staff have been retained; the need for renewed growth is clear; and avenues for expansion are opening up. Now, as the company begins to embark on the next stage of its life, is a good time to review the state of governance at Cenovus.

Cenovus was spun off from Encana in 2009. For reasons of stability, its initial Board comprised a subset of former Encana directors and, for strategic continuity, no significant changes were made to Board composition for the first years of operation. Continuing this policy would have meant that by now the majority of directors would be at or over the age of 70. In 2014 we initiated a Board renewal program to ensure that your Board would have the necessary balance of skills, age and gender to best satisfy its ongoing role and responsibilities.

At the conclusion of this year's Annual General Meeting we will have completed that program. Half the Board members will be at or under the age of 65, of which two will be women. The Board will enjoy the benefit of CEO-level experience in: resource extraction; marketing and transportation; refining; accounting; and capital markets. It will be able to draw on CEO- or executive-level experience in all ancillary areas of public company activities. I will be retiring at the conclusion of this year's Annual General Meeting and Patrick Daniel, a seasoned Board member and former CEO, will take over as Chair. I encourage you to read the Directors' bios that are included in this year's proxy to learn more about the Board's composition and collective expertise.

Your Board will have the necessary and sufficient breadth of expertise to question, challenge and provide feedback to management on both design and execution of strategy. It will be well equipped to monitor: the operating performance of Cenovus; its financial health; and its risk management program. It will be able to adequately assess the company's social capital and ensure accountability to all stakeholders. And it will certainly have the capability to approve compensation for senior management and manage CEO succession. I suggest that all elements of good governance are in place and the state of governance at Cenovus is sound.

I began by positing that essential ingredients for growth are in place along with the premise that the need for growth is clear. Growth is necessary to attract, motivate and retain top talent. It is necessary to produce adequate returns on your investment and essential for the full potential value of the company to be realized. Shareholders can be assured that plans for renewed growth are being developed and implemented under sound oversight.

Respectfully submitted on behalf of the Board,

/s/ Michael A. Grandin

*MICHAEL A. GRANDIN*
Board Chair

OUR

# LEADERSHIP TEAM

Our Leadership Team guides our plans, prioritizes our initiatives and leads by example. Underpinning their strong leadership is a tremendous depth of talent and knowledge that will enable us to execute on our business plan and continue to increase value for our shareholders. In April 2016, we welcomed Kieron McFadyen to our Leadership Team as Executive Vice-President & President, Upstream Oil & Gas.

From left to right:

**Al Reid** Executive Vice-President, Environment, Corporate Affairs, Legal & General Counsel

**Jacqui McGillivray** Executive Vice-President, Safety & Organization Effectiveness

**Kieron McFadyen** Executive Vice-President & President, Upstream Oil & Gas

**Brian Ferguson** President & Chief Executive Officer

**Robert Pease** Executive Vice-President, Corporate Strategy & President, Downstream

**Drew Zieglgansberger** Executive Vice-President, Oil Sands Manufacturing

**Judy Fairburn** Executive Vice-President, Business Innovation

**Ivor Ruste** Executive Vice-President & Chief Financial Officer

**Harbir Chhina** Executive Vice-President, Oil Sands Development

# MANAGEMENT'S DISCUSSION AND ANALYSIS FOR THE YEAR ENDED DECEMBER 31, 2016



This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", or "Cenovus", mean Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated February 15, 2017, should be read in conjunction with our December 31, 2016 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 15, 2017, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. 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 15, 2017. 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, 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, 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.

**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 (previously labelled Cash Flow), Operating Earnings, Free Funds Flow (previously labelled Free Cash Flow), Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. We previously identified Operating Cash Flow, now relabelled Operating Margin, as a non-GAAP measure; however, Operating Margin is an additional subtotal found in Note 1 of our Consolidated Financial Statements, and therefore we no longer identify it as a non-GAAP measure.

The relabelling of Operating Cash Flow to Operating Margin and Cash Flow to Adjusted Funds Flow was based on recently published regulatory guidance. The definition and reconciliation, if applicable, of each non-GAAP measure or additional subtotal is presented in the Financial Results, Operating Results, Liquidity and Capital Resources sections of this MD&A, or the Advisory on page 98.

## OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On December 31, 2016, we had a market capitalization of approximately $17 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada. We conduct marketing activities and have refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "crude oil") production in 2016 was approximately 205,860 barrels per day and our average natural gas production was 394 MMcf per day. The refining operations processed an average of 444,000 gross barrels per day of crude oil feedstock into an average of 471,000 gross barrels per day of refined products.

### Our Strategy

Our strategy is to focus on generating total shareholder return as a low cost energy producer in North America through our strategic differentiators: premium asset quality, disciplined manufacturing, value-added integration, focused innovation, and trusted reputation.

#### *Premium Quality Assets*

We have a portfolio of premium-quality oil sands, conventional, and refining and marketing assets. We plan to add value by investing in prudent and focused growth at our producing oil sands projects, notably Foster Creek and Christina Lake, while focusing our innovation efforts to achieve step-change reductions in costs for future oil sands projects. Oil sands growth will be complemented by investment in select low-cost and short-cycle time conventional opportunities that are well-suited to responding to changes in macro conditions.

Our producing asset mix includes:

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

Our marketing, products and transportation activities include:

- Refining oil into various products to reduce the impact of commodity price fluctuations;
- Creating a variety of oil blends to help maximize our transportation and refining options; and
- Accessing new markets that will position us to achieve the best pricing for our oil.

#### *Disciplined Manufacturing*

We continue to focus on executing our business plan in a predictable and reliable way and are committed to developing our resources safely and responsibly. The manufacturing approach we use to produce crude oil is a key factor in how we execute our strategy. Applying standardized and repeatable designs and processes to the construction and operation of our facilities provides us with opportunities to reduce costs and improve productivity and efficiencies at every phase of our oil sands projects. This approach incorporates learnings from previous phases into future growth plans. Manufacturing principles will be deployed for each area of our business to balance innovation, agility, cost focus and efficiency.

#### *Value-Added Integration*

Our integrated business approach positions us to capture the full value chain from production to high-quality end products like transportation fuels. This helps provide stability to our cash flows and maximize value for every barrel of oil we produce.

#### *Focused Innovation*

Our focused innovation is aimed at enabling Cenovus to be a low-cost and environmentally-responsible energy producer. Our innovation efforts are focused on initiatives intended to increase recoveries from our reservoirs, improve cycle times and margins, and enhance environmental performance. We plan to build on our track record of developing innovative solutions that unlock challenging crude oil resources and plan to work to commercialize successful technologies through continued investment as well as global partnerships that will bring smart minds, funds and third-party advocates together.

#### *Trusted Reputation*

We are committed to providing a safe and healthy workplace, building strong relationships with stakeholders, and minimizing our environmental footprint. Our actions support our trusted reputation.

#### *Financial Strength*

Maintaining a strong balance sheet is necessary to execute our strategy. To help protect our financial flexibility, we will focus on maximizing cost efficiencies and maintaining our financial resilience. We anticipate our total annual capital investment for 2017 to be between $1.2 billion and $1.4 billion, approximately 30 percent higher than in 2016. While we anticipate crude oil prices will continue to be volatile in 2017, sustainable cost reductions achieved over the last two years provide us the flexibility to consider advancing certain projects. At December 31, 2016, we had $3.7 billion of cash on hand, $4.0 billion of undrawn capacity under our committed credit facility, and no debt maturing until the fourth quarter of 2019.

### *Dividend*

In 2016, we paid a dividend of $0.20 per share compared with $0.8524 per share in 2015. The declaration of dividends is at the sole discretion of our Board and is considered each quarter.

## Our Operations

### *Oil Sands*

Our operations include steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta, namely Foster Creek, Christina Lake, Narrows Lake and other emerging projects. Foster Creek and Christina Lake are producing, while Narrows Lake is in the initial stages of development. These three projects, located in the Athabasca region of northeastern Alberta, are operated by Cenovus and jointly owned (50 percent-owned) with ConocoPhillips, an unrelated U.S. public company. Two of our 100 percent-owned emerging projects are Telephone Lake and Grand Rapids, located within the Borealis and Greater Pelican Lake regions of northeastern Alberta, respectively.

| | 2016 | |
|---|---|---|
| ($ millions) | **Crude Oil** | **Natural Gas** |
| Operating Margin | **875** | **4** |
| Capital Investment | **601** | **3** |
| **Operating Margin Net of Related Capital Investment** | **274** | **1** |

### *Conventional*

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

| | 2016 | |
|---|---|---|
| ($ millions) | **Crude Oil (1)** | **Natural Gas** |
| Operating Margin | **402** | **137** |
| Capital Investment | **161** | **10** |
| **Operating Margin Net of Related Capital Investment** | **241** | **127** |

*(1) Includes NGLs.*

We have established crude oil and natural gas producing assets, including heavy oil assets at Pelican Lake, a carbon dioxide ("$CO_2$") enhanced oil recovery project in Weyburn, Saskatchewan and emerging tight oil assets in Alberta.

### *Refining and Marketing*

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

| | 2016 | |
|---|---|---|
| | **Ownership Interest** (percent) | **Gross Nameplate Capacity** (Mbbls/d) |
| Wood River | **50** | **314** |
| Borger | **50** | **146** |

Refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with regional North American light/heavy crude oil price differential fluctuations. This segment also includes our crude-by-rail terminal operations, located in Bruderheim, Alberta, and the marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

| ($ millions) | **2016** |
|---|---|
| Operating Margin | **346** |
| Capital Investment | **220** |
| **Operating Margin Net of Related Capital Investment** | **126** |

## 2016 HIGHLIGHTS

In 2016, our financial results continued to be significantly impacted by volatile crude oil prices. In the first quarter of 2016, the West Texas Intermediate ("WTI") benchmark price reached a low of US$26.05 per barrel, before gradually strengthening to close the year at US$53.72 per barrel. Our companywide Netback of $11.33 per BOE for 2016, before realized risk management activities, was considerably lower than in prior years.

As a result of the continued price volatility, we focused on delivering value through preserving financial resilience, exercising capital discipline and achieving sustained cost reductions, while delivering safe and reliable operating performance. We exited the year with a strong balance sheet with over $3.7 billion of cash on hand and $4.0 billion of undrawn capacity under our committed credit facility.

In 2016, we:

- Achieved Cash From Operating Activities and Adjusted Funds Flow of $861 million and $1,423 million, respectively. Declines from 2015 were primarily due to a decrease in realized risk management gains and lower commodity prices, partially offset by lower operating costs;
- Incurred a Net Loss of $545 million compared with Net Earnings of $618 million in 2015 primarily due to an after-tax gain in 2015 of approximately $1.9 billion from the divestiture of our royalty interest and mineral fee title lands business;
- Decreased total crude oil operating costs by $1.63 per barrel, or 14 percent compared with 2015;
- Invested $1,026 million in capital, a 40 percent reduction from 2015;
- Added incremental crude oil production volumes from Foster Creek phase G and Christina Lake phase F. Start-up of these phases, which includes cogeneration at Christina Lake phase F, added 80,000 gross barrels per day of production capacity and approximately 100 gross megawatts of electrical generation capacity;
- Increased proved bitumen reserves by seven percent primarily due to the area expansion at Christina Lake;
- Successfully completed the debottlenecking project at the Wood River refinery; and
- Reduced our annual dividend from $0.8524 per share in 2015 to $0.20 per share.

## OPERATING RESULTS

Our upstream assets continued to perform well in 2016. Total crude oil production remained relatively consistent as higher production from our Oil Sands segment was offset by lower production from our Conventional properties.

### Crude Oil Production Volumes

| (barrels per day) | **2016** | **Percent Change** | 2015 | Percent Change | 2014 |
|---|---|---|---|---|---|
| **Oil Sands** | | | | | |
| Foster Creek | **70,244** | **7%** | 65,345 | 10% | 59,172 |
| Christina Lake | **79,449** | **6%** | 74,975 | 9% | 69,023 |
| | **149,693** | **7%** | 140,320 | 9% | 128,195 |
| **Conventional** | | | | | |
| Heavy Oil | **29,185** | **(16)%** | 34,888 | (12)% | 39,546 |
| Light and Medium Oil | **25,915** | **(15)%** | 30,486 | (12)% | 34,531 |
| NGLs [(1)] | **1,065** | **(15)%** | 1,253 | 3% | 1,221 |
| | **56,165** | **(16)%** | 66,627 | (12)% | 75,298 |
| **Total Crude Oil Production** | **205,858** | **(1)%** | 206,947 | 2% | 203,493 |

*(1) NGLs include condensate volumes.*

In 2016, production rose at Foster Creek primarily due to incremental production volumes from the phase G expansion and additional wells being brought online. Ramp-up of phase G has progressed well and is now expected to take 12 months from start-up, which occurred early in the third quarter of 2016. In the second quarter of 2015, a nearby forest fire temporarily shut down operations and decreased full year production by approximately 2,600 barrels per day.

Production from Christina Lake increased compared with 2015 due to the start-up of the phase F expansion and the related increase in wells brought online, incremental production from the optimization project completed in 2015, and reliable performance of our facilities. Ramp-up of phase F began in the fourth quarter and is expected to take 12 months from start-up.

Our Conventional crude oil production decreased from 2015 due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in July 2015. Divested assets contributed 2,555 barrels per day in 2015. Production also decreased in 2016 due to reduced capital investment.

### Natural Gas Production Volumes

| (MMcf per day) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Conventional | **377** | 422 | 466 |
| Oil Sands | **17** | 19 | 22 |
| | **394** | 441 | 488 |

Our natural gas production was 11 percent lower in 2016. Production decreased due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in 2015.

### Oil and Gas Reserves

Based on our reserves report prepared by independent qualified reserves evaluators ("IQREs"), our proved bitumen reserves increased seven percent to approximately 2.3 billion barrels and our proved plus probable bitumen reserves rose slightly to approximately 3.3 billion barrels. Additional information about our reserves and resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

### Netbacks

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. The crude oil sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the heavy 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 ("COGE Handbook").

| | **Crude Oil** (1) ($/bbl) | | | **Natural Gas** ($/Mcf) | | |
|---|---|---|---|---|---|---|
| | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| Sales Price | **31.20** | 35.38 | 71.35 | **2.32** | 2.92 | 4.37 |
| Royalties | **1.79** | 1.75 | 6.18 | **0.10** | 0.07 | 0.08 |
| Transportation and Blending | **5.81** | 5.48 | 2.98 | **0.11** | 0.11 | 0.12 |
| Operating Expenses | **10.35** | 11.98 | 15.40 | **1.15** | 1.20 | 1.22 |
| Production and Mineral Taxes | **0.16** | 0.22 | 0.50 | **-** | 0.01 | 0.05 |
| **Netback Excluding Realized Risk Management** (2) | **13.09** | 15.95 | 46.29 | **0.96** | 1.53 | 2.90 |
| Realized Risk Management Gain (Loss) | **3.23** | 7.51 | 0.50 | **-** | 0.37 | 0.04 |
| **Netback Including Realized Risk Management** | **16.32** | 23.46 | 46.79 | **0.96** | 1.90 | 2.94 |

(1) *Includes NGLs.*
(2) *Netbacks do not reflect non-cash write-downs of product inventory until the product is sold.*

Our average crude oil Netback in 2016, excluding realized risk management gains and losses, decreased compared with 2015. Lower sales prices, consistent with the decline in benchmark prices, were partially offset by a decrease in operating costs and the weakening of the Canadian dollar relative to the U.S. dollar. The weakening of the Canadian dollar compared with 2015 had a positive impact on our crude oil price of approximately $1.09 per barrel.

In 2016, our average natural gas Netback, excluding realized risk management gains and losses, decreased primarily due to lower sales prices, consistent with the decline in the AECO benchmark price.

### Refining and Marketing

In the third quarter of 2016, the Wood River debottlenecking project was successfully completed. Strong operational performance in 2016 resulted in higher crude oil runs and refined product output, which helped to partially offset the decline in our Refining and Marketing Operating Margin. The decline in Operating Margin was primarily due to lower average market crack spreads.

| | 2016 | Percent Change | 2015 | Percent Change | 2014 |
|---|---|---|---|---|---|
| Crude Oil Runs (1) (Mbbls/d) | **444** | **6%** | 419 | (1)% | 423 |
| Heavy Crude Oil (1) | **233** | **17%** | 200 | 1% | 199 |
| Refined Product (1) (Mbbls/d) | **471** | **6%** | 444 | -% | 445 |
| Crude Utilization (1) (percent) | **97** | **6%** | 91 | (1)% | 92 |

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

Further information on the changes in our production volumes, items included in our Netbacks and refining 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 section of this MD&A and in the notes to the Consolidated Financial Statements.

## COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

### Selected Benchmark Prices and Exchange Rates (1)

| | **Q4 2016** | Q4 2015 | **2016** | 2015 | **Percent Change** | 2014 |
|---|---|---|---|---|---|---|
| **Crude Oil Prices** (US$/bbl) | | | | | | |
| Brent | | | | | | |
| Average | **51.13** | 44.71 | **45.04** | 53.64 | **(16)%** | 99.51 |
| End of Period | **56.82** | 37.28 | **56.82** | 37.28 | **52%** | 57.33 |
| WTI | | | | | | |
| Average | **49.29** | 42.18 | **43.32** | 48.80 | **(11)%** | 93.00 |
| End of Period | **53.72** | 37.04 | **53.72** | 37.04 | **45%** | 53.27 |
| Average Differential Brent-WTI | **1.84** | 2.53 | **1.72** | 4.84 | **(64)%** | 6.51 |
| WCS (2) | | | | | | |
| Average | **34.97** | 27.69 | **29.48** | 35.28 | **(16)%** | 73.60 |
| End of Period | **38.81** | 24.98 | **38.81** | 24.98 | **55%** | 37.59 |
| Average Differential WTI-WCS | **14.32** | 14.49 | **13.84** | 13.52 | **2%** | 19.40 |
| Condensate (C5 @ Edmonton) (3) | | | | | | |
| Average | **48.33** | 41.67 | **42.47** | 47.36 | **(10)%** | 92.95 |
| Average Differential WTI-Condensate (Premium)/Discount | **0.96** | 0.51 | **0.85** | 1.44 | **(41)%** | 0.05 |
| Average Differential WCS-Condensate (Premium)/Discount | **(13.36)** | (13.98) | **(12.99)** | (12.08) | **8%** | (19.35) |
| **Average Refined Product Prices** (US$/bbl) | | | | | | |
| Chicago Regular Unleaded Gasoline ("RUL") | **59.46** | 55.24 | **56.24** | 67.68 | **(17)%** | 107.40 |
| Chicago Ultra-low Sulphur Diesel ("ULSD") | **61.50** | 59.23 | **56.33** | 68.12 | **(17)%** | 117.55 |
| **Refining Margin: Average 3-2-1 Crack Spread (4)** (US$/bbl) | | | | | | |
| Chicago | **10.96** | 14.47 | **13.07** | 19.11 | **(32)%** | 17.61 |
| **Average Natural Gas Prices** | | | | | | |
| AECO (C$/Mcf) | **2.81** | 2.65 | **2.09** | 2.77 | **(25)%** | 4.42 |
| NYMEX (US$/Mcf) | **2.98** | 2.27 | **2.46** | 2.66 | **(8)%** | 4.42 |
| Basis Differential NYMEX-AECO (US$/Mcf) | **0.86** | 0.27 | **0.89** | 0.49 | **82%** | 0.40 |
| **Foreign Exchange Rates** (US$ per C$1) | | | | | | |
| Average | **0.750** | 0.749 | **0.755** | 0.782 | **(3)%** | 0.905 |

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

(2) *The average Canadian dollar WCS benchmark price for 2016 was $39.05 per barrel (2015 – $45.12 per barrel; 2014 – $81.33 per barrel); fourth quarter average WCS benchmark price was $46.63 per barrel (2015 – $36.97 per barrel).*

(3) *The average Canadian dollar condensate benchmark price for 2016 was $56.25 per barrel (2015 – $60.56 per barrel; 2014 – $102.71 per barrel); fourth quarter average condensate benchmark price was $64.44 per barrel (2015 – $55.63 per barrel).*

(4) *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.*

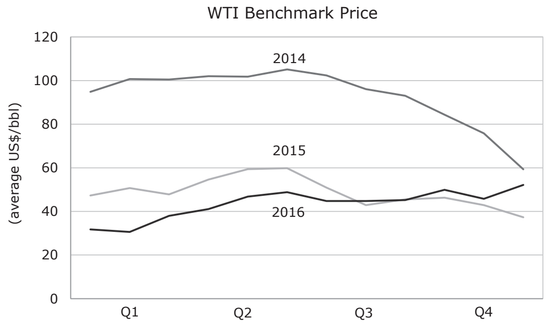
### Crude Oil Benchmarks

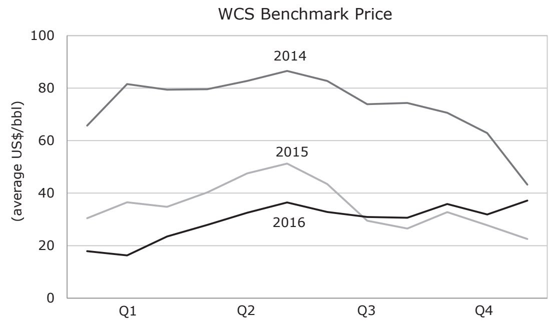
Average WTI declined US$5.48 per barrel in 2016 compared with 2015 as a result of excess crude oil and refined product inventories. Overall, average crude oil benchmark prices in 2016 continued to be volatile. We saw a steep decline in crude oil prices in the first quarter, with the WTI benchmark price falling as low as US$26.05 per barrel. A gradual recovery occurred over the remainder of the year and WTI closed at US$53.72 per barrel. Prices were boosted in November 2016 as the Organization of Petroleum Exporting Countries ("OPEC"), along with select non-OPEC countries, such as Russia, reached an agreement to reduce production. As a result, average crude oil benchmark prices in the fourth quarter of 2016 improved 18 percent compared with the same period in 2015. WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential was slightly wider in 2016 compared with 2015 as additional U.S. imports of medium crude oil competed for refining capacity, and heavy oil prices were pressured by an oversupply of heavy oil products, such as fuel oil and bunker fuel.

Blending condensate with bitumen and heavy oil enables our production to be transported through pipelines. Our blending ratios range between 10 percent and 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. Since the supply of condensate in Alberta does not meet demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the cost attributed to transporting the condensate to Edmonton.

The average WTI-Condensate differential narrowed in 2016 compared with 2015. Declining U.S. light oil production reduced condensate supply from the U.S. Gulf Coast while higher heavy oil production in Alberta increased demand. However, in the second quarter of 2016, the Alberta forest fires reduced heavy oil production and the associated demand for diluent.

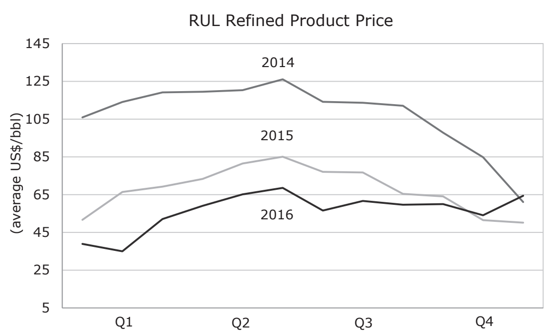


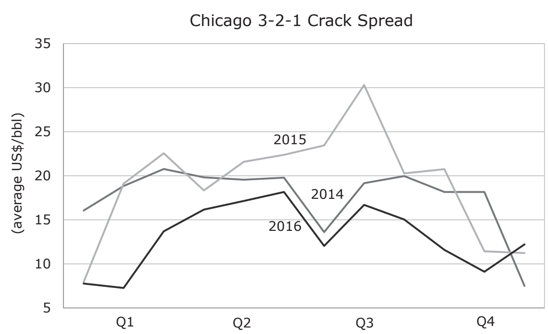




### *Refining Benchmarks*

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 crack spread. The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and valued on a last in, first out accounting basis.

Average Chicago 3-2-1 crack spreads decreased in 2016 compared with 2015 due to higher global refined product inventory, and strengthening of the WTI benchmark price compared with Brent due to the lifting of the U.S. export ban. 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 natural gas prices decreased in 2016 compared with 2015 primarily due to high inventory levels in North America given a warmer than normal 2015/2016 winter and stable North American supply.

### *Foreign Exchange Benchmarks*

Revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, we have chosen to borrow U.S. dollar long-term debt. In periods of a strengthening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange gains when translated to Canadian dollars.

In 2016 compared with 2015, the Canadian dollar weakened relative to the U.S. dollar due to lower commodity prices and strengthening of the U.S. economy. The weakening of the Canadian dollar in 2016 had a positive impact of approximately $422 million on our revenues. The Canadian dollar at December 31, 2016 compared with December 31, 2015 was three percent stronger, resulting in $196 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

## FINANCIAL RESULTS

### Selected Consolidated Financial Results

Volatile commodity prices in 2016 impacted our financial results. The following key performance measures are discussed in more detail within this MD&A.

| ($ millions, except per share amounts) | **2016** | **Percent Change** | 2015 | Percent Change | 2014 |
|---|---|---|---|---|---|
| **Revenues** | **12,134** | **(7)%** | 13,064 | (33)% | 19,642 |
| **Operating Margin** (1) | **1,767** | **(28)%** | 2,439 | (42)% | 4,179 |
| **Cash From Operating Activities** | **861** | **(42)%** | 1,474 | (58)% | 3,526 |
| **Adjusted Funds Flow** (2) | **1,423** | **(16)%** | 1,691 | (51)% | 3,479 |
| **Operating Earnings (Loss)** (2) | **(377)** | **6%** | (403) | (164)% | 633 |
| Per Share – Diluted | **(0.45)** | **8%** | (0.49) | (158)% | 0.84 |
| **Net Earnings (Loss)** | **(545)** | **(188)%** | 618 | (17)% | 744 |
| Per Share – Basic and Diluted ($) | **(0.65)** | **(187)%** | 0.75 | (23)% | 0.98 |
| **Total Assets** | **25,258** | **(2)%** | 25,791 | 4% | 24,695 |
| **Total Long-Term Financial Liabilities** (3) | **6,373** | **(2)%** | 6,552 | 19% | 5,484 |
| **Capital Investment** (4) | **1,026** | **(40)%** | 1,714 | (44)% | 3,051 |
| **Dividends** | | | | | |
| Cash Dividends | **166** | **(69)%** | 528 | (34)% | 805 |
| In Shares From Treasury | **-** | **-** | 182 | - | - |
| Per Share ($) | **0.20** | **(77)%** | 0.8524 | (20)% | 1.0648 |

*(1) Additional subtotal found in Note 1 of the Consolidated Financial Statements and defined in this MD&A.*
*(2) Non-GAAP measure defined in this MD&A.*
*(3) Includes Long-Term Debt, Risk Management Liabilities and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.*
*(4) Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.*

### Revenues

| ($ millions) | **2016 vs. 2015** | 2015 vs. 2014 |
|---|---|---|
| **Revenues, Comparative Year** | **13,064** | 19,642 |
| Increase (Decrease) due to: | | |
| Oil Sands | **(81)** | (1,799) |
| Conventional | **(467)** | (1,401) |
| Refining and Marketing | **(366)** | (3,853) |
| Corporate and Eliminations | **(16)** | 475 |
| **Revenues, End of Year** | **12,134** | 13,064 |

Combined Oil Sands and Conventional revenues declined 12 percent in 2016 compared with 2015 due to lower crude oil and natural gas sales prices and a decline in natural gas sales volumes, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar. The sale of our royalty interest and mineral fee title lands business in 2015 also reduced revenues.

Revenues from our Refining and Marketing segment decreased four percent from 2015. Refining revenues declined due to the decrease in refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices. The decrease in our reported revenues was partially offset by higher refined product output and a weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in 2016 increased 23 percent from 2015, primarily due to higher purchased crude oil and natural gas volumes, and higher crude oil sales prices, partially offset by lower natural gas sales prices.

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

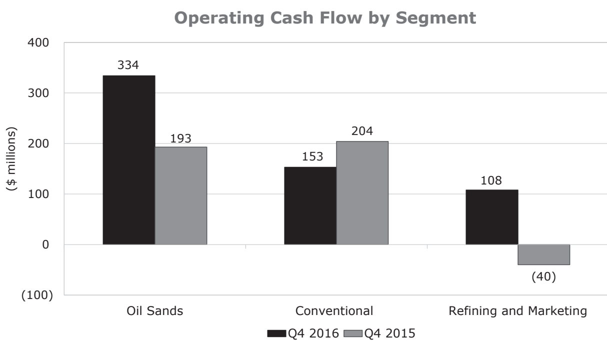
Overall, revenues decreased in 2015 compared with 2014 primarily due to lower crude oil and natural gas sales prices and a decline in refined product pricing, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar.

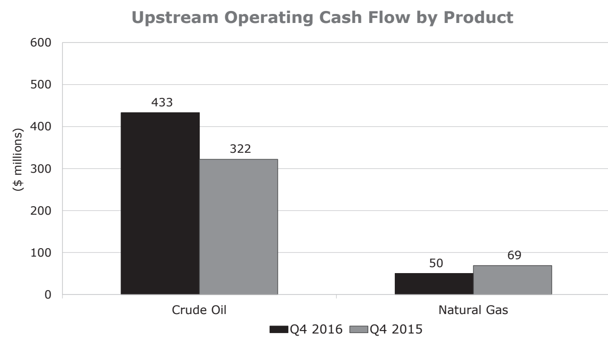
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

### Operating Margin

Operating Margin is an additional subtotal found in Note 1 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) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Revenues | **12,487** | 13,401 | 20,454 |
| (Add) Deduct: | | | |
| Purchased Product | **7,325** | 7,709 | 11,767 |
| Transportation and Blending | **1,907** | 2,045 | 2,477 |
| Operating Expenses | **1,687** | 1,846 | 2,051 |
| Production and Mineral Taxes | **12** | 18 | 46 |
| Realized (Gain) Loss on Risk Management | **(211)** | (656) | (66) |
| **Operating Margin** | **1,767** | 2,439 | 4,179 |



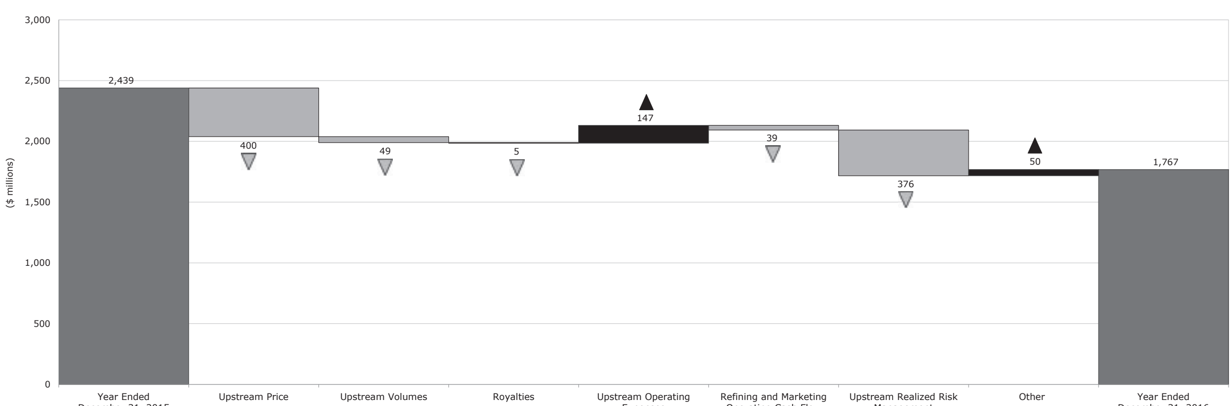

Operating Margin declined 28 percent in 2016 compared with 2015 primarily due to:

- A 12 percent decrease in our average crude oil sales price and a 21 percent reduction in our average natural gas sales price. Our average crude oil price in 2016 was significantly impacted by lower prices in the first quarter;
- Realized risk management gains of $237 million, excluding Refining and Marketing, compared with gains of $613 million in 2015;
- An 11 percent decline in our natural gas sales volumes; and
- Lower Operating Margin from Refining and Marketing as a result of lower average market crack spreads and realized risk management losses as compared with gains in 2015. This was partially offset by widening heavy and medium crude oil differentials, higher utilization rates, and weakening of the Canadian dollar relative to the U.S. dollar.

These declines to Operating Margin were partially offset by:

- A decrease of $1.63 per barrel in crude oil operating expenses primarily due to a decline in repairs and maintenance, lower chemical costs, and workforce reductions; and
- An inventory write-down of $4 million (2015 – $66 million).

### *Operating Margin Variance*




Additional details explaining the changes in Operating Margin 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. Net change in other assets and liabilities is composed of site restoration costs and pension funding. Non-cash working capital is composed of current assets and current liabilities, excluding cash and cash equivalents and risk management.

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| **Cash From Operating Activities** | **861** | 1,474 | 3,526 |
| (Add) Deduct: | | | |
| Net Change in Other Assets and Liabilities | **(91)** | (107) | (135) |
| Net Change in Non-Cash Working Capital | **(471)** | (110) | 182 |
| **Adjusted Funds Flow** | **1,423** | 1,691 | 3,479 |

In 2016, Cash From Operating Activities and Adjusted Funds Flow decreased primarily as a result of lower Operating Margin, as discussed above, partially offset by a cash tax recovery due to losses carried back to recover taxes previously paid and lower costs related to larger workforce reductions in 2015 as compared with 2016. The change in working capital was primarily due to the improvement of commodity prices at the end of 2016 compared with 2015, resulting in higher accounts receivable, accounts payable, and Refining and Marketing inventory values. In addition, crude oil inventory volumes rose year over year.

### Operating Earnings (Loss)

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, gain on bargain purchase, 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.

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| **Earnings (Loss), Before Income Tax** | **(927)** | 537 | 1,195 |
| Add (Deduct): | | | |
| Unrealized Risk Management (Gain) Loss (1) | **554** | 195 | (596) |
| Non-operating Unrealized Foreign Exchange (Gain) Loss (2) | **(196)** | 1,064 | 458 |
| (Gain) Loss on Divestiture of Assets | **6** | (2,392) | (156) |
| **Operating Earnings (Loss), Before Income Tax** | **(563)** | (596) | 901 |
| Income Tax Expense (Recovery) | **(186)** | (193) | 268 |
| **Operating Earnings (Loss)** | **(377)** | (403) | 633 |

(1) *Includes the reversal of unrealized (gains) losses recorded in prior periods.*
(2) *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 Loss decreased compared with 2015 primarily due to a decline in depreciation, depletion and amortization ("DD&A"), related to lower DD&A rates and asset impairments, and a decline in exploration expense.

The lower Operating Loss was partially offset by:
- A decline in Cash From Operating Activities and Adjusted Funds Flow, as discussed above;
- A non-cash expense of $61 million for office space in excess of Cenovus's current and near-term requirements;
- Higher long-term employee incentive costs primarily due to an increase in our share price; and
- An asset impairment of $23 million and termination costs of $7 million as a result of the Government of Canada's decision to reject the Northern Gateway Pipeline project.

Refer to the Reportable Segments section for more details.

### Net Earnings (Loss)

| ($ millions) | 2016 vs. 2015 | 2015 vs. 2014 |
|---|---|---|
| **Net Earnings (Loss), Comparative Year** | **618** | 744 |
| Increase (Decrease) due to: | | |
| Operating Margin | **(672)** | (1,740) |
| Corporate and Eliminations: | | |
| Unrealized Risk Management Gain (Loss) | **(359)** | (791) |
| Unrealized Foreign Exchange Gain (Loss) | **1,286** | (686) |
| Gain (Loss) on Divestiture of Assets | **(2,398)** | 2,236 |
| Expenses (1) | **(73)** | 46 |
| Depreciation, Depletion and Amortization | **616** | (168) |
| Goodwill Impairment | **-** | 497 |
| Exploration Expense | **136** | (52) |
| Income Tax Recovery (Expense) | **301** | 532 |
| **Net Earnings (Loss), End of Year** | **(545)** | 618 |

(1) *Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.*

In 2016, Net Earnings declined primarily due to:

- An after-tax gain in 2015 of approximately $1.9 billion from the divestiture of our royalty interest and mineral fee title lands business;
- A lower deferred income tax recovery of $209 million (2015 – $655 million); and
- Unrealized risk management losses of $554 million (2015 – $195 million).

The decline was partially offset by non-operating unrealized foreign exchange gains of $196 million, compared with unrealized losses of $1,064 million in 2015, and a lower Operating Loss, as discussed above.

Net Earnings declined in 2015 compared with 2014 primarily due to lower Operating Earnings, larger non-operating unrealized foreign exchange losses, and unrealized risk management losses compared with gains in 2014. These declines were partially offset by the gain from the divestiture of our royalty interest and mineral fee title lands business in 2015.

### Net Capital Investment

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Oil Sands | **604** | 1,185 | 1,986 |
| Conventional | **171** | 244 | 840 |
| Refining and Marketing | **220** | 248 | 163 |
| Corporate and Eliminations | **31** | 37 | 62 |
| **Capital Investment** | **1,026** | 1,714 | 3,051 |
| Acquisitions | **11** | 87 | 18 |
| Divestitures | **(8)** | (3,344) | (277) |
| **Net Capital Investment (1)** | **1,029** | (1,543) | 2,792 |

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

Capital investment in 2016 declined 40 percent compared with 2015 as we reduced our spending in light of the low commodity price environment. Oil Sands capital investment focused primarily on sustaining capital related to existing production, as well as completing the facilities at Foster Creek phase G and Christina Lake phase F. Conventional capital investment focused on drilling stratigraphic test wells for tight oil, maintenance capital and spending for our $CO_2$ enhanced oil recovery project at Weyburn. Capital investment in the Refining and Marketing segment focused on completion of the debottlenecking project at Wood River, capital maintenance, projects to improve our refinery reliability and safety, and environmental initiatives.

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

#### *Acquisitions and Divestitures*

We had no significant acquisitions or divestitures in 2016. In 2015, we completed the sale of our royalty interest and mineral fee title lands business for cash proceeds of approximately $3.3 billion, recording an after-tax gain of approximately $1.9 billion. The sale included approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. A royalty on Cenovus's working interest production on these fee lands and a gross overriding royalty on production from our Pelican Lake and Weyburn assets were also included. In 2015, we also purchased a crude-by-rail terminal for $75 million, plus adjustments, to expand our portfolio of transportation options. In 2014, divestitures included the sale of certain of our Bakken assets in southeastern Saskatchewan and certain of our Wainwright assets in Alberta for net proceeds of $269 million.

### Capital Investment Decisions

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

- First, to capital for our existing business operations;
- Second, to paying a dividend as part of providing strong total shareholder return; and
- Third, for growth or discretionary capital.

Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria within the context of achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which position us to be financially resilient in times of lower cash flows. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

| ($ millions) | **2016** | 2015 | 2014 |
|---|---|---|---|
| Adjusted Funds Flow [(1)] | **1,423** | 1,691 | 3,479 |
| Capital Investment (Sustaining and Growth) | **1,026** | 1,714 | 3,051 |
| Free Funds Flow [(2)] | **397** | (23) | 428 |
| Cash Dividends | **166** | 528 | 805 |
| | **231** | (551) | (377) |

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

We expect our capital investment for 2017 to be funded from internally generated cash flows and our cash balance on hand.

## REPORTABLE SEGMENTS

Our reportable segments are as follows:

**Oil Sands,** which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. Certain of Cenovus's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

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

**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.


**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 operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues, and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.

### Revenues by Reportable Segment

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Oil Sands | **2,920** | 3,001 | 4,800 |
| Conventional | **1,128** | 1,595 | 2,996 |
| Refining and Marketing | **8,439** | 8,805 | 12,658 |
| Corporate and Eliminations | **(353)** | (337) | (812) |
| | **12,134** | 13,064 | 19,642 |

## OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects. We have several emerging projects in the early stages of development, including our 100 percent-owned projects at Telephone Lake and Grand Rapids. The Oil Sands segment also includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant developments that impacted our Oil Sands segment in 2016 compared with 2015 include:

- Reducing our crude oil operating costs by $1.22 per barrel, a 12 percent decline;
- Crude oil Netbacks, excluding realized risk management activities, of $11.94 per barrel (2015 – $13.53 per barrel);
- Generating Operating Margin net of capital investment of $273 million, an increase of $399 million;
- Reducing capital investment by $581 million, or 49 percent compared with 2015; and
- Adding incremental crude oil production volumes from Foster Creek phase G and Christina Lake phase F. Start-up of these expansion phases, which includes cogeneration at Christina Lake phase F, added 80,000 gross barrels per day of production capacity and approximately 100 gross megawatts of electrical generation capacity.

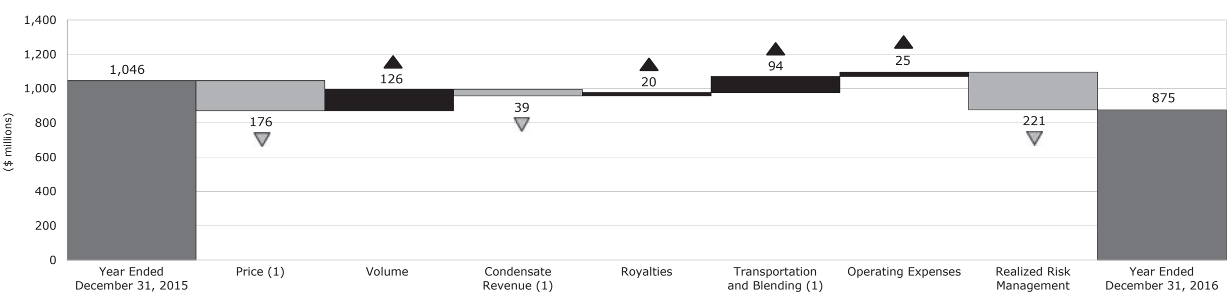
### Oil Sands – Crude Oil

*Financial Results*

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| **Gross Sales** | **2,911** | 3,000 | 4,963 |
| Less: Royalties | **9** | 29 | 233 |
| **Revenues** | **2,902** | 2,971 | 4,730 |
| **Expenses** | | | |
| Transportation and Blending | **1,720** | 1,814 | 2,130 |
| Operating | **486** | 511 | 615 |
| (Gain) Loss on Risk Management | **(179)** | (400) | (38) |
| **Operating Margin** | **875** | 1,046 | 2,023 |
| Capital Investment | **601** | 1,184 | 1,980 |
| **Operating Margin Net of Related Capital Investment** | **274** | (138) | 43 |

In 2015, capital investment in excess of Operating Margin from Oil Sands was funded through Operating Margin generated by our Conventional and Refining and Marketing segments.

**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

*Pricing*

In 2016, our average crude oil sales price was $27.64 per barrel, a 10 percent decrease from 2015. Our first quarter crude oil sales price was approximately $20.50 per barrel to $26.50 per barrel lower than our average quarterly sales prices for the remainder of 2016, and significantly impacted our 2016 average price. The decline in our crude oil sales price was consistent with the decrease in the WCS and Christina Dilbit Blend ("CDB") benchmark prices, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar and a decline in the cost of condensate.

Our bitumen 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. As such, our 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 blend it with our production. In a rising price environment, we expect to see some benefit in our bitumen sales price as we are using condensate purchased at a lower price earlier in the year.

The WCS-CDB differential narrowed by 14 percent to a discount of US$2.05 per barrel (2015 – a discount of US$2.37 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In 2016, 88 percent of our Christina Lake production was sold as CDB (2015 – 86 percent), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

*Production Volumes*

| (barrels per day) | **2016** | **Percent Change** | 2015 | Percent Change | 2014 |
|---|---|---|---|---|---|
| Foster Creek | **70,244** | **7%** | 65,345 | 10% | 59,172 |
| Christina Lake | **79,449** | **6%** | 74,975 | 9% | 69,023 |
| | **149,693** | **7%** | 140,320 | 9% | 128,195 |

In 2016, production rose at Foster Creek primarily due to incremental production volumes from the phase G expansion, and additional wells being brought online. Ramp-up of phase G has progressed well and is now expected to take 12 months from start-up, which occurred early in the third quarter of 2016. In the second quarter of 2015, a nearby forest fire temporarily shut down operations and decreased full year production by approximately 2,600 barrels per day.

Production from Christina Lake increased compared with 2015 due to the start-up of the phase F expansion and the related increase in wells brought online, incremental production from the optimization project completed in 2015, and reliable performance of our facilities. Ramp-up of phase F began in the fourth quarter and is expected to take 12 months from start-up.

*Condensate*

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the widening of the WCS-Condensate differential in 2016, the proportion of the cost of recovered condensate decreased.

*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. Royalty calculations differ between properties.

Royalties at Foster Creek, a post-payout project, are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and sales prices. Net profits are a function of sales volumes, sales prices and allowed operating and capital costs. The royalty calculation was based on gross revenues in 2016 and 2015.

Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Effective Royalty Rates

| (percent) | **2016** | 2015 | 2014 |
|---|---|---|---|
| Foster Creek | **-** | 1.9 | 8.8 |
| Christina Lake | **1.6** | 2.8 | 7.5 |

Royalties decreased $20 million compared with 2015. At Foster Creek, the royalty rate declined in 2016 due to low crude oil sales prices, a decline in the WTI benchmark price (which determines the royalty rate), and a credit associated with the revision of prior period royalty calculations, related to the inclusion of additional employee costs and a 2015 true-up. In 2015, we received regulatory approval to include certain capital costs incurred in previous years in our royalty calculation. Excluding the prior year credits, the effective royalty rate in 2016 and 2015 for Foster Creek would have been 1.3 percent and 3.1 percent, respectively. The Christina Lake royalty rate decreased in 2016 as a result of the decline in the WTI benchmark price and lower sales prices.

### Expenses

*Transportation and Blending*

Transportation and blending costs decreased $94 million in 2016. Blending costs declined due to lower condensate prices, partially offset by higher condensate volumes. In 2015, we recorded a $44 million write-down of our crude oil and condensate inventory to net realizable value as a result of the decline in crude oil prices. There was no inventory write-down in 2016. Our condensate costs exceeded the average benchmark price in 2016 primarily due to the transportation costs associated with moving the condensate from the purchase point to our oil sands projects.

Transportation costs increased primarily due to higher production. The proportion of sales shipped to the U.S. in 2016 was consistent with 2015. Sales to the U.S. market incur additional tariff charges, but generally secure a higher sales price. To help ensure adequate capacity for our expected future production growth, we have capacity commitments in excess of our current production. Production growth is expected to reduce our per-barrel transportation costs.

Transportation costs related to rail decreased, despite moving higher volumes, as we transported volumes across shorter distances. We transported an average of 4,906 barrels per day of crude oil by rail (2015 – 3,529 barrels per day).

*Operating*

Primary drivers of our operating expenses for 2016 were workforce, fuel, workovers, chemical costs, and repairs and maintenance. Total operating expenses decreased $25 million or $1.22 per barrel, primarily as a result of a decline in repairs and maintenance activities, workforce reductions, and a decrease in chemical costs.

Per-unit Operating Expenses

| ($/bbl) | **2016** | **Percent Change** | 2015 | Percent Change | 2014 |
|---|---|---|---|---|---|
| **Foster Creek** | | | | | |
| Fuel | **2.46** | **(12)%** | 2.80 | (37)% | 4.46 |
| Non-fuel | **8.09** | **(17)%** | 9.80 | (18)% | 11.89 |
| Total | **10.55** | **(16)%** | 12.60 | (23)% | 16.35 |
| **Christina Lake** | | | | | |
| Fuel | **2.08** | **(5)%** | 2.20 | (40)% | 3.65 |
| Non-fuel | **5.40** | **(7)%** | 5.81 | (22)% | 7.44 |
| Total | **7.48** | **(7)%** | 8.01 | (28)% | 11.09 |
| **Total** | **8.91** | **(12)%** | 10.13 | (25)% | 13.50 |

At Foster Creek, fuel costs decreased primarily due to the decline in natural gas prices, partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined on a per-barrel basis primarily due to higher production, in addition to:

- Lower repairs and maintenance costs from focusing on critical operational activities;
- Workforce reductions; and
- Lower fluid, waste handling and trucking costs due to reduced maintenance activity levels.

At Christina Lake, fuel costs declined due to lower natural gas prices, partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased on a per-barrel basis primarily due to higher production and lower chemical costs due to supply chain initiatives. These decreases were offset by turnaround activities and higher workover costs due to more pump changes.

### Netbacks (1)

| | **Foster Creek** | | | **Christina Lake** | | |
|---|---|---|---|---|---|---|
| ($/bbl) | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| Sales Price (2) | **30.32** | 33.65 | 69.43 | **25.30** | 28.45 | 61.57 |
| Royalties | **(0.01)** | 0.47 | 5.95 | **0.33** | 0.67 | 4.40 |
| Transportation and Blending (2) | **8.84** | 8.84 | 1.98 | **4.68** | 4.72 | 3.53 |
| Operating Expenses | **10.55** | 12.60 | 16.35 | **7.48** | 8.01 | 11.09 |
| **Netback Excluding Realized Risk Management (3)** | **10.94** | 11.74 | 45.15 | **12.81** | 15.05 | 42.55 |
| Realized Risk Management Gain (Loss) | **3.51** | 8.60 | 1.39 | **3.08** | 7.33 | 0.36 |
| **Netback Including Realized Risk Management** | **14.45** | 20.34 | 46.54 | **15.89** | 22.38 | 42.91 |

*(1) Non-GAAP measure defined in this MD&A. Refer to the Operating Results section of this MD&A for details.*
*(2) Sales price and transportation and blending costs exclude the cost of purchased condensate, which is blended with the heavy oil.*
*(3) Netbacks do not reflect non-cash write-downs of product inventory until the product is sold.*

*Risk Management*

Risk management activities in 2016 resulted in realized gains of $179 million (2015 – $400 million), consistent with our contract prices exceeding average benchmark prices.

**Oil Sands – Natural Gas**

Oil Sands includes our natural gas operations in northeastern Alberta. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for 2016, net of internal usage, was 17 MMcf per day (2015 – 19 MMcf per day). Operating Margin was $4 million in 2016 (2015 – $10 million), declining primarily due to lower natural gas sales prices.

**Oil Sands – Capital Investment**

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Foster Creek | **263** | 403 | 796 |
| Christina Lake | **282** | 647 | 794 |
| | **545** | 1,050 | 1,590 |
| Narrows Lake | **7** | 47 | 175 |
| Telephone Lake | **16** | 24 | 112 |
| Grand Rapids | **6** | 38 | 63 |
| Other [1] | **30** | 26 | 46 |
| **Capital Investment [2]** | **604** | 1,185 | 1,986 |

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

***Existing Projects***

Capital investment at Foster Creek and Christina Lake in 2016 focused on sustaining capital related to existing production and the completion of the Foster Creek phase G and Christina Lake phase F facilities, with ramp-up underway. In addition, we drilled stratigraphic test wells in the first and fourth quarters to help identify well pad locations for sustaining wells and near-term expansion phases. Incremental production from Foster Creek phase G began in the third quarter of 2016 and ramp-up is now expected to take approximately 12 months from start-up. Completion of Foster Creek phase G added gross production capacity of 30,000 barrels per day. Incremental production from Christina Lake phase F began in the fourth quarter of 2016 and ramp-up is expected to take approximately 12 months from start-up. Start-up of Christina Lake phase F added gross production capacity of 50,000 barrels per day and approximately 100 gross megawatts of electrical generation capacity.

Capital investment declined in 2016 due to spending reductions in response to the low commodity price environment and multiple capital reduction strategies such as quicker drilling time, supply chain initiatives, redesigned well pads, and longer reach horizontal well pairs. Lower capital investment at Christina Lake is also attributable to the completion of the optimization project in 2015.

In 2016, capital investment at Narrows Lake focused on engineering work. Capital investment declined compared with 2015 due to the suspension of construction.

***Emerging Projects***

In 2016, capital investment at Telephone Lake focused on front-end engineering work for the central processing facility. Capital investment declined as a result of slowing the pace of development in 2016 in response to the low commodity price environment.

Capital investment at Grand Rapids decreased in 2016 as spending was limited to the wind down of the SAGD pilot. In 2015, a third pilot well pair was completed at Grand Rapids.

***Drilling Activity***

| | **Gross Stratigraphic Test Wells** | | | **Gross Production Wells [1]** | | |
|---|---|---|---|---|---|---|
| | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| Foster Creek | **95** | 124 | 165 | **18** | 28 | 63 |
| Christina Lake | **104** | 40 | 57 | **35** | 67 | 67 |
| | **199** | 164 | 222 | **53** | 95 | 130 |
| Narrows Lake | **1** | - | 22 | **-** | - | - |
| Telephone Lake | **-** | - | 45 | **-** | - | - |
| Grand Rapids | **-** | - | 10 | **-** | 1 | - |
| Other | **5** | - | 21 | **1** | - | - |
| | **205** | 164 | 320 | **54** | 96 | 130 |

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

Stratigraphic test wells were drilled at Foster Creek and Christina Lake to help identify well pad locations for sustaining wells and near-term expansion phases.

### Future Capital Investment

While we expect continued crude oil price volatility in 2017, the progress we have made in 2016 in achieving sustainable cost reductions leaves us well positioned to consider advancing certain strategic growth projects. Our 2017 Oil Sands capital investment is forecast to be between $685 million and $815 million. For more information, we direct our readers to review the news release for our 2017 guidance dated December 8, 2016. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

Foster Creek is currently producing from phases A through G. Capital investment for 2017 is forecast to be between $325 million and $375 million. We plan to continue focusing on sustaining capital related to existing production and to progress engineering and design work on phase H. Spending related to construction work on phase H was deferred in 2015 in response to the low commodity price environment.

Christina Lake is producing from phases A through F. Capital investment for 2017 is forecast to be between $300 million and $350 million, focused on sustaining capital and resuming construction of the phase G expansion, which had previously been deferred. Construction of phase G, which has an initial design capacity of 50,000 gross barrels per day, is expected to begin in the first half of 2017. We received regulatory approval in December 2015 for the phase H expansion, a 50,000 gross barrels per day phase.

Capital investment at Narrows Lake and our new resource plays in 2017 is forecast to be between $60 million and $90 million, focusing on phase A engineering and equipment preservation related to the suspension of construction at Narrows Lake and a stratigraphic test well program at Telephone Lake. Further activity with respect to the SAGD pilot at Grand Rapids was deferred in 2016 in response to the low commodity price environment.

### DD&A and Exploration Expense

#### *DD&A*

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.

In 2016, Oil Sands DD&A decreased $42 million due to lower DD&A rates, partially offset by higher sales volumes. The average depletion rate was approximately $11.30 per barrel compared with $11.65 per barrel in 2015 as the impact of proved reserves additions offset higher PP&E and future development expenditures. Future development costs, which compose approximately 60 percent of the depletable base, increased due to expansion of the development area at Christina Lake. In 2016, an impairment loss of $16 million was recorded related to preliminary engineering costs associated with a cancelled project, and equipment that was written down to its recoverable amount.

DD&A in 2015 compared to 2014 increased $72 million primarily due to higher sales volumes and an impairment loss of $16 million related to a sulphur recovery facility.

#### *Exploration Expense*

In 2016, exploration expense was $2 million. In 2015, we expensed $67 million related to exploration assets within the Northern Alberta cash-generating unit ("CGU") that were deemed not to be technically feasible and commercially viable. In 2014, $4 million of costs related to the expiry of leases in the Borealis CGU were recorded as exploration expense.

## CONVENTIONAL

Our Conventional operations include reliable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a $CO_2$ enhanced oil recovery project in Weyburn, our heavy oil asset at Pelican Lake that uses polymer flood and waterflood technology and emerging tight oil assets in Alberta. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced. The cash flows generated in our Conventional segment helps to fund future growth opportunities in our Oil Sands segment while our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations.

Significant developments that impacted our Conventional segment in 2016 compared with 2015 include:

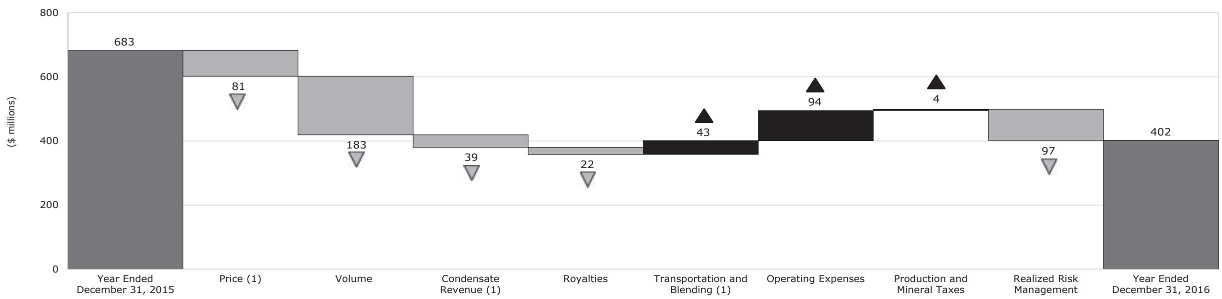
- Reducing our crude oil operating costs by $94 million or $1.60 per barrel;
- Crude oil and natural gas Netbacks, excluding realized risk management activities, of $16.17 per barrel (2015 – $20.92 per barrel) and $1.00 per Mcf (2015 – $1.58 per Mcf), respectively;
- Generating Operating Margin net of capital investment of $373 million, a decrease of 50 percent;
- Crude oil production averaging 56,165 barrels per day, decreasing 16 percent, due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in 2015; and
- Achieving a significant safety milestone with 25 years of employee lost-time-incident-free work at one of our operations.

## Conventional – Crude Oil

### *Financial Results*

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| **Gross Sales** | **936** | 1,239 | 2,456 |
| Less: Royalties | **125** | 103 | 217 |
| **Revenues** | **811** | 1,136 | 2,239 |
| **Expenses** | | | |
| Transportation and Blending | **170** | 213 | 326 |
| Operating | **287** | 381 | 505 |
| Production and Mineral Taxes | **12** | 16 | 37 |
| (Gain) Loss on Risk Management | **(60)** | (157) | 4 |
| **Operating Margin** | **402** | 683 | 1,367 |
| Capital Investment | **161** | 231 | 812 |
| **Operating Margin Net of Related Capital Investment** | **241** | 452 | 555 |

### 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

*Pricing*

Our Conventional crude oil assets produce a diverse spectrum of crude oils, ranging from heavy oil, which secures a price based on the WCS benchmark, to light oil, which secures a price closer to the WTI benchmark.

Our crude oil sales price averaged $40.67 per barrel in 2016, a nine percent decrease from 2015, due to lower crude oil benchmark prices, adjusted for applicable differentials, partially offset by a decline in the cost of condensate used for blending our heavy oil. As the cost of condensate decreases relative to the price of blended crude oil, our heavy oil sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising price environment, we expect to see some benefit in our heavy oil sales price as we are using condensate purchased at a lower price earlier in the year.

*Production Volumes*

| (barrels per day) | 2016 | Percent Change | 2015 | Percent Change | 2014 |
|---|---|---|---|---|---|
| Heavy Oil | **29,185** | **(16)%** | 34,888 | (12)% | 39,546 |
| Light and Medium Oil | **25,915** | **(15)%** | 30,486 | (12)% | 34,531 |
| NGLs | **1,065** | **(15)%** | 1,253 | 3% | 1,221 |
| | **56,165** | **(16)%** | 66,627 | (12)% | 75,298 |

Production decreased as a result of expected natural declines and the sale of our royalty interest and mineral fee title lands business in 2015. Divested assets contributed 2,555 barrels per day in 2015. Production also decreased due to reduced capital investment.

*Condensate*

The heavy oil currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Our blending ratios for Conventional heavy oil range between 10 percent and 16 percent. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the widening of the WCS-Condensate differential in 2016, the proportion of the cost of recovered condensate decreased.

*Royalties*

Royalties increased $22 million in 2016 primarily due to additional royalty burdens from the sale of our royalty interest and mineral fee title lands business in 2015. In addition, royalties increased due to lower allowable operating and capital costs at Pelican Lake and Weyburn, partially offset by a reduction in sales volumes and lower sales prices. In 2016, the effective crude oil royalty rate for our Conventional properties was 16.3 percent (2015 – 9.9 percent).

Crown royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project, therefore royalties are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and sales prices. Net profits are a function of sales volumes, sales prices and allowed operating and capital costs. The Pelican Lake royalty calculation was based on net profits in 2016 and 2015.

In 2016, production and mineral taxes decreased consistent with the decline in crude oil prices, and due to the sale of our royalty interest and mineral fee title lands business in 2015.

### Expenses

*Transportation and Blending*

Transportation and blending costs decreased $43 million in 2016. Blending costs declined due to a reduction in condensate volumes, consistent with lower production, and a decrease in condensate prices. In 2015, we recorded a $7 million write-down of our crude oil and condensate inventory to net realizable value as a result of the decline in crude oil prices. There was no inventory write-down in 2016.

Transportation charges were lower largely due to a decline in sales volumes, partially offset by higher transportation costs associated with optimizing our sales and additional costs due to pipeline capacity commitments in excess of our current production.

*Operating*

Primary drivers of our operating expenses for 2016 were workforce costs, workover activities, electricity, property taxes and lease costs, repairs and maintenance, and chemical costs. Operating expenses declined $94 million or $1.60 per barrel.

The per-unit decline was primarily due to:

- A decrease in repairs and maintenance and workover costs due to a focus on critical activities;
- Lower chemical costs associated with reduced polymer consumption and chemical optimization;
- Workforce reductions; and
- A decline in electricity costs as a result of lower prices and a decrease in consumption.

These decreases were partially offset by lower production.

### Netbacks [1]

| | **Heavy Oil** | | | **Light and Medium** | | |
|---|---|---|---|---|---|---|
| ($/bbl) | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| Sales Price [2] | **35.82** | 39.95 | 76.25 | **46.48** | 50.64 | 88.30 |
| Royalties | **3.31** | 2.97 | 7.09 | **9.28** | 5.66 | 9.15 |
| Transportation and Blending [2] | **4.60** | 3.36 | 3.29 | **2.73** | 2.91 | 3.34 |
| Operating Expenses | **13.38** | 15.92 | 20.51 | **15.65** | 16.27 | 16.98 |
| Production and Mineral Taxes | **0.01** | 0.04 | 0.18 | **1.24** | 1.41 | 2.70 |
| **Netback Excluding Realized Risk Management [3]** | **14.52** | 17.66 | 45.18 | **17.58** | 24.39 | 56.13 |
| Realized Risk Management Gain (Loss) | **3.18** | 6.77 | (0.03) | **3.11** | 6.79 | (0.08) |
| **Netback Including Realized Risk Management** | **17.70** | 24.43 | 45.15 | **20.69** | 31.18 | 56.05 |

*(1) Non-GAAP measure defined in this MD&A. Refer to the Operating Results section of this MD&A for details.*
*(2) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate, which is blended with the heavy oil.*
*(3) Netbacks do not reflect non-cash write-downs of product inventory until the product is sold.*

*Risk Management*

Risk management activities for 2016 resulted in realized gains of $60 million (2015 – $157 million), consistent with our contract prices exceeding average benchmark prices.

## Conventional – Natural Gas

### *Financial Results*

| ($ millions) | **2016** | 2015 | 2014 |
|---|---|---|---|
| **Gross Sales** | **321** | 450 | 744 |
| Less: Royalties | **14** | 11 | 12 |
| **Revenues** | **307** | 439 | 732 |
| **Expenses** | | | |
| Transportation and Blending | **16** | 17 | 20 |
| Operating | **152** | 175 | 198 |
| Production and Mineral Taxes | **-** | 2 | 9 |
| (Gain) Loss on Risk Management | **2** | (52) | (5) |
| **Operating Margin** | **137** | 297 | 510 |
| Capital Investment | **10** | 13 | 28 |
| **Operating Margin Net of Related Capital Investment** | **127** | 284 | 482 |

Operating Margin from natural gas continued to help fund growth opportunities in our Oil Sands segment.

### Revenues

*Pricing*

In 2016, our average natural gas sales price decreased 20 percent to $2.33 per Mcf, consistent with the decline in the AECO benchmark price.

*Production*

Production decreased 11 percent to 377 MMcf per day in 2016 due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in 2015, which produced 10 MMcf per day in 2015.

*Royalties*

Royalties increased compared with 2015. Reduced royalties due to lower prices and production declines were offset by additional royalty burdens from the sale of our royalty interest and mineral fee title lands business in 2015. The average royalty rate in 2016 was 4.7 percent (2015 – 2.7 percent).

### Expenses

*Transportation*

In 2016, transportation costs decreased slightly primarily due to lower sales volumes, partially offset by additional charges from a true-up of 2015 transportation contracts.

*Operating*

Primary drivers of our operating expenses were property taxes and lease costs, workforce, and repairs and maintenance. In 2016, operating expenses decreased by $23 million primarily due to lower workforce costs, repairs and maintenance, and a decline in electricity costs from lower pricing.

*Risk Management*

Risk management activities resulted in realized losses of $2 million in 2016 (2015 – realized gains $52 million), consistent with average benchmark prices exceeding our contract prices.

## Conventional – Capital Investment

| ($ millions) | **2016** | 2015 | 2014 |
|---|---|---|---|
| Heavy Oil | **44** | 63 | 338 |
| Light and Medium Oil | **117** | 168 | 474 |
| Natural Gas | **10** | 13 | 28 |
| **Capital Investment** (1) | **171** | 244 | 840 |

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

Capital investment in 2016 was primarily related to drilling stratigraphic test wells for tight oil, maintenance capital and spending for our $CO_2$ enhanced oil recovery project at Weyburn. Capital investment declined compared with 2015 primarily due to spending reductions on crude oil activities in response to the low commodity price environment.

***Drilling Activity***

| (net wells, unless otherwise stated) | **2016** | 2015 | 2014 |
|---|---|---|---|
| Crude Oil | **9** | 32 | 126 |
| Recompletions | **69** | 724 | 803 |
| Gross Stratigraphic Test Wells | **58** | 13 | 30 |
| Other [1] | **-** | 3 | 40 |

*(1) Includes dry and abandoned, observation and service wells.*

Drilling activity in 2016 focused on drilling stratigraphic test wells for tight oil, and natural gas recompletions performed to optimize production.

**Future Capital Investment**

With the expectation of continued crude oil price volatility in 2017, we are taking a more moderate approach to developing our conventional crude oil opportunities. We plan to focus on drilling projects that are considered to be relatively low risk, with short production cycle times and strong expected returns.

Our 2017 crude oil capital investment forecast is between $275 million and $325 million with spending plans mainly focused on sustaining capital and tight oil opportunities in southern Alberta. For more information, we direct our readers to review the news release for our 2017 guidance dated December 8, 2016. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

**DD&A, Exploration Expense and Goodwill Impairment**

***DD&A***

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.

Conventional DD&A decreased $581 million in 2016 primarily due to lower DD&A rates, a decrease in asset impairments, and a decline in sales volumes.

The average depletion rate decreased approximately 30 percent in 2016 as the impact of lower proved reserves due to the slowdown of our development plans was more than offset by lower PP&E. PP&E declined primarily due to impairment losses and a decrease in estimated decommissioning costs. Future development costs, which compose approximately 40 percent of the depletable base, declined from 2015 due to minimal capital investment planned at Pelican Lake in the near term.

Earlier in 2016, we recorded a $380 million impairment loss for our Northern Alberta CGU (2015 – $184 million) primarily due to a decline in long-term forward heavy crude oil prices. In the fourth quarter of 2016, we reversed $400 million of impairment losses, net of the DD&A that would have been recorded had no impairments occurred. The reversal arose due to the increase in the CGU’s estimated recoverable amount caused by an average reduction in expected future operating costs of five percent and lower future development costs, partially offset by a decline in estimated reserves. This resulted in a net impairment reversal in 2016 of $20 million.

We also recorded a $65 million (2015 – $ nil) impairment loss earlier in 2016 related to our Suffield CGU. Due to an increase in the estimated recoverable amount of the CGU caused by a decline in expected future royalties, the full impairment loss, net of DD&A ($62 million) was reversed.

In 2016, we recognized impairment losses of $20 million related primarily to equipment that was written down to its recoverable amount.

DD&A in 2015 compared to 2014 increased $66 million primarily due to impairment losses of $184 million in 2015 compared with $65 million in 2014, and higher DD&A rates, partially offset by lower sales volumes. The 2014 impairment loss related to equipment that we did not have future plans for and the shut-in and abandonment of a natural gas property.

***Exploration Expense***

There was no exploration expense recorded in 2016. In 2015, we expensed $71 million (2014 – $82 million) related to exploration assets within the Northern Alberta and Saskatchewan CGUs that were deemed not to be technically feasible and commercially viable.

***Goodwill Impairment***

In 2014, we recorded $497 million of goodwill impairment associated with our Pelican Lake property.

## REFINING AND MARKETING

Cenovus is a 50 percent partner in the Wood River and Borger refineries (the “Refineries”), which are located in the U.S. Our Refining and Marketing segment positions us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated approach provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to the Refineries. This segment captures our marketing and transportation initiatives as well as our crude-by-rail terminal operations located in Bruderheim, Alberta. In 2016, we loaded an average of 11,584 gross barrels per day (2015 – 6,530 gross barrels per day).

Significant developments that impacted our Refining and Marketing segment in 2016 compared with 2015 includes:

- Successfully completing the debottlenecking project at Wood River in the third quarter of 2016;
- Increasing crude utilization as a result of strong performance at the Refineries; and
- Generating Operating Margin of $346 million, a 10 percent decline from 2015.

### Refinery Operations (1)

| | 2016 | 2015 | 2014 |
|---|---|---|---|
| **Crude Oil Capacity** (Mbbls/d) | **460** | 460 | 460 |
| **Crude Oil Runs** (Mbbls/d) | **444** | 419 | 423 |
| Heavy Crude Oil | **233** | 200 | 199 |
| Light/Medium | **211** | 219 | 224 |
| **Refined Products** (Mbbls/d) | **471** | 444 | 445 |
| Gasoline | **236** | 228 | 231 |
| Distillate | **146** | 137 | 137 |
| Other | **89** | 79 | 77 |
| **Crude Utilization** (percent) | **97** | 91 | 92 |

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

On a 100-percent basis, the Refineries have a total processing capacity of approximately 460,000 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. 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 WCS 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.

In 2016, crude oil runs and refined product output increased. Strong performance at the Refineries was slightly offset by planned and unplanned maintenance in 2016. In 2015, performance was impacted by unplanned outages and planned turnarounds at the Refineries. Higher heavy crude oil volumes were processed in 2016 primarily due to the optimization of the total crude input slate.

### Refining and Marketing Financial Results

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Revenues | **8,439** | 8,805 | 12,658 |
| Purchased Product | **7,325** | 7,709 | 11,767 |
| **Gross Margin** | **1,114** | 1,096 | 891 |
| **Expenses** | | | |
| Operating | **742** | 754 | 703 |
| (Gain) Loss on Risk Management | **26** | (43) | (27) |
| **Operating Margin** | **346** | 385 | 215 |
| Capital Investment | **220** | 248 | 163 |
| **Operating Margin Net of Related Capital Investment** | **126** | 137 | 52 |

#### *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, 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 2016, Refining and Marketing gross margin increased primarily due to:

- Wider heavy and medium crude oil differentials;
- Higher utilization rates;
- A weaker Canadian dollar relative to the U.S. dollar, which had a positive impact of approximately $36 million on the gross margin;
- An increase in third party crude oil and natural gas sales, primarily due to higher sales volumes and a rise in crude oil sales prices, partially offset by lower natural gas sales prices and an increase in purchased volumes; and
- An inventory write-down of $4 million (2015 – $15 million) related to refined product inventory.

The increase in gross margin was partially offset by lower average market crack spreads and higher costs associated with Renewable Identification Numbers ("RINs"). The Refineries do not blend renewable fuels into the motor fuel products produced. Consequently, to meet the renewable fuel standards, RINs must be purchased. In 2016, the cost of RINs was $294 million (2015 – $200 million). The increase is consistent with the 49 percent increase in the ethanol RINs benchmark price.

***Expenses***

Primary drivers of operating expenses in 2016 were labour, maintenance and utilities. Reported operating expenses declined primarily due to fewer maintenance activities associated with unplanned outages and planned turnarounds and a decrease in utility costs, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar.

**Refining and Marketing – Capital Investment**

| ($ millions) | **2016** | 2015 | 2014 |
|---|---|---|---|
| Wood River Refinery | **147** | 162 | 101 |
| Borger Refinery | **66** | 78 | 61 |
| Marketing | **7** | 8 | 1 |
| | **220** | 248 | 163 |

Capital expenditures in 2016 focused on completing the debottlenecking project at Wood River, capital maintenance, projects improving the refinery reliability and safety, and environmental initiatives. The Wood River debottlenecking project was successfully completed in the third quarter of 2016. The amount of heavy crude oil processed continues to be dependent on the optimization of the total input slate.

In 2017, we expect to invest between $210 million and $240 million mainly related to capital maintenance and reliability work. For more information, we direct our readers to review the news release for our 2017 guidance dated December 8, 2016. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

***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 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by $20 million in 2016 primarily due to the change in the U.S./Canadian dollar exchange rate.

## CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, and the unrealized mark-to-market gains and losses on the power purchase contract and interest rate swaps. In 2016, our risk management activities resulted in $554 million of unrealized losses (2015 – $195 million of unrealized losses).

The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing costs and research costs.

| ($ millions) | **2016** | 2015 | 2014 |
|---|---|---|---|
| General and Administrative | **326** | 335 | 379 |
| Finance Costs | **492** | 482 | 445 |
| Interest Income | **(52)** | (28) | (33) |
| Foreign Exchange (Gain) Loss, Net | **(198)** | 1,036 | 411 |
| Research Costs | **36** | 27 | 15 |
| (Gain) Loss on Divestiture of Assets | **6** | (2,392) | (156) |
| Other (Income) Loss, Net | **34** | 2 | (4) |
| | **644** | (538) | 1,057 |

***Expenses***

**General and Administrative**

Primary drivers of our general and administrative expense in 2016 were workforce, office rent and information technology costs. General and administrative expenses decreased by $9 million primarily due to a decline in workforce costs related to larger workforce reductions in 2015, lower information technology costs, and reduced discretionary spending. In 2016, severance payments were $19 million (2015 – $43 million). The decrease in general and administrative expenses was partially offset by a $61 million non-cash expense recorded in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements, and an increase in long-term employee incentive costs primarily due to an increase in our share price.

**Finance Costs**

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated partnership contribution payable (that was repaid in March 2014), as well as the unwinding of the discount on decommissioning liabilities. Finance costs increased $10 million in 2016 compared with 2015 primarily due to the weakening of the Canadian dollar relative to the U.S. dollar.

The weighted average interest rate on outstanding debt for 2016 was 5.3 percent (2015 – 5.3 percent).

### Foreign Exchange

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Unrealized Foreign Exchange (Gain) Loss | **(189)** | 1,097 | 411 |
| Realized Foreign Exchange (Gain) Loss | **(9)** | (61) | - |
| | **(198)** | 1,036 | 411 |

The majority of unrealized foreign exchange gains in 2016 stem from translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar was three percent stronger at December 31, 2016 compared with December 31, 2015, resulting in unrealized gains.

### Other Income (Loss), Net

In November 2016, the Government of Canada rendered its decision to reject the Northern Gateway Pipeline project. As a result, we wrote-off $23 million of costs associated with the project and recorded $7 million of expected costs associated with termination.

### DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. 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. DD&A in 2016 was $65 million (2015 – $78 million).

### Income Tax

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| Current Tax | | | |
| Canada | **(174)** | 586 | 94 |
| United States | **1** | (12) | (2) |
| **Total Current Tax Expense (Recovery)** | **(173)** | 574 | 92 |
| **Deferred Tax Expense (Recovery)** | **(209)** | (655) | 359 |
| | **(382)** | (81) | 451 |

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

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| **Earnings (Loss) Before Income Tax** | **(927)** | 537 | 1,195 |
| Canadian Statutory Rate | **27.0%** | 26.1% | 25.2% |
| **Expected Income Tax (Recovery)** | **(250)** | 140 | 301 |
| Effect of Taxes Resulting From: | | | |
| Foreign Tax Rate Differential | **(46)** | (41) | (43) |
| Non-Deductible Stock-Based Compensation | **5** | 7 | 13 |
| Non-Taxable Capital (Gains) Losses | **(26)** | 137 | 74 |
| Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange | **(26)** | 135 | 50 |
| Adjustments Arising From Prior Year Tax Filings | **(46)** | (55) | (16) |
| Derecognition (Recognition) of Capital Losses | **-** | (149) | (9) |
| (Recognition) of U.S. Tax Basis | **-** | (415) | - |
| Change in Statutory Rate | **-** | 161 | - |
| Foreign Exchange Gain (Loss) not Included in Net Earnings (Loss) | **-** | - | (13) |
| Goodwill Impairment | **-** | - | 125 |
| Other | **7** | (1) | (31) |
| **Total Tax (Recovery)** | **(382)** | (81) | 451 |
| **Effective Tax Rate** | **41.2%** | (15.1)% | 37.7% |

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.

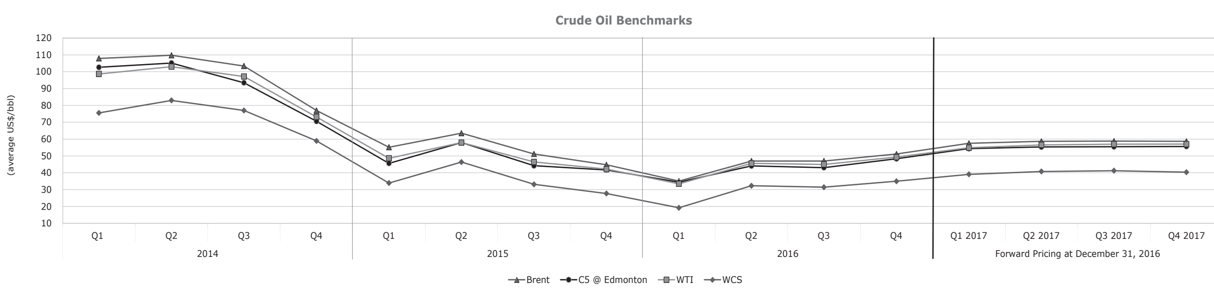
In 2016, we incurred losses for income tax purposes in Canada which will be carried back to recover income taxes previously paid or recognized as a deferred tax recovery. A current tax recovery was also recognized due to prior year adjustments. In 2015, current income tax expense included $391 million attributable to the sale of our royalty interest and mineral fee title lands.

In 2016, a deferred tax recovery was recorded. The recovery was largely due to unrealized risk management losses and the recognition of current year operating losses that will be claimed in a future period. In 2015, we recorded a deferred tax recovery of $415 million arising from an adjustment to the tax basis of our refining assets. Furthermore, a one-time charge of approximately $161 million was recorded in 2015 from the revaluation of our deferred tax liability due to the increase in the Alberta corporate tax rate offset by operating losses deferred for tax purposes.

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 higher U.S. tax rates, non-taxable unrealized 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.

## QUARTERLY RESULTS

Our quarterly results over the last eight quarters were impacted primarily by volatility in commodity prices. A substantial downward shift in the commodity price environment occurred late in 2014 and low crude oil prices continued throughout 2015 and 2016. Crude oil prices reached a 13 year low, with WTI averaging US$33.45 per barrel in the first quarter of 2016 and gradually increasing to an average of US$49.29 per barrel in the fourth quarter of 2016. Average WTI and WCS benchmark prices increased 17 percent and 26 percent, respectively in the fourth quarter of 2016 compared with 2015. Our companywide Netback of $21.61 per BOE in December 2016, before realized risk management activities, was the highest it has been since July 2015.




| ($ millions, except per share amounts or where otherwise indicated) | 2016 Q4 | 2016 Q3 | 2016 Q2 | 2016 Q1 | 2015 Q4 | 2015 Q3 | 2015 Q2 | 2015 Q1 | 2014 Q4 |
|---|---|---|---|---|---|---|---|---|---|
| **Production Volumes** | | | | | | | | | |
| Crude Oil (bbls/d) | **219,551** | **208,072** | **198,080** | **197,551** | 199,556 | 210,422 | 199,954 | 218,020 | 216,177 |
| Natural Gas (MMcf/d) | **379** | **392** | **399** | **408** | 424 | 430 | 450 | 462 | 479 |
| **Refinery Operations** | | | | | | | | | |
| Crude Oil Runs (Mbbls/d) | **421** | **463** | **458** | **435** | 405 | 394 | 441 | 439 | 420 |
| Refined Products (Mbbls/d) | **448** | **494** | **483** | **460** | 430 | 414 | 462 | 469 | 442 |
| **Revenues** | **3,642** | **3,240** | **3,007** | **2,245** | 2,924 | 3,273 | 3,726 | 3,141 | 4,238 |
| **Operating Margin** [(1)] | **595** | **487** | **541** | **144** | 357 | 602 | 932 | 548 | 537 |
| **Cash From Operating Activities** | **164** | **310** | **205** | **182** | 322 | 542 | 335 | 275 | 868 |
| **Adjusted Funds Flow** [(2)] | **535** | **422** | **440** | **26** | 275 | 444 | 477 | 495 | 401 |
| **Operating Earnings (Loss)** [(2)] | **321** | **(236)** | **(39)** | **(423)** | (438) | (28) | 151 | (88) | (590) |
| Per Share – Diluted ($) | **0.39** | **(0.28)** | **(0.05)** | **(0.51)** | (0.53) | (0.03) | 0.18 | (0.11) | (0.78) |
| **Net Earnings (Loss)** | **91** | **(251)** | **(267)** | **(118)** | (641) | 1,801 | 126 | (668) | (472) |
| Per Share – Basic and Diluted ($) | **0.11** | **(0.30)** | **(0.32)** | **(0.14)** | (0.77) | 2.16 | 0.15 | (0.86) | (0.62) |
| **Capital Investment** [(3)] | **259** | **208** | **236** | **323** | 428 | 400 | 357 | 529 | 786 |
| **Dividends** | | | | | | | | | |
| Cash Dividends | **42** | **41** | **42** | **41** | 132 | 133 | 125 | 138 | 201 |
| In Shares From Treasury | **-** | **-** | **-** | **-** | - | - | 98 | 84 | - |
| Per Share ($) | **0.05** | **0.05** | **0.05** | **0.05** | 0.16 | 0.16 | 0.2662 | 0.2662 | 0.2662 |

*(1) Additional subtotal found in Note 1 of the Consolidated Financial Statements and defined in this MD&A.*
*(2) Non-GAAP measure defined in this MD&A.*
*(3) Includes expenditures on PP&E and E&E assets.*

## Fourth Quarter 2016 Results Compared With the Fourth Quarter 2015

### *Production Volumes*

Total crude oil production increased 10 percent primarily due to incremental production volumes from Foster Creek phase G and Christina Lake phase F, which started-up in the third quarter and fourth quarter of 2016, respectively, partially offset by expected natural declines from our conventional production. Natural gas production in the fourth quarter of 2016 decreased 11 percent due to expected natural declines. We continued to focus capital investment on high rate of return projects and directed the majority of our total capital investment to our crude oil properties.

### *Refinery Operations*

Crude oil runs and refined product output increased in 2016, despite unplanned outages at the Borger refinery. In 2015, the Wood River refinery experienced planned and unplanned outages in the fourth quarter.

### *Revenue*

Revenues increased $718 million primarily due to:

- Higher revenues from third-party crude oil and natural gas sales undertaken by the marketing group. The increase was largely due to higher purchased crude oil volumes and a rise in crude oil sales prices;
- A 43 percent rise in crude oil sales prices (excluding financial hedging) to $39.38 per barrel;
- An increase in refining revenues largely due to a rise in refined product output and higher refined product prices; and
- An eight percent increase in crude oil sales volumes.

The increases to revenues were partially offset by higher crude oil royalties.

### *Operating Margin*

Operating Margin increased 67 percent in the three months ended December 31, 2016 compared with 2015. Upstream Operating Margin rose 23 percent due to higher crude oil and natural gas sales prices, and an increase in crude oil sales volumes, partially offset by realized risk management gains of $15 million compared with gains of $223 million in 2015.

Refining and Marketing Operating Margin increased by $148 million. The increase was due to a rise in refined product output, higher utilization rates, a decline in feedstock costs and lower operating costs, partially offset by a decline in average market crack spreads and realized risk management losses compared to gains in 2015.

### *Cash From Operating Activities and Adjusted Funds Flow*

Cash From Operating Activities and Adjusted Funds Flow increased in the fourth quarter of 2016 compared with 2015, primarily due to a higher Operating Margin, as discussed above, and higher severance costs in 2015, partially offset by a lower current income tax recovery in 2016. In 2016, the change in working capital was primarily due to a rise in commodity prices increasing the value of accounts receivables, accounts payable and inventory. In 2015, commodity prices experienced a significant decline, which decreased inventory values.

### *Operating Earnings (Loss)*

In the fourth quarter of 2016, Operating Earnings was $321 million compared with a loss of $438 million in 2015. The improvement was primarily due to a decline in DD&A, related to the reversal of $462 million of impairment losses and lower DD&A rates, an increase in Cash From Operating Activities and Adjusted Funds Flow, as discussed above, and a decline in exploration expense. This was partially offset by an asset impairment of $23 million and termination costs of $7 million as a result of the Government of Canada's decision to reject the Northern Gateway Pipeline project.

The impairment reversal arose primarily due to the increase in our Northern Alberta CGU's estimated recoverable amount caused by an average reduction in expected future operating costs and lower future development costs, partially offset by a decline in estimated reserves. In 2015, we recorded $200 million of impairment losses primarily related to our Northern Alberta CGU due to a decline in long-term forward heavy crude oil prices. There was no exploration expense recorded in 2016. In 2015, we expensed $117 million related to exploration assets that were deemed not to be technically feasible and commercially viable.

### *Net Earnings (Loss)*

In 2016, Net Earnings of $91 million included unrealized risk management losses of $114 million and non-operating foreign exchange losses of $147 million. In 2015, we had a Net Loss of $641 million which included unrealized risk management losses of $26 million and non-operating foreign exchange losses of $212 million.

### *Capital Investment*

Capital investment in the fourth quarter of 2016 was $259 million, a 39 percent decrease from 2015 primarily due to lower spending in our Oil Sands and Conventional segments. Capital investment was reduced with the intent of conserving cash and maintaining the strength of our balance sheet in light of the low commodity price environment.

## OIL AND GAS RESERVES AND RESOURCES

We retain IQREs to evaluate and prepare reports on 100 percent of our bitumen, heavy oil, light and medium oil, NGLs, natural gas and coal bed methane ("CBM") proved and probable reserves and 100 percent of our contingent and prospective bitumen resources recoverable using established technology.

Developments in 2016 compared with 2015 include:

- Bitumen proved reserves increasing seven percent primarily due to Christina Lake adding 186 million barrels of proved reserves resulting from regulatory approval of the Kirby East area expansion converting probable reserves to proved reserves, and from improved reservoir performance;
- Proved plus probable bitumen reserves increasing one percent as improved reservoir performance at Foster Creek and Christina Lake offset 2016 production;
- Both heavy oil proved reserves and heavy oil proved plus probable reserves declining 14 percent primarily due to the deferral of drilling at Pelican Lake;
- Light and medium oil and NGLs proved reserves and light and medium oil and NGLs proved plus probable reserves decreasing eight percent and six percent, respectively, as production exceeded additions;
- Natural gas proved reserves declining 10 percent and natural gas proved plus probable reserves decreasing nine percent as additions and improved performance was more than offset by reductions due to production; and
- Bitumen best estimate economic contingent resources decreasing five percent to 8.8 billion barrels and bitumen best estimate prospective resources decreasing three percent to 7.1 billion barrels, both primarily due to a slightly lower recovery factor for select properties with increased well pair spacing.

The reserves and resources data that follows is presented as at December 31, 2016 using McDaniel & Associates Consultants Ltd.'s ("McDaniel's") January 1, 2017 forecast prices and inflation. Comparative information as at December 31, 2015 uses McDaniel's January 1, 2016 forecast prices and inflation.

### Reserves

| As at December 31, | Bitumen (MMbbls) | | Heavy Oil (MMbbls) | | Light & Medium Oil & NGLs (MMbbls) | | Natural Gas & CBM (Bcf) | |
|---|---|---|---|---|---|---|---|---|
| (before royalties) | **2016** | 2015 | **2016** | 2015 | **2016** | 2015 | **2016** | 2015 |
| Proved | **2,343** | 2,183 | **114** | 133 | **101** | 110 | **652** | 721 |
| Probable | **976** | 1,115 | **75** | 87 | **44** | 44 | **212** | 232 |
| **Proved plus Probable** | **3,319** | 3,298 | **189** | 220 | **145** | 154 | **864** | 953 |

### Reconciliation of Proved Reserves

| (before royalties) | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| December 31, 2015 | **2,183** | **133** | **110** | **721** |
| Extensions and Improved Recovery | **154** | **-** | **-** | **-** |
| Technical Revisions | **61** | **(8)** | **1** | **79** |
| Dispositions | **-** | **-** | **-** | **(1)** |
| Production (1) | **(55)** | **(11)** | **(10)** | **(147)** |
| **December 31, 2016** | **2,343** | **114** | **101** | **652** |
| Year Over Year Change | **160** | **(19)** | **(9)** | **(69)** |
| | **7%** | **(14)%** | **(8)%** | **(10)%** |

*(1) Production includes the natural gas used as a fuel source in our oil sands operations and excludes royalty interest production.*

### Reconciliation of Probable Reserves

| (before royalties) | Bitumen (MMbbls) | Heavy Oil (MMbbls) | Light & Medium Oil & NGLs (MMbbls) | Natural Gas & CBM (Bcf) |
|---|---|---|---|---|
| December 31, 2015 | **1,115** | **87** | **44** | **232** |
| Technical Revisions | **(139)** | **(12)** | **-** | **(20)** |
| **December 31, 2016** | **976** | **75** | **44** | **212** |
| Year Over Year Change | **(139)** | **(12)** | **-** | **(20)** |
| | **(12)%** | **(14)%** | **-%** | **(9)%** |

### Contingent and Prospective Resources

| As at December 31, (billions of barrels, before royalties) | Bitumen 2016 | 2015 |
|---|---|---|
| **Economic Contingent Resources** [1] | | |
| Best Estimate | **8.8** | 9.3 |
| **Prospective Resources** [1] [2] | | |
| Best Estimate | **7.1** | 7.4 |

(1) *See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and best estimates. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.*
(2) *There is uncertainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Prospective resources are not screened for economic viability.*

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), and material risks and uncertainties associated with estimates of reserves is contained in our AIF for the year ended December 31, 2016. Further information with respect to contingent and prospective resources including material risks and uncertainties, project descriptions, significant factors relevant to the resource estimates, and contingencies which prevent the classification of contingent resources as reserves is contained in our supplemental Statement of Contingent and Prospective Resources for the year ended December 31, 2016. Both our AIF and the Statement of Contingent and Prospective Resources are available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com.

## LIQUIDITY AND CAPITAL RESOURCES

| ($ millions) | 2016 | 2015 | 2014 |
|---|---|---|---|
| **Cash From (Used In)** | | | |
| Operating Activities | **861** | 1,474 | 3,526 |
| Investing Activities | **(1,079)** | 888 | (4,350) |
| **Net Cash Provided (Used) Before Financing Activities** | **(218)** | 2,362 | (824) |
| Financing Activities | **(168)** | 894 | (797) |
| Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency | **1** | (34) | 52 |
| **Increase (Decrease) in Cash and Cash Equivalents** | **(385)** | 3,222 | (1,569) |

| As at December 31, | 2016 | 2015 | 2014 |
|---|---|---|---|
| **Cash and Cash Equivalents** | **3,720** | 4,105 | 883 |
| **Committed and Undrawn Credit Facility** | **4,000** | 4,000 | 3,000 |

### Cash From (Used In) Operating Activities

Cash From Operating Activities decreased in 2016 mainly due to lower Operating Margin, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, working capital was $4,423 million at December 31, 2016 compared with $4,337 million at December 31, 2015. The change in working capital was due to the improvement of commodity prices at the end of 2016 compared with 2015, resulting in higher accounts receivable, accounts payable, and Refining and Marketing inventory values. In addition, crude oil inventory volumes rose year over year.

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

### Cash From (Used In) Investing Activities

In 2016, cash used in investing activities was primarily for capital investment. In 2015, the divestiture of our royalty interest and mineral fee title lands business for approximately $2.9 billion, net of tax, resulted in net cash generated by investing activities.

### Cash From (Used In) Financing Activities

In 2016, financing activities included dividend payments of $0.20 per share or $166 million (2015 – $0.8524 per share or $710 million, of which $528 million was paid in cash). The declaration of dividends is at the sole discretion of the Board and is considered quarterly. In 2015, cash from financing activities included net proceeds of $1.4 billion from the issuance of common shares which was partially offset by a net repayment of short-term borrowings.

Our long-term debt at December 31, 2016 was $6,332 million (2015 – $6,525 million) with no principal payments due until October 2019 (US$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars has remained unchanged since August 2012. The $193 million decrease in long-term debt is due to the change in the Canadian dollar relative to the U.S. dollar.

As at December 31, 2016, we were in compliance with all of the terms of our debt agreements.

### Available Sources of Liquidity

We expect cash flows from our crude oil, natural gas and refining operations to fund a portion of our cash requirements. Any potential shortfalls may be required to be funded through prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us.

The following sources of liquidity are available at December 31, 2016:

| ($ millions) | Amount | Term |
|---|---|---|
| Cash and Cash Equivalents | **3,720** | **N/A** |
| Committed Credit Facility | **1,000** | **April 2019** |
| Committed Credit Facility | **3,000** | **November 2019** |
| Base Shelf Prospectus (1) | **US$5,000** | **March 2018** |

*(1) Availability is subject to market conditions.*

#### *Committed Credit Facility*

As at December 31, 2016, no amounts had been drawn on our committed credit facility.

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

See below for the Debt to Capitalization ratio used by Cenovus to monitor our capital structure.

#### *Base Shelf Prospectus*

On February 24, 2016, Cenovus filed a base shelf prospectus. The base shelf prospectus allows us 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 will expire in March 2018.

As at December 31, 2016, no issuances had been made under the prospectus.

### Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing 12-month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

Over the long-term, we target a Debt to Capitalization ratio of between 30 percent to 40 percent and a Debt to Adjusted EBITDA of between 1.0 times to 2.0 times. At different points within the economic cycle, we expect these ratios may periodically be outside of the target range.

Debt to Capitalization increased slightly as lower debt balances from the strengthening of the Canadian dollar relative to the U.S. dollar were offset by the decline in Shareholders' Equity. Debt to Adjusted EBITDA increased as a result of a decrease in Adjusted EBITDA, primarily due to a decline in commodity prices, partially offset by the lower long-term debt balance.

Debt to Capitalization and Net Debt to Capitalization are calculated as follows:

| As at December 31, | **2016** | 2015 | 2014 |
|---|---|---|---|
| Debt | **6,332** | 6,525 | 5,458 |
| Shareholders' Equity | **11,590** | 12,391 | 10,186 |
| Capitalization | **17,922** | 18,916 | 15,644 |
| **Debt to Capitalization** | **35%** | 34% | 35% |
| Net Debt (1) | **2,612** | 2,420 | 4,575 |
| Shareholders' Equity | **11,590** | 12,391 | 10,186 |
| Capitalization | **14,202** | 14,811 | 14,761 |
| **Net Debt to Capitalization** | **18%** | 16% | 31% |

*(1) Net Debt is defined as Debt net of Cash and Cash Equivalents.*

The following is a reconciliation of Adjusted EBITDA, and the calculations of Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA:

| As at December 31, | 2016 | 2015 | 2014 |
|---|---|---|---|
| **Debt** | **6,332** | 6,525 | 5,458 |
| **Net Debt** [1] | **2,612** | 2,420 | 4,575 |
| | | | |
| **Adjusted EBITDA** | | | |
| Net Earnings (Loss) | **(545)** | 618 | 744 |
| Add (Deduct): | | | |
| Finance Costs | **492** | 482 | 445 |
| Interest Income | **(52)** | (28) | (33) |
| Income Tax (Recovery) Expense | **(382)** | (81) | 451 |
| DD&A | **1,498** | 2,114 | 1,946 |
| Goodwill Impairment | **-** | - | 497 |
| E&E Impairment | **2** | 138 | 86 |
| Unrealized (Gain) Loss on Risk Management | **554** | 195 | (596) |
| Foreign Exchange (Gain) Loss, Net | **(198)** | 1,036 | 411 |
| (Gain) Loss on Divestiture of Assets | **6** | (2,392) | (156) |
| Other (Income) Loss, Net | **34** | 2 | (4) |
| | **1,409** | 2,084 | 3,791 |
| | | | |
| **Debt to Adjusted EBITDA** | **4.5x** | 3.1x | 1.4x |
| **Net Debt to Adjusted EBITDA** | **1.9x** | 1.2x | 1.2x |

*(1) Net Debt is defined as Debt net of Cash and Cash Equivalents.*

Additional information regarding our financial metrics 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, 2016, there were approximately 833 million common shares outstanding (2015 – 833 million common shares). Cenovus issued 76.2 million common shares in 2015, including 8.7 million shares issued under the dividend reinvestment plan and 67.5 million shares issued related to the common share issuance in the first quarter of 2015.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan as well as Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Refer to Note 27 of the Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

| As at January 31, 2017 | Units Outstanding (thousands) | Units Exercisable (thousands) |
|---|---|---|
| Common Shares | **833,290** | **N/A** |
| Stock Options | **44,982** | **33,379** |
| Other Stock-Based Compensation Plans [1] | **11,617** | **1,598** |

*(1) Includes PSUs, RSUs, and DSUs.*

### Contractual Obligations and Commitments

Cenovus has obligations for goods and services that were entered into in the normal course of business. Obligations are primarily related to demand charges on firm transportation agreements, operating leases on buildings, 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. The items below have been grouped as operating, investing and financing, relating to the type of cash outflow that will arise.

| ($ millions) | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| | Expected Payment Date | | | | | | |
| **Operating** | | | | | | | |
| Transportation and Storage (1) | 682 | 711 | 722 | 1,031 | 1,239 | 21,875 | **26,260** |
| Operating Leases (Building Leases) | 101 | 146 | 146 | 145 | 142 | 2,465 | **3,145** |
| Product Purchases | 70 | - | - | - | - | - | **70** |
| Other Long-term Commitments | 80 | 27 | 26 | 15 | 15 | 108 | **271** |
| Interest on Long-term Debt | 339 | 339 | 339 | 239 | 239 | 3,828 | **5,323** |
| Decommissioning Liabilities | 43 | 47 | 47 | 35 | 27 | 6,070 | **6,269** |
| Other | 19 | 10 | 7 | 6 | 4 | 16 | **62** |
| **Total Operating** | 1,334 | 1,280 | 1,287 | 1,471 | 1,666 | 34,362 | **41,400** |
| **Investing** | | | | | | | |
| Capital Commitments | 23 | 3 | - | - | - | - | **26** |
| **Total Investing** | 23 | 3 | - | - | - | - | **26** |
| **Financing** | | | | | | | |
| Long-term Debt (principal only) | - | - | 1,746 | - | - | 4,632 | **6,378** |
| Other | - | 1 | 1 | 1 | - | 3 | **6** |
| **Total Financing** | - | 1 | 1,747 | 1 | - | 4,635 | **6,384** |
| **Total Payments (2)** | 1,357 | 1,284 | 3,034 | 1,472 | 1,666 | 38,997 | **47,810** |
| Fixed Price Product Sales | 3 | - | - | - | - | - | **3** |

*(1) Includes transportation commitments of $19 billion that are subject to regulatory approval or have been approved but are not yet in service.*
*(2) Contracts on behalf of FCCL Partnership ("FCCL") and WRB Refining LP ("WRB") are reflected at our 50 percent interest.*

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

Commitments for various firm service pipeline transportation agreements were $26.3 billion, a decline of $1.1 billion from 2015. Our obligations were reduced primarily due to our use of contracts and changes in toll estimates. This was partially offset by increases to our U.S. dollar commitments due to the weakening of the Canadian dollar relative to the U.S. dollar. These agreements, some of which are subject to regulatory approval or have been approved but are not yet in service, are for terms up to 20 years subsequent to the date of commencement, and should help align our future transportation requirements with our anticipated production growth.

We continue to focus on near- and mid-term strategies to broaden market access for our crude oil production, as illustrated by our purchase in 2015 of our crude-by-rail terminal and exporting crude oil from the U.S. Gulf Coast. 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, assessing options to maximize the value of our crude oil by offering a wider range of products, including existing dilbit blends, partially upgraded bitumen, under-blended bitumen or dry bitumen, and potential expansions of our refining capacity as our production grows.

As at December 31, 2016, there were outstanding letters of credit aggregating $258 million issued as security for performance under certain contracts (December 31, 2015 – $64 million).

As at December 31, 2016, Cenovus remained a party to fixed price physical contracts for natural gas with a current delivery of approximately 21 MMcf per day, with varying terms and volumes through to February 1, 2017. The total volume to be delivered within the terms of these contracts is 11 Bcf of natural gas, at a weighted average price of $4.94 per Mcf.

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

### Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations. 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.

### Related Party Transactions

Cenovus did not enter into any related party transactions during the years ended December 31, 2016 or 2015, except for our key management compensation. A summary of key management compensation can be found in the notes to the Consolidated Financial Statements.

## RISK MANAGEMENT

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of risk across Cenovus.

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


### Risk Assessment

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

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

Management determines if additional risk treatment is required based on the residual risk ranking. There are prescribed actions for escalating and communicating risk to the right decision makers.

### Significant Risk Factors

The following discussion describes the financial, operational and regulatory risks relating to Cenovus and our operations. A description of the risk factors and uncertainties can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2016.

#### *Financial Risk*

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. From time to time, Management may enter into financially or physically settled contracts to mitigate risk associated with fluctuations of commodity prices, interest rates and foreign exchange rates.

#### Commodity Prices

Fluctuations in commodity prices and refined product prices impacts our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

Crude oil and natural gas prices are impacted by a number of factors, including but not limited to, global and regional supply and demand and economic conditions, the actions of OPEC, government regulation, political stability, transportation constraints, weather conditions and availability of alternative fuels, all of which are beyond our control and can result in a high degree of price volatility. Changing prices will affect the revenues generated by the sale of our production. Our financial performance is also affected by price differentials since our upstream production differs in quality and location from underlying benchmark commodity prices quoted on financial exchanges.

Commodity prices began to decline in the fourth quarter of 2014 and have remained at low levels throughout 2015 and 2016 with a gradual improvement starting in the second quarter of 2016. Should commodity prices decline or remain at current low levels, our capital spending could be reduced causing projects to be impaired, delayed or cancelled, and production could be curtailed or suspended, among other impacts.

Refined product prices are affected by several factors, including global supply and demand for refined products, weather conditions, and planned and unplanned refinery maintenance, all of which are beyond our control and can result in a high degree of price volatility. The financial performance of the Refineries is also impacted by margin volatility due to fluctuations in the supply and demand for refined products, crude oil costs, market competition, and seasonal factors when production changes to match seasonal demand.

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 the 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 and 32 to the Consolidated Financial Statements.

*Impact of Financial Risk Management Activities*

| | 2016 | | | 2015 | | |
|---|---|---|---|---|---|---|
| ($ millions) | **Realized** | **Unrealized** | **Total** | Realized | Unrealized | Total |
| Crude Oil | **(216)** | **560** | **344** | (571) | 123 | (448) |
| Natural Gas | **-** | **-** | **-** | (59) | 55 | (4) |
| Refining | **(1)** | **5** | **4** | (36) | 10 | (26) |
| Power | **6** | **(14)** | **(8)** | 10 | 5 | 15 |
| Interest Rate | **-** | **3** | **3** | - | 2 | 2 |
| **(Gain) Loss on Risk Management** | **(211)** | **554** | **343** | (656) | 195 | (461) |
| Income Tax Expense (Recovery) | **54** | **(150)** | **(96)** | 175 | (54) | 121 |
| **(Gain) Loss on Risk Management, After Tax** | **(157)** | **404** | **247** | (481) | 141 | (340) |

In 2016, we recorded realized gains on crude oil risk management activities, consistent with our contract prices exceeding the average benchmark price. We recorded unrealized losses on our crude oil financial instruments primarily due to the realization of settled positions, and changes in market prices.

*Commodity Price Sensitivities – Risk Management Positions*

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuations in commodity prices on risk management positions as at December 31, 2016 could have resulted in unrealized gains (losses) for the year as follows:

| Commodity | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude Oil Commodity Price | ± US$5.00 per bbl Applied to Brent, WTI and Condensate Hedges | **(198)** | **193** |
| Crude Oil Differential Price | ± US$2.50 per bbl Applied to Differential Hedges Tied to Production | **1** | **(1)** |
| Interest Rate Swaps | ± 50 Basis Points | **45** | **(52)** |

*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're unable to fulfill our delivery obligations related to the underlying physical transaction. Financial instruments may limit the benefit to Cenovus if commodity prices increase. These risks are minimized through hedging limits that are reviewed annually by the Board, as required by our Market Risk Mitigation Policy.

### Liquidity

Liquidity risk is the risk that we will not be able to meet all our financial obligations as they come due, be unable to liquidate assets in a timely manner at a reasonable price, or access capital markets at acceptable terms and conditions. In declining economic times, such as a low commodity price environment, or due to unforeseen events that impact financial markets, our liquidity risk could become heightened.

Liquidity risk is further impacted by the amount and timing of financial and operating commitments, future capital expenditures, debt repayments as well as available sources of liquidity, which may be impacted by our credit ratings. If we were unable to meet our financial obligations as they became due or unable to liquidate assets in a timely manner at a reasonable price, this could have a material adverse effect on our financial condition, results of operations, cash flows, access to capital, ability to comply with various financial and operating covenants, credit ratings and reputation.

We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including, but not limited to, cash and cash equivalents, Cash From Operating Activities, an undrawn credit facility and availability under our base shelf prospectus. At December 31, 2016, we had cash and cash equivalents of $3.7 billion. No amounts were drawn on our $4.0 billion committed credit facility. In addition, we had US$5.0 billion in unused capacity under our base shelf prospectus, the availability of which is dependent on market conditions.

### Foreign Exchange Rates

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, we have chosen to borrow U.S. dollar long-term debt. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars. To manage exposure to exchange rate fluctuations, Cenovus may enter into forward or other foreign exchange contracts. Exchange rate fluctuations could have a material adverse effect on our financial condition, results of operations and cash flows.

***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 risk, we have a system of standards, practices and procedures called the Cenovus Operations Management System ("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.

**Market Access and Transportation Restrictions**

Cenovus's production is transported through pipelines, by rail and marine shipments. The Refineries are reliant on pipelines to receive feedstock. Disruptions in, or restricted availability of, pipeline, rail or marine services could adversely affect our crude oil and natural gas sales, projected production growth, refining operations and cash flows. 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 Outages and Major Environmental or Safety Incidents**

Our crude oil and natural gas production activities are subject to inherent operational risks such as encountering unexpected formations or pressures, blowouts, equipment failures and other accidents, interdependence of component systems, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, migration of harmful substances into water systems, adverse weather conditions, oil spills, pollution and other environmental risks. Our refining and marketing activities are subject to risks including slowdowns due to equipment failure or transportation disruptions, weather, fires, explosions, railcar incidents or derailments, marine transport incidents, unavailability of feedstock, and quality of feedstock. Cenovus's operations could also be interrupted by natural disasters or other events beyond our control.

Failure to manage these risks effectively could result in potential fatalities, serious injury, asset damage or environmental impacts, any of which could have a material adverse effect on our reputation, financial condition, results of operations and cash flows. Cenovus does not insure against all potential occurrences and disruptions, and our insurance may not be sufficient to fully recover the financial loss from an occurrence or disruption.

**Project Execution**

There are risks associated with the execution and operations of the upstream and refining growth and development projects. Successful project execution will be highly dependent upon the availability and cost of materials, equipment and skilled labour, our ability to finance growth and general economic conditions. Project execution will also be impacted by our ability to obtain the necessary environmental and regulatory approvals, and the effect of changing government regulations and public expectations in relation to the impact of oil sands development on the environment. The commissioning and integration of new facilities within our existing asset base could also cause delays in achieving targets and objectives. Failure to manage these risks could have a material adverse effect on our financial condition, results of operations and cash flows.

**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. Operating costs associated with our crude oil production are largely fixed in the short-term and, as a result, are largely dependent on levels of production. 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.

**Reserves Replacement**

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.

**Leadership and Talent**

Our success is dependent upon our Management, our leadership capabilities and the quality and competency of our talent. There is a risk that Cenovus may have difficulty sourcing, developing and retaining the required talent for current and future operations. Failure to retain critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies could have a material adverse effect on our financial condition, results of operations and pace of growth.

### Information Systems

Our operations rely heavily on information technology, such as computer hardware and software systems, to properly operate our business. These systems could be damaged, corrupted or interrupted by natural disasters, telecommunications failures, power loss, malicious acts or code, computer viruses, physical or electronic security breaches, user misuse or user error. A system disruption or breach could adversely impact our reputation, financial condition, results of operations and cash flows.

## *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 compliance costs, adversely impacting our financial condition, results of operations and cash flows.

### Regulatory Approvals

Our operations are subject to regulation and intervention by governments in areas such as energy policies, environmental and safety policies, land tenure, taxes, royalties, government fees, the export of crude oil, natural gas and other products, production rates, expropriation or cancellation of contract rights, acquisition of exploration and production rights, and control over the development and abandonment of fields. Failure to obtain required regulatory approvals, satisfy conditions of an approval or future changes to government regulation, or the interpretation thereof, could impact Cenovus's existing and planned projects or increase capital investment or operating expenses, adversely impacting our financial condition, results of operations and cash flows.

### Abandonment and Reclamation Cost Risk

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. In the case where one party becomes insolvent and is unable to fund the A&R activities, the solvent parties can claim the insolvent party's share of the costs (orphaned asset) against the Orphan Well Association (the "OWA"). The OWA administers orphaned assets and is funded through a levy imposed on licensees and approval holders, including Cenovus, based on each party's proportionate share of the oil and gas industry's deemed A&R liabilities for facilities, wells and unreclaimed sites in Alberta. Saskatchewan has a similar regime.

In May, 2016, the Alberta Court of Queen's Bench issued a decision in the case of Redwater Energy Corporation ("Redwater") that trustees and receivers of insolvent parties may disclaim or renounce uneconomic oil and gas assets to the Alberta Energy Regulator (the "AER") before starting the sales process for the insolvent party's assets. These wells and facilities then become "orphans" to be remediated by the OWA. Prior to Redwater, the sales process for the insolvent party's assets would have typically included both the economic and uneconomic assets, and only in instances where the sales process failed to sell all of the assets would the remaining assets be classified as orphaned assets by the AER and disclaimed to the OWA. Redwater is currently under appeal by the AER and the OWA.

In June 2016, in response to Redwater, 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 transfers. The governments of British Columbia and Saskatchewan have announced similar policies within those provinces. These changes may impact Cenovus's ability to transfer its licences, approvals or permits, and may result in increased costs and delays or require changes to or abandonment of projects and transactions.

Due to the current economic environment and the Redwater decision, the number of orphaned wells in Alberta may increase significantly and accordingly, the aggregate value of the A&R liabilities assumed by the OWA may increase. It is unclear how these liabilities will be satisfied by the OWA and the manner, if any, through which the OWA or provincial regulators may seek compensation for such liabilities from industry participants, including Cenovus. While the impact on Cenovus of any legislative, regulatory or policy decisions as a result of the Redwater decision, and its pending appeal, cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may adversely impact, among other things, our business, financial condition, results of operations and cash flows.

### 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 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.

### United States Tax Risk

In November 2016, the U.S. elected a Republican president. As a result, the Republicans control both the U.S. House of Representatives and the U.S. Senate. The new administration is reported to be considering a comprehensive tax reform that could have a significant impact on Cenovus's financial condition or results from operations.

### Royalty Regimes

The Governments of Alberta and Saskatchewan receive royalties on the production of crude oil and natural gas from lands where they own the mineral rights. On January 1, 2017, the Government of Alberta implemented a modernized royalty framework (the "Modernized Framework") for conventional production based on recommendations of the Royalty Review Advisory Panel. The Modernized Framework includes new programs, formulas, royalty rates, and new drilling and completion cost reporting requirements. The new framework allows all conventional wells drilled prior to 2017 to be grandfathered under the current rules for 10 years. The oil sands royalty regime was left intact with exception of some proposed modifications to the allowed cost framework and certain administrative components of the regime.

These changes to the Alberta provincial royalty structure are not anticipated to materially impact Cenovus's financial condition; however, any future changes to the royalty and mineral tax regimes in provinces in which we operate could have a significant impact on Cenovus's financial condition, results of operations, cash flows, and future capital expenditures.

### Environmental Regulations

Environmental regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances in the environment. They also impose restrictions, liabilities and obligations in connection with the management of 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 can require significant expenditures, including clean-up costs and damages arising from spills or contaminated properties. We anticipate that future capital expenditures and operating expenses could continue to increase as a result of the implementation of new environmental regulations.

Failure to comply with environmental regulations may result in the imposition of fines, penalties and environmental protection orders. The costs of complying with environmental regulations in the future may have a material adverse effect on our financial condition, results of operations and cash flows. Non-compliance with environmental regulations could have an adverse impact on Cenovus's reputation. There is also a risk that Cenovus could face litigation initiated by third parties relating to climate change or other environmental regulations.

*Species at Risk Act*

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

*Climate Change*

Various federal, provincial and U.S. state governments have announced intentions to regulate greenhouse gas emissions ("GHG") and other air pollutants. The Alberta Climate Leadership Plan introduced a new GHG emissions pricing regime. The Climate Leadership Act (the "CLA") received royal assent on June 13, 2016 and came into force on January 1, 2017. The Climate Leadership Regulation ("CL Regulation"), which provides further detail in respect of the carbon levy regime set out in the CLA, was released on November 3, 2016, and also came into force on January 1, 2017. The CLA establishes an Alberta carbon pricing regime in the form of a carbon levy on various types of fuel, based on rates of $20 per tonne of GHG emissions as of January 1, 2017 and $30 per tonne for 2018. The carbon levy revenue will be used to fund initiatives to reduce GHG emissions, to support Alberta's ability to adapt to climate change, and for rebates or adjustments related to the carbon levy to consumers, businesses and communities.

We are also subject to the Specified Gas Emitters Regulation (the "SGER"), which imposes GHG emissions intensity limits and reduction requirements for owners of GHG emitting facilities. Recent amendments to the SGER have increased the maximum emission intensity reduction requirement for facility owners to 20 percent below an average baseline of the facility's historic emissions performance. We may meet the reduction requirements in one of four ways: (1) reducing emissions intensity at our facilities; (2) purchasing or using emission offset credits (3) purchasing or using performance credits; or (4) contributing to an emissions fund at a price of $30 per tonne. Beginning in 2018, facilities subject to the SGER will transition from a historic emissions performance baseline to an output-based allocation approach.

Under the CLA and CL Regulation, facilities subject to the SGER (which includes Cenovus's operating oil sands assets) are exempt from the carbon levy. Activities integral to oil and gas production processes are exempt until 2023. At this time, the determination of what constitutes an activity that is "integral" to conventional oil and gas production is still being clarified with the Alberta government. We expect our operations to have minimal direct carbon levy exposure until 2023.

In addition to GHG emissions pricing, the CLP outlined two additional components relevant to the oil and gas sector: (1) limiting oil sands emissions to a province-wide total of 100 megatonnes per year (compared to current industry emissions levels of approximately 70 megatonnes per year), with certain exceptions for cogeneration power sources and new upgrading capacity; and (2) reducing methane emissions from oil and gas activities by 45 percent by 2025. Additional changes to provincial climate change legislation may have adverse effects for us which cannot be reliably or accurately estimated at this time.

In October 2016, the Canadian federal government announced a new national carbon pricing regime (the "Carbon Strategy") in response to the Paris Agreement that was ratified by Canada and other nations in October 2016. Under the Carbon Strategy, all provinces will be required to adopt a carbon pricing scheme that includes, at a minimum, a price on carbon emissions of $10 per tonne in 2018, rising by $10 per tonne each year to $50 per tonne in 2022. The Carbon Strategy also proposes a federal backstop in the event that jurisdictions fail to meet the benchmark. As Alberta has already established a carbon pricing system, in the short-term, the national price on carbon will likely have little additional impact. It is unclear how the Carbon Strategy will be imposed on Saskatchewan.

Adverse impacts to our business as a result of comprehensive GHG legislation and regulations, may include increased compliance costs, permitting delays, and substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses and reduce demand for crude oil and certain refined products. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to Cenovus. Beyond existing legal requirements, the extent and magnitude of any adverse impacts of these additional programs or regulations cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

*Water Licences*

To operate our crude oil facilities we rely on water, which is obtained under licences issued through the Alberta Water Act. Currently, we are not required to pay for the water we use under these licences. If a change under these licences reduces the amount of water available for our use, our 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. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of our projects rely on securing 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.

*Alberta's Land-Use Framework*

The Government of Alberta implemented the Lower Athabasca Regional Plan ("LARP"), which identifies legally binding management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. Uncertainty exists with respect to future development applications in the areas covered by the LARP, including the potential for development restrictions and mineral rights cancellation. This may have a material adverse effect on our financial condition, results of operations and cash flows.

The Government of Alberta has also implemented the South Saskatchewan Regional Plan ("SSRP"). This plan applies to Cenovus's conventional oil and gas operations in southern Alberta. To date, the SSRP is not expected to materially impact Cenovus's existing conventional oil and gas operations, but no assurance can be given that future expansion of these operations will not be affected. Additional regional plans are in the process of being developed and no assurances can be given that such plans, if approved and implemented, will not materially impact our operations or future operations.

## CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES 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*

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

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

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the 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. The partnerships do not have any third-party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and, as such, are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

### *Exploration and Evaluation Assets*

The application of Cenovus'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 Cenovus's internal approval process.

### *Identification of 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 Cenovus's upstream, refining, crude-by-rail 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.

## 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 and DD&A expense of our crude oil and natural gas assets in the Oil Sands and Conventional segments. Cenovus's crude oil and natural gas reserves are evaluated annually and reported to Cenovus by our IQREs. Refer to the Outlook section of this MD&A for more details on future commodity prices.

### *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 our 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 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. Refer to the reportable segments section of this MD&A for more details on impairments and reversals.

As at December 31, 2016, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal 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. 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, 2016 by our IQREs.

#### Crude Oil and Natural Gas Prices

The forward prices as at December 31, 2016, used to determine future cash flows from crude oil and natural gas reserves were:

| | 2017 | 2018 | 2019 | 2020 | 2021 | Average Annual Increase Thereafter |
|---|---|---|---|---|---|---|
| WTI (US$/barrel) | 55.00 | 58.70 | 62.40 | 69.00 | 75.80 | 2.0% |
| WCS (C$/barrel) | 53.70 | 58.20 | 61.90 | 66.50 | 71.00 | 2.0% |
| AECO (C$/Mcf) (1) | 3.40 | 3.15 | 3.30 | 3.60 | 3.90 | 2.2% |

*(1) Assumes gas heating value of one million British Thermal Units per thousand cubic feet.*

#### Discount and Inflation Rates

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent and inflation is estimated at two percent, which is common industry practice and used by Cenovus's IQREs in preparing their reserves reports. Based on the individual characteristics of the CGU, other economic and operating factors are also considered, which may increase or decrease the implied discount rate.

### *Decommissioning Costs*

Provisions are recorded for the future decommissioning and restoration of our upstream crude oil and natural gas 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. Refer to Note 22 of the Consolidated Financial Statements for more details on changes to decommissioning costs.

### *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. Refer to the Corporate and Eliminations section of this MD&A for more details on changes to estimates related to income taxes.

## Changes in Accounting Policies

Cenovus adopted the following new amendment:

### *Liabilities Arising From Financing Activities*

Cenovus has early adopted the disclosure requirements in "*Disclosure Initiative (Amendments to IAS 7)*" ("IAS 7") before the mandatory effective date of January 1, 2017. Additional disclosures for changes in liabilities arising from financing activities have been included in Note 21 of the Consolidated Financial Statements. As allowed by IAS 7, comparative information has not been presented.

### New Accounting Standards and Interpretations not yet Adopted

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2017 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2016. The standards applicable to Cenovus are as follows and will be adopted on their respective effective dates:

#### *Leases*

On January 13, 2016, the IASB issued IFRS 16, "*Leases*" ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases.

Lessors will continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue, and what assets would be recorded.

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15, "*Revenue From Contracts With Customers*" has been adopted. The standard may be applied retrospectively or using a 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. It is anticipated that the adoption of IFRS 16 will have a material impact on our Consolidated Balance Sheets due to material operating lease commitments as disclosed in Note 34 of the Consolidated Financial Statements. We plan to apply IFRS 16 initially on January 1, 2019; however, the transition approach on adoption has not yet been determined.

#### *Revenue Recognition*

On May 28, 2014, the IASB issued IFRS 15, "*Revenue From Contracts With Customers*" ("IFRS 15") replacing IAS 11, "*Construction Contracts*", IAS 18, "*Revenue*" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

IFRS 15 is effective for annual periods beginning on or after January 1, 2018. Early adoption is permitted. The standard may be applied retrospectively or using a modified retrospective approach. We are currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements and plan to adopt the standard for the year ended December 31, 2018.

#### *Financial Instruments*

On July 24, 2014, the IASB issued the final version of IFRS 9, "*Financial Instruments*" ("IFRS 9") to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39").

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The IAS 39 measurement categories for financial assets will be replaced by fair value through profit or loss, fair value through other comprehensive income and amortized cost. Based on our preliminary assessment, we do not believe the change in classification will have a material impact on the Consolidated Financial Statements.

IFRS 9 retains most of the IAS 39 requirements for financial liabilities. However, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than net earnings, unless this creates an accounting mismatch. Cenovus currently does not designate any financial liabilities as fair value through profit or loss.

A new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. We do not expect the change in the impairment model to have a material impact on the Consolidated Financial Statements.

In addition, IFRS 9 includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Cenovus does not currently apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. We plan to adopt IFRS 9 for the year ended December 31, 2018.

## CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2016. 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 internal control over financial reporting. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2016.

The effectiveness of our ICFR was audited 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, 2016. There have been no changes during the year ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

## CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and integrating our corporate responsibility principles in the way we conduct our business. Our Corporate Responsibility ("CR") policy guides our activities in the areas of: Leadership, Corporate Governance and Business Practices, People, Innovation, Environmental Performance, Stakeholder and Aboriginal Engagement, and Community Involvement and Investment.

We published our 2015 CR report in July 2016, detailing our efforts to accelerate improvement in our environmental performance, protect the health and safety of our staff, invest in and engage with the communities where we operate and maintain the highest standards of corporate governance. Our CR report also lists external recognition we received for our commitment to corporate responsibility and our efforts to balance economic, governance, social and environmental performance. Our CR policy and CR report are available on our website at cenovus.com.

## OUTLOOK

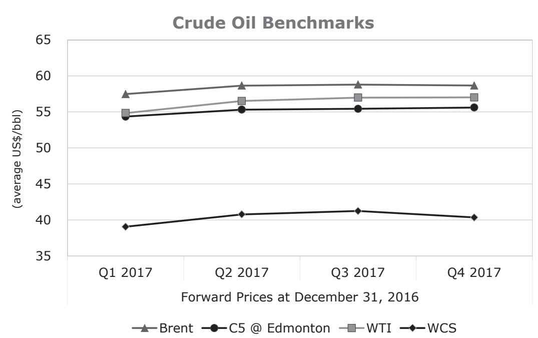
We anticipate ongoing price volatility for the foreseeable future and accordingly, we continue to be prudent in how we allocate capital and manage the pace at which we choose to invest. We will focus on maximizing our cost efficiencies and maintaining financial resilience while delivering safe and reliable operations, as well as resuming investment in certain strategic growth projects. We will continue to monitor future changes implemented by the newly elected U.S. president, some of which could have a significant impact on Cenovus's future financial results.

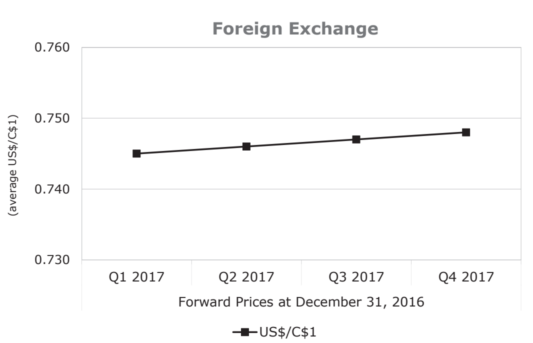
The following outlook commentary is focused on the next twelve months.

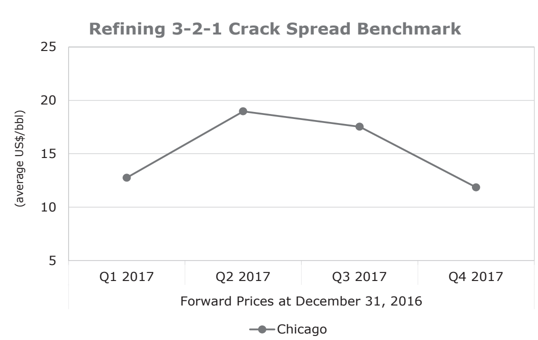
### Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment, compliance of OPEC and select non-OPEC countries with the plan to reduce production, the impact of geopolitical supply disruptions, and the pace of growth in global demand as influenced by macro-economic events. Overall, we expect a modest crude oil price improvement in the next twelve months.
- We anticipate that the WTI-WCS differential will widen due to increasing heavy oil production in Alberta and limited pipeline capacity.



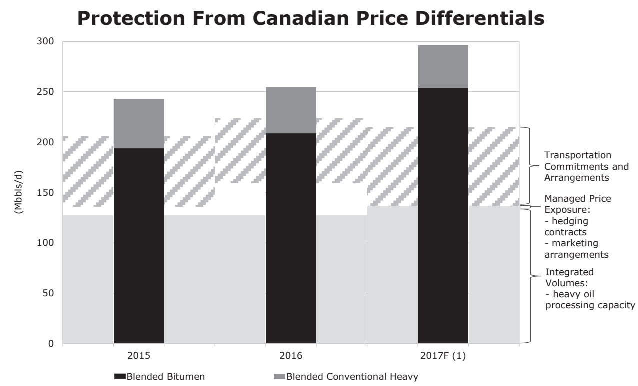

U.S. refining crack spreads are expected to follow historical seasonal patterns over the next twelve months and we expect that they will be impacted by the pace of rebalancing excess crude oil and refined product inventories.

The Canadian dollar will likely continue to be tied to crude oil prices, tempered by rising interest rate expectations in the U.S. Overall, excluding the change in crude oil prices, a stronger Canadian dollar is expected to have a negative impact on our revenues and Operating Margin.

Natural gas prices are anticipated to improve in the next twelve months due to limited supply growth, strengthening U.S. industrial demand, and an increase in U.S. natural gas export capacity. We expect that supply growth will be impacted by a relatively low U.S. natural gas rig count and pipeline congestion in the U.S. Northeast. However, significantly higher prices will likely be limited by the ability of the power sector to use coal as a substitute for natural gas.

Our exposure to the light/heavy 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 option to mitigate our exposure to light/heavy price differentials through the following:

- 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;
- Financial hedge transactions – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – limiting the impact of fluctuations in upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Transportation commitments and arrangements – supporting transportation projects that move crude oil from our production areas to consuming markets and also to tidewater markets.




(1) *Expected production volumes. For further information, refer to our 2017 Guidance as updated on December 8, 2016, available at cenovus.com.*

## Key Priorities for 2017

### *Disciplined and Value-added Growth*

We anticipate capital investment in 2017 to be between $1.2 billion and $1.4 billion. We plan to direct the majority of our 2017 capital budget towards sustaining oil sands production and base production at our other operations. A portion of our capital budget is planned for growth at our existing oil sands assets as well as at our tight oil assets in southern Alberta. With integration remaining an important part of our overall strategy, capital investment is also allocated for scheduled maintenance and reliability work at the Refineries.

### *Sustainable Cost Improvements*

In the past two years, we have achieved substantial improvements in our operating and sustaining capital costs through identifying efficiencies, maximizing the strengths of our functional business model, and disciplined manufacturing. In 2017, we plan to continue to focus on making sustainable cost improvements across the organization. We anticipate maintaining lower costs while increasing production and capital investment.

### *Maintain Financial Resilience*

Maintaining our financial resilience, while maintaining safe operations, continues to be a top priority. At December 31, 2016, we had $3.7 billion of cash on hand and $4.0 billion of undrawn capacity under our committed credit facility. Our debt has a weighted average maturity of approximately 15 years, with no debt maturing until the fourth quarter of 2019. We also have a US$5.0 billion base shelf prospectus, the availability of which is dependent on market conditions.

### *Market Access*

Access to markets for Canadian crude oil continues to be a challenge. In 2017, we plan to continue assessing a variety of options available to market our growing oil sands production, including tidewater access.

# CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEAR ENDED DECEMBER 31, 2016

# 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 meets with Management and the independent auditors on at least a quarterly basis to review and approve interim Consolidated Financial Statements and Management's Discussion and Analysis prior to their public release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

### *Management's Assessment of Internal Control over Financial Reporting*

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the design and effectiveness of internal control over financial reporting as at December 31, 2016. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") 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, 2016.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2016, as stated in their Report of Independent Registered Public Accounting Firm dated February 15, 2017. PricewaterhouseCoopers LLP has provided such opinions.

/s/ Brian C. Ferguson

**Brian C. Ferguson**
President &
Chief Executive Officer
Cenovus Energy Inc.

/s/ Ivor M. Ruste

**Ivor M. Ruste**
Executive Vice-President &
Chief Financial Officer
Cenovus Energy Inc.

**February 15, 2017**

# REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

***To the Shareholders of Cenovus Energy Inc.***

We have audited the accompanying Consolidated Balance Sheets of Cenovus Energy Inc. as of December 31, 2016 and December 31, 2015 and the Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss), Shareholders' Equity and Cash Flows for each of the years in the three-year period ended December 31, 2016. We also have audited Cenovus Energy Inc.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the COSO. 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 Report of Management. Our responsibility is to express an opinion on these Consolidated Financial Statements and an opinion on Cenovus Energy Inc.'s internal control over financial reporting based on our integrated audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the Consolidated Financial Statements included examining, on a test basis, evidence supporting the amounts and disclosures in the Consolidated Financial Statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall Consolidated Financial Statement presentation. 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.

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.

In our opinion, the Consolidated Financial Statements referred to above present fairly, in all material respects, the financial position of Cenovus Energy Inc. as of December 31, 2016 and December 31, 2015 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2016 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also, in our opinion, Cenovus Energy Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by COSO.

/s/ PricewaterhouseCoopers LLP

**PricewaterhouseCoopers LLP**
Chartered Professional Accountants
Calgary, Alberta, Canada

**February 15, 2017**

# CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

**For the years ended December 31,**
**($ millions, except per share amounts)**

| | Notes | 2016 | 2015 | 2014 |
|---|---|---|---|---|
| **Revenues** | 1 | | | |
| Gross Sales | | **12,282** | 13,207 | 20,107 |
| Less: Royalties | | **148** | 143 | 465 |
| | | **12,134** | 13,064 | 19,642 |
| **Expenses** | 1 | | | |
| Purchased Product | | **6,978** | 7,374 | 10,955 |
| Transportation and Blending | | **1,901** | 2,043 | 2,477 |
| Operating | | **1,683** | 1,839 | 2,045 |
| Production and Mineral Taxes | | **12** | 18 | 46 |
| (Gain) Loss on Risk Management | 31 | **343** | (461) | (662) |
| Depreciation, Depletion and Amortization | 9,16 | **1,498** | 2,114 | 1,946 |
| Goodwill Impairment | 9 | **-** | - | 497 |
| Exploration Expense | 9,15 | **2** | 138 | 86 |
| General and Administrative | | **326** | 335 | 379 |
| Finance Costs | 5 | **492** | 482 | 445 |
| Interest Income | | **(52)** | (28) | (33) |
| Foreign Exchange (Gain) Loss, Net | 6 | **(198)** | 1,036 | 411 |
| Research Costs | | **36** | 27 | 15 |
| (Gain) Loss on Divestiture of Assets | 7 | **6** | (2,392) | (156) |
| Other (Income) Loss, Net | 8 | **34** | 2 | (4) |
| **Earnings (Loss) Before Income Tax** | | **(927)** | 537 | 1,195 |
| Income Tax Expense (Recovery) | 10 | **(382)** | (81) | 451 |
| **Net Earnings (Loss)** | | **(545)** | 618 | 744 |
| | | | | |
| **Net Earnings (Loss) Per Share** ($) | 11 | | | |
| Basic and Diluted | | **(0.65)** | 0.75 | 0.98 |

*See accompanying Notes to Consolidated Financial Statements.*

# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

**For the years ended December 31,**
**($ millions)**

| | Notes | 2016 | 2015 | 2014 |
|---|---|---|---|---|
| **Net Earnings (Loss)** | | **(545)** | 618 | 744 |
| **Other Comprehensive Income (Loss), Net of Tax** | 26 | | | |
| *Items That Will Not be Reclassified to Profit or Loss:* | | | | |
| Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits | | **(3)** | 20 | (18) |
| *Items That May be Reclassified to Profit or Loss:* | | | | |
| Available for Sale Financial Assets – Change in Fair Value | | **(2)** | 6 | - |
| Available for Sale Financial Assets – Reclassified to Profit or Loss | | **1** | - | - |
| Foreign Currency Translation Adjustment | | **(106)** | 587 | 215 |
| **Total Other Comprehensive Income (Loss), Net of Tax** | | **(110)** | 613 | 197 |
| **Comprehensive Income (Loss)** | | **(655)** | 1,231 | 941 |

*See accompanying Notes to Consolidated Financial Statements.*

# CONSOLIDATED BALANCE SHEETS

**As at December 31,**
**($ millions)**

| | Notes | 2016 | 2015 |
|---|---|---|---|
| **Assets** | | | |
| **Current Assets** | | | |
| Cash and Cash Equivalents | 12 | **3,720** | 4,105 |
| Accounts Receivable and Accrued Revenues | 13 | **1,838** | 1,251 |
| Income Tax Receivable | | **6** | 6 |
| Inventories | 14 | **1,237** | 810 |
| Risk Management | 31,32 | **21** | 301 |
| **Total Current Assets** | | **6,822** | 6,473 |
| Exploration and Evaluation Assets | 1,15 | **1,585** | 1,575 |
| Property, Plant and Equipment, Net | 1,16 | **16,426** | 17,335 |
| Risk Management | 31,32 | **3** | - |
| Income Tax Receivable | | **124** | 90 |
| Other Assets | 8,18 | **56** | 76 |
| Goodwill | 1,19 | **242** | 242 |
| **Total Assets** | | **25,258** | 25,791 |
| | | | |
| **Liabilities and Shareholders' Equity** | | | |
| **Current Liabilities** | | | |
| Accounts Payable and Accrued Liabilities | 20 | **2,266** | 1,702 |
| Income Tax Payable | | **112** | 133 |
| Risk Management | 31,32 | **293** | 23 |
| **Total Current Liabilities** | | **2,671** | 1,858 |
| Long-Term Debt | 21 | **6,332** | 6,525 |
| Risk Management | 31,32 | **22** | 7 |
| Decommissioning Liabilities | 22 | **1,847** | 2,052 |
| Other Liabilities | 23 | **211** | 142 |
| Deferred Income Taxes | 10 | **2,585** | 2,816 |
| **Total Liabilities** | | **13,668** | 13,400 |
| Shareholders' Equity | | **11,590** | 12,391 |
| **Total Liabilities and Shareholders' Equity** | | **25,258** | 25,791 |
| | | | |
| Commitments and Contingencies | 34 | | |

*See accompanying Notes to Consolidated Financial Statements.*

Approved by the Board of Directors

/s/ Michael A. Grandin

**Michael A. Grandin**
Director
Cenovus Energy Inc.

/s/ Colin Taylor

**Colin Taylor**
Director
Cenovus Energy Inc.

# CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

**($ millions)**

| | Share Capital (Note 25) | Paid in Surplus (Note 25) | Retained Earnings | AOCI [1] (Note 26) | **Total** |
|---|---|---|---|---|---|
| As at December 31, 2013 | 3,857 | 4,219 | 1,660 | 210 | 9,946 |
| Net Earnings | - | - | 744 | - | 744 |
| Other Comprehensive Income | - | - | - | 197 | 197 |
| Total Comprehensive Income | - | - | 744 | 197 | 941 |
| Common Shares Issued Under Stock Option Plans | 32 | - | - | - | 32 |
| Stock-Based Compensation Expense | - | 72 | - | - | 72 |
| Dividends on Common Shares | - | - | (805) | - | (805) |
| As at December 31, 2014 | 3,889 | 4,291 | 1,599 | 407 | 10,186 |
| Net Earnings | - | - | 618 | - | 618 |
| Other Comprehensive Income | - | - | - | 613 | 613 |
| Total Comprehensive Income | - | - | 618 | 613 | 1,231 |
| Common Shares Issued for Cash | 1,463 | - | - | - | 1,463 |
| Common Shares Issued Pursuant to Dividend Reinvestment Plan | 182 | - | - | - | 182 |
| Stock-Based Compensation Expense | - | 39 | - | - | 39 |
| Dividends on Common Shares | - | - | (710) | - | (710) |
| As at December 31, 2015 | 5,534 | 4,330 | 1,507 | 1,020 | 12,391 |
| Net Earnings (Loss) | - | - | (545) | - | (545) |
| Other Comprehensive Income (Loss) | - | - | - | (110) | (110) |
| Total Comprehensive Income (Loss) | - | - | (545) | (110) | (655) |
| Stock-Based Compensation Expense | - | 20 | - | - | 20 |
| Dividends on Common Shares | - | - | (166) | - | (166) |
| **As at December 31, 2016** | **5,534** | **4,350** | **796** | **910** | **11,590** |

*(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 | **2016** | 2015 | 2014 |
|---|---|---|---|---|
| **Operating Activities** | | | | |
| Net Earnings (Loss) | | **(545)** | 618 | 744 |
| Depreciation, Depletion and Amortization | 9,16 | **1,498** | 2,114 | 1,946 |
| Goodwill Impairment | 9 | **-** | - | 497 |
| Exploration Expense | 9,15 | **2** | 138 | 86 |
| Deferred Income Taxes | 10 | **(209)** | (655) | 359 |
| Unrealized (Gain) Loss on Risk Management | 31 | **554** | 195 | (596) |
| Unrealized Foreign Exchange (Gain) Loss | 6 | **(189)** | 1,097 | 411 |
| (Gain) Loss on Divestiture of Assets | 7 | **6** | (2,392) | (156) |
| Current Tax on Divestiture of Assets | 7 | **-** | 391 | - |
| Unwinding of Discount on Decommissioning Liabilities | 5,22 | **130** | 126 | 120 |
| Onerous Contract Provisions, Net of Cash Paid | | **53** | - | - |
| Other Asset Impairments | 8 | **30** | - | - |
| Other | | **93** | 59 | 68 |
| Net Change in Other Assets and Liabilities | | **(91)** | (107) | (135) |
| Net Change in Non-Cash Working Capital | | **(471)** | (110) | 182 |
| **Cash From Operating Activities** | | **861** | 1,474 | 3,526 |
| **Investing Activities** | | | | |
| Capital Expenditures – Exploration and Evaluation Assets | 15 | **(67)** | (138) | (279) |
| Capital Expenditures – Property, Plant and Equipment | 16 | **(967)** | (1,576) | (2,779) |
| Acquisition | 17 | **-** | (84) | - |
| Proceeds From Divestiture of Assets | 7 | **8** | 3,344 | 276 |
| Current Tax on Divestiture of Assets | 7 | **-** | (391) | - |
| Net Change in Investments and Other | | **(1)** | 3 | (1,583) |
| Net Change in Non-Cash Working Capital | | **(52)** | (270) | 15 |
| **Cash From (Used in) Investing Activities** | | **(1,079)** | 888 | (4,350) |
| **Net Cash Provided (Used) Before Financing Activities** | | **(218)** | 2,362 | (824) |
| **Financing Activities** | | | | |
| Net Issuance (Repayment) of Short-Term Borrowings | | **-** | (25) | (18) |
| Common Shares Issued, Net of Issuance Costs | 25 | **-** | 1,449 | - |
| Common Shares Issued Under Stock Option Plans | | **-** | - | 28 |
| Dividends Paid on Common Shares | 11 | **(166)** | (528) | (805) |
| Other | | **(2)** | (2) | (2) |
| **Cash From (Used in) Financing Activities** | | **(168)** | 894 | (797) |
| **Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency** | | **1** | (34) | 52 |
| **Increase (Decrease) in Cash and Cash Equivalents** | | **(385)** | 3,222 | (1,569) |
| **Cash and Cash Equivalents, Beginning of Year** | | **4,105** | 883 | 2,452 |
| **Cash and Cash Equivalents, End of Year** | | **3,720** | 4,105 | 883 |
| Supplementary Cash Flow Information | 33 | | | |

*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 2600, 500 Centre Street S.E., Calgary, Alberta, Canada, T2G 1A6. Information on the Company's basis of preparation for these Consolidated Financial Statements is found in Note 2.

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by Cenovus's chief operating decision makers. The Company evaluates the financial performance of its operating segments primarily based on operating margin. The Company's reportable segments are:

- **Oil Sands,** which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional,** which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.
- **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 operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues, and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory. The 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.

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

| For the years ended December 31, | Oil Sands 2016 | 2015 | 2014 | Conventional 2016 | 2015 | 2014 | Refining and Marketing 2016 | 2015 | 2014 |
|---|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | | |
| Gross Sales | **2,929** | 3,030 | 5,036 | **1,267** | 1,709 | 3,225 | **8,439** | 8,805 | 12,658 |
| Less: Royalties | **9** | 29 | 236 | **139** | 114 | 229 | **-** | - | - |
| | **2,920** | 3,001 | 4,800 | **1,128** | 1,595 | 2,996 | **8,439** | 8,805 | 12,658 |
| **Expenses** | | | | | | | | | |
| Purchased Product | **-** | - | - | **-** | - | - | **7,325** | 7,709 | 11,767 |
| Transportation and Blending | **1,721** | 1,815 | 2,131 | **186** | 230 | 346 | **-** | - | - |
| Operating | **501** | 531 | 639 | **444** | 561 | 709 | **742** | 754 | 703 |
| Production and Mineral Taxes | **-** | - | - | **12** | 18 | 46 | **-** | - | - |
| (Gain) Loss on Risk Management | **(179)** | (404) | (38) | **(58)** | (209) | (1) | **26** | (43) | (27) |
| **Operating Margin** [(1)] | **877** | 1,059 | 2,068 | **544** | 995 | 1,896 | **346** | 385 | 215 |
| Depreciation, Depletion and Amortization | **655** | 697 | 625 | **567** | 1,148 | 1,082 | **211** | 191 | 156 |
| Goodwill Impairment | **-** | - | - | **-** | - | 497 | **-** | - | - |
| Exploration Expense | **2** | 67 | 4 | **-** | 71 | 82 | **-** | - | - |
| **Segment Income (Loss)** | **220** | 295 | 1,439 | **(23)** | (224) | 235 | **135** | 194 | 59 |

*(1) Previously labelled Operating Cash Flow.*

| For the years ended December 31, | Corporate and Eliminations 2016 | 2015 | 2014 | Consolidated 2016 | 2015 | 2014 |
|---|---|---|---|---|---|---|
| **Revenues** | | | | | | |
| Gross Sales | **(353)** | (337) | (812) | **12,282** | 13,207 | 20,107 |
| Less: Royalties | **-** | - | - | **148** | 143 | 465 |
| | **(353)** | (337) | (812) | **12,134** | 13,064 | 19,642 |
| **Expenses** | | | | | | |
| Purchased Product | **(347)** | (335) | (812) | **6,978** | 7,374 | 10,955 |
| Transportation and Blending | **(6)** | (2) | - | **1,901** | 2,043 | 2,477 |
| Operating | **(4)** | (7) | (6) | **1,683** | 1,839 | 2,045 |
| Production and Mineral Taxes | **-** | - | - | **12** | 18 | 46 |
| (Gain) Loss on Risk Management | **554** | 195 | (596) | **343** | (461) | (662) |
| Depreciation, Depletion and Amortization | **65** | 78 | 83 | **1,498** | 2,114 | 1,946 |
| Goodwill Impairment | **-** | - | - | **-** | - | 497 |
| Exploration Expense | **-** | - | - | **2** | 138 | 86 |
| **Segment Income (Loss)** | **(615)** | (266) | 519 | **(283)** | (1) | 2,252 |
| General and Administrative | **326** | 335 | 379 | **326** | 335 | 379 |
| Finance Costs | **492** | 482 | 445 | **492** | 482 | 445 |
| Interest Income | **(52)** | (28) | (33) | **(52)** | (28) | (33) |
| Foreign Exchange (Gain) Loss, Net | **(198)** | 1,036 | 411 | **(198)** | 1,036 | 411 |
| Research Costs | **36** | 27 | 15 | **36** | 27 | 15 |
| (Gain) Loss on Divestiture of Assets | **6** | (2,392) | (156) | **6** | (2,392) | (156) |
| Other (Income) Loss, Net | **34** | 2 | (4) | **34** | 2 | (4) |
| | **644** | (538) | 1,057 | **644** | (538) | 1,057 |
| **Earnings (Loss) Before Income Tax** | | | | **(927)** | 537 | 1,195 |
| Income Tax Expense (Recovery) | | | | **(382)** | (81) | 451 |
| **Net Earnings (Loss)** | | | | **(545)** | 618 | 744 |

### B) Financial Results by Upstream Product

| | Crude Oil [1] | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil Sands | | | Conventional | | | Total | | |
| For the years ended December 31, | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| **Revenues** | | | | | | | | | |
| Gross Sales | **2,911** | 3,000 | 4,963 | **936** | 1,239 | 2,456 | **3,847** | 4,239 | 7,419 |
| Less: Royalties | **9** | 29 | 233 | **125** | 103 | 217 | **134** | 132 | 450 |
| | **2,902** | 2,971 | 4,730 | **811** | 1,136 | 2,239 | **3,713** | 4,107 | 6,969 |
| **Expenses** | | | | | | | | | |
| Transportation and Blending | **1,720** | 1,814 | 2,130 | **170** | 213 | 326 | **1,890** | 2,027 | 2,456 |
| Operating | **486** | 511 | 615 | **287** | 381 | 505 | **773** | 892 | 1,120 |
| Production and Mineral Taxes | **-** | - | - | **12** | 16 | 37 | **12** | 16 | 37 |
| (Gain) Loss on Risk Management | **(179)** | (400) | (38) | **(60)** | (157) | 4 | **(239)** | (557) | (34) |
| **Operating Margin [2]** | **875** | 1,046 | 2,023 | **402** | 683 | 1,367 | **1,277** | 1,729 | 3,390 |

| | Natural Gas | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil Sands | | | Conventional | | | Total | | |
| For the years ended December 31, | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| **Revenues** | | | | | | | | | |
| Gross Sales | **16** | 22 | 67 | **321** | 450 | 744 | **337** | 472 | 811 |
| Less: Royalties | **-** | - | 3 | **14** | 11 | 12 | **14** | 11 | 15 |
| | **16** | 22 | 64 | **307** | 439 | 732 | **323** | 461 | 796 |
| **Expenses** | | | | | | | | | |
| Transportation and Blending | **1** | 1 | 1 | **16** | 17 | 20 | **17** | 18 | 21 |
| Operating | **11** | 15 | 17 | **152** | 175 | 198 | **163** | 190 | 215 |
| Production and Mineral Taxes | **-** | - | - | **-** | 2 | 9 | **-** | 2 | 9 |
| (Gain) Loss on Risk Management | **-** | (4) | - | **2** | (52) | (5) | **2** | (56) | (5) |
| **Operating Margin [2]** | **4** | 10 | 46 | **137** | 297 | 510 | **141** | 307 | 556 |

| | Other | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil Sands | | | Conventional | | | Total | | |
| For the years ended December 31, | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| **Revenues** | | | | | | | | | |
| Gross Sales | **2** | 8 | 6 | **10** | 20 | 25 | **12** | 28 | 31 |
| Less: Royalties | **-** | - | - | **-** | - | - | **-** | - | - |
| | **2** | 8 | 6 | **10** | 20 | 25 | **12** | 28 | 31 |
| **Expenses** | | | | | | | | | |
| Transportation and Blending | **-** | - | - | **-** | - | - | **-** | - | - |
| Operating | **4** | 5 | 7 | **5** | 5 | 6 | **9** | 10 | 13 |
| Production and Mineral Taxes | **-** | - | - | **-** | - | - | **-** | - | - |
| (Gain) Loss on Risk Management | **-** | - | - | **-** | - | - | **-** | - | - |
| **Operating Margin [2]** | **(2)** | 3 | (1) | **5** | 15 | 19 | **3** | 18 | 18 |

| | Total Upstream | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil Sands | | | Conventional | | | Total | | |
| For the years ended December 31, | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| **Revenues** | | | | | | | | | |
| Gross Sales | **2,929** | 3,030 | 5,036 | **1,267** | 1,709 | 3,225 | **4,196** | 4,739 | 8,261 |
| Less: Royalties | **9** | 29 | 236 | **139** | 114 | 229 | **148** | 143 | 465 |
| | **2,920** | 3,001 | 4,800 | **1,128** | 1,595 | 2,996 | **4,048** | 4,596 | 7,796 |
| **Expenses** | | | | | | | | | |
| Transportation and Blending | **1,721** | 1,815 | 2,131 | **186** | 230 | 346 | **1,907** | 2,045 | 2,477 |
| Operating | **501** | 531 | 639 | **444** | 561 | 709 | **945** | 1,092 | 1,348 |
| Production and Mineral Taxes | **-** | - | - | **12** | 18 | 46 | **12** | 18 | 46 |
| (Gain) Loss on Risk Management | **(179)** | (404) | (38) | **(58)** | (209) | (1) | **(237)** | (613) | (39) |
| **Operating Margin [2]** | **877** | 1,059 | 2,068 | **544** | 995 | 1,896 | **1,421** | 2,054 | 3,964 |

*(1) Includes NGLs.*
*(2) Previously labelled Operating Cash Flow.*

### C) Exploration and Evaluation Assets, Property, Plant and Equipment, Goodwill and Total Assets

| | E&E [1] | | PP&E [2] | | Goodwill | | Total Assets | |
|---|---|---|---|---|---|---|---|---|
| As at December 31, | **2016** | 2015 | **2016** | 2015 | **2016** | 2015 | **2016** | 2015 |
| Oil Sands | **1,564** | 1,560 | **8,798** | 8,907 | **242** | 242 | **11,112** | 11,069 |
| Conventional | **21** | 15 | **3,080** | 3,720 | **-** | - | **3,196** | 3,830 |
| Refining and Marketing | **-** | - | **4,273** | 4,398 | **-** | - | **6,613** | 5,844 |
| Corporate and Eliminations | **-** | - | **275** | 310 | **-** | - | **4,337** | 5,048 |
| **Consolidated** | **1,585** | 1,575 | **16,426** | 17,335 | **242** | 242 | **25,258** | 25,791 |

*(1) Exploration and Evaluation ("E&E") assets.*
*(2) Property, Plant and Equipment ("PP&E").*

### D) Geographical Information

| | Revenues | | |
|---|---|---|---|
| For the years ended December 31, | **2016** | 2015 | 2014 |
| Canada | **6,106** | 6,264 | 10,139 |
| United States | **6,028** | 6,800 | 9,503 |
| **Consolidated** | **12,134** | 13,064 | 19,642 |

| | Non-Current Assets [3] | |
|---|---|---|
| As at December 31, | **2016** | 2015 |
| Canada | **14,130** | 14,921 |
| United States | **4,179** | 4,307 |
| **Consolidated** | **18,309** | 19,228 |

*(3) Includes E&E, PP&E, goodwill and other assets.*

#### *Export Sales*

Sales of crude oil, natural gas and NGLs produced or purchased in Canada that have been delivered to customers outside of Canada were $974 million (2015 – $870 million; 2014 – $821 million).

#### *Major Customers*

In connection with the marketing and sale of Cenovus's own and purchased crude oil, natural gas and refined products for the year ended December 31, 2016, Cenovus had three customers (2015 – three; 2014 – three) 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 $4,742 million, $1,623 million and $1,400 million, respectively (2015 – $4,647 million, $1,705 million and $1,545 million; 2014 – $7,210 million, $2,668 million and $2,316 million), which are included in all of the Company's segments.

### E) Capital Expenditures [4]

| For the years ended December 31, | **2016** | 2015 | 2014 |
|---|---|---|---|
| **Capital** | | | |
| Oil Sands | **604** | 1,185 | 1,986 |
| Conventional | **171** | 244 | 840 |
| Refining and Marketing | **220** | 248 | 163 |
| Corporate | **31** | 37 | 62 |
| **Capital Investment** | **1,026** | 1,714 | 3,051 |
| | | | |
| **Acquisition Capital** | | | |
| Oil Sands | **11** | 3 | 15 |
| Conventional | **-** | 1 | 3 |
| Refining and Marketing | **-** | 83 | - |
| **Total Capital Expenditures** | **1,037** | 1,801 | 3,069 |

*(4) Includes expenditures on PP&E and E&E.*

## 2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

These Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). These Consolidated Financial Statements have been prepared in compliance with IFRS.

These Consolidated Financial Statements have been prepared on a historical cost basis, except as detailed in the Company's accounting policies disclosed in Note 3.

These Consolidated Financial Statements were approved by the Board of Directors on February 15, 2017.

## 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. Substantially all of the Company's Oil Sands and Refining activities are conducted through two joint operations, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), and accordingly, the accounts reflect the Company's share of the assets, liabilities, revenues and expenses.

### 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.

### C) Revenue Recognition

Revenues associated with the sales of Cenovus's crude oil, natural gas, NGLs, and petroleum and refined products are recognized when the significant risks and rewards of ownership have been transferred to the customer, the sales price and costs can be measured reliably and it is probable that the economic benefits will flow to the Company. This is generally met when title passes from the Company to its customer. Revenues from crude oil and natural gas production represent the Company's share, net of royalty payments to governments and other mineral interest owners.

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, natural gas and NGLs, 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.

**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. 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 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 pipelines and information technology assets used to support the upstream business. These assets are depreciated on a straight-line basis over their useful lives of three to 35 years.

### *Refining Assets*

The 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 20 years
- Refining equipment 5 to 35 years

The residual value, method of amortization and the useful life of each component are reviewed annually and adjusted on a prospective basis, if appropriate.

### *Other Assets*

Costs associated with the crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 40 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

### *Non-Financial Assets*

PP&E and E&E 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 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.

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.

E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. Goodwill is allocated to the CGUs to which it contributes to the future cash flows.

Impairment losses on PP&E and E&E assets are recognized in the Consolidated Statements of Earnings as additional DD&A and exploration expense, respectively.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

### *Financial Assets*

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is objective evidence of impairment, the loss event has an impact on future cash 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.

## N) Leases

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term.

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. 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) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and any non-controlling interest are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net earnings.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

## P) 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.

### *Decommissioning Liabilities*

Decommissioning liabilities include those legal or constructive obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing facilities, 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.

## Q) 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.

### R) Stock-Based Compensation

Cenovus has a number of stock-based compensation plans which include stock options with associated net settlement rights ("NSRs"), stock options with associated tandem stock appreciation rights ("TSARs"), performance share units ("PSUs"), restricted share units ("RSUs") and deferred share units ("DSUs"). Stock-based compensation costs are recorded in general and administrative expense, or E&E 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.

### S) 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, risk management liabilities, short-term borrowings 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. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership. A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, this exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability. The difference in the carrying amounts of the liabilities is recognized in the Consolidated Statements of Earnings.

Financial instruments are classified as either "fair value through profit and loss", "loans and receivables", "held-to-maturity investments", "available for sale financial assets" or "financial liabilities measured at amortized cost". The Company determines the classification of its financial instruments at initial recognition. Financial instruments are initially measured at fair value except in the case of "financial liabilities measured at amortized cost", which are initially measured at fair value net of directly attributable transaction costs.

As required by IFRS, 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.

#### *Fair Value through Profit or Loss*

Financial assets and financial liabilities at "fair value through profit or loss" are either "held-for-trading" or have been "designated at fair value through profit or loss". In both cases, the financial assets and financial liabilities are measured at fair value with changes in fair value recognized in net earnings.

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the Consolidated Balance Sheets as either an asset or liability with changes in fair value recognized in net earnings as a (gain) loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Derivative financial instruments are not used for speculative purposes. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

#### *Loans and Receivables*

"Loans and receivables" are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. "Loans and receivables" comprise cash and cash equivalents, accounts receivable and accrued revenues, and long-term receivables. Gains and losses on "loans and receivables" are recognized in net earnings when the "loans and receivables" are derecognized or impaired.

#### *Available for Sale Financial Assets*

"Available for sale financial assets" are measured at fair value, with changes in fair value recognized in OCI. When an active market is non-existent, fair value is determined using valuation techniques. When fair value cannot be reliably measured, such assets are carried at cost. Available for sale financial assets comprise investments in the equity of private companies that the Company does not control or have significant influence over.

#### *Financial Liabilities Measured at Amortized Cost*

These financial liabilities are measured at amortized cost at the settlement date using the effective interest method of amortization. Financial liabilities measured at amortized cost comprise accounts payable and accrued liabilities, short-term borrowings and long-term debt. Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt or as a prepayment and amortized using the effective interest method.

### T) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2016.

### U) Recent Accounting Pronouncements

#### *Amended Accounting Standard Adopted*

The Company adopted the following new amendment:

##### Liabilities Arising From Financing Activities

The Company has early adopted the disclosure requirements in "*Disclosure Initiative (Amendments to IAS 7)*" ("IAS 7") before the mandatory effective date of January 1, 2017. Additional disclosures for changes in liabilities arising from financing activities has been included in Note 21. As allowed by IAS 7, comparative information has not been presented.

#### *New Accounting Standards and Interpretations not yet Adopted*

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2017 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2016. The standards applicable to the Company are as follows and will be adopted on their respective effective dates:

##### Leases

On January 13, 2016, the IASB issued IFRS 16, "*Leases*" ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases.

Lessors will continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue, and what assets would be recorded.

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 "*Revenue From Contracts With Customers*" has been adopted. The standard may be applied retrospectively or using a 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. It is anticipated that the adoption of IFRS 16 will have a material impact on the Company's Consolidated Balance Sheets due to material operating lease commitments as disclosed in Note 34. The Company plans to apply IFRS 16 initially on January 1, 2019; however, the transition approach on adoption has not yet been determined.

### Revenue Recognition

On May 28, 2014, the IASB issued IFRS 15, "*Revenue From Contracts With Customers*" ("IFRS 15") replacing IAS 11, "*Construction Contracts*", IAS 18, "*Revenue*" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

IFRS 15 is effective for annual periods beginning on or after January 1, 2018. Early adoption is permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements and plans to adopt the standard for its year ended December 31, 2018.

### Financial Instruments

On July 24, 2014, the IASB issued the final version of IFRS 9, "*Financial Instruments*" ("IFRS 9") to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39").

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The IAS 39 measurement categories for financial assets will be replaced by fair value through profit or loss, fair value through other comprehensive income and amortized cost. Based on its preliminary assessment, the Company does not believe the change in classification will have a material impact on the Consolidated Financial Statements.

IFRS 9 retains most of the IAS 39 requirements for financial liabilities. However, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. Cenovus currently does not designate any financial liabilities as fair value through profit or loss.

A new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. The Company does not expect the change in the impairment model to have a material impact on the Consolidated Financial Statements.

In addition, IFRS 9 includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Cenovus does not currently apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company plans to adopt IFRS 9 for its year ended December 31, 2018.

## 4. 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*

Cenovus holds a 50 percent ownership interest in two jointly controlled entities, FCCL and WRB. The classification of these joint arrangements as either a joint operation or a joint venture requires judgment. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB.

As a result, these joint arrangements are classified as joint operations and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, *"Joint Arrangements"*, 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. The partnerships do not have any third-party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and, as such, are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

#### *Exploration and Evaluation Assets*

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating 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 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 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.

### 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 and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands and Conventional segments. The Company's crude oil and natural gas reserves are evaluated 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 crude oil and natural gas 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.

### *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.

## 5. FINANCE COSTS

| For the years ended December 31, | **2016** | 2015 | 2014 |
|---|---|---|---|
| Interest Expense – Short-Term Borrowings and Long-Term Debt | **341** | 328 | 285 |
| Unwinding of Discount on Decommissioning Liabilities (Note 22) | **130** | 126 | 120 |
| Other | **21** | 28 | 18 |
| Interest Expense – Partnership Contribution Payable (1) | **-** | - | 22 |
| | **492** | 482 | 445 |

*(1) In 2014, Cenovus repaid the remaining principal and accrued interest due under the Partnership Contribution Payable.*

## 6. FOREIGN EXCHANGE (GAIN) LOSS, NET

| For the years ended December 31, | **2016** | 2015 | 2014 |
|---|---|---|---|
| Unrealized Foreign Exchange (Gain) Loss on Translation of: | | | |
| U.S. Dollar Debt Issued From Canada | **(196)** | 1,064 | 458 |
| Other | **7** | 33 | (47) |
| **Unrealized Foreign Exchange (Gain) Loss** | **(189)** | 1,097 | 411 |
| **Realized Foreign Exchange (Gain) Loss** | **(9)** | (61) | - |
| | **(198)** | 1,036 | 411 |

## 7. DIVESTITURES

In the third quarter of 2016, the Company completed the sale of land to an unrelated third party for cash proceeds of $8 million, resulting in a loss of $5 million. In the second quarter of 2016, the Company sold equipment at a loss of $1 million. These assets, related liabilities and results of operations were reported in the Conventional segment.

In the third quarter of 2015, the Company completed the sale of Heritage Royalty Limited Partnership ("HRP"), a wholly-owned subsidiary, to a third party for gross cash proceeds of $3.3 billion, resulting in a gain of $2.4 billion. HRP was a royalty business consisting of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. These assets, related liabilities and results of operations were reported in the Conventional segment.

The divestiture gave rise to a taxable gain for which the Company recognized a current tax expense of $391 million. The majority of HRP's assets had been acquired at a nominal cost and, as such, had minimal benefit from tax depreciation in prior years. For this reason, the current tax expense associated with the divestiture was specifically identifiable; therefore, it has been classified as an investing activity in the Consolidated Statements of Cash Flows.

In the first quarter of 2015, the Company divested an office building, recording a gain of $16 million.

In 2014, the Company completed the sale of certain Wainwright properties to an unrelated third party for net proceeds of $234 million, resulting in a gain of $137 million. The Company also completed the sale of certain Bakken properties to an unrelated third party for net proceeds of $35 million, resulting in a gain of $16 million. Other divestitures in 2014 included the sale of certain non-core properties, resulting in a gain of $4 million. These assets and results of operations were reported in the Conventional segment.

## 8. OTHER (INCOME) LOSS, NET

As at December 31, 2016, due to the Government of Canada's decision to reject the Northern Gateway Pipeline project, the Company has written off $23 million of capitalized costs associated with its funding support unit in Northern Gateway Pipeline. In addition, $7 million of expected costs associated with termination have been recorded.

In 2016, $7 million (2015 – $nil) of certain investments in private equity companies were written off.

## 9. IMPAIRMENT CHARGES AND REVERSALS

### A) CGU Net Impairments

The review of the Company's PP&E and E&E assets for indicators of impairment as at December 31, 2016 provided evidence that a portion of the impairment losses previously recorded should be reversed.

#### *2016 Net Upstream Impairments*

As at December 31, 2016, the recoverable value of the Northern Alberta CGU was estimated to be $1.1 billion. Earlier in 2016 and 2015, impairment losses of $380 million and $184 million, respectively, were recorded primarily due to a decline in long-term heavy crude oil prices and a slowing of the development plan. In the fourth quarter of 2016, the Company reversed $400 million of impairment losses, net of the DD&A that would have been recorded had no impairments been recorded. The reversal arose due to the increase in the CGU's estimated recoverable amount caused by an average reduction in expected future operating costs of five percent and lower future development costs, partially offset by a decline in estimated reserves. The impairment losses and subsequent reversal were recorded as DD&A in the Conventional segment. The Northern Alberta CGU includes the Pelican Lake and Elk Point producing assets and other emerging assets in the exploration and evaluation stage.

As at December 31, 2016, the recoverable amount of the Suffield CGU was estimated to be $548 million. Earlier in 2016, an impairment loss of $65 million was recognized due to lower long-term forward natural gas and heavy crude oil prices. In the fourth quarter of 2016, the Company reversed the full amount of the impairment losses, net of the DD&A that would have been recorded had no impairment been recorded ($62 million). The reversal arose due to a decline in expected future royalties increasing the estimated recoverable amount of the CGU. The impairment loss and the subsequent reversal were recorded as DD&A in the Conventional segment. The Suffield CGU includes production of natural gas and heavy crude oil in Alberta on the Canadian Forces Base.

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. There were no goodwill impairments for the twelve months ended December 31, 2016.

### *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, 2016 by the IQREs.

#### Crude Oil and Natural Gas Prices

The forward prices as at December 31, 2016, used to determine future cash flows from crude oil and natural gas reserves were:

| | 2017 | 2018 | 2019 | 2020 | 2021 | Average Annual Increase Thereafter |
|---|---|---|---|---|---|---|
| WTI (US$/barrel) (1) | 55.00 | 58.70 | 62.40 | 69.00 | 75.80 | 2.0% |
| WCS (C$/barrel) (2) | 53.70 | 58.20 | 61.90 | 66.50 | 71.00 | 2.0% |
| AECO (C$/Mcf) (3) (4) | 3.40 | 3.15 | 3.30 | 3.60 | 3.90 | 2.2% |

*(1) West Texas Intermediate ("WTI") crude oil.*
*(2) Western Canadian Select ("WCS") crude oil blend.*
*(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

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent and inflation is estimated at two percent, which is common industry practice and used by Cenovus's IQREs in preparing the reserves report. Based on the individual characteristics of the CGU, other economic and operating factors are also considered, which may increase or decrease the implied discount rate.

#### Sensitivities

The estimated recoverable value of the Northern Alberta CGU is sensitive to discount rate and forward price estimates over the life of the reserves. Changes to these assumptions, assuming all other variables remained constant, would have had the following impact on the 2016 net impairment of the Northern Alberta CGU:

| | **One Percent Increase in the Discount Rate** | **One Percent Decrease in the Discount Rate (1)** | **Five Percent Increase in the Forward Price Estimates (1)** | **Five Percent Decrease in the Forward Price Estimates** |
|---|---|---|---|---|
| Increase (Decrease) to Net Impairment of PP&E | **132** | **(106)** | **(106)** | **270** |

*(1) The $106 million represents the remaining impairment loss that could be reversed as at December 31, 2016.*

### *2015 Impairments*

As at December 31, 2015, the Company determined that the carrying amount of the Northern Alberta CGU exceeded its recoverable amount, resulting in an impairment loss of $184 million. The impairment was recorded as additional DD&A in the Conventional segment. Future cash flows for the CGU declined due to lower forward crude oil prices, a decline in reserves estimates and a slowing down of the development plan. This was partially offset by lower future development and operating costs.

The recoverable amount was determined using FVLCOD. The fair value of producing properties was 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). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 10 percent. As at December 31, 2015, the recoverable amount of the Northern Alberta CGU was estimated to be approximately $1.5 billion.

There were no goodwill impairments for the twelve months ended December 31, 2015.

***2014 Impairments***

As at December 31, 2014, the Company determined that the carrying amount of the Northern Alberta CGU exceeded its recoverable amount and the full amount of the impairment was attributed to goodwill. An impairment loss of $497 million was recorded as goodwill impairment on the Consolidated Statements of Earnings. The operating results of the CGU are included in the Conventional segment. Future cash flows for the CGU declined due to lower crude oil prices and a slowing down of the Pelican Lake development plan.

The recoverable amount was determined using FVLCOD. The fair value for producing properties was 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). The fair value of E&E assets was determined using market comparable transactions (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 11 percent. To assess reasonableness, an evaluation of fair value based on comparable asset transactions was also completed. As at December 31, 2014, the recoverable amount of the Northern Alberta CGU was estimated to be $2.3 billion.

**B) Asset Impairments**

***Exploration and Evaluation Assets***

In 2016, $2 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable. This impairment loss was recorded as exploration expense in the Oil Sands segment.

In 2015, $138 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable, and were recorded as exploration expense. This impairment loss included $67 million and $71 million within the Oil Sands and Conventional segments, respectively.

In 2014, $82 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable, and were recorded as exploration expense in the Conventional segment. In addition, $4 million of costs related to the expiry of leases in the Borealis CGU were recorded as exploration expense in the Oil Sands segment.

***Property, Plant and Equipment, Net***

In the fourth quarter of 2016, the Company recorded an impairment loss of $20 million primarily related to equipment that was written down to its recoverable amount. This impairment was recorded as additional DD&A in the Conventional segment.

In the third quarter of 2016, the Company recorded an impairment loss of $16 million related to preliminary engineering costs associated with a project that was cancelled and equipment that was written down to its recoverable amount. This impairment loss was recorded as additional DD&A in the Oil Sands segment. In the second quarter of 2016, $4 million of leasehold improvements were written off. This impairment loss was recorded as additional DD&A in the Corporate and Eliminations segment.

In 2015, the Company impaired a sulphur recovery facility for $16 million, which was recorded as additional DD&A in the Oil Sands segment. The Company did not have future plans for the assets and did not believe it would recover the carrying amount through a sale.

In 2014, the Company impaired equipment for $52 million. The Company did not have future plans for the equipment and did not believe it would recover the carrying amount through a sale. The asset was written down to FVLCOD. Additionally, a minor natural gas property was shut-in and abandonment commenced, resulting in an impairment of $13 million. These impairments were recorded as additional DD&A in the Conventional segment.

## 10. INCOME TAXES

The provision for income taxes is:

| For the years ended December 31, | **2016** | 2015 | 2014 |
|---|---|---|---|
| Current Tax | | | |
| Canada | **(174)** | 586 | 94 |
| United States | **1** | (12) | (2) |
| **Total Current Tax Expense (Recovery)** | **(173)** | 574 | 92 |
| **Deferred Tax Expense (Recovery)** | **(209)** | (655) | 359 |
| | **(382)** | (81) | 451 |

In 2016, the Company recorded a current tax recovery due to the carryback of losses for income tax purposes and prior year adjustments.

In 2015, the Company recorded a deferred tax recovery of $415 million arising from an adjustment to the tax basis of the 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. The Government of Alberta enacted a two percent increase in the corporate income tax rate effective July 1, 2015, increasing the statutory tax rate for the year to 26.1 percent. As a result, the Company's deferred income tax liability increased by $161 million for the year ended December 31, 2015.

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

| For the years ended December 31, | **2016** | 2015 | 2014 |
|---|---|---|---|
| **Earnings (Loss) Before Income Tax** | **(927)** | 537 | 1,195 |
| Canadian Statutory Rate | **27.0%** | 26.1% | 25.2% |
| **Expected Income Tax (Recovery)** | **(250)** | 140 | 301 |
| Effect of Taxes Resulting From: | | | |
| Foreign Tax Rate Differential | **(46)** | (41) | (43) |
| Non-Deductible Stock-Based Compensation | **5** | 7 | 13 |
| Non-Taxable Capital (Gains) Losses | **(26)** | 137 | 74 |
| Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange | **(26)** | 135 | 50 |
| Adjustments Arising From Prior Year Tax Filings | **(46)** | (55) | (16) |
| Derecognition (Recognition) of Capital Losses | **-** | (149) | (9) |
| (Recognition) of U.S. Tax Basis | **-** | (415) | - |
| Change in Statutory Rate | **-** | 161 | - |
| Foreign Exchange Gains (Losses) not Included in Net Earnings | **-** | - | (13) |
| Goodwill Impairment | **-** | - | 125 |
| Other | **7** | (1) | (31) |
| **Total Tax (Recovery)** | **(382)** | (81) | 451 |
| **Effective Tax Rate** | **41.2%** | (15.1)% | 37.7% |

The analysis of deferred income tax liabilities and deferred income tax assets is as follows:

| As at December 31, | **2016** | 2015 |
|---|---|---|
| **Deferred Income Tax Liabilities** | | |
| Deferred Tax Liabilities to be Settled Within 12 Months | **6** | 100 |
| Deferred Tax Liabilities to be Settled After More Than 12 Months | **3,147** | 3,051 |
| | **3,153** | 3,151 |
| **Deferred Income Tax Assets** | | |
| Deferred Tax Assets to be Recovered Within 12 Months | **(117)** | (42) |
| Deferred Tax Assets to be Recovered After More Than 12 Months | **(451)** | (293) |
| | **(568)** | (335) |
| **Net Deferred Income Tax Liability** | **2,585** | 2,816 |

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 | Property, Plant and Equipment | Timing of Partnership Items | Risk Management | Other | Total |
|---|---|---|---|---|---|
| As at December 31, 2014 | 3,106 | 167 | 121 | 41 | 3,435 |
| Charged (Credited) to Earnings | (246) | (167) | (39) | (24) | (476) |
| Charged (Credited) to OCI | 192 | - | - | - | 192 |
| As at December 31, 2015 | 3,052 | - | 82 | 17 | 3,151 |
| Charged (Credited) to Earnings | 118 | - | (76) | (16) | 26 |
| Charged (Credited) to OCI | (24) | - | - | - | (24) |
| **As at December 31, 2016** | **3,146** | **-** | **6** | **1** | **3,153** |

| Deferred Income Tax Assets | Unused Tax Losses | Timing of Partnership Items | Risk Management | Other | Total |
|---|---|---|---|---|---|
| As at December 31, 2014 | (72) | - | (4) | (57) | (133) |
| Charged (Credited) to Earnings | (80) | (36) | (4) | (59) | (179) |
| Charged (Credited) to OCI | (20) | - | - | (3) | (23) |
| As at December 31, 2015 | (172) | (36) | (8) | (119) | (335) |
| Charged (Credited) to Earnings | (102) | 36 | (77) | (92) | (235) |
| Charged (Credited) to OCI | 4 | - | - | (2) | 2 |
| **As at December 31, 2016** | **(270)** | **-** | **(85)** | **(213)** | **(568)** |

| Net Deferred Income Tax Liabilities | Total |
|---|---|
| Net Deferred Income Tax Liabilities as at December 31, 2014 | 3,302 |
| Charged (Credited) to Earnings | (655) |
| Charged (Credited) to OCI | 169 |
| Net Deferred Income Tax Liabilities as at December 31, 2015 | 2,816 |
| Charged (Credited) to Earnings | (209) |
| Charged (Credited) to OCI | (22) |
| **Net Deferred Income Tax Liabilities as at December 31, 2016** | **2,585** |

No deferred tax liability has been recognized as at December 31, 2016 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. As at December 31, 2016, the Company had temporary differences of $7,457 million (2015 – $6,692 million) in respect of certain of these investments where, on dissolution or sale, a tax liability may exist.

The approximate amounts of tax pools available, including tax losses, are:

| As at December 31, | 2016 | 2015 |
|---|---|---|
| Canada | **4,273** | 4,882 |
| United States | **2,036** | 2,119 |
| | **6,309** | 7,001 |

As at December 31, 2016, the above tax pools included $46 million (2015 – $13 million) of Canadian non-capital losses and $623 million (2015 – $380 million) of U.S. federal net operating losses. These losses expire no earlier than 2031.

Also included in the December 31, 2016 tax pools are Canadian net capital losses totaling $43 million (2015 – $44 million), which are available for carry forward to reduce future capital gains. Of these losses, $40 million are unrecognized as a deferred income tax asset as at December 31, 2016 (2015 – $41 million). Recognition is dependent on future capital gains. The Company has not recognized $730 million (2015 – $828 million) of net capital losses associated with unrealized foreign exchange losses on its U.S. denominated debt.

## 11. PER SHARE AMOUNTS

### A) Net Earnings (Loss) Per Share

| For the years ended December 31, | 2016 | 2015 | 2014 |
|---|---|---|---|
| Net Earnings (Loss) – Basic and Diluted ($ millions) | **(545)** | 618 | 744 |
| Weighted Average Number of Shares – Basic (millions) | **833.3** | 818.7 | 756.9 |
| Dilutive Effect of Cenovus TSARs | **-** | - | 0.7 |
| Weighted Average Number of Shares – Diluted | **833.3** | 818.7 | 757.6 |
| **Net Earnings (Loss) Per Share** – Basic and Diluted ($) | **(0.65)** | 0.75 | 0.98 |

### B) Dividends Per Share

For the year ended December 31, 2016, the Company paid dividends of $166 million or $0.20 per share, all of which were paid in cash (2015 – $710 million or $0.8524 per share, including cash dividends of $528 million; 2014 – $805 million or $1.0648 per share, all of which were paid in cash). The Cenovus Board of Directors declared a first quarter dividend of $0.05 per share, payable on March 31, 2017, to common shareholders of record as of March 15, 2017.

## 12. CASH AND CASH EQUIVALENTS

| As at December 31, | 2016 | 2015 |
|---|---|---|
| Cash | **542** | 323 |
| Short-Term Investments | **3,178** | 3,782 |
| | **3,720** | 4,105 |

## 13. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

| As at December 31, | 2016 | 2015 |
|---|---|---|
| Accruals | **1,606** | 1,037 |
| Partner Advances | **-** | 35 |
| Prepaids and Deposits | **127** | 71 |
| Note Receivable From Partner (1) | **50** | - |
| Trade | **29** | 61 |
| Joint Operations Receivables | **11** | 13 |
| Other | **15** | 34 |
| | **1,838** | 1,251 |

*(1) Note receivable from partner is interest bearing at a rate of 1.6783 percent per annum and is due on demand.*

## 14. INVENTORIES

| As at December 31, | 2016 | 2015 |
|---|---|---|
| **Product** | | |
| Refining and Marketing | **1,006** | 591 |
| Oil Sands | **156** | 158 |
| Conventional | **20** | 11 |
| **Parts and Supplies** | **55** | 50 |
| | **1,237** | 810 |

During the year ended December 31, 2016, approximately $9,964 million of produced and purchased inventory was recorded as an expense (2015 – $10,618 million; 2014 – $15,065 million).

As a result of a decline in commodity prices, Cenovus recorded a write-down of its product inventory of $4 million from cost to net realizable value as at December 31, 2016 (2015 – $66 million).

## 15. EXPLORATION AND EVALUATION ASSETS

| | Total |
|---|---|
| As at December 31, 2014 | 1,625 |
| Additions | 138 |
| Acquisitions | 3 |
| Transfers to PP&E (Note 16) | (49) |
| Exploration Expense (Note 9) | (138) |
| Change in Decommissioning Liabilities | (4) |
| As at December 31, 2015 | 1,575 |
| Additions | 67 |
| Transfers to PP&E (Note 16) | (49) |
| Exploration Expense (Note 9) | (2) |
| Change in Decommissioning Liabilities | (6) |
| **As at December 31, 2016** | **1,585** |

## 16. PROPERTY, PLANT AND EQUIPMENT, NET

| | Upstream Assets | | | | |
|---|---|---|---|---|---|
| | Development & Production | Other Upstream | Refining Equipment | Other [1] | Total |
| **COST** | | | | | |
| As at December 31, 2014 | 31,701 | 329 | 4,151 | 910 | 37,091 |
| Additions | 1,289 | 2 | 240 | 45 | 1,576 |
| Acquisition (Note 17) | 1 | - | - | 83 | 84 |
| Transfers From E&E Assets (Note 15) | 49 | - | - | - | 49 |
| Change in Decommissioning Liabilities | (635) | - | 1 | (1) | (635) |
| Exchange Rate Movements and Other | (1) | - | 814 | - | 813 |
| Divestitures (Note 7) | (923) | - | - | - | (923) |
| As at December 31, 2015 | 31,481 | 331 | 5,206 | 1,037 | 38,055 |
| Additions | 717 | 2 | 213 | 38 | 970 |
| Transfers From E&E Assets (Note 15) | 49 | - | - | - | 49 |
| Change in Decommissioning Liabilities | (267) | - | (8) | - | (275) |
| Exchange Rate Movements and Other | (16) | - | (152) | (1) | (169) |
| Divestitures (Note 7) | (23) | - | - | - | (23) |
| **As at December 31, 2016** | **31,941** | **333** | **5,259** | **1,074** | **38,607** |
| **ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION** | | | | | |
| As at December 31, 2014 | 17,153 | 233 | 584 | 558 | 18,528 |
| DD&A | 1,601 | 44 | 189 | 80 | 1,914 |
| Impairment Losses (Note 9) | 200 | - | - | - | 200 |
| Exchange Rate Movements and Other | (1) | - | 123 | 1 | 123 |
| Divestitures (Note 7) | (45) | - | - | - | (45) |
| As at December 31, 2015 | 18,908 | 277 | 896 | 639 | 20,720 |
| DD&A | 1,173 | 31 | 205 | 66 | 1,475 |
| Impairment Losses (Note 9) | 481 | - | - | 4 | 485 |
| Reversal of Impairment Losses (Note 9) | (462) | - | - | - | (462) |
| Exchange Rate Movements and Other | (4) | - | (25) | - | (29) |
| Divestitures (Note 7) | (8) | - | - | - | (8) |
| **As at December 31, 2016** | **20,088** | **308** | **1,076** | **709** | **22,181** |
| **CARRYING VALUE** | | | | | |
| As at December 31, 2014 | 14,548 | 96 | 3,567 | 352 | 18,563 |
| As at December 31, 2015 | 12,573 | 54 | 4,310 | 398 | 17,335 |
| **As at December 31, 2016** | **11,853** | **25** | **4,183** | **365** | **16,426** |

(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, | **2016** | 2015 |
|---|---|---|
| Development and Production | **537** | 537 |
| Refining Equipment | **206** | 265 |
| | **743** | 802 |

## 17. ACQUISITION

In 2015, the Company completed the acquisition of a crude-by-rail terminal for cash consideration of $75 million, plus adjustments. The transaction was accounted for using the acquisition method of accounting. In connection with the acquisition, the Company assumed an associated decommissioning liability of $4 million, working capital of $1 million and net transportation commitments of $92 million. Transaction costs associated with the acquisition were expensed. These assets, related liabilities and results of operations are reported in the Refining and Marketing segment.

## 18. OTHER ASSETS

| As at December 31, | **2016** | 2015 |
|---|---|---|
| Equity Investments | **35** | 46 |
| Long-Term Receivables | **15** | 1 |
| Prepaids | **5** | 7 |
| Other (Note 8) | **1** | 22 |
| | **56** | 76 |

## 19. GOODWILL

All of the Company's goodwill arose in 2002 upon the formation of its predecessor corporation. As at December 31, 2016 and 2015, the $242 million carrying amount of goodwill was associated with the Company's Primrose (Foster Creek) CGU.

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, 2016 are consistent to those disclosed in Note 9.

## 20. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

| As at December 31, | **2016** | 2015 |
|---|---|---|
| Accruals | **1,927** | 1,366 |
| Trade | **105** | 68 |
| Interest | **72** | 73 |
| Note Payable to Partner (1) | **50** | - |
| Employee Long-Term Incentives | **42** | 47 |
| Onerous Contract Provisions | **18** | - |
| Other | **52** | 113 |
| Partner Advances | **-** | 35 |
| | **2,266** | 1,702 |

*(1) Note payable to partner is interest bearing at a rate of 1.6783 percent per annum and is due on demand.*

## 21. LONG-TERM DEBT

| As at December 31, | | 2016 | 2015 |
|---|---|---|---|
| Revolving Term Debt [1] | A | **-** | - |
| U.S. Dollar Denominated Unsecured Notes | B | **6,378** | 6,574 |
| **Total Debt Principal** | C | **6,378** | 6,574 |
| Debt Discounts and Transaction Costs | D | **(46)** | (49) |
| | | **6,332** | 6,525 |

*(1) Revolving term debt may include Bankers' Acceptances, London Interbank Offered Rate ("LIBOR") based loans, prime rate loans and U.S. base rate loans.*

The weighted average interest rate on outstanding debt for the year ended December 31, 2016 was 5.3 percent (2015 – 5.3 percent).

### A) Revolving Term Debt

As at December 31, 2016, Cenovus had in place a committed credit facility in the amount of $4.0 billion or the equivalent amount in U.S. dollars. On April 22, 2016, the Company renegotiated the maturity date of the $1.0 billion tranche from November 30, 2017 to April 30, 2019. The $3.0 billion tranche matures on November 30, 2019. The maturity dates are extendable from time to time, at the option of Cenovus and upon agreement from the lenders. Borrowings are available by way of Bankers' Acceptances, LIBOR based loans, prime rate loans or U.S. base rate loans. As at December 31, 2016, there were no amounts drawn on Cenovus's committed bank credit facility (2015 – $nil).

### B) Unsecured Notes

Unsecured notes are composed of:

| As at December 31, | US$ Principal Amount | 2016 | 2015 |
|---|---|---|---|
| 5.70% due October 15, 2019 | 1,300 | **1,746** | 1,799 |
| 3.00% due August 15, 2022 | 500 | **671** | 692 |
| 3.80% due September 15, 2023 | 450 | **604** | 623 |
| 6.75% due November 15, 2039 | 1,400 | **1,880** | 1,938 |
| 4.45% due September 15, 2042 | 750 | **1,007** | 1,038 |
| 5.20% due September 15, 2043 | 350 | **470** | 484 |
| | 4,750 | **6,378** | 6,574 |

On February 24, 2016, Cenovus filed a base shelf prospectus. The base shelf prospectus 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 will expire in March 2018. As at December 31, 2016, no issuances have been made under the US$5.0 billion base shelf prospectus.

As at December 31, 2016, the Company is in compliance with all of the terms of its debt agreements.

### C) Mandatory Debt Payments

| | US$ Principal Amount | C$ Principal Amount | Total C$ Equivalent |
|---|---|---|---|
| 2017 | - | - | **-** |
| 2018 | - | - | **-** |
| 2019 | 1,300 | - | **1,746** |
| 2020 | - | - | **-** |
| 2021 | - | - | **-** |
| Thereafter | 3,450 | - | **4,632** |
| | 4,750 | - | **6,378** |

### D) Debt Discounts and Transaction Costs

Long-term debt transaction costs and discounts associated with the unsecured notes are recorded within long-term debt and are amortized using the effective interest rate method. Transaction costs associated with the revolving term debt are recorded as a prepayment and are amortized over the remaining term of the committed credit facility. During 2016, additional transaction costs of $1 million were recorded (2015 – $3 million).

### E) Reconciliation of Liabilities to Cash Flows Arising From Financing Activities

| | Short-Term Borrowings | Long-Term Borrowings |
|---|---|---|
| As at December 31, 2015 | - | 6,525 |
| Changes From Financing Cash Flows | - | - |
| Non-Cash Changes: | | |
| Unrealized Foreign Exchange (Gain) Loss (Note 6) | - | (196) |
| Amortization of Debt Discounts | - | 3 |
| **As at December 31, 2016** | **-** | **6,332** |

## 22. 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:

| As at December 31, | 2016 | 2015 |
|---|---|---|
| Decommissioning Liabilities, Beginning of Year | **2,052** | 2,616 |
| Liabilities Incurred | **11** | 10 |
| Liabilities Acquired | **-** | 4 |
| Liabilities Settled | **(51)** | (62) |
| Liabilities Divested | **(1)** | - |
| Change in Estimated Future Cash Flows | **(423)** | (70) |
| Change in Discount Rate | **131** | (579) |
| Unwinding of Discount on Decommissioning Liabilities | **130** | 126 |
| Foreign Currency Translation | **(2)** | 7 |
| **Decommissioning Liabilities, End of Year** | **1,847** | 2,052 |

As at December 31, 2016, the undiscounted amount of estimated future cash flows required to settle the obligation is $6,270 million (2015 – $6,665 million), which has been discounted using a credit-adjusted risk-free rate of 5.9 percent (2015 – 6.4 percent). An inflation rate of two percent (2015 – two percent) was used to calculate the decommissioning provision. 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 $90 million of decommissioning liabilities over the next year. Revisions in estimated future cash flows resulted from lower cost estimates, partially offset by accelerated timing of decommissioning liabilities over the estimated life of the reserves.

### Sensitivities

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

| | **2016** | | 2015 | |
|---|---|---|---|---|
| As at December 31, | **Credit-Adjusted Risk-Free Rate** | **Inflation Rate** | Credit-Adjusted Risk-Free Rate | Inflation Rate |
| One Percent Increase | **(248)** | **327** | (247) | 319 |
| One Percent Decrease | **317** | **(259)** | 308 | (259) |

## 23. OTHER LIABILITIES

| As at December 31, | 2016 | 2015 |
|---|---|---|
| Employee Long-Term Incentives | **72** | 40 |
| Pension and OPEB (Note 24) | **71** | 66 |
| Onerous Contract Provisions | **35** | - |
| Other | **33** | 36 |
| | **211** | 142 |

## 24. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension that includes either a defined contribution or defined benefit component and OPEB. Most of the employees participate in the defined contribution pension. Starting in 2012, employees who meet certain criteria may move from the current defined contribution component to a defined benefit component for their future service.

The defined benefit pension provides pension benefits at retirement based on years of service and final average earnings. Future enrollment is limited to eligible employees who meet certain criteria. The Company's OPEB provides certain retired employees with health care and dental benefits until age 65 and life insurance benefits.

The Company is required to file an actuarial valuation of its registered defined benefit pension with the provincial regulator at least every three years. The most recently filed valuation was dated December 31, 2014 and the next required actuarial valuation will be as at December 31, 2017.

### 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, | 2016 | 2015 | 2016 | 2015 |
| **Defined Benefit Obligation** | | | | |
| Defined Benefit Obligation, Beginning of Year | **168** | 200 | **26** | 23 |
| Current Service Costs | **14** | 19 | **(3)** | 3 |
| Interest Costs [1] | **7** | 8 | **1** | 1 |
| Benefits Paid | **(25)** | (6) | **(1)** | (1) |
| Plan Participant Contributions | **2** | 3 | **-** | - |
| Past Service Costs – Curtailments | **-** | (5) | **-** | - |
| Settlements | **-** | (20) | **-** | - |
| Remeasurements: | | | | |
| (Gains) Losses from Experience Adjustments | **-** | (3) | **-** | - |
| (Gains) Losses from Changes in Financial Assumptions | **7** | (28) | **-** | - |
| **Defined Benefit Obligation, End of Year** | **173** | 168 | **23** | 26 |
| **Plan Assets** | | | | |
| Fair Value of Plan Assets, Beginning of Year | **128** | 139 | **-** | - |
| Employer Contributions | **14** | 16 | **-** | - |
| Plan Participant Contributions | **2** | 3 | **-** | - |
| Benefits Paid | **(25)** | (6) | **-** | - |
| Settlements | **-** | (23) | **-** | - |
| Interest Income [1] | **3** | 2 | **-** | - |
| Remeasurements: | | | | |
| Return on Plan Assets (Excluding Interest Income) | **3** | (3) | **-** | - |
| **Fair Value of Plan Assets, End of Year** | **125** | 128 | **-** | - |
| **Pension and OPEB (Liability) [2]** | **(48)** | (40) | **(23)** | (26) |

(1) *Based on the discount rate of the defined benefit obligation at the beginning of the year.*
(2) *Pension and OPEB liabilities are included in other liabilities on the Consolidated Balance Sheets.*

The weighted average duration of the defined benefit pension and OPEB obligations are 16 years and 11 years, respectively.

### B) Pension and OPEB Costs

| For the years ended December 31, | Pension Benefits | | | OPEB | | |
|---|---|---|---|---|---|---|
| | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| **Defined Benefit Plan Cost** | | | | | | |
| Current Service Costs | **14** | 19 | 15 | **(3)** | 3 | 2 |
| Past Service Costs – Curtailments | **-** | (5) | - | **-** | - | - |
| Net Settlement Costs | **-** | 3 | - | **-** | - | - |
| Net Interest Costs | **4** | 6 | 3 | **1** | 1 | 1 |
| Remeasurements: | | | | | | |
| Return on Plan Assets (Excluding Interest Income) | **(3)** | 3 | (8) | **-** | - | - |
| (Gains) Losses from Experience Adjustments | **-** | (3) | - | **-** | - | - |
| (Gains) Losses from Changes in Demographic Assumptions | **-** | - | (1) | **-** | - | - |
| (Gains) Losses from Changes in Financial Assumptions | **7** | (28) | 31 | **-** | - | 2 |
| **Defined Benefit Plan Cost (Gain)** | **22** | (5) | 40 | **(2)** | 4 | 5 |
| **Defined Contribution Plan Cost** | **25** | 29 | 30 | **-** | - | - |
| **Total Plan Cost** | **47** | 24 | 70 | **(2)** | 4 | 5 |

### 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 quarterly and is re-balanced as necessary. The asset allocation structure targets an investment of 50 to 75 percent in equity securities, 25 to 35 percent in fixed income assets, zero to 15 percent in real estate assets and zero 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, | **2016** | 2015 |
|---|---|---|
| Equity Funds | **73** | 73 |
| Bond Funds | **25** | 31 |
| Non-Invested Assets | **13** | 17 |
| Real Estate Funds | **9** | 4 |
| Cash and Cash Equivalents | **5** | 3 |
| | **125** | 128 |

Fair value of equity securities and bond funds are based on the trading price of the underlying funds. The fair value of the non-invested assets is the discounted value of the expected future payments. The fair value of the real estate fund reflects the market value and the fund manager's appraisal value of the assets.

Equity securities do not include any direct investments in Cenovus shares.

### D) Funding

The defined benefit pension is funded in accordance with federal and provincial government pension legislation, where applicable. Contributions are made to trust funds administered by an independent trustee. The Company's contributions to the defined benefit pension plan are based on actuarial valuations 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, 2017 are $14 million for the defined benefit pension plan and $nil for the OPEB. The OPEB is funded on an as required basis.

### E) Actuarial Assumptions and Sensitivities

*Actuarial Assumptions*

The principal weighted average actuarial assumptions used to determine benefit obligations and expenses are as follows:

| | Pension Benefits | | | OPEB | | |
|---|---|---|---|---|---|---|
| For the years ended December 31, | **2016** | 2015 | 2014 | **2016** | 2015 | 2014 |
| Discount Rate | **3.75%** | 4.00% | 3.75% | **3.75%** | 3.75% | 3.75% |
| Future Salary Growth Rate | **3.80%** | 3.80% | 4.32% | **5.15%** | 5.15% | 5.65% |
| Average Longevity (years) | **87.9** | 88.3 | 88.3 | **87.9** | 88.3 | 88.3 |
| Health Care Cost Trend Rate | **N/A** | N/A | N/A | **7.00%** | 7.00% | 7.00% |

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:

| | 2016 | | 2015 | |
|---|---|---|---|---|
| As at December 31, | **Increase** | **Decrease** | Increase | Decrease |
| One Percent Change: | | | | |
| Discount Rate | **(25)** | **32** | (27) | 35 |
| Future Salary Growth Rate | **3** | **(3)** | 3 | (3) |
| Health Care Cost Trend Rate | **2** | **(1)** | 2 | (2) |
| One Year Change in Assumed Life Expectancy | **4** | **(4)** | 4 | (4) |

The above sensitivity analysis is based on a change in an assumption while holding all other assumptions constant; however, the changes in some assumptions may be correlated. The same methodologies have been used to calculate the sensitivity of the defined benefit obligation to significant actuarial assumptions as have been applied when calculating the defined benefit pension liability 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.

## 25. 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

| | **2016** | | 2015 | |
|---|---|---|---|---|
| As at December 31, | **Number of Common Shares** (thousands) | **Amount** | Number of Common Shares (thousands) | Amount |
| Outstanding, Beginning of Year | **833,290** | **5,534** | 757,103 | 3,889 |
| Common Shares Issued, Net of Issuance Costs | **-** | **-** | 67,500 | 1,463 |
| Common Shares Issued Pursuant to Dividend Reinvestment Plan | **-** | **-** | 8,687 | 182 |
| **Outstanding, End of Year** | **833,290** | **5,534** | 833,290 | 5,534 |

On March 3, 2015, Cenovus issued 67.5 million common shares at a price of $22.25 per common share. Share issuance costs of $53 million were incurred.

The Company has a DRIP, whereby holders of common shares may reinvest all or a portion of the cash dividends payable on their common shares in additional common shares. At the discretion of the Company, the additional common shares may be issued from treasury or purchased on the market. During the year ended December 31, 2016, the Company issued no common shares from treasury under the DRIP (2015 – 8.7 million).

There were no preferred shares outstanding as at December 31, 2016 (2015 – nil).

As at December 31, 2016, there were 12 million (2015 – 12 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 and Cenovus (pre-arrangement earnings). In addition, paid in surplus includes stock-based compensation expense related to the Company's NSRs discussed in Note 27A.

| | **Pre-Arrangement Earnings** | **Stock-Based Compensation** | **Total** |
|---|---|---|---|
| As at December 31, 2014 | 4,086 | 205 | 4,291 |
| Stock-Based Compensation Expense | - | 39 | 39 |
| As at December 31, 2015 | 4,086 | 244 | 4,330 |
| Stock-Based Compensation Expense | - | 20 | 20 |
| **As at December 31, 2016** | **4,086** | **264** | **4,350** |

## 26. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

| | **Defined Benefit Plan** | **Foreign Currency Translation** | **Available for Sale Financial Assets** | **Total** |
|---|---|---|---|---|
| As at December 31, 2014 | (30) | 427 | 10 | 407 |
| Other Comprehensive Income (Loss), Before Tax | 28 | 587 | 8 | 623 |
| Income Tax | (8) | - | (2) | (10) |
| As at December 31, 2015 | (10) | 1,014 | 16 | 1,020 |
| Other Comprehensive Income (Loss), Before Tax | **(4)** | **(106)** | **(4)** | **(114)** |
| Income Tax | **1** | **-** | **3** | **4** |
| **As at December 31, 2016** | **(13)** | **908** | **15** | **910** |

## 27. STOCK-BASED COMPENSATION PLANS

### A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of the Company. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options 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.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 have associated TSARs. In lieu of exercising the options, the TSARs give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

The TSARs and 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, 2016 was $3.77 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 | **0.72%** |
| Expected Dividend Yield | **1.01%** |
| Expected Volatility (1) | **27.82%** |
| Expected Life (years) | **3.50** |

*(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.*

The following tables summarize information related to the NSRs:

| As at December 31, 2016 | **Number of NSRs** (thousands) | **Weighted Average Exercise Price** ($) |
|---|---|---|
| Outstanding, Beginning of Year | **42,114** | **31.65** |
| Granted | **3,646** | **19.54** |
| Exercised | **-** | **-** |
| Forfeited | **(4,116)** | **31.76** |
| **Outstanding, End of Year** | **41,644** | **30.57** |

| | **Outstanding NSRs** | | | **Exercisable NSRs** | |
|---|---|---|---|---|---|
| As at December 31, 2016<br>**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** ($) |
| 15.00 to 19.99 | **3,588** | **6.32** | **19.54** | **1** | **17.93** |
| 20.00 to 24.99 | **3,932** | **5.15** | **22.26** | **1,212** | **22.28** |
| 25.00 to 29.99 | **12,777** | **4.14** | **28.38** | **7,772** | **28.40** |
| 30.00 to 34.99 | **11,194** | **3.18** | **32.62** | **10,868** | **32.63** |
| 35.00 to 39.99 | **10,153** | **1.78** | **38.20** | **10,153** | **38.20** |
| | **41,644** | **3.59** | **30.57** | **30,006** | **33.00** |

***TSARs***

The Company had a liability of $nil as at December 31, 2016 (2015 – $1 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period-end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

| | |
|---|---|
| Risk-Free Interest Rate | **1.11%** |
| Expected Dividend Yield | **1.08%** |
| Expected Volatility [1] | **35.19%** |
| Cenovus's Common Share Price ($) | **20.30** |

*(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.*

The intrinsic value of vested TSARs held by Cenovus employees as at December 31, 2016 was $nil (2015 – $nil).

The following tables summarize information related to the TSARs held by Cenovus employees:

| As at December 31, 2016 | **Number of TSARs** (thousands) | **Weighted Average Exercise Price** ($) |
|---|---|---|
| Outstanding, Beginning of Year | **3,645** | **26.72** |
| Exercised for Cash Payment | **-** | **-** |
| Exercised as Options for Common Shares | **-** | **-** |
| Forfeited | **(272)** | **27.45** |
| Expired | **-** | **-** |
| **Outstanding, End of Year** | **3,373** | **26.66** |

| As at December 31, 2016 | **Outstanding and Exercisable TSARs** | | |
|---|---|---|---|
| **Range of Exercise Price** ($) | **Number of TSARs** (thousands) | **Weighted Average Remaining Contractual Life** (years) | **Weighted Average Exercise Price** ($) |
| 20.00 to 29.99 | **3,261** | **0.16** | **26.45** |
| 30.00 to 34.99 | **112** | **0.97** | **32.86** |
| | **3,373** | **0.19** | **26.66** |

The market price of Cenovus's common shares on the TSX as at December 31, 2016 was $20.30.

### 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 a portion of PSUs, the number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three. All PSUs are eligible to vest based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $51 million as at December 31, 2016 (2015 – $49 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, 2016 and 2015.

The following table summarizes the information related to the PSUs held by Cenovus employees:

| As at December 31, 2016 | **Number of PSUs** (thousands) |
|---|---|
| Outstanding, Beginning of Year | **6,427** |
| Granted | **2,345** |
| Vested and Paid Out | **(979)** |
| Cancelled | **(1,697)** |
| Units in Lieu of Dividends | **61** |
| **Outstanding, End of Year** | **6,157** |

### 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 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 $30 million as at December 31, 2016 (2015 – $11 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, 2016 and 2015.

The following table summarizes the information related to the RSUs held by Cenovus employees:

| As at December 31, 2016 | **Number of RSUs** (thousands) |
|---|---|
| Outstanding, Beginning of Year | **2,267** |
| Granted | **1,718** |
| Vested and Paid Out | **(32)** |
| Cancelled | **(200)** |
| Units in Lieu of Dividends | **37** |
| **Outstanding, End of Year** | **3,790** |

### 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 $32 million as at December 31, 2016 (2015 – $26 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:

| As at December 31, 2016 | **Number of DSUs** (thousands) |
|---|---|
| Outstanding, Beginning of Year | **1,488** |
| Granted to Directors | **92** |
| Granted | **11** |
| Units in Lieu of Dividends | **17** |
| Redeemed | **(10)** |
| **Outstanding, End of Year** | **1,598** |

### E) Total Stock-Based Compensation

| For the years ended December 31, | **2016** | 2015 | 2014 |
|---|---|---|---|
| NSRs | **15** | 27 | 41 |
| TSARs | **(1)** | (5) | (10) |
| PSUs | **13** | (13) | 34 |
| RSUs | **13** | 6 | - |
| DSUs | **7** | (5) | (5) |
| **Stock-Based Compensation Expense** | **47** | 10 | 60 |
| **Stock-Based Compensation Costs Capitalized** | **12** | 6 | 29 |
| **Total Stock-Based Compensation** | **59** | 16 | 89 |

## 28. EMPLOYEE SALARIES AND BENEFIT EXPENSES

| For the years ended December 31, | **2016** | 2015 | 2014 |
|---|---|---|---|
| Salaries, Bonuses and Other Short-Term Employee Benefits | **500** | 534 | 550 |
| Defined Contribution Pension Plan | **16** | 19 | 18 |
| Defined Benefit Pension Plan and OPEB | **11** | 17 | 14 |
| Stock-Based Compensation Expense (Note 27) | **47** | 10 | 60 |
| Termination Benefits | **19** | 43 | - |
| | **593** | 623 | 642 |

## 29. 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, | **2016** | 2015 | 2014 |
|---|---|---|---|
| Salaries, Director Fees and Short-Term Benefits | **27** | 30 | 29 |
| Post-Employment Benefits | **4** | 5 | 4 |
| Stock-Based Compensation | **4** | 5 | 20 |
| | **35** | 40 | 53 |

Post-employment benefits represent the present value of future pension benefits earned during the year. Stock-based compensation includes the costs recorded during the year associated with stock options, NSRs, TSARs, PSUs, RSUs and DSUs.

## 30. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt is defined as short-term borrowings, and the current and long-term portions of long-term debt. 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. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes and DD&A ("Adjusted EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength.

Over the long term, Cenovus targets a Debt to Capitalization ratio of between 30 and 40 percent and a Debt to Adjusted EBITDA ratio of between 1.0 and 2.0 times. At different points within the economic cycle, Cenovus expects these ratios may periodically be outside of the target range.

### A) Debt to Capitalization and Net Debt to Capitalization

| As at December 31, | 2016 | 2015 | 2014 |
|---|---|---|---|
| Debt | **6,332** | 6,525 | 5,458 |
| Shareholders' Equity | **11,590** | 12,391 | 10,186 |
| | **17,922** | 18,916 | 15,644 |
| **Debt to Capitalization** | **35%** | 34% | 35% |
| Debt | **6,332** | 6,525 | 5,458 |
| Add (Deduct): | | | |
| Cash and Cash Equivalents | **(3,720)** | (4,105) | (883) |
| Net Debt | **2,612** | 2,420 | 4,575 |
| Shareholders' Equity | **11,590** | 12,391 | 10,186 |
| | **14,202** | 14,811 | 14,761 |
| **Net Debt to Capitalization** | **18%** | 16% | 31% |

### B) Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA

| As at December 31, | 2016 | 2015 | 2014 |
|---|---|---|---|
| Debt | **6,332** | 6,525 | 5,458 |
| Net Debt | **2,612** | 2,420 | 4,575 |
| Net Earnings (Loss) | **(545)** | 618 | 744 |
| Add (Deduct): | | | |
| Finance Costs | **492** | 482 | 445 |
| Interest Income | **(52)** | (28) | (33) |
| Income Tax Expense (Recovery) | **(382)** | (81) | 451 |
| DD&A | **1,498** | 2,114 | 1,946 |
| Goodwill Impairment | **-** | - | 497 |
| E&E Impairment | **2** | 138 | 86 |
| Unrealized (Gain) Loss on Risk Management | **554** | 195 | (596) |
| Foreign Exchange (Gain) Loss, Net | **(198)** | 1,036 | 411 |
| (Gain) Loss on Divestitures of Assets | **6** | (2,392) | (156) |
| Other (Income) Loss, Net | **34** | 2 | (4) |
| Adjusted EBITDA | **1,409** | 2,084 | 3,791 |
| **Debt to Adjusted EBITDA** | **4.5x** | 3.1x | 1.4x |
| **Net Debt to Adjusted EBITDA** | **1.9x** | 1.2x | 1.2x |

Cenovus will maintain a high level of capital discipline and manage its capital structure to help ensure sufficient liquidity through all stages of the economic cycle. To manage its capital structure, Cenovus may, among other actions, adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facility or repay existing debt.

Effective April 22, 2016, the Company extended the maturity date of the $1.0 billion tranche of the committed credit facility from November 30, 2017 to April 30, 2019. As at December 31, 2016, Cenovus had $4.0 billion available on its committed credit facility. In addition, Cenovus has in place a US$5.0 billion base shelf prospectus, the availability of which is dependent on market conditions.

Under the 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.

As at December 31, 2016, Cenovus is in compliance with all of the terms of its debt agreements.

## 31. FINANCIAL INSTRUMENTS

Cenovus's financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, risk management assets and liabilities, available for sale financial assets, long-term receivables, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments.

### A) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of these instruments.

The fair values of long-term receivables approximate their carrying amount due to the specific non-tradeable nature of these instruments.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on period-end trading prices of long-term borrowings on the secondary market (Level 2). As at December 31, 2016, the carrying value of Cenovus's long-term debt was $6,332 million and the fair value was $6,539 million (2015 carrying value – $6,525 million, fair value – $6,050 million).

Available for sale financial assets comprise private equity investments. These assets are carried at fair value on the Consolidated Balance Sheets in other assets. Fair value is determined based on recent private placement transactions (Level 3) when available. The following table provides a reconciliation of changes in the fair value of available for sale financial assets:

| As at December 31, | **2016** | 2015 |
|---|---|---|
| Fair Value, Beginning of Year | **42** | 32 |
| Acquisition of Investments | **-** | 2 |
| Change in Fair Value [1] | **(4)** | 8 |
| Impairment Losses [2] | **(3)** | - |
| **Fair Value, End of Year** | **35** | 42 |

*(1) Changes in fair value on available for sale financial assets are recorded in other comprehensive income.*
*(2) Impairment losses on available for sale financial assets are reclassified from other comprehensive income to profit or loss.*

### B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil, condensate, power purchase contracts and interest rate swaps. Crude oil, condensate and, if entered, natural gas contracts, are recorded at their estimated fair value based on the difference between the contracted price and the period-end forward price for the same commodity, using quoted market prices or the period-end forward price for the same commodity extrapolated to the end of the term of the contract (Level 2). The fair value of power purchase contracts are calculated internally based on observable and unobservable inputs such as forward power prices in less active markets (Level 3). The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness. The 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***

| | **2016** | | | 2015 | | |
|---|---|---|---|---|---|---|
| | **Risk Management** | | | Risk Management | | |
| As at December 31, | **Asset** | **Liability** | **Net** | Asset | Liability | Net |
| **Commodity Prices** | | | | | | |
| Crude Oil | **21** | **307** | **(286)** | 301 | 15 | 286 |
| Power | **-** | **-** | **-** | - | 13 | (13) |
| | **21** | **307** | **(286)** | 301 | 28 | 273 |
| **Interest Rate** | **3** | **8** | **(5)** | - | 2 | (2) |
| **Total Fair Value** | **24** | **315** | **(291)** | 301 | 30 | 271 |

The following table presents the Company's fair value hierarchy for risk management assets and liabilities carried at fair value:

| As at December 31, | 2016 | 2015 |
|---|---|---|
| **Level 2 – Prices Sourced From Observable Data or Market Corroboration** | **(291)** | 284 |
| **Level 3 – Prices Determined From Unobservable Inputs** | **-** | (13) |
| | **(291)** | 271 |

Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data. Prices determined from unobservable inputs refers to the fair value of contracts valued using data that is both unobservable and significant to the overall fair value measurement.

The following table provides a reconciliation of changes in the fair value of Cenovus's risk management assets and liabilities:

| As at December 31, | 2016 | 2015 |
|---|---|---|
| Fair Value of Contracts, Beginning of Year | **271** | 462 |
| Fair Value of Contracts Realized During the Year (1) | **(211)** | (656) |
| Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year (2) | **(343)** | 461 |
| Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts | **(8)** | 4 |
| **Fair Value of Contracts, End of Year** | **(291)** | 271 |

(1) *Includes a realized loss of $6 million related to power contracts (2015 – $10 million loss).*
(2) *Includes an increase of $7 million related to power contracts (2015 – $14 million decrease).*

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:

| | **2016** | | | 2015 | | |
|---|---|---|---|---|---|---|
| | **Risk Management** | | | Risk Management | | |
| As at December 31, | **Asset** | **Liability** | **Net** | Asset | Liability | Net |
| **Recognized Risk Management Positions** | | | | | | |
| Gross Amount | **75** | **366** | **(291)** | 317 | 46 | 271 |
| Amount Offset | **(51)** | **(51)** | **-** | (16) | (16) | - |
| **Net Amount per Consolidated Financial Statements** | **24** | **315** | **(291)** | 301 | 30 | 271 |

The derivative liabilities do not have credit risk-related contingent features. Due to credit practices that limit transactions according to counterparties' credit quality, the change in fair value through profit or loss attributable to changes in the credit risk of financial liabilities is immaterial.

Cenovus pledges cash collateral with respect to certain of these risk management contracts, which is not offset against the related financial liability. The amount of cash collateral required will vary daily over the life of these risk management contracts as commodity prices change. Additional cash collateral is required if, on a net basis, risk management payables exceed risk management receivables on a particular day. As at December 31, 2016, $84 million (2015 – $26 million) was pledged as collateral, of which $18 million (2015 – $5 million) could have been withdrawn.

### C) Earnings Impact of (Gains) Losses From Risk Management Positions

| For the years ended December 31, | 2016 | 2015 | 2014 |
|---|---|---|---|
| Realized (Gain) Loss (1) | **(211)** | (656) | (66) |
| Unrealized (Gain) Loss (2) | **554** | 195 | (596) |
| **(Gain) Loss on Risk Management** | **343** | (461) | (662) |

(1) *Realized gains and losses on risk management are recorded in the operating segment to which the derivative instrument relates.*
(2) *Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.*

## 32. 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.

### *Net Fair Value of Risk Management Positions*

| As at December 31, 2016 | Notional Volumes | Terms | Average Price | Fair Value |
|---|---|---|---|---|
| **Crude Oil Contracts** | | | | |
| Fixed Price Contracts | | | | |
| Brent Fixed Price | 10,000 bbls/d | July – December 2017 | US$53.09/bbl | **(14)** |
| Brent Fixed Price | 10,000 bbls/d | January – June 2018 | US$54.06/bbl | **(11)** |
| WTI Fixed Price | 70,000 bbls/d | January – June 2017 | US$46.35/bbl | **(159)** |
| WTI Collars | 50,000 bbls/d | July – December 2017 | US$44.84 – US$56.47/bbl | **(52)** |
| WTI Collars | 10,000 bbls/d | January – June 2018 | US$45.30 – US$62.77/bbl | **(3)** |
| Other Financial Positions [1] | | | | **(47)** |
| Crude Oil Fair Value Position | | | | **(286)** |
| **Interest Rate Swaps** | | | | **(5)** |
| **Total Fair Value** | | | | **(291)** |

*(1) Other financial positions are part of ongoing operations to market the Company's production.*

### *Sensitivities – Risk Management Positions*

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices or interest rates, 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 or interest rates 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, 2016 | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude Oil Commodity Price | ± US$5.00 per bbl Applied to Brent, WTI and Condensate Hedges | **(198)** | **193** |
| Crude Oil Differential Price | ± US$2.50 per bbl Applied to Differential Hedges Tied to Production | **1** | **(1)** |
| Interest Rate Swaps | ± 50 Basis Points | **45** | **(52)** |

| As at December 31, 2015 | Sensitivity Range | Increase | Decrease |
|---|---|---|---|
| Crude Oil Commodity Price | ± US$10.00 per bbl Applied to Brent, WTI and Condensate Hedges | (220) | 222 |
| Crude Oil Differential Price | ± US$5.00 per bbl Applied to Differential Hedges Tied to Production | 80 | (80) |
| Interest Rate Swaps | ± 50 Basis Points | 38 | (46) |

### 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 is not to use derivative instruments for speculative purposes.

**Crude Oil** – The Company has used fixed price swaps 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 limited number of swaps and futures to help protect against widening light/heavy crude oil price differentials.

**Condensate** – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its condensate purchases.

**Natural Gas** – To partially mitigate the natural gas commodity price risk, the Company may enter into swaps, which fix the AECO or the New York Mercantile Exchange ("NYMEX") price. To help protect against widening natural gas price differentials in various production areas, Cenovus may also enter into swaps to manage the price differentials between production areas and various sales points.

### 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 6, 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, 2016, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (2015 – US$4,750 million). In respect of these financial instruments, the impact of changes in the U.S. to Canadian dollar exchange rate would have resulted in a change to the foreign exchange (gain) loss as follows:

| For the years ended December 31, | **2016** | 2015 | 2014 |
|---|---|---|---|
| $0.01 Increase in the U.S. to Canadian Dollar Foreign Exchange Rate | **48** | 48 | 48 |
| $0.01 Decrease in the U.S. to Canadian Dollar Foreign Exchange Rate | **(48)** | (48) | (48) |

### 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 entered into interest rate swap contracts related to expected future debt issuances. As at December 31, 2016, Cenovus had a notional amount of US$400 million in interest rate swaps.

As at December 31, 2016, the increase or decrease in net earnings for a one percent change in interest rates on floating rate debt amounts to $nil (2015 – $nil, 2014 – $nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

### D) Credit Risk

Credit risk arises from the potential that the Company may incur a 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.

As at December 31, 2016 and 2015, substantially all of the Company's accounts receivable were less than 60 days. As at December 31, 2016, 90 percent (2015 – 91 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties. As at December 31, 2016, Cenovus had three counterparties (2015 – one counterparty) whose net settlement position individually accounted for more than 10 percent of the fair value of the outstanding in-the-money net financial and physical contracts. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, and long-term receivables is the total carrying value.

### E) Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit, which may be impacted by the Company's credit ratings. As disclosed in Note 30, over the long term, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities and availability under its shelf prospectuses. As at December 31, 2016, Cenovus had $3.7 billion in cash and cash equivalents, and $4.0 billion available on its committed credit facility. In addition, Cenovus has in place a US$5.0 billion base shelf prospectus, the availability of which is dependent on market conditions.

Undiscounted cash outflows relating to financial liabilities are:

| As at December 31, 2016 | Less than 1 Year | 1-3 Years | 4-5 Years | Thereafter | **Total** |
|---|---|---|---|---|---|
| Accounts Payable and Accrued Liabilities | 2,266 | - | - | - | **2,266** |
| Risk Management Liabilities [1] | 293 | 22 | - | - | **315** |
| Long-Term Debt [2] | 339 | 2,662 | 1,150 | 7,550 | **11,701** |
| Other | - | 25 | 8 | 16 | **49** |

| As at December 31, 2015 | Less than 1 Year | 1-3 Years | 4-5 Years | Thereafter | **Total** |
|---|---|---|---|---|---|
| Accounts Payable and Accrued Liabilities | 1,702 | - | - | - | 1,702 |
| Risk Management Liabilities [1] | 23 | 5 | 2 | - | 30 |
| Long-Term Debt [2] | 349 | 2,847 | 493 | 8,721 | 12,410 |
| Other | - | 3 | 1 | 4 | 8 |

(1) *Risk management liabilities subject to master netting agreements.*
(2) *Principal and interest, including current portion.*

## 33. SUPPLEMENTARY CASH FLOW INFORMATION

| For the years ended December 31, | **2016** | 2015 | 2014 |
|---|---|---|---|
| Interest Paid | **350** | 330 | 335 |
| Interest Received | **32** | 19 | 33 |
| Income Taxes Paid | **11** | 933 | 46 |

## 34. 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, 2016 | 1 Year | 2 Years | 3 Years | 4 Years | 5 Years | Thereafter | **Total** |
|---|---|---|---|---|---|---|---|
| Transportation and Storage [1] | 682 | 711 | 722 | 1,031 | 1,239 | 21,875 | **26,260** |
| Operating Leases (Building Leases) [2] | 101 | 146 | 146 | 145 | 142 | 2,465 | **3,145** |
| Product Purchases | 70 | - | - | - | - | - | **70** |
| Capital Commitments | 23 | 3 | - | - | - | - | **26** |
| Other Long-Term Commitments | 80 | 27 | 26 | 15 | 15 | 108 | **271** |
| **Total Payments** [3] | 956 | 887 | 894 | 1,191 | 1,396 | 24,448 | **29,772** |
| **Fixed Price Product Sales** | 3 | - | - | - | - | - | **3** |

| As at December 31, 2015 | 1 Year | 2 Years | 3 Years | 4 Years | 5 Years | Thereafter | **Total** |
|---|---|---|---|---|---|---|---|
| Transportation and Storage [1] | 702 | 715 | 780 | 774 | 901 | 23,537 | 27,409 |
| Operating Leases (Building Leases) [2] | 116 | 120 | 156 | 153 | 151 | 2,647 | 3,343 |
| Product Purchases | 84 | 3 | - | - | - | - | 87 |
| Capital Commitments | 61 | 14 | 4 | - | - | - | 79 |
| Other Long-Term Commitments | 45 | 31 | 24 | 26 | 15 | 125 | 266 |
| **Total Payments** [3] | 1,008 | 883 | 964 | 953 | 1,067 | 26,309 | 31,184 |
| **Fixed Price Product Sales** | 55 | 3 | - | - | - | - | 58 |

(1) *Includes transportation commitments of $19 billion (2015 – $19 billion) that are subject to regulatory approval or have been approved but are not yet in service.*
(2) *Excludes committed payment for which a provision has been provided.*
(3) *Contracts undertaken on behalf of FCCL and WRB are reflected at Cenovus's 50 percent interest.*

For the year ended December 31, 2016, the Company's transportation commitments decreased approximately $1.1 billion primarily due to the use of contracts and changes in toll estimates. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement.

As at December 31, 2016, there were outstanding letters of credit aggregating $258 million issued as security for performance under certain contracts (2015 – $64 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 32.

**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 $1,847 million, based on current legislation and estimated costs, related to its crude oil and natural gas properties, refining facilities and midstream facilities. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

***Income Tax Matters***

The tax regulations and legislation and interpretations thereof in the various jurisdictions in which Cenovus operates are continually changing. As a result, there are usually a number of tax matters under review. Management believes that the provision for taxes is adequate.

## SUPPLEMENTAL INFORMATION *(unaudited)*

### Financial Statistics

*($ millions, except per share amounts)*

| Revenues | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| Gross Sales | | | | | | |
| Upstream | **4,196** | **1,326** | 1,123 | 1,003 | 744 | 4,739 |
| Refining and Marketing | **8,439** | **2,477** | 2,245 | 2,129 | 1,588 | 8,805 |
| Corporate and Eliminations | **(353)** | **(108)** | (89) | (89) | (67) | (337) |
| Less: Royalties | **148** | **53** | 39 | 36 | 20 | 143 |
| **Revenues** | **12,134** | **3,642** | 3,240 | 3,007 | 2,245 | 13,064 |

| Operating Margin [1] | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| Crude Oil and Natural Gas Liquids | | | | | | |
| Foster Creek | **399** | **165** | 125 | 98 | 11 | 454 |
| Christina Lake | **476** | **168** | 140 | 134 | 34 | 592 |
| Conventional | **402** | **100** | 108 | 106 | 88 | 683 |
| Natural Gas | **141** | **50** | 47 | 10 | 34 | 307 |
| Other Upstream Operations | **3** | **4** | (1) | - | - | 18 |
| | **1,421** | **487** | 419 | 348 | 167 | 2,054 |
| Refining and Marketing | **346** | **108** | 68 | 193 | (23) | 385 |
| **Operating Margin** | **1,767** | **595** | 487 | 541 | 144 | 2,439 |

| Adjusted Funds Flow [2] | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Cash From Operating Activities** | **861** | **164** | 310 | 205 | 182 | 1,474 |
| Deduct (Add Back): | | | | | | |
| Net Change in Other Assets and Liabilities | **(91)** | **(32)** | (13) | (17) | (29) | (107) |
| Net Change in Non-Cash Working Capital | **(471)** | **(339)** | (99) | (218) | 185 | (110) |
| **Adjusted Funds Flow** | **1,423** | **535** | 422 | 440 | 26 | 1,691 |
| Per Share - Basic | **1.71** | **0.64** | 0.51 | 0.53 | 0.03 | 2.07 |
| - Diluted | **1.71** | **0.64** | 0.51 | 0.53 | 0.03 | 2.07 |

| Earnings | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Operating Earnings (Loss)** [3] | **(377)** | **321** | (236) | (39) | (423) | (403) |
| Per Share - Diluted | **(0.45)** | **0.39** | (0.28) | (0.05) | (0.51) | (0.49) |
| **Net Earnings (Loss)** | **(545)** | **91** | (251) | (267) | (118) | 618 |
| Per Share - Basic | **(0.65)** | **0.11** | (0.30) | (0.32) | (0.14) | 0.75 |
| - Diluted | **(0.65)** | **0.11** | (0.30) | (0.32) | (0.14) | 0.75 |

| Income Tax & Exchange Rates | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Effective Tax Rates Using:** | | | | | | |
| Net Earnings [4] | **41.2%** | | | | | (15.1)% |
| Operating Earnings, Excluding Divestitures | **33.0%** | | | | | 32.4% |
| Canadian Statutory Rate [5] | **27.0%** | | | | | 26.1% |
| U.S. Statutory Rate | **38.0%** | | | | | 38.0% |
| **Foreign Exchange Rates** *(US$ per C$1)* | | | | | | |
| Average | **0.755** | **0.750** | 0.766 | 0.776 | 0.728 | 0.782 |
| Period End | **0.745** | **0.745** | 0.762 | 0.769 | 0.771 | 0.723 |

(1) Operating Margin (previously labelled Operating Cash Flow) is an additional subtotal found in Note 1 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 and production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Margin.

(2) Adjusted Funds Flow (previously labelled Cash Flow) is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. 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, both of which are defined on the Consolidated Statement of Cash Flows. Net change in other assets and liabilities is composed of site restoration costs and pension funding.

(3) Operating Earnings (Loss) is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings (Loss) is defined as Earnings (Loss) Before Income Tax excluding gain (loss) on discontinuance, gain on bargain purchase, 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.

(4) The 2015 effective tax rate reflects an increase to the tax basis of Cenovus's U.S. assets, the two percent increase in the Alberta corporate income tax rate and the benefit from recognition of previously unrecognized capital losses.

(5) On June 29, 2015, the Alberta government enacted a two percent increase in the corporate income tax rate. The rate increase was effective July 1, 2015.

| Financial Metrics (Non-GAAP Measures) | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| Net Debt to Capitalization [1] [2] | **18%** | **18%** | 17% | 17% | 16% | 16% |
| Debt to Capitalization [3] [4] | **35%** | **35%** | 35% | 34% | 34% | 34% |
| Net Debt to Adjusted EBITDA [1] [5] | **1.9x** | **1.9x** | 2.0x | 1.9x | 1.3x | 1.2x |
| Debt to Adjusted EBITDA [3] [5] | **4.5x** | **4.5x** | 5.3x | 4.8x | 3.6x | 3.1x |
| Return on Capital Employed [6] | **(2)%** | **(2)%** | (6)% | 6% | 8% | 5% |
| Return on Common Equity [7] | **(5)%** | **(5)%** | (10)% | 7% | 10% | 5% |

(1) 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.

(2) Net debt to capitalization is defined as net debt divided by net debt plus shareholders' equity.

(3) Debt includes the Company's short-term borrowings and the current and long-term portions of long-term debt.

(4) Capitalization is a non-GAAP measure defined as debt plus shareholders' equity.

(5) Adjusted EBITDA is defined as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing twelve-month basis.

(6) Return on capital employed is calculated, on a trailing twelve-month basis, as net earnings before after-tax interest divided by average shareholders' equity plus average debt.

(7) Return on common equity is calculated, on a trailing twelve-month basis, as net earnings divided by average shareholders' equity.

## SUPPLEMENTAL INFORMATION *(unaudited)*

### Financial Statistics (continued)

**Common Share Information**

| | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Common Shares Outstanding** *(millions)* | | | | | | |
| Period End | **833.3** | **833.3** | 833.3 | 833.3 | 833.3 | 833.3 |
| Average - Basic | **833.3** | **833.3** | 833.3 | 833.3 | 833.3 | 818.7 |
| Average - Diluted | **833.3** | **833.3** | 833.3 | 833.3 | 833.3 | 818.7 |
| **Price Range** *($ per share)* | | | | | | |
| **TSX - C$** | | | | | | |
| High | **22.07** | **22.07** | 20.06 | 21.00 | 18.15 | 26.42 |
| Low | **12.70** | **17.96** | 17.15 | 16.12 | 12.70 | 15.75 |
| Close | **20.30** | **20.30** | 18.83 | 17.87 | 16.90 | 17.50 |
| **NYSE - US$** | | | | | | |
| High | **16.82** | **16.82** | 15.72 | 16.56 | 13.97 | 21.12 |
| Low | **9.10** | **13.36** | 12.93 | 12.25 | 9.10 | 11.85 |
| Close | **15.13** | **15.13** | 14.37 | 13.82 | 13.00 | 12.62 |
| **Dividends** *($ per share)* | **0.2000** | **0.0500** | 0.0500 | 0.0500 | 0.0500 | 0.8524 |
| **Share Volume Traded** *(millions)* | **1,491.7** | **322.6** | 313.0 | 373.3 | 482.8 | 1,691.2 |

**Net Capital Investment**

| | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Capital Investment** *($ millions)* | | | | | | |
| Oil Sands | | | | | | |
| Foster Creek | **263** | **52** | 54 | 68 | 89 | 403 |
| Christina Lake | **282** | **60** | 47 | 61 | 114 | 647 |
| Total | **545** | **112** | 101 | 129 | 203 | 1,050 |
| Other Oil Sands | **59** | **16** | 9 | 10 | 24 | 135 |
| | **604** | **128** | 110 | 139 | 227 | 1,185 |
| Conventional | **171** | **57** | 41 | 34 | 39 | 244 |
| Refining and Marketing | **220** | **64** | 51 | 53 | 52 | 248 |
| Corporate | **31** | **10** | 6 | 10 | 5 | 37 |
| Capital Investment | **1,026** | **259** | 208 | 236 | 323 | 1,714 |
| Acquisitions | **11** | **-** | - | 11 | - | 87 |
| Divestitures | **(8)** | **-** | (8) | - | - | (3,344) |
| Net Acquisition and Divestiture Activity | **3** | **-** | (8) | 11 | - | (3,257) |
| **Net Capital Investment** | **1,029** | **259** | 200 | 247 | 323 | (1,543) |

### Operating Statistics - Before Royalties

**Upstream Production Volumes**

| | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Crude Oil and Natural Gas Liquids** *(bbls/d)* | | | | | | |
| Oil Sands | | | | | | |
| Foster Creek | **70,244** | **81,588** | 73,798 | 64,544 | 60,882 | 65,345 |
| Christina Lake | **79,449** | **82,808** | 79,793 | 78,060 | 77,093 | 74,975 |
| | **149,693** | **164,396** | 153,591 | 142,604 | 137,975 | 140,320 |
| Conventional | | | | | | |
| Heavy Oil | **29,185** | **28,913** | 28,096 | 28,500 | 31,247 | 34,888 |
| Light and Medium Oil | **25,915** | **25,065** | 25,311 | 26,177 | 27,121 | 30,486 |
| Natural Gas Liquids [1] | **1,065** | **1,177** | 1,074 | 799 | 1,208 | 1,253 |
| | **56,165** | **55,155** | 54,481 | 55,476 | 59,576 | 66,627 |
| Total Crude Oil and Natural Gas Liquids | **205,858** | **219,551** | 208,072 | 198,080 | 197,551 | 206,947 |
| **Natural Gas** *(MMcf/d)* | | | | | | |
| Oil Sands | **17** | **17** | 18 | 18 | 17 | 19 |
| Conventional | **377** | **362** | 374 | 381 | 391 | 422 |
| Total Natural Gas | **394** | **379** | 392 | 399 | 408 | 441 |
| **Total Production [2]** *(BOE/d)* | **271,525** | **282,718** | 273,405 | 264,580 | 265,551 | 280,447 |

**Upstream Sales Volumes**

| | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Crude Oil and Natural Gas Liquids** *(bbls/d)* | | | | | | |
| Oil Sands | | | | | | |
| Foster Creek | **69,647** | **79,827** | 76,318 | 62,089 | 60,169 | 64,467 |
| Christina Lake | **79,481** | **81,398** | 80,313 | 76,066 | 80,118 | 73,872 |
| | **149,128** | **161,225** | 156,631 | 138,155 | 140,287 | 138,339 |
| Conventional | | | | | | |
| Heavy Oil | **28,958** | **28,833** | 27,953 | 28,294 | 30,764 | 35,597 |
| Light and Medium Oil | **25,965** | **24,903** | 25,359 | 26,407 | 27,210 | 30,517 |
| Natural Gas Liquids [1] | **1,065** | **1,177** | 1,074 | 799 | 1,208 | 1,253 |
| | **55,988** | **54,913** | 54,386 | 55,500 | 59,182 | 67,367 |
| Total Crude Oil and Natural Gas Liquids | **205,116** | **216,138** | 211,017 | 193,655 | 199,469 | 205,706 |
| **Natural Gas** *(MMcf/d)* | | | | | | |
| Oil Sands | **17** | **17** | 18 | 18 | 17 | 19 |
| Conventional | **377** | **362** | 374 | 381 | 391 | 422 |
| Total Natural Gas | **394** | **379** | 392 | 399 | 408 | 441 |
| **Total Sales [2]** *(BOE/d)* | **270,783** | **279,305** | 276,350 | 260,155 | 267,469 | 279,206 |

(1) Natural gas liquids include condensate volumes.

(2) Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six thousand cubic feet (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 to 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.

**Average Royalty Rates**

*(Excluding Impact of Realized Gain (Loss) on Risk Management)*

| | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Oil Sands** | | | | | | |
| Foster Creek | **0.0%** | **(0.9)%** | 0.8% | 1.0% | (4.9)% | 1.9% |
| Christina Lake | **1.6%** | **1.8%** | 1.6% | 1.2% | 1.2% | 2.8% |
| **Conventional Oil** | | | | | | |
| Pelican Lake | **12.5%** | **11.9%** | 14.1% | 14.3% | 8.3% | 9.0% |
| Weyburn | **23.6%** | **28.3%** | 23.0% | 23.9% | 16.6% | 17.7% |
| Other | **12.8%** | **19.3%** | 10.4% | 8.6% | 12.0% | 5.2% |
| Natural Gas Liquids | **13.5%** | **12.2%** | 12.0% | 15.0% | 16.1% | 5.6% |
| **Natural Gas** | **4.6%** | **5.3%** | 4.5% | 3.7% | 4.3% | 2.5% |

**Refining**

| | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Refinery Operations [1]** | | | | | | |
| Crude Oil Capacity *(Mbbls/d)* | **460** | **460** | 460 | 460 | 460 | 460 |
| Crude Oil Runs *(Mbbls/d)* | **444** | **421** | 463 | 458 | 435 | 419 |
| Heavy Oil | **233** | **223** | 241 | 228 | 241 | 200 |
| Light/Medium | **211** | **198** | 222 | 230 | 194 | 219 |
| Crude Utilization | **97%** | **92%** | 101% | 100% | 95% | 91% |
| Refined Products *(Mbbls/d)* | **471** | **448** | 494 | 483 | 460 | 444 |

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

## SUPPLEMENTAL INFORMATION *(unaudited)*

### Operating Statistics - Before Royalties (continued)

**Selected Average Benchmark Prices**

| | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Crude Oil Prices** *(US$/bbl)* | | | | | | |
| Brent | **45.04** | **51.13** | 46.98 | 46.97 | 35.08 | 53.64 |
| West Texas Intermediate ("WTI") | **43.32** | **49.29** | 44.94 | 45.59 | 33.45 | 48.80 |
| Differential Brent - WTI | **1.72** | **1.84** | 2.04 | 1.38 | 1.63 | 4.84 |
| Western Canadian Select ("WCS") | **29.48** | **34.97** | 31.44 | 32.29 | 19.21 | 35.28 |
| Differential WTI - WCS | **13.84** | **14.32** | 13.50 | 13.30 | 14.24 | 13.52 |
| Condensate (C5 @ Edmonton) | **42.47** | **48.33** | 43.07 | 44.07 | 34.39 | 47.36 |
| Differential WTI - Condensate (Premium)/Discount | **0.85** | **0.96** | 1.87 | 1.52 | (0.94) | 1.44 |
| **Refining Margins 3-2-1 Crack Spreads** [(1)] *(US$/bbl)* | | | | | | |
| Chicago | **13.07** | **10.96** | 14.58 | 17.15 | 9.58 | 19.11 |
| Group 3 | **12.27** | **10.95** | 14.56 | 13.03 | 10.52 | 18.16 |
| **Natural Gas Prices** | | | | | | |
| AECO *(C$/Mcf)* | **2.09** | **2.81** | 2.20 | 1.25 | 2.11 | 2.77 |
| NYMEX *(US$/Mcf)* | **2.46** | **2.98** | 2.81 | 1.95 | 2.09 | 2.66 |
| Differential NYMEX - AECO *(US$/Mcf)* | **0.89** | **0.86** | 1.13 | 0.99 | 0.56 | 0.49 |

(1) The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and on a last in, first out accounting basis ("LIFO").

**Netbacks** [(1)]

*(Excluding Impact of Realized Gain (Loss) on Risk Management)*

| | 2016 | | | | | 2015 |
|---|---|---|---|---|---|---|
| | **Year** | **Q4** | Q3 | Q2 | Q1 | Year |
| **Heavy Oil - Foster Creek** *($/bbl)* | | | | | | |
| Sales Price | **30.32** | **38.59** | 33.61 | 33.40 | 11.82 | 33.65 |
| Royalties | **(0.01)** | **(0.27)** | 0.19 | 0.23 | (0.16) | 0.47 |
| Transportation and Blending | **8.84** | **7.37** | 8.38 | 11.44 | 8.70 | 8.84 |
| Operating | **10.55** | **10.60** | 9.63 | 10.15 | 12.05 | 12.60 |
| Netback | **10.94** | **20.89** | 15.41 | 11.58 | (8.77) | 11.74 |
| **Heavy Oil - Christina Lake** *($/bbl)* | | | | | | |
| Sales Price | **25.30** | **34.78** | 29.11 | 28.31 | 8.85 | 28.45 |
| Royalties | **0.33** | **0.56** | 0.41 | 0.28 | 0.05 | 0.67 |
| Transportation and Blending | **4.68** | **4.08** | 4.49 | 4.90 | 5.28 | 4.72 |
| Operating | **7.48** | **8.15** | 7.72 | 6.35 | 7.61 | 8.01 |
| Netback | **12.81** | **21.99** | 16.49 | 16.78 | (4.09) | 15.05 |
| **Total Heavy Oil - Oil Sands** *($/bbl)* | | | | | | |
| Sales Price | **27.64** | **36.67** | 31.30 | 30.59 | 10.13 | 30.88 |
| Royalties | **0.17** | **0.14** | 0.30 | 0.26 | (0.04) | 0.58 |
| Transportation and Blending | **6.62** | **5.71** | 6.39 | 7.84 | 6.75 | 6.64 |
| Operating | **8.91** | **9.37** | 8.65 | 8.06 | 9.52 | 10.13 |
| Netback | **11.94** | **21.45** | 15.96 | 14.43 | (6.10) | 13.53 |
| **Heavy Oil - Conventional** *($/bbl)* | | | | | | |
| Sales Price | **35.82** | **40.72** | 40.50 | 36.77 | 25.99 | 39.95 |
| Royalties | **3.31** | **4.08** | 3.97 | 3.95 | 1.40 | 2.97 |
| Transportation and Blending | **4.60** | **4.90** | 4.86 | 3.85 | 4.77 | 3.36 |
| Operating | **13.38** | **14.69** | 12.43 | 12.34 | 13.98 | 15.92 |
| Production and Mineral Taxes | **0.01** | **0.01** | 0.01 | 0.01 | - | 0.04 |
| Netback | **14.52** | **17.04** | 19.23 | 16.62 | 5.84 | 17.66 |
| **Light and Medium Oil** *($/bbl)* | | | | | | |
| Sales Price | **46.48** | **55.35** | 48.97 | 48.09 | 34.36 | 50.64 |
| Royalties | **9.28** | **14.87** | 8.91 | 8.52 | 5.18 | 5.66 |
| Transportation and Blending | **2.73** | **2.69** | 2.71 | 2.77 | 2.73 | 2.91 |
| Operating | **15.65** | **16.05** | 13.94 | 16.21 | 16.34 | 16.27 |
| Production and Mineral Taxes | **1.24** | **1.50** | 1.48 | 1.18 | 0.82 | 1.41 |
| Netback | **17.58** | **20.24** | 21.93 | 19.41 | 9.29 | 24.39 |
| **Total Crude Oil** *($/bbl)* | | | | | | |
| Sales Price | **31.20** | **39.37** | 34.66 | 33.89 | 15.91 | 35.41 |
| Royalties | **1.77** | **2.38** | 1.83 | 1.93 | 0.90 | 1.75 |
| Transportation and Blending | **5.84** | **5.25** | 5.74 | 6.56 | 5.89 | 5.51 |
| Operating | **10.40** | **10.85** | 9.79 | 9.80 | 11.14 | 12.05 |
| Production and Mineral Taxes | **0.16** | **0.17** | 0.18 | 0.16 | 0.11 | 0.22 |
| Netback | **13.03** | **20.72** | 17.12 | 15.44 | (2.13) | 15.88 |
| **Natural Gas Liquids** *($/bbl)* | | | | | | |
| Sales Price | **31.16** | **40.79** | 29.71 | 28.11 | 24.99 | 30.98 |
| Royalties | **4.21** | **4.97** | 3.58 | 4.20 | 4.03 | 1.74 |
| Netback | **26.95** | **35.82** | 26.13 | 23.91 | 20.96 | 29.24 |
| **Total Liquids** *($/bbl)* | | | | | | |
| Sales Price | **31.20** | **39.38** | 34.64 | 33.87 | 15.97 | 35.38 |
| Royalties | **1.79** | **2.39** | 1.84 | 1.94 | 0.92 | 1.75 |
| Transportation and Blending | **5.81** | **5.22** | 5.71 | 6.53 | 5.85 | 5.48 |
| Operating | **10.35** | **10.80** | 9.74 | 9.76 | 11.08 | 11.98 |
| Production and Mineral Taxes | **0.16** | **0.17** | 0.18 | 0.16 | 0.11 | 0.22 |
| Netback | **13.09** | **20.80** | 17.17 | 15.48 | (1.99) | 15.95 |
| **Total Natural Gas** *($/Mcf)* | | | | | | |
| Sales Price | **2.32** | **2.99** | 2.49 | 1.53 | 2.31 | 2.92 |
| Royalties | **0.10** | **0.15** | 0.10 | 0.04 | 0.09 | 0.07 |
| Transportation and Blending | **0.11** | **0.12** | 0.10 | 0.13 | 0.10 | 0.11 |
| Operating | **1.15** | **1.25** | 1.05 | 1.06 | 1.23 | 1.20 |
| Production and Mineral Taxes | **-** | **-** | 0.01 | - | - | 0.01 |
| Netback | **0.96** | **1.47** | 1.23 | 0.30 | 0.89 | 1.53 |
| **Total** [(2)] *($/BOE)* | | | | | | |
| Sales Price | **27.01** | **34.53** | 29.98 | 27.56 | 15.43 | 30.67 |
| Royalties | **1.49** | **2.06** | 1.55 | 1.51 | 0.82 | 1.40 |
| Transportation and Blending | **4.56** | **4.20** | 4.51 | 5.07 | 4.51 | 4.21 |
| Operating | **9.51** | **10.05** | 8.92 | 8.89 | 10.14 | 10.72 |
| Production and Mineral Taxes | **0.12** | **0.13** | 0.15 | 0.12 | 0.08 | 0.18 |
| Netback | **11.33** | **18.09** | 14.85 | 11.97 | (0.12) | 14.16 |
| **Realized Gain (Loss) on Risk Management** | | | | | | |
| Liquids *($/bbl)* | **3.23** | **0.91** | 2.14 | 1.97 | 8.16 | 7.51 |
| Natural Gas *($/Mcf)* | **-** | **-** | - | - | - | 0.37 |
| Total [(2)] *($/BOE)* | **2.44** | **0.70** | 1.63 | 1.46 | 6.08 | 6.11 |

(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. Our 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. The reconciliation of the financial components of each Netback to Operating Margin can be found in Management's Discussion and Analysis and the Annual Information Form.

(2) Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six thousand cubic feet (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 to 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.

# ADVISORY

**Oil and Gas Information**

The estimates of reserves and resources data and related information were prepared effective December 31, 2016 by independent qualified reserves evaluators, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Estimates are presented using McDaniel & Associates Consultants Ltd. January 1, 2017 price forecast. For additional information about our reserves, resources and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our Annual Information Form for the year ended December 31, 2016 and our Statement of Contingent and Prospective Resources for the year ended December 31, 2016.

Contingent resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The estimate of contingent resources has not been adjusted for risk based on the chance of development.

Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus's case, contingent resources were evaluated using the same commodity price assumptions that were used for the 2016 reserves evaluation, which comply with NI 51-101 requirements.

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

Best estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate. The contingent resources were estimated for individual projects and then aggregated for disclosure purposes.

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.

Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates, is contained in our Annual Information Form and Form 40-F for the year ended December 31, 2016, and our Statement of Contingent and Prospective Resources for the year ended December 31, 2016, available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com.

**Forward-looking Information**

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "estimate", "plan", "forecast" or "F", "future", "target", "position", "project", "capacity", "could", "should", "focus", "goal", "outlook", "proposed", "potential", "may", "schedule", "on track", "strategy", "forward", "opportunity" or similar expressions and includes suggestions of future outcomes and statements about: our strategy (including all statements under the heading "Our Cenovus" and under sub-headings within such discussion), related milestones and schedules; projected future value; projections for 2017 and future years; forecast operating and financial results; our ability to preserve our financial resilience and plans and strategies with respect thereto; targets for our Debt to Capitalization and Debt to EBITDA ratios; planned capital expenditures, including the timing and financing thereof; expected future production, including the timing, stability or growth thereof; expected reserves and resources; broadening market access; expected capacities, including for projects, transportation and refining; achieved and forecast cost reductions, including sustainability and expected impacts thereto; our expectations regarding growth from our planned oil sands expansions, construction and potential restarts, and future impacts to our oil sands production capacity; expected impacts of completion of the Wood River debottlenecking project; dividend plans and strategy; anticipated timelines for future regulatory, partner or internal approvals; future impact of regulatory measures; forecast commodity prices and exchange rates and expected impact to Cenovus; our future opportunities for oil development; future use and development of technology, including expected effects on our environmental impact; expected impact of our hedging program; 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 the forward-looking information is based include: assumptions inherent in our current guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2017 guidance, as updated on December 8, 2016, assumes: Brent of US$48.75/bbl, WTI of US$47.25/bbl; WCS of US$31.50/bbl; NYMEX of US$3.00/MMBtu; AECO of $2.60/GJ; Chicago 3-2-1 crack spread of US$11.25/bbl; and an exchange rate of $0.74 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and natural gas prices; 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; commodity prices, currency and interest rates; product supply and demand; 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 operation of our crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of debt to adjusted EBITDA and net debt to adjusted EBITDA as well as debt to capitalization and 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 the dividend reinvestment plan; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated 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; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation, including sufficient pipeline, crude-by-rail, marine or other 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; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see “Risk Factors” in our Annual Information Form or Form 40-F for the year ended December 31, 2016, available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com.

## ABBREVIATIONS

*The following abbreviations have been used in this document:*

| ***Crude Oil*** | | ***Natural Gas*** | |
|---|---|---|---|
| *bbl* | *barrel* | *Mcf* | *thousand cubic feet* |
| *bbls/d* | *barrels per day* | *MMcf* | *million cubic feet* |
| *Mbbls/d* | *thousand barrels per day* | *Bcf* | *billion cubic feet* |
| *MMbbls* | *million barrels* | *MMBtu* | *million British thermal units* |
| *BOE* | *barrel of oil equivalent* | *GJ* | *gigajoule* |
| *BOE/d* | *barrel of oil equivalent per day* | *AECO* | *Alberta Energy Company* |
| *MBOE* | *thousand barrel of oil equivalent* | NYMEX | *New York Mercantile Exchange* |
| *MMBOE* | *million barrel of oil equivalent* | | |
| *WTI* | *West Texas Intermediate* | | |
| *WCS* | *Western Canadian Select* | | |
| *CDB* | *Christina Dilbit Blend* | *TM* | *trademark of Cenovus Energy Inc.* |

## 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 our margin on a per-barrel basis of unblended crude oil. As such, the crude oil sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the heavy oil to reduce its thickness in order to transport it to market. Our Netback calculation is aligned with the definition found in the COGE Handbook.

The following tables provide a reconcilition of the items comprising Netbacks (in millions of dollars) to our Consolidated Financial Statements.

### Sales Volumes

| (barrels per day, unless otherwise stated) | **2016** | 2015 | 2014 |
|---|---|---|---|
| **Oil Sands** | | | |
| Foster Creek | **69,647** | 64,467 | 57,336 |
| Christina Lake | **79,481** | 73,872 | 67,349 |
| | **149,128** | 138,339 | 124,685 |
| **Conventional** | | | |
| Heavy Oil | **28,958** | 35,597 | 39,231 |
| Light and Medium Oil | **25,965** | 30,517 | 34,434 |
| Natural Gas Liquids (“NGLs”) | **1,065** | 1,253 | 1,221 |
| | **55,988** | 67,367 | 74,886 |
| **Crude Oil and NGLs Sales** | **205,116** | 205,706 | 199,571 |
| **Natural Gas Sales** (MMcf per day) | **394** | 441 | 488 |
| **Total Sales** (BOE per day) | **270,783** | 279,206 | 280,904 |

## Total Crude Oil, NGLs and Natural Gas

| Year ended December 31, 2016 ($ millions) | Basis of Netback Calculation: Crude Oil & NGLs | Natural Gas | Total | Adjustments: Condensate | Inventory (2) | Other | Per Consolidated Financial Statements (1): Other Products | Total Upstream |
|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | |
| Gross Sales | 2,342 | 335 | 2,677 | 1,505 | - | 2 | 12 | **4,196** |
| Less: Royalties | 134 | 14 | 148 | - | - | - | - | **148** |
| | 2,208 | 321 | 2,529 | 1,505 | - | 2 | 12 | **4,048** |
| **Expenses** | | | | | | | | |
| Transportation and Blending | 436 | 17 | 453 | 1,505 | (51) | - | - | **1,907** |
| Operating | 777 | 165 | 942 | - | - | (6) | 9 | **945** |
| Production and Mineral Taxes | 12 | - | 12 | - | - | - | - | **12** |
| **Netback** | 983 | 139 | 1,122 | - | 51 | 8 | 3 | **1,184** |
| (Gain) Loss on Risk Management | (243) | - | (243) | - | - | 6 | - | **(237)** |
| **Operating Margin** | 1,226 | 139 | 1,365 | - | 51 | 2 | 3 | **1,421** |

*(1) Found in Note 1 of the Consolidated Financial Statements.*
*(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.*

| Year ended December 31, 2015 ($ millions) | Basis of Netback Calculation: Crude Oil & NGLs | Natural Gas | Total | Adjustments: Condensate | Inventory (2) | Other | Per Consolidated Financial Statements (1): Other Products | Total Upstream |
|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | |
| Gross Sales | 2,656 | 469 | 3,125 | 1,583 | - | 3 | 28 | **4,739** |
| Less: Royalties | 132 | 11 | 143 | - | - | - | - | **143** |
| | 2,524 | 458 | 2,982 | 1,583 | - | 3 | 28 | **4,596** |
| **Expenses** | | | | | | | | |
| Transportation and Blending | 411 | 18 | 429 | 1,583 | 33 | - | - | **2,045** |
| Operating | 899 | 193 | 1,092 | - | - | (10) | 10 | **1,092** |
| Production and Mineral Taxes | 16 | 2 | 18 | - | - | - | - | **18** |
| **Netback** | 1,198 | 245 | 1,443 | - | (33) | 13 | 18 | **1,441** |
| (Gain) Loss on Risk Management | (564) | (59) | (623) | - | - | 10 | - | **(613)** |
| **Operating Margin** | 1,762 | 304 | 2,066 | - | (33) | 3 | 18 | **2,054** |

*(1) Found in Note 1 of the Consolidated Financial Statements.*
*(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.*

| Year ended December 31, 2014 ($ millions) | Basis of Netback Calculation: Crude Oil & NGLs | Natural Gas | Total | Adjustments: Condensate | Inventory (2) | Other | Per Consolidated Financial Statements (1): Other Products | Total Upstream |
|---|---|---|---|---|---|---|---|---|
| **Revenues** | | | | | | | | |
| Gross Sales | 5,198 | 778 | 5,976 | 2,221 | - | 33 | 31 | **8,261** |
| Less: Royalties | 450 | 15 | 465 | - | - | - | - | **465** |
| | 4,748 | 763 | 5,511 | 2,221 | - | 33 | 31 | **7,796** |
| **Expenses** | | | | | | | | |
| Transportation and Blending | 217 | 21 | 238 | 2,221 | 18 | - | - | **2,477** |
| Operating | 1,123 | 216 | 1,339 | - | - | (4) | 13 | **1,348** |
| Production and Mineral Taxes | 37 | 9 | 46 | - | - | - | - | **46** |
| **Netback** | 3,371 | 517 | 3,888 | - | (18) | 37 | 18 | **3,925** |
| (Gain) Loss on Risk Management | (37) | (6) | (43) | - | - | 4 | - | **(39)** |
| **Operating Margin** | 3,408 | 523 | 3,931 | - | (18) | 33 | 18 | **3,964** |

*(1) Found in Note 1 of the Consolidated Financial Statements.*
*(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.*

## Oil Sands Crude Oil

| Year ended December 31, 2016 ($ millions) | Basis of Netback Calculation: Foster Creek | Christina Lake | Total Crude Oil | Adjustments: Condensate | Inventory (2) | Per Consolidated Financial Statements(1): Total Oil Sands Crude Oil |
|---|---|---|---|---|---|---|
| **Revenues** | | | | | | |
| Gross Sales | 773 | 736 | 1,509 | 1,402 | - | **2,911** |
| Less: Royalties | - | 9 | 9 | - | - | **9** |
| | 773 | 727 | 1,500 | 1,402 | - | **2,902** |
| **Expenses** | | | | | | |
| Transportation and Blending | 225 | 137 | 362 | 1,402 | (44) | **1,720** |
| Operating | 269 | 217 | 486 | - | - | **486** |
| **Netback** | 279 | 373 | 652 | - | 44 | **696** |
| (Gain) Loss on Risk Management | (90) | (89) | (179) | - | - | **(179)** |
| **Operating Margin** | 369 | 462 | 831 | - | 44 | **875** |

*(1) Found in Note 1 of the Consolidated Financial Statements.*
*(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.*

| Year ended December 31, 2015 ($ millions) | Basis of Netback Calculation: Foster Creek | Christina Lake | Total Crude Oil | Adjustments: Condensate | Inventory (2) | Per Consolidated Financial Statements(1): Total Oil Sands Crude Oil |
|---|---|---|---|---|---|---|
| **Revenues** | | | | | | |
| Gross Sales | 792 | 767 | 1,559 | 1,441 | - | **3,000** |
| Less: Royalties | 11 | 18 | 29 | - | - | **29** |
| | 781 | 749 | 1,530 | 1,441 | - | **2,971** |
| **Expenses** | | | | | | |
| Transportation and Blending | 208 | 127 | 335 | 1,441 | 38 | **1,814** |
| Operating | 295 | 216 | 511 | - | - | **511** |
| **Netback** | 278 | 406 | 684 | - | (38) | **646** |
| (Gain) Loss on Risk Management | (202) | (198) | (400) | - | - | **(400)** |
| **Operating Margin** | 480 | 604 | 1,084 | - | (38) | **1,046** |

*(1) Found in Note 1 of the Consolidated Financial Statements.*
*(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.*

| Year ended December 31, 2014 ($ millions) | Basis of Netback Calculation: Foster Creek | Christina Lake | Total Crude Oil | Adjustments: Condensate | Inventory (2) | Per Consolidated Financial Statements(1): Total Oil Sands Crude Oil |
|---|---|---|---|---|---|---|
| **Revenues** | | | | | | |
| Gross Sales | 1,453 | 1,514 | 2,967 | 1,996 | - | **4,963** |
| Less: Royalties | 125 | 108 | 233 | - | - | **233** |
| | 1,328 | 1,406 | 2,734 | 1,996 | - | **4,730** |
| **Expenses** | | | | | | |
| Transportation and Blending | 41 | 87 | 128 | 1,996 | 6 | **2,130** |
| Operating | 342 | 273 | 615 | - | - | **615** |
| **Netback** | 945 | 1,046 | 1,991 | - | (6) | **1,985** |
| (Gain) Loss on Risk Management | (29) | (9) | (38) | - | - | **(38)** |
| **Operating Margin** | 974 | 1,055 | 2,029 | - | (6) | **2,023** |

*(1) Found in Note 1 of the Consolidated Financial Statements.*
*(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.*

## Conventional Crude Oil and NGLs

| Year ended December 31, 2016 ($ millions) | Basis of Netback Calculation | | | | Adjustments | | | Per Consolidated Financial Statements[1] |
|---|---|---|---|---|---|---|---|---|
| | Heavy Oil | Light & Medium | NGLs | Conventional Crude Oil & NGLs | Condensate | Inventory [2] | Other | Total Conventional Crude Oil & NGLs |
| **Revenues** | | | | | | | | |
| Gross Sales | 380 | 442 | 11 | 833 | 103 | - | - | **936** |
| Less: Royalties | 35 | 88 | 2 | 125 | - | - | - | **125** |
| | 345 | 354 | 9 | 708 | 103 | - | - | **811** |
| **Expenses** | | | | | | | | |
| Transportation and Blending | 49 | 25 | - | 74 | 103 | (7) | - | **170** |
| Operating | 142 | 149 | - | 291 | - | - | (4) | **287** |
| Production and Mineral Taxes | - | 12 | - | 12 | - | - | - | **12** |
| **Netback** | 154 | 168 | 9 | 331 | - | 7 | 4 | **342** |
| (Gain) Loss on Risk Management | (34) | (30) | - | (64) | - | - | 4 | **(60)** |
| **Operating Margin** | 188 | 198 | 9 | 395 | - | 7 | - | **402** |

*(1) Found in Note 1 of the Consolidated Financial Statements.*
*(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.*

| Year ended December 31, 2015 ($ millions) | Basis of Netback Calculation | | | | Adjustments | | | Per Consolidated Financial Statements[1] |
|---|---|---|---|---|---|---|---|---|
| | Heavy Oil | Light & Medium | NGLs | Conventional Crude Oil & NGLs | Condensate | Inventory [2] | Other | Total Conventional Crude Oil & NGLs |
| **Revenues** | | | | | | | | |
| Gross Sales | 519 | 564 | 14 | 1,097 | 142 | - | - | **1,239** |
| Less: Royalties | 39 | 63 | 1 | 103 | - | - | - | **103** |
| | 480 | 501 | 13 | 994 | 142 | - | - | **1,136** |
| **Expenses** | | | | | | | | |
| Transportation and Blending | 44 | 32 | - | 76 | 142 | (5) | - | **213** |
| Operating | 207 | 181 | - | 388 | - | - | (7) | **381** |
| Production and Mineral Taxes | - | 16 | - | 16 | - | - | - | **16** |
| **Netback** | 229 | 272 | 13 | 514 | - | 5 | 7 | **526** |
| (Gain) Loss on Risk Management | (88) | (76) | - | (164) | - | - | 7 | **(157)** |
| **Operating Margin** | 317 | 348 | 13 | 678 | - | 5 | - | **683** |

*(1) Found in Note 1 of the Consolidated Financial Statements.*
*(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.*

| Year ended December 31, 2014 ($ millions) | Basis of Netback Calculation | | | | Adjustments | | | Per Consolidated Financial Statements[1] |
|---|---|---|---|---|---|---|---|---|
| | Heavy Oil | Light & Medium | NGLs | Conventional Crude Oil & NGLs | Condensate | Inventory [2] | Other | Total Conventional Crude Oil & NGLs |
| **Revenues** | | | | | | | | |
| Gross Sales | 1,092 | 1,110 | 29 | 2,231 | 225 | - | - | **2,456** |
| Less: Royalties | 101 | 115 | 1 | 217 | - | - | - | **217** |
| | 991 | 995 | 28 | 2,014 | 225 | - | - | **2,239** |
| **Expenses** | | | | | | | | |
| Transportation and Blending | 47 | 42 | - | 89 | 225 | 12 | - | **326** |
| Operating | 295 | 214 | - | 509 | - | - | (4) | **505** |
| Production and Mineral Taxes | 3 | 34 | - | 37 | - | - | - | **37** |
| **Netback** | 646 | 705 | 28 | 1,379 | - | (12) | 4 | **1,371** |
| (Gain) Loss on Risk Management | - | - | - | - | - | - | 4 | **4** |
| **Operating Margin** | 646 | 705 | 28 | 1,379 | - | (12) | - | **1,367** |

*(1) Found in Note 1 of the Consolidated Financial Statements.*
*(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.*

INFORMATION FOR

# SHAREHOLDERS

### ANNUAL MEETING

Shareholders are invited to attend the annual meeting of shareholders to be held on Wednesday, April 26, 2017 at 2 p.m. (Calgary time) at The Westin Calgary, Grand Ballroom, 320 – 4 Avenue SW, Calgary, Alberta, Canada. Please see our management information circular available on our website, cenovus.com, for additional information.

### TRANSFER AGENT & REGISTRAR

**Computershare Investor Services Inc.**
8th Floor, 100 University Avenue
Toronto, Ontario M5J 2Y1
Canada
www.investorcentre.com/cenovus
Shareholder inquiries by phone 1.866.332.8898 (North America, English and French) or 1.514.982.8717 (outside North America, English and French).

### SHAREHOLDER ACCOUNT MATTERS

For information regarding your shareholdings or to change your address, transfer shares, eliminate duplicate mailings, direct deposit of dividends, etc., please contact Computershare Investor Services Inc.

### STOCK EXCHANGES

Cenovus common shares trade on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol CVE.

### ANNUAL INFORMATION FORM/FORM 40-F

Our Annual Information Form is filed with the Canadian Securities Administrators in Canada on SEDAR at sedar.com and with the U.S. Securities and Exchange Commission under the Multi-Jurisdictional Disclosure System as an Annual Report on Form 40-F on EDGAR at sec.gov.

### NYSE CORPORATE GOVERNANCE STANDARDS

As a Canadian company listed on the NYSE, we are not required to comply with most of the NYSE corporate governance standards and instead may comply with Canadian corporate governance requirements. We are, however, required to disclose the significant differences between our corporate governance practices and those required to be followed by U.S. domestic companies under the NYSE corporate governance standards. Except as summarized on our website, cenovus.com, we are in compliance with the NYSE corporate governance standards in all significant respects.

### INVESTOR RELATIONS

Please visit the *Investors* section of our website, cenovus.com for investor information.

Investor inquiries should be directed to:
403.766.7711
investor.relations@cenovus.com

Media inquiries should be directed to:
403.766.7751
media.relations@cenovus.com

### CENOVUS HEAD OFFICE

**Cenovus Energy Inc.**
500 Centre Street SE
PO Box 766
Calgary, Alberta T2P 0M5
Canada
Phone: 403.766.2000
cenovus.com

### CENOVUS'S BOARD OF DIRECTORS

(as at December 31, 2016)
Michael A. Grandin, Board Chair, Calgary, Alberta [3,7]
Patrick D. Daniel, Calgary, Alberta [1,2,3]
Ian W. Delaney, Toronto, Ontario [2,3,5]
Brian C. Ferguson, Calgary, Alberta [6]
Steven F. Leer, Boca Grande, Florida [1,3,4]
Richard J. Marcogliese, Alamo, California [3,4,5]
Claude Mongeau, Montreal, Quebec [8]
Valerie A.A. Nielsen, Victoria, British Columbia [2,3,5]
Charles M. Rampacek, Dallas, Texas [2,3,5]
Colin Taylor, Toronto, Ontario [1,3,4]
Wayne G. Thomson, Calgary, Alberta [1,3,4]
Rhonda I. Zygocki, Friday Harbor, Washington [2,3,5]

(1) Member of the Audit Committee
(2) Member of the Human Resources and Compensation Committee
(3) Member of the Nominating and Corporate Governance Committee
(4) Member of the Reserves Committee
(5) Member of the Safety, Environment and Responsibility Committee
(6) As an officer and a non-independent director, Brian Ferguson is not a member of any of the committees of Cenovus's Board
(7) Ex-officio non-voting member of all other committees of Cenovus's Board
(8) Claude Mongeau is not currently a member of any standing committees of the Board

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# CENOVUS ENERGY IS A CANADIAN INTEGRATED OIL COMPANY

We're focused on creating long-term value through the development of our vast oil sands assets in northern Alberta, where we drill for oil and use specialized methods to pump it to the surface. We also have established conventional natural gas and oil production in Alberta and Saskatchewan and 50 percent ownership in two U.S. refineries. We're based in Calgary, Alberta and our shares trade on the Toronto and New York stock exchanges under the symbol CVE.

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