Husky Energy

Focus

Annual Report **2017**

Corporate Profile

Husky Energy is an integrated oil and gas company based in Calgary, Alberta and its common shares are publicly traded on the Toronto Stock Exchange under the symbol HSE. The Company operates in Canada, the United States and the Asia Pacific region with Upstream and Downstream business segments.

Husky has two businesses:

Integrated Corridor
The Integrated Corridor includes the production of thermal bitumen, natural gas and associated liquids in Western Canada, the Lloydminster upgrading and refining complex, a 35 percent working interest and operatorship of Husky Midstream Limited Partnership, and the Lima, Superior and Toledo refineries in the U.S. Midwest.

Offshore
The Offshore business includes operations and exploration in the Asia Pacific region, primarily offshore China and Indonesia, and in the Atlantic region offshore Newfoundland and Labrador.

Asia Pacific drilling rig

Results

Financial(1)

Year ended December 31	**2017**	2016
(millions of dollars except where indicated)		
Gross revenues and Marketing and other	**18,946**	13,224
Revenues, net of royalties	**18,583**	12,919
Funds from operations(2)	**3,306**	2,198
Per common share – basic *($/share)*	**3.29**	2.19
Free cash flow(2)	**1,086**	493
Adjusted net earnings (loss)(2)	**882**	(655)
Per common share – basic *($/share)*	**0.88**	(0.65)
Net earnings	**786**	922
Per common share – basic *($/share)*	**0.75**	0.88
Net debt(2)	**2,927**	4,020
Dividends per common share – ordinary *(dollars)*(3)	**0.075**	0.00
Capital expenditures(4)(5)	**2,220**	1,705

Operations

Daily production, before royalties		
Total equivalent production *(mboe/day)*	**322.9**	321.2
Crude oil & NGLs *(mbbls/day)*	**233.0**	228.6
Natural gas *(mmcf/day)*	**539.1**	555.9
Total proved reserves, before royalties *(mmboe)*(6)	**1,301**	1,224
U.S. refinery net throughputs *(mbbls/day)*(7)	**254.3**	200.4
Canadian refining and upgrading throughputs *(mbbls/day)*	**106.5**	109.7

(1) Results are reported in accordance with IFRS, as issued by the IASB, except where indicated.
(2) Non-GAAP measures. Please refer to Section 9.3 of the MD&A.
(3) Declared for the three-month period ended Dec. 31, 2017; payable on April 2, 2018.
(4) Excludes acquisition of the Superior Refinery in Q4; excludes asset retirement obligations and capitalized interest.
(5) Capitalized expenditures exclude amounts related to the Husky-CNOOC Madura and Husky Midstream Limited Partnership joint ventures, which are accounted for under the equity method for financial statement purposes.
(6) Total proved reserves based on forecasted prices in accordance with National Instrument 51-101.
(7) Husky owns 50% of the Toledo Refinery.

Report to Shareholders

Husky made significant progress in achieving its business targets in 2017, recording four quarters of improved funds from operations and free cash flow while driving higher margins and delivering on its operational objectives in both the Integrated Corridor and Offshore businesses.


Lloydminster Refinery

Net debt was reduced from $4 billion at the end of 2016 to $2.9 billion at the end of 2017, well below the target of less than two times net debt to funds from operations. This was accomplished even with the acquisition of the Superior Refinery and completion of an increased scope of work.

The Company marked several important milestones, including record production at the Tucker Thermal Project, the Sunrise Energy Project and the Liwan Gas Project. In addition, the Downstream business realized strong performance, with record throughputs and reliability.

Along the Integrated Corridor, the Board approved two new Lloyd thermal bitumen projects that will add a combined 20,000 barrels per day (bbls/day) of capacity in 2021, in addition to the 40,000 bbls/day currently in development.

The resource play business in Western Canada has been strategically repositioned to focus on more material liquids-rich gas projects, resulting in a leaner portfolio with lower asset retirement obligations and sustaining capital requirements.

Ongoing investments to increase Downstream heavy oil processing capacity and efficiency continue to support Husky's thermal production. The acquisition of the Superior Refinery in the U.S. Midwest has increased total upgrading and refining capacity to approximately 395,000 bbls/day, while expanding the scale of the Company's asphalt business.

Offshore, Husky is building out its Asia Pacific and Atlantic businesses, which provide solid returns. The Board sanctioned the third field at the Liwan Gas Project in China, and first production was realized at the liquids-rich BD Project in Indonesia. Construction is set to ramp up at the West White Rose Project offshore Newfoundland and Labrador, which will result in significant growth for Husky's Atlantic business when it is brought on production in 2022.

Husky's approach to Environment, Social and Governance (ESG) issues provides for better risk management and helps communicate the Company's performance to investors, employees and other stakeholders. The annual ESG Report facilitates an open dialogue on existing and emerging issues that have the potential to affect the industry. Husky is holding itself accountable by tracking, measuring and reporting its progress at every step.

Liwan Gas Project

Taking into account Husky's strong balance sheet and improved cash flow and the price environment, the Board took a decision in early 2018 to establish a cash dividend. The dividend is amply covered by current free cash flow.

With a deep portfolio of higher return investment opportunities and ongoing reductions to its cost structure, Husky is now better positioned to grow profitably and deliver sustainable value to shareholders, while further improving its resiliency and unrelenting focus on safety.

We thank our shareholders for their ongoing support.

Victor T.K. Li
Co-Chairman

Canning K.N. Fok
Co-Chairman

Message from the CEO

Steps taken to enhance our value proposition in 2017 further reduced our cost structure, reinforced our strong balance sheet and set the stage for more low-cost production growth and returning cash to our shareholders.

Rob Peabody
President & Chief Executive Officer

2017 represented the first year in a five-year plan, as presented at our annual Investor Day. At year-end, we had met or exceeded all of the targets in this plan, including driving efficiencies in our capital program and lowering our operating costs.

The outlook continues to improve over the coming four years, with an anticipated compound annual average production growth rate of seven percent through 2021 to approximately 400,000 barrels of oil equivalent per day (boe/day).

Strategic investments in our Integrated Corridor and Offshore businesses have resulted in stronger returns, higher margins and further reductions to our earnings and cash break-evens.

Along the Integrated Corridor, our overall thermal bitumen production is on pace to increase 50 percent over the coming four years, including six Lloyd projects in development representing 60,000 bbls/day of design capacity.

The close integration of our upgrading and refining complex in Lloydminster and the U.S. Midwest means we can capture increased profitability from these developments, from the wellhead to the refinery rack.

Our resource play business is targeting high rate, liquids-rich gas plays in Alberta while providing an internal hedge for the gas consumption at our refineries and thermal projects.

The Offshore business in the Asia Pacific and Atlantic regions delivered amongst the highest netbacks in the portfolio, averaging $55.22 per boe. In Asia, rising gas sales at the Liwan Gas Project are expected to further increase following the tie-in of the Liuhua 29-1 field in 2021. And in the Atlantic, we continued to advance a series of development wells to support production until the start-up of the West White Rose Project in 2022.

Our portfolio continues to be transformed through lower cost, higher return production. Improved operational performance, including drilling and installation efficiencies, has been a significant factor in this transformation.

We also saw a reduction in the number of serious or critical incidents and continued progress in our Total Recordable Incident Rate, along with improvements in reliability as the Husky Operations Integrity Management System (HOIMS) is further ingrained in our business.

Looking ahead, we are on track to meet our 2018 business objectives. We expect to further reduce our cost structure and increase our funds from operations and free cash flow while maintaining safety as a foundation of everything we do.

Rob Peabody

SeaRose FPSO

2017 Highlights

Overall

- Met or exceeded all targets set out at 2017 Investor Day:
  - Production of 323,000 boe/day
  - Funds from operations of $3.3 billion
  - Free cash flow of $1.1 billion
  - Reduced capital spending to $2.2 billion, while increasing the scope of work
  - Net debt of less than one times 2017 funds from operations, ending the year at $2.9 billion
  - Average Upstream operating cost of $13.93 per barrel
  - Proved reserves replacement ratio of 167 percent, excluding economic factors (165 percent including economic factors)
- Reduced number of serious or critical incidents per 200,000 hours worked from 0.18 to 0.15

Integrated Corridor

- Annual average Upstream production of 249,200 boe/day
- Upstream average operating netback of $16.38 per barrel compared to $9.29 per barrel in 2016
- Sanction of two additional Lloyd thermal projects at Edam Central and Westhazel
- Record upgrading and refining average throughputs of 361,000 bbls/day compared to 310,000 bbls/day in 2016
- Downstream upgrading and refining margin of $14.75 per barrel compared to $12.31 per barrel in 2016
- Acquisition of the Superior Refinery in the U.S. Midwest; increased total upgrading and refining capacity to approximately 395,000 bbls/day
- Creation of a single coast-to-coast truck transport network of approximately 160 travel centres/cardlock fuel facilities with Imperial Oil; expanded network and customer options has doubled Husky's cardlock diesel volumes

Offshore

- Annual average production of 73,700 boe/day
- Average operating netbacks of $55.22 per boe
- Record production at the Liwan Gas Project
- First production and commercial gas sales from the liquids-rich BD Project offshore Indonesia
- Sanction of Liuhua 29-1, the third field at the Liwan Gas Project
- Sanction of the West White Rose Project offshore Newfoundland and Labrador

Business Results

Production
Annual average production was within guidance at 323,000 boe/day, despite the sale of about 20,200 bbls/day of legacy assets in Western Canada in 2017.

Along the Integrated Corridor, annual average thermal bitumen production from Lloyd thermals, Tucker and Sunrise increased 22 percent over 2016 to 119,100 bbls/day.

In the Offshore business, record production was achieved at the Liwan Gas Project, with annual sales averaging 312 million cubic feet per day (153 mmcf/day Husky working interest) and 13,900 bbls/day of associated liquids (6,800 bbls/day Husky working interest).

Also in 2017, the liquids-rich BD Project offshore Indonesia was commissioned and began commercial production. Gas sales in the fourth quarter were 40 mmcf/day (17 mmcf/day Husky working interest) and 6,200 bbls/day of associated liquids (2,300 bbls/day Husky working interest). Annual sales averaged 8 mmcf/day of gas and 600 bbls/day of liquids (Husky working interest).

In the Atlantic region, three new wells at North Amethyst, South White Rose and the main White Rose field added 13,500 bbls/day (Husky working interest) of peak production capacity.

The West White Rose Project received sanction and construction will ramp up throughout 2018. Engineering, fabrication and installation contracts were signed for the topsides and platform.

Funds from Operations and Free Cash Flow
Funds from operations increased 50 percent in 2017 over the previous year to $3.3 billion.

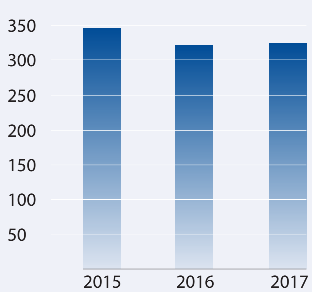
The improved results take into account a higher average realized crude oil and natural gas liquids price of $46.09 per boe, up 29 percent from $35.78 per boe in 2016, as well as strong results from the Asia Pacific region and increased margin capture along the Integrated Corridor.

Free cash flow was approximately $1.1 billion compared to $493 million in 2016.

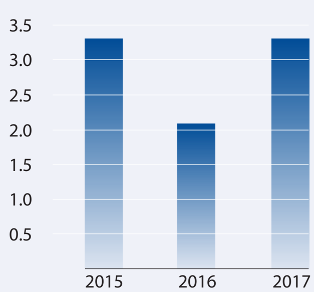
Debt Reduction
Husky further reduced its net debt in 2017 to well below its target of less than two times funds from operations. Following the closing of the Superior Refinery acquisition in the fourth quarter, net debt was $2.9 billion, representing less than one times 2017 funds from operations.

The Company continues to maintain strong investment grade credit ratings.

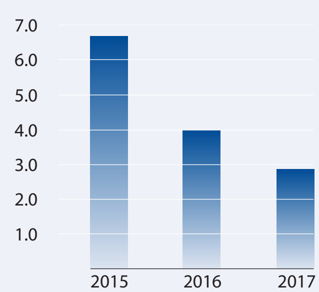
Production
(mboe/day)



Funds from Operations
($ billions)



Net Debt
($ billions)



Earnings

Net earnings of $786 million reflected higher realized crude oil prices and ongoing cost efficiencies. Adjusted net earnings were $882 million.

Changes to U.S. tax policy included a deferred tax contribution of $436 million to net earnings in the fourth quarter. Future reductions in cash taxes are anticipated to be approximately $75 million per year starting in 2020, further benefiting the Integrated Corridor business.

Capital Expenditures

Due in part to increased cost efficiencies across the business, capital expenditures were reduced by approximately 15 percent from annual guidance to $2.2 billion by the end of 2017. Including the acquisition of the Superior Refinery in the fourth quarter of 2017, total capital spending was $2.9 billion.

The scope of work planned for 2017 was expanded to include the acceleration of the Rush Lake 2 thermal project, the Montney drilling program and the advancement of two Atlantic infill wells.

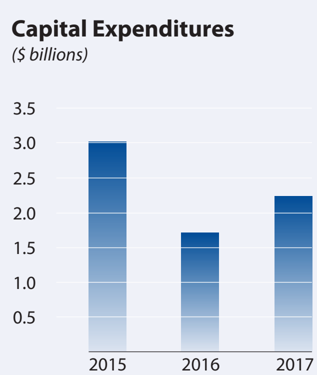
Reserves Replacement

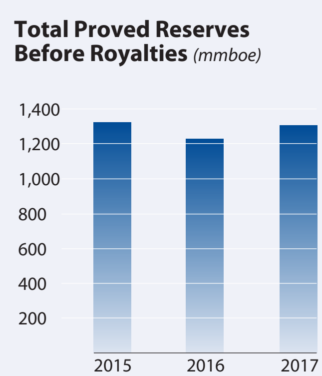
The 2017 proved reserves replacement ratio was 167 percent, excluding economic factors (165 percent including economic factors). The average five-year proved reserves replacement ratio was 144 percent, excluding economic factors (122 percent including economic factors). These take into account acquisitions and the disposition in Western Canada of 62 million boe of proved reserves in 2017 and 90 million boe of proved reserves in 2016.

The results exceed the five-year annual average proved reserves replacement ratio target outlined at Investor Day of more than 130 percent.

Total proved reserves before royalties at the end of 2017 were 1.3 billion boe. Probable reserves were 1.1 billion boe.

Proved reserves additions and revisions of 256 million boe, including economic factors, take into account additions related to the sanction of the West White Rose Project and three new Lloyd thermal bitumen projects, and improved performance in heavy oil production and Asia Pacific gas production.





Operations

Integrated Corridor

Thermal production

Thermal bitumen production increased 22 percent to 119,100 bbls/day, reflecting steady performance from Lloyd thermal projects and increased production from the Tucker Thermal Project and Phase 1 of the Sunrise Energy Project.

Combined thermal operating costs averaged $11.27 per boe.

Six new Lloyd thermal bitumen projects, representing 60,000 bbls/day of design capacity, are under construction or planned, including:

- Rush Lake 2, Dee Valley, Spruce Lake North and Spruce Lake Central will add a combined 40,000 bbls/day in design capacity when they are brought online in 2019 and 2020.
- Two additional thermal bitumen projects were sanctioned in 2017 at Edam Central and Westhazel, which are expected to add a combined 20,000 bbls/day of design capacity in the second half of 2021.

At Tucker, a new 15-well pad commenced steaming in the fourth quarter, with volumes continuing to ramp up, bringing Tucker towards its target of 30,000 bbls/day by the end of 2018.

At Sunrise, 14 well pairs were brought online, contributing to annual average production of 40,200 bbls/day (20,100 bbls/day Husky working interest), with production in the fourth quarter of 46,000 bbls/day (23,000 bbls/day Husky working interest). The project is expected to ramp up towards full capacity of 60,000 bbls/day (30,000 bbls/day Husky working interest) by the end of 2018.

Altogether, the Company expects to deliver a 50 percent increase in thermal production over the coming four years.

Pikes Peak South

Resource Plays

Husky's resource play business in Western Canada has been transformed with a focus on developing larger, more material short-cycle plays from a deep inventory of drilling opportunities.

The disposition program in Western Canada is complete. Altogether, approximately 52,000 boe/day of legacy assets have been sold since late 2015.

The Company completed a 16-well program targeting the Wilrich formation in the Ansell and Kakwa areas. Due in part to increased efficiency, two additional wells scheduled for 2018 were drilled in the fourth quarter.

At Ansell, improved operating efficiencies resulted in a 30 percent improvement in drilling times during the year, with an associated reduction of 22 percent in per-well drilling costs.

In the Montney formation, three liquids-rich gas wells were drilled in the Wembley area, and two oil wells at Karr.

Downstream

The Company's heavy oil refining capacity, combined with long-term commitments on the existing Keystone pipeline, has largely eliminated its exposure to Canadian heavy oil differentials.

Downstream throughputs increased to approximately 361,000 bbls/day, compared to 310,000 bbls/day in 2016. With the acquisition of the Superior Refinery in the U.S. Midwest, overall throughput capacity increased to approximately 395,000 bbls/day.

The Superior acquisition included the refinery's associated assets, including two asphalt terminals, two product terminals, a marine terminal, 3.6 million barrels of crude and product storage and a fuels and asphalt marketing business. The refinery produces a slate of products including asphalt, gasoline, diesel and heavy fuel oils.

Ongoing initiatives to improve reliability in 2017 resulted in record U.S. refinery utilizations of nearly 100 percent. The Lloydminster Upgrader achieved capacity utilization of more than 95 percent.

Superior Refinery

Operations

Offshore

Asia Pacific

Husky's production in the Asia Pacific region includes the Liwan Gas Project offshore China and a series of natural gas fields in production or under development offshore Indonesia.

Record production was achieved at the two producing gas fields at Liwan. Gas sales from the Liwan 3-1 and Liuhua 34-2 fields averaged 312 mmcf/day (153 mmcf/day Husky working interest) with an average realized sales price of $13.29 Cdn per thousand cubic feet (mcf).

A gas sales agreement was reached for the third gas field at Liuhua 29-1, which was sanctioned in the fourth quarter of 2017.

Production from Liuhua 29-1 will be tied into existing subsea infrastructure at Liwan, with first gas anticipated in 2021.

Offshore Indonesia in the Madura Strait, the BD Project was brought online and began to ramp up towards full sales production of 100 mmcf/day of gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated liquids (2,400 bbls/day Husky working interest). Gas is processed through an FPSO (floating production, storage and offloading vessel) and sold to the East Java market at contracted rates, which delivered an average realized price of $9.51 Cdn per mcf.

Three additional fields in the Madura Strait were advanced, including the combined MDA-MBH fields. Seven production wells are scheduled to be drilled at these shallow water fields in 2018, with first gas anticipated in 2019. A third well at MDK is expected to be tied in during the same timeframe and all three fields will share infrastructure, including a leased floating production vessel.

Combined sales volumes from the BD, MDA-MBH and MDK fields are expected to be approximately 250 mmcf/day of gas (100 mmcf/day Husky working interest) and 6,000 bbls/day of associated liquids (2,400 bbls/day Husky working interest) once production is fully ramped up.

BD Project, Madura Strait

Pre-engineering activities commenced at the MAC field, and additional fields in the Madura Strait are being assessed.

Husky continued to evaluate a range of exploration and investment opportunities in the Asia Pacific region. The Company plans to drill four shallow water exploration wells offshore China in 2018, two on Block 15/33 and two on Block 16/25.

Results from a 3-D seismic program completed in 2017 on an exploration block offshore Taiwan continue to be analyzed.

Atlantic

The next chapter of growth in the Atlantic region is under way following the sanctioning of the West White Rose Project offshore Newfoundland and Labrador in 2017. Construction will ramp up in 2018 with first oil anticipated in 2022.

The project will use a fixed wellhead platform and be tied back to the *SeaRose* FPSO to maximize resource recovery. The West White Rose Project is expected to achieve a gross peak production of approximately 75,000 bbls/day in 2025 (52,500 bbls/day Husky working interest) as additional development wells are brought online.

A series of high netback infill wells is supporting production in the region until the startup of West White Rose. Three new wells at North Amethyst, South White Rose and the main White Rose field added 13,500 bbls/day of net peak production capacity in 2017, with tie-backs to the *SeaRose* FPSO providing for improved capital efficiencies.

A new field at Northwest White Rose is being evaluated for potential commercial development. Husky has a 93.2 percent ownership interest in the 2017 discovery.

The Company continues to assess the commercial potential of its recent exploration drilling programs in the Jeanne d'Arc Basin and Flemish Pass. Husky holds significant exploration acreage offshore Newfoundland and Labrador, including the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries in the Flemish Pass.

Atlantic Canada drilling rig

Environment, Social and Governance

Husky holds itself accountable to all stakeholders, including shareholders, employees and the broader community, as it delivers essential products to the world in a safe and responsible manner.

As part of that commitment, Husky continues to advance its approach to improving, and reporting on, the Company's environmental, social and governance (ESG) performance. This includes asset integrity and reliability, air emissions management, water use, community and Indigenous engagement and creating a workplace that reflects diversity and inclusion.

The management of ESG issues is becoming increasingly important to the Company's stakeholders, and striving for strong performance in these areas reduces overall risk and creates and retains value. It is simply good business.

In 2017, Husky undertook a materiality assessment of all potential ESG topics. This involved assessing and prioritizing those deemed to have the most impact on the Company's long-term sustainability and success.

Husky continues to improve its ESG performance, as well as its disclosure of ESG metrics.

Environmental monitoring

Process and Occupational Safety

The Company continued to drive improvements in its safety culture, with a focus on process and occupational safety and reliability.

The number of serious or critical incidents per 200,000 hours worked was reduced from 0.18 to 0.15, or one event for almost 1.5 million hours worked.

The Total Recordable Injury Rate (TRIR), which measures lost time, restricted work, medical aid incidents and fatalities, was 0.62 in 2017, compared to 0.55 in 2016.

Husky developed a new mechanical integrity procedure to further improve the safety, efficiency and reliability of its pipeline operations, and introduced a geotechnical program to identify, monitor and mitigate potential impacts to pipelines from natural earth movements.

Following an ice management issue offshore Newfoundland and Labrador in the first quarter of 2017, actions have been taken to strengthen the Company's risk identification and emergency response procedures. This has further reinforced Husky's strong commitment in the region to process and occupational safety.

Lloydminster pipeline terminal

Innovation and Technology

Husky invests in innovation and technology to reduce costs, increase resource recovery and improve environmental performance. The Company has developed strategies that offer the highest value potential, while also incorporating cost-efficient advances from across the energy industry.

Recent innovations include piloting Husky-patented diluent reduction technology at the Sunrise Energy Project to increase the quality and value of recovered bitumen, reduce the required diluent and increase effective pipeline capacity, and provide for reduced CO_2 emissions. A 500 barrel-per-day pilot program has received federal and provincial support and is expected to commence operations in 2018.

At Lloydminster, the Company has developed technologies to improve integration and heat exchange at new thermal facilities and to maximize resource recovery.

In addition, CO_2-enhanced recovery technologies have been used to produce more than 3.2 million barrels of heavy oil to date. The Company is continuing to test and invest in innovative carbon-capture initiatives. A new plant at the Pikes Peak South thermal facility is being designed to capture up to 30 tonnes per day of CO_2 from the steam generator.

With rigorous emissions controls, and new technologies in place or on the horizon, Husky is working to reduce its environmental footprint as it delivers its essential products safely and reliably to the market.

Sunrise Energy Project

Management's Discussion and Analysis

February 28, 2018

Contents

1.0 Financial Summary

Selected Annual Information *($ millions, except where indicated)*	**2017**	2016	2015
Gross revenues and Marketing and other	**18,946**	13,224	16,801
Net earnings (loss) by business segment			
Upstream	**260**	1,091	(4,254)
Downstream	**448**	342	660
Corporate	**78**	(511)	(256)
Net earnings (loss)	**786**	922	(3,850)
Net earnings (loss) per share – basic	**0.75**	0.88	(3.95)
Net earnings (loss) per share – diluted	**0.75**	0.88	(4.01)
Adjusted net earnings (loss)(1)	**882**	(655)	149
Cash flow – operating activities	**3,704**	1,971	3,760
Funds from operations(1)	**3,306**	2,198	3,333
Ordinary dividends per common share(2)	**0.075**	—	0.900
Dividends per cumulative redeemable preferred share, series 1	**0.60**	0.73	1.11
Dividends per cumulative redeemable preferred share, series 2	**0.57**	0.42	—
Dividends per cumulative redeemable preferred share, series 3	**1.13**	1.13	1.19
Dividends per cumulative redeemable preferred share, series 5	**1.13**	1.25	0.90
Dividends per cumulative redeemable preferred share, series 7	**1.15**	1.15	0.62
Total assets	**32,927**	32,260	33,056
Net debt(3)	**2,927**	4,020	6,686

(1) *Adjusted net earnings and funds from operations are non-GAAP measures. The calculation of funds from operations changed in the second quarter of 2017. Prior periods have been revised to conform with the current period presentation. Refer to Section 9.3 for a reconciliation to the GAAP measures.*

(2) *Dividends declared for the third quarter of 2015 were issued in the form of common shares. The quarterly common share dividend was suspended in respect of the fourth quarter of 2015, but was reinstated during the first quarter of 2018. On February 28, 2018, the Board of Directors declared a quarterly dividend of $0.075 per common share for the three-month period ended December 31, 2017. The dividend will be payable on April 2, 2018 to shareholders of record at the close of business on March 20, 2018.*

(3) *Net debt is a non-GAAP measure. Refer to Section 9.3 for a reconciliation to the GAAP measure.*

2.0 Husky Business Overview

Husky Energy Inc. ("Husky" or the "Company") is one of Canada's largest integrated energy companies and is based in Calgary, Alberta. The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and the Cumulative Redeemable Preferred Shares Series 1, Series 2, Series 3, Series 5 and Series 7 are listed under the symbols "HSE.PR.A", "HSE.PR.B", "HSE.PR.C", "HSE.PR.E" and "HSE.PR.G", respectively. The Company operates in Canada, the United States and the Asia Pacific region with Upstream and Downstream business segments.

2.1 Corporate Strategy

The Company's business strategy is to focus on returns from investment in a deep portfolio of opportunities that can generate increased funds from operations and free cash flow.

The Company has two main businesses: (i) an integrated Canada-U.S. Upstream and Downstream corridor ("Integrated Corridor"); and (ii) production located offshore the east coast of Canada ("Atlantic") and offshore China and Indonesia ("Asia Pacific") (Atlantic and Asia Pacific collectively, "Offshore").

Integrated Corridor

The Company's business in the Integrated Corridor includes crude oil, bitumen, natural gas and natural gas liquids ("NGL") production from Western Canada, the Lloydminster upgrading and asphalt refining complex, the Prince George Refinery, Husky Midstream Limited Partnership (35 percent working interest and operatorship), and the Lima, Toledo and Superior refineries in the U.S. midwest. Natural gas production from the Western Canada portfolio is closely aligned with the Company's energy requirements for refining and thermal bitumen production and acts as a natural hedge.

Offshore

The Company's Offshore business includes operations, development and exploration in Asia Pacific and Atlantic. Each area generates high-netback production, with near and long-term investment potential.

2.2 Operations Overview and 2017 Highlights

Upstream Operations

Upstream operations in the Integrated Corridor and Offshore include exploration for, and development and production of, crude oil, bitumen, natural gas and NGL ("Exploration and Production") and marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and natural gas and storage of crude oil, diluent and natural gas ("Infrastructure and Marketing"). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Western Canada, Asia Pacific and Atlantic.

Exploration and Production

Thermal Developments

The Company is building on its thermal expertise by expanding its Lloyd thermal bitumen projects, and ramping up both the Tucker Thermal Project and the Sunrise Energy Project. The Company continued to advance its inventory of thermal projects in 2017. These long-life developments are being built with modular, repeatable designs and require low sustaining capital once brought online.

Total bitumen production, including Lloyd thermal projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 119,100 bbls/day in 2017.

Lloyd Thermal Projects

The Company expects to bring on 60,000 bbls/day of long-life thermal bitumen production over the next four years.

Development continued at the 10,000 bbls/day Rush Lake 2 Thermal Project. Construction of the central processing facility is progressing ahead of schedule (65 percent complete as of the end of 2017) and drilling of the 12 Steam-Assisted Gravity Drainage ("SAGD") injector-producer well pairs was completed in February 2018. First production is expected in the first quarter of 2019.

In late 2016, the Company sanctioned three Lloyd thermal projects with a total design capacity of 30,000 bbls/day at Dee Valley, Spruce Lake North and Spruce Lake Central. Regulatory approval for all three projects was received in 2017. Site clearing was completed at Dee Valley in the fourth quarter of 2017 and construction will commence in 2018. Site clearing and construction will start at Spruce Lake Central in 2018, and at Spruce Lake North site clearing will start in 2018 with construction commencing in 2019. First production for all three projects is expected in 2020.

In November 2017, the Company sanctioned two new 10,000 bbls/day thermal projects at Westhazel and Edam Central. First production for these two projects is expected in the second half of 2021.

Tucker Thermal Project

First oil was achieved at a new eight-well pad in the first quarter of 2017. Steaming commenced on a new 15-well pad drilled in the second quarter of 2017, with production expected to ramp up through the first half of 2018. Total production at the Tucker Thermal Project is expected to reach its 30,000 bbls/day design capacity by the end of 2018. In support of this, planned work to de-bottleneck the field and plant infrastructure is expected to be completed in the third quarter of 2018.

Sunrise Energy Project

Average annual production in 2017 was approximately 40,200 bbls/day (20,100 bbls/day Husky working interest), while December 2017 production averaged 47,100 bbls/day (23,550 bbls/day Husky working interest). The project is expected to reach its nameplate capacity of 60,000 bbls/day by the end of 2018.

14 previously drilled well pairs were tied in during 2017, with 13 well pairs on production in late 2017 and the remaining well pair on production in early 2018.

Western Canada

Western Canada continues to execute its resource play strategy to advance developments in the Spirit River (predominantly Wilrich) and Montney formations.

Oil and Natural Gas Resource Plays

A 16-well drilling program targeting the Spirit River formation in the Ansell and Kakwa areas was completed in the fourth quarter of 2017. 10 of the 16 wells drilled during the year were producing prior to the end of 2017. The remaining six wells will start production in early 2018. Due to improved operating efficiencies, drilling times were reduced by 30 percent during 2017, contributing to a 22 percent reduction in per-well drilling costs.

A drilling program targeting the oil and liquids-rich Montney formation in the Wembley and Karr areas is continuing. At Wembley, three wells were drilled in 2017, of which one well was producing prior to the end of 2017 and the other two wells are expected to be on production in 2018. At Karr, two wells were drilled and producing by the end of 2017.

Non-Thermal Developments

The Company is managing the natural decline in Cold Heavy Oil Production with Sand ("CHOPS") operations with an active optimization program as well as using Waterflooding and Polymer injection technology.

Enhanced Oil Recovery

In 2017, the Company operated five carbon dioxide ("CO_2") injection enhanced oil recovery ("EOR") pilot projects and a CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant. The liquefied CO_2 is used in the ongoing EOR piloting program. The Company is also piloting several types of CO_2 capture technology at the Lashburn facility in Saskatchewan.

Asia Pacific

Asia Pacific consists of the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields on Block 29/26 located in the South China Sea. The Madura Strait, offshore Indonesia, consists of the operating BD field, the MDA, MBH, MDK and MAC developments and three additional discoveries. The Company has rights to additional exploration blocks in the South China Sea, offshore Taiwan and Indonesia.

The Company continues to develop its fixed-price natural gas business offshore China and Indonesia, further protecting the Company from commodity price instability.

China

Block 29/26

Gross production from Liwan 3-1 and Liuhua 34-2 averaged 65,900 boe/day (32,300 boe/day Husky working interest) in 2017. Production consists of gross natural gas production of 312 mmcf/day and NGL production of 13,900 bbls/day. In comparison, 2016 production averaged 48,800 boe/day (24,800 boe/day Husky working interest), consisting of gross natural gas production of 224 mmcf/day and NGL production of 11,500 bbls/day.

A gas sales agreement was reached for future gas production from Liuhua 29-1, the third deepwater gas field at the Liwan Gas Project. The project was sanctioned in the fourth quarter of 2017. Construction is scheduled to begin in 2018 and first production is expected in 2021.

Blocks 15/33 and 16/25

On April 10, 2017, the Company signed a new production sharing contract ("PSC") for a new exploration block offshore China, Block 16/25, with China National Offshore Oil Corporation ("CNOOC"). Block 16/25 is located in the Pearl River Mouth Basin, about 150 kilometres southeast of the Hong Kong Special Administrative Region.

The Company expects to drill two exploration wells on the shallow water Block 16/25 during the 2018 timeframe, which are planned to be drilled in conjunction with the two planned exploration wells at the nearby exploration Block 15/33. The Company is the operator of both blocks during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, CNOOC may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases.

Block DW-1

During 2017, on Block DW-1 offshore Taiwan, the Company completed the acquisition of three-dimensional seismic survey data. Analysis of the data has commenced to identify potential drilling prospects on the block.

Wenchang

The Company's participation in the Wenchang oilfields petroleum contract expired in November 2017 and the Company will not be entitled to any further production rights. The Company's share of light oil production averaged 5,300 bbls/day in 2017 compared to 6,600 bbls/day in 2016.

The Company had deposited funds of $95 million related to the Wenchang field for decommissioning and disposal expenses.

Indonesia

Madura Strait

Progress continued on the natural gas developments in the Madura Strait block. Total gross sales volumes from the BD Project, MDA-MBH and MDK fields are expected to be approximately 250 mmcf/day of natural gas (100 mmcf/day Husky working interest) and 6,000 bbls/day (2,400 bbls/day Husky working interest) of associated NGL once production is fully ramped up.

First gas production from the BD Project was achieved during the third quarter of 2017 and the first lifting of NGL occurred in mid-October. Gas is being sold from the onshore gas distribution facility in East Java under a fixed-price gas contract. NGL are produced and stored in the purpose built floating production, storage and offloading vessel ("FPSO"). Gross natural gas production averaged 20 mmcf/day (8 mmcf/day Husky working interest) and gross NGL production averaged 1,600 bbls/day (600 bbls/day Husky working interest) in 2017. The project is expected to ramp up in 2018 towards full sales gas rates, with a gross daily sales target of 100 mmcf/day of natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGL (2,400 bbls/day Husky working interest).

Construction and installation of the shallow water jackets and subsea pipelines for the MDA-MBH fields were completed in the second quarter of 2017. The contract for a leased floating production unit has been signed and planning for the build has commenced. Drilling of five MDA field production wells and two MBH field production wells is planned for the first half of 2018, with first gas expected in the 2019 timeframe. The additional MDK shallow water field is expected to be tied in during the same period.

Pre-engineering activities progressed at the MAC field, where an approved Plan of Development is in place. Additional discoveries in the region are being evaluated for potential development.

Anugerah

During 2015, the Company acquired two-dimensional and three-dimensional seismic survey data on the contract area. An analysis of the data continues to be evaluated to determine the potential for future drilling opportunities.

Atlantic

The Company's Atlantic portfolio has short and long-term opportunities that provide for high return production growth.

White Rose Field and Satellite Extensions

In the second quarter of 2017, the Company and its partners announced plans to move ahead with the West White Rose Project offshore Newfoundland and Labrador. The project was sanctioned in May 2017 and will be developed using a fixed drilling platform, which has received regulatory approval. Contracts were awarded in the third quarter of 2017 and early development work commenced. Preparations for construction of the concrete gravity structure to support the topsides began in the fourth quarter of 2017 at the purpose-built graving dock in Argentia, Newfoundland and Labrador ("NL"). The platform will leverage existing offshore infrastructure, including the *SeaRose* FPSO vessel. First oil is expected in 2022 with an expected ramp-up to gross peak production capacity of 75,000 bbls/day (52,500 bbls/day Husky working interest) in 2025 as development wells are drilled and brought online.

The Company continues to offset natural reservoir declines through infill and development well drilling at the White Rose field and satellite extensions. At North Amethyst, an infill well commenced production during the first quarter of 2017 with peak production of approximately 12,500 bbls/day (8,600 bbls/day Husky working interest). At South White Rose, an oil production well and a supporting water injection well were completed during the third quarter of 2017. An additional infill well was completed during the fourth quarter of 2017 drilled from the South White Rose field targeting the main White Rose field. All wells are tied back to the *SeaRose* FPSO, providing for improved capital efficiencies.

Atlantic Exploration

A new discovery at Northwest White Rose was announced in May 2017, and evaluation of results is ongoing. A potential development could leverage the *SeaRose* FPSO vessel, existing subsea infrastructure, and the West White Rose wellhead platform. The Company has a 93.232 percent ownership interest in the discovery.

In the first half of 2017, the Company and its partner drilled two exploration wells in the Flemish Pass that did not encounter economic quantities of hydrocarbons. The Company continues to evaluate the results of recent drilling programs in the Flemish Pass where it holds a 35 percent non-operated working interest in each of the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. The Canada-Newfoundland and Labrador Offshore Petroleum Board ("C-NLOPB") issued a significant discovery licence for Bay du Nord in November 2017, which covers an area of 13,149 hectares.

In November 2017, the C-NLOPB announced that the Company was the successful bidder on a parcel of land in its 2017 land sale (50 percent Husky working interest). The lands cover an area of 121,453 hectares in the Jeanne d'Arc Basin. The lands are adjacent to the Company's other exploration licences in the basin.

Infrastructure and Marketing

Husky Midstream Limited Partnership

On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The assets are held by Husky Midstream Limited Partnership ("HMLP"), of which the Company owns 35 percent, Power Assets Holdings Limited ("PAH") owns 48.75 percent and CK Infrastructure Holdings Limited ("CKI") owns 16.25 percent. The Company remains the operator of HMLP's assets.

HMLP has approximately 1,900 kilometres of pipeline in the Lloydminster region, storage at Hardisty and Lloydminster, and other ancillary assets. The pipeline systems transport blended heavy crude oil to Lloydminster, accessing markets through Husky's Upgrader and Asphalt Refinery. The Hardisty Terminal acts as the exclusive blending hub for Western Canada Select. HMLP is in the process of diversifying its operations beyond the Lloydminster and Hardisty area and has commercial support to enter the natural gas processing segment.

LLB Direct – Cold Lake Gathering System to Hardisty

During the year, HMLP commenced the construction of a new 150-kilometres pipeline system in Alberta, which creates additional pipeline capacity to handle the expected growth in the Company's thermal operations in Alberta and Saskatchewan. The construction is currently ahead of schedule and is expected to be completed in 2018.

Rush Lake 2 Line

Phase two of the Saskatchewan Gathering System Expansion commenced with construction activities on the Rush Lake 2 line. The multi-year expansion program is underway on several fronts and will provide transportation of diluent and heavy oil blend for several additional thermal plants.

Natural Gas Storage Facilities

The Company has operated a 25 bcf natural gas storage facility at Hussar, Alberta since 2000.

Commodity Marketing

The Company has developed its commodity marketing operations to include the acquisition of third-party volumes to enhance the value of its midstream assets. The Company also markets both its own and third-party production of crude oil, synthetic crude oil, NGL, natural gas and sulphur. Additionally, the Company markets petroleum coke, a by-product from the Lloydminster Upgrader, and its Ohio and Wisconsin refineries.

Downstream Operations

Downstream operations in the Integrated Corridor include upgrading of heavy crude oil feedstock into synthetic crude oil in Canada ("Upgrading"), refining crude oil in Canada, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol ("Canadian Refined Products"). It also includes refining in the U.S. of primarily crude oil to produce and market diesel fuels, gasoline, jet fuel and asphalt that meet U.S. clean fuels standards ("U.S. Refining and Marketing"). Upgrading, Canadian Refined Products and U.S. Refining and Marketing all process and refine natural resources into marketable products and are grouped together as the Downstream business segment due to the similar nature of their products and services.

The Company's Downstream operations target three primary objectives: increasing feedstock flexibility to bring the best-priced crude to the Company's refineries, improving flexibility in the range of its products to capitalize on opportunities and enhancing market access to achieve the best returns. The Company's focused integration strategy helps to capture the margin on refined product pricing for its Western Canada heavy oil, bitumen and light oil production and assists in mitigating market volatility.

Upgrading

The heavy oil upgrading facility, located in Lloydminster, Saskatchewan, has a throughput capacity of 82,000 bbls/day. The Lloydminster Upgrader produces synthetic crude oil, diluent and ultra low sulphur diesel. It is designed to process blended heavy crude oil feedstock into high quality, low sulphur synthetic crude oil. Synthetic crude oil is used as refinery feedstock for the production of transportation fuels in Canada and the U.S. In addition, the Lloydminster Upgrader recovers diluent, which is blended with the heavy crude oil and bitumen prior to pipeline transportation to reduce viscosity and facilitate its movement, and returns it to the field to be reused. The Upgrader's current rated production capacity is 82,000 bbls/day of synthetic crude oil, diluent and ultra low sulphur diesel.

In the second quarter of 2017, a major turnaround was completed at the facility.

Canadian Refined Products

Lloydminster Asphalt Refinery
The Company is the largest marketer of paving asphalt in Western Canada. The Lloydminster Asphalt Refinery in Lloydminster, Alberta, has a throughput capacity of 29,000 bbls/day and is integrated with the local heavy oil and bitumen production, as well as transportation and upgrading infrastructure.

In the second quarter of 2017, a major turnaround was completed at the Asphalt Refinery.

A final investment decision for the potential expansion of the Lloydminster Asphalt Refinery has now been deferred to post-2020, in light of the Superior Refinery acquisition. The investment decision was initially planned for 2018.

Ethanol Plants
The Company is the largest producer of ethanol in Western Canada. The Company has two ethanol plants, one in Lloydminster, Saskatchewan and one in Minnedosa, Manitoba, with combined capacity of 260 million litres per year.

Prince George Refinery
The Prince George Refinery in British Columbia has a throughput capacity of 12,000 bbls/day and produces low sulphur gasoline and ultra-low sulphur diesel.

Branded Petroleum Product Outlets, Commercial Distribution and Truck Transportation Network
The Company is a major regional motor fuel marketer with an average of 518 retail marketing locations in 2017, including bulk plants and travel centres, with strategic land positions in Western Canada and Ontario.

In the third quarter of 2017, the Company and Imperial Oil closed their previously announced transaction to create a single expanded truck transport network of approximately 160 sites. As a result, the Company now has one of the largest cardlock networks in Canada.

U.S. Refining and Marketing

Lima Refinery

The Lima Refinery in Ohio has a throughput capacity of 165,000 bbls/day and produces low sulphur gasoline, gasoline blend stocks, ultra-low sulphur diesel, jet fuel, petrochemical feedstock and other by-products.

In 2016, the Company completed the first stage of the crude oil flexibility project and the refinery is now able to process up to 10,000 bbls/day of heavy crude oil feedstock. The project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada when completed, providing the ability to swing between light and heavy crude oil feedstock.

The timing of completion for the crude oil flexibility project, which was expected to be completed around the end of 2018, has been updated and is expected to be completed in phases over a two-year period through 2018 and 2019. This revised schedule coordinates project work with normal maintenance to provide higher levels of sustained production.

BP-Husky Toledo Refinery

The BP-Husky Toledo Refinery in Ohio has a name plate throughput capacity of 160,000 bbls/day and produces low sulphur gasoline, ultra-low sulphur diesel, aviation fuels, propane and asphalt. The crude oil refinery is owned 50 percent by the Company and 50 percent by BP Corporation North America Inc ("BP"), and is operated by BP. The Company and its partner completed a feedstock optimization project in 2016, allowing the refinery to process approximately 55,000 to 70,000 bbls/day of high content naphthenic acids ("high-TAN")crude oil to support production from the Sunrise Energy Project. The refinery's overall nameplate capacity remained unchanged.

Superior Refinery

On November 8, 2017, the Company completed the purchase of the Superior Refinery, a 50,000 bbls/day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet Specialty Products Partners, L.P. ("Calumet") for $670 million (US$527 million) in cash, which includes $108 million (US$85 million) of working capital, subject to final adjustments. The refinery produces gasoline, diesel, asphalt and heavy fuel oils.

A project to increase the heavy oil processing capacity at the Superior Refinery is expected to be completed in the first half of 2018.

2.3 Financial Strategic Plan

The Company is committed to ensuring sufficient liquidity, financial flexibility and access to long-term capital to fund its growth. The Company maintains undrawn committed term credit facilities with a portfolio of creditworthy financial institutions and other sources of liquidity to provide timely access to funding to supplement cash flow.

The Company intends to continue maintaining a healthy balance sheet to provide financial flexibility. The Company's target is to maintain a debt to funds from operations ratio of less than 2.0 times and a debt to capital employed ratio of less than 25 percent. Debt to funds from operations and debt to capital employed are both non-GAAP measures (refer to Sections 6.4 and 9.3). The Company is committed to retaining its investment grade credit ratings to support access to debt capital markets. The Company has taken measures to strengthen its financial position and navigate through commodity cycles. Past measures included, but were not limited to, a reduction of budgeted capital spending, the suspension of the quarterly common share dividend, the sale of non-core assets in Western Canada and the continued transition to higher return production. Refer to Section 6.0 for additional information on the Company's liquidity and capital resources.

In 2017, the Company:

- Issued $750 million in notes maturing March 10, 2027, with a coupon of 3.60 percent.
- Repaid the maturing 6.20 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to note holders was $365 million, including $11 million of interest.
- Completed the sale of select assets in Western Canada, representing approximately 20,200 boe/day for gross proceeds of approximately $185 million.

3.0 The 2017 Business Environment

The Company's operations are significantly influenced by domestic and international factors including, but not limited to, the following:

- The global crude oil market continued to rebalance, with production reductions by certain members of the Organization of the Petroleum Exporting Countries ("OPEC") and non-OPEC members, leading to higher key crude oil benchmarks in 2017. The production cuts were partially offset by increased production from OPEC members not bound to the production restrictions and growth in U.S. shale oil production.
- The U.S. Energy Information Administration ("EIA") estimated that global demand for crude oil increased by an estimated 1.6 mmboe/day in 2017 and is forecasted to increase by 1.7 mmboe/day in 2018.
- North American natural gas benchmarks continued to be weak in 2017 due to an oversupply of natural gas in North America, which is largely the result of technological advances in horizontal drilling and hydraulic fracturing that have unlocked significant reserves.
- The cost of the U.S. Renewable Fuels Standard legislation has become a material economic factor for refineries in the U.S. U.S. refiners observed significant volatility in the price of Renewable Identification Numbers ("RINs") in 2017.
- The Canadian dollar strengthened against the U.S. dollar in 2017 compared to 2016.
- Alternative and improved extraction methods have rapidly evolved in North American and international onshore and offshore activity.
- A continuing emphasis on environmental, the impacts of climate change, health and safety, enterprise risk management, resource sustainability and corporate social responsibility concerns.
- The income tax effects related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018.
- Transportation constraints on crude oil produced in western Canada. The oil and gas industry continues to work with stakeholders to develop a strong network of transportation infrastructure including pipelines, rail, marine and trucks. The development of a strong infrastructure network continues to be an important challenge for the industry in order to obtain market access for the growing supply of crude oil from the western Canadian oil sands.

Major business factors are considered in the formulation of the Company's short and long term business strategy.

The Company is exposed to a number of risks inherent in the exploration, development, production, marketing, transportation, storage and sale of crude oil, liquids-rich natural gas and related products. For a discussion on Risk and Risk Management, see Section 5.0 and the Company's Annual Information Form for the year ended December 31, 2017.

Average Benchmarks

Commodity prices, refining crack spreads and foreign exchange rates are some of the most significant factors that affect the results of the Company's operations. The following average benchmarks have been provided to assist in understanding the Company's financial results.

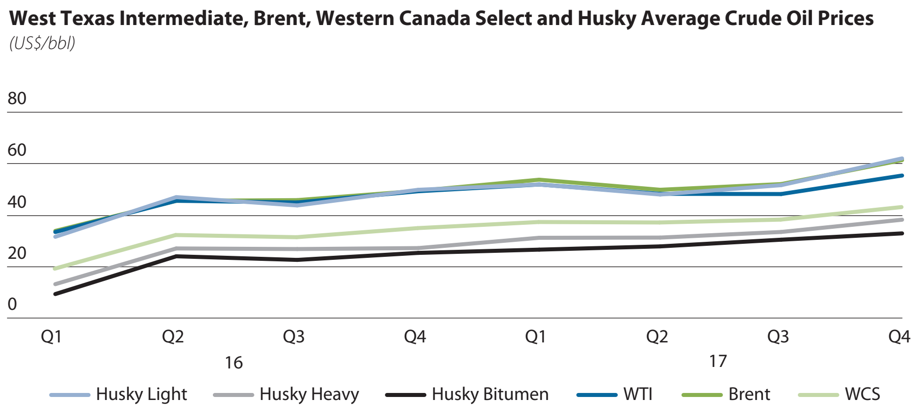
Average Benchmarks Summary		2017	2016
West Texas Intermediate ("WTI") crude oil[1]	(US$/bbl)	**50.95**	43.32
Brent crude oil[2]	(US$/bbl)	**54.28**	43.69
Light sweet at Edmonton	($/bbl)	**62.91**	52.99
Daqing[3]	(US$/bbl)	**51.78**	40.86
Western Canada Select at Hardisty[4]	(US$/bbl)	**38.98**	29.48
Lloyd heavy crude oil at Lloydminster	($/bbl)	**44.36**	32.61
WTI/Lloyd crude blend differential	(US$/bbl)	**11.76**	13.70
Condensate at Edmonton	(US$/bbl)	**51.57**	42.47
NYMEX natural gas[5]	(US$/mmbtu)	**3.11**	2.46
Nova Inventory Transfer ("NIT") natural gas	($/GJ)	**2.30**	1.98
Chicago Regular Unleaded Gasoline	(US$/bbl)	**66.22**	56.07
Chicago Ultra-low Sulphur Diesel	(US$/bbl)	**69.05**	56.48
Chicago 3:2:1 crack spread	(US$/bbl)	**16.31**	12.74
U.S./Canadian dollar exchange rate	(US$)	**0.771**	0.755
Canadian Equivalents[6]			
WTI crude oil	($/bbl)	**66.08**	57.38
Brent crude oil	($/bbl)	**70.40**	57.87
Daqing	($/bbl)	**67.16**	54.12
Western Canada Select at Hardisty	($/bbl)	**50.56**	39.05
WTI/Lloyd crude blend differential	($/bbl)	**15.25**	18.15
NYMEX natural gas	($/mmbtu)	**4.03**	3.26

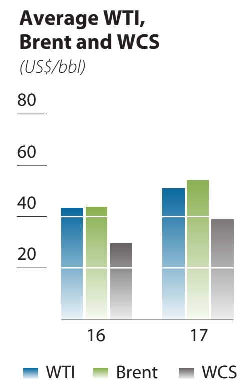
(1) *Calendar Month Average of settled prices for West Texas Intermediate at Cushing, Oklahoma.*
(2) *Calendar Month Average of settled prices for Dated Brent.*
(3) *Calendar Month Average of settled prices for Daqing.*
(4) *Western Canadian Select is a heavy blended crude oil, comprised of conventional and bitumen crude oils, blended with diluent, which terminals at Hardisty, Alberta. Quoted prices are indicative of the Index for Western Canadian Select at Hardisty, Alberta, set in the month prior to delivery.*
(5) *Prices quoted are average settlement prices during the period.*
(6) *Prices quoted are calculated using U.S. dollar benchmark commodity prices and U.S./Canadian dollar exchange rates.*

As an integrated producer, the Company's profitability is largely determined by realized prices for crude oil and natural gas, marketing margins on committed pipeline capacity and refinery margins, as well as the effect of changes in the U.S./Canadian dollar exchange rate. All of the Company's crude oil production and the majority of its natural gas production receives the prevailing market price. The price realized for crude oil is determined by North American and global factors. The price realized for natural gas production from Western Canada is determined primarily by North American fundamentals since virtually all natural gas production in North America is consumed by North American customers. In Asia Pacific, the natural gas price is determined by fixed long-term sales contracts.

The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil and bitumen. In the Upgrading business, heavy crude oil feedstock is processed into light synthetic crude oil. The Company's U.S. Refining and Marketing business processes a mix of different types of crude oil from various sources, but the mix is primarily light sweet crude oil at the Lima Refinery and approximately 55 percent heavy crude oil and bitumen feedstock at the BP-Husky Toledo Refinery. The Company's Canadian Refined Products business relies primarily on purchased refined products for resale in the retail distribution network. Refined products are acquired, under supply contracts, from other Canadian refiners or gasoline and diesel production from the Prince George Refinery and diesel production from the Lloydminster Upgrader.

Crude Oil Benchmarks



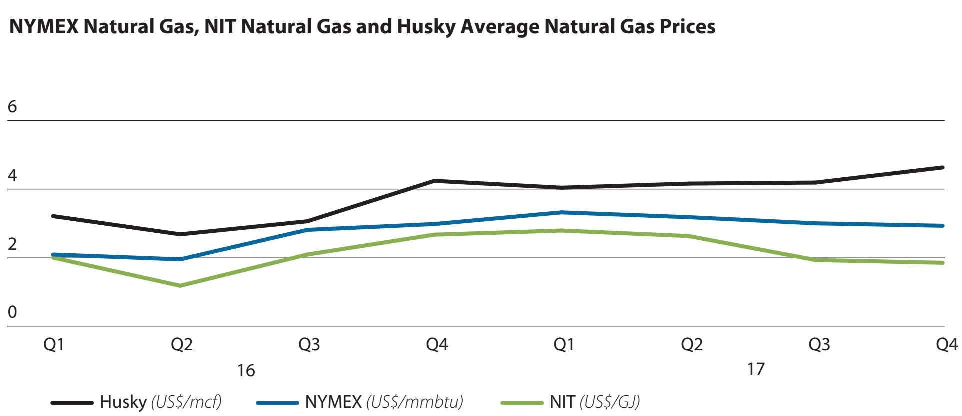


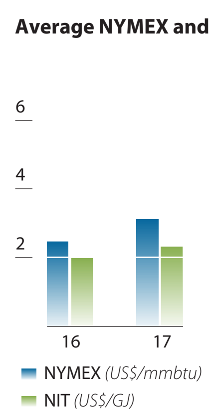
Global crude oil benchmarks strengthened in 2017 primarily due to the production reductions made by certain members of OPEC and some key non-OPEC producers, along with global demand growth of an estimated 1.6 mmboe/day per the EIA. The production cuts were partially offset by increased production from OPEC members not bound to the production restrictions and growth in U.S. shale oil production. WTI averaged US$50.95/bbl in 2017 compared to US$43.32/bbl in 2016. Brent averaged US$54.28/bbl in 2017 compared to US$43.69/bbl in 2016.

The price received by the Company for crude oil production from Western Canada is primarily driven by the price of WTI, adjusted to Western Canada. The price received by the Company for crude oil production from Atlantic is primarily driven by the price of Brent and the price received by the Company for crude oil and NGL production from Asia Pacific is primarily driven by the price of Daqing. The majority of the Company's crude oil production from Western Canada is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2017, approximately 70 percent of the Company's crude oil and NGL production was heavy crude oil or bitumen compared to approximately 66 percent in 2016.

The Company's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate. The price of condensate at Edmonton increased in 2017 primarily due to the increase in crude oil benchmark pricing.

Natural Gas Benchmarks





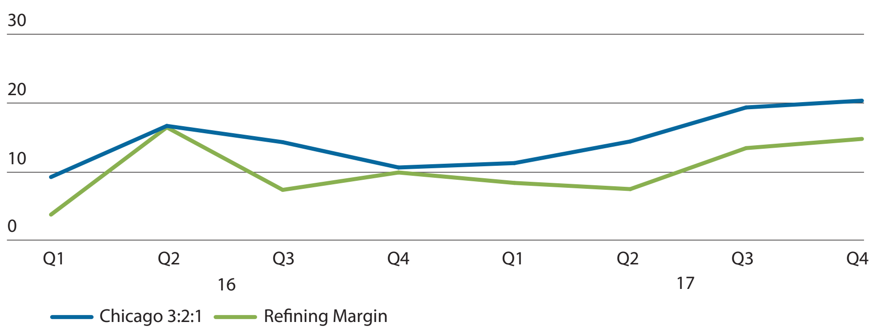
North American natural gas benchmarks continued to be weak in 2017 due to the continued oversupply of natural gas in North America. The oversupply is largely the result of technological advances in horizontal drilling and hydraulic fracturing that have unlocked significant reserves that were not economical under previously applied extraction methods. The NIT natural gas price benchmark increased in 2017 compared to 2016 due to a temporary decline in natural gas demand from Canadian oil sands operations in 2016, resulting from the wildfire at Fort McMurray, Alberta.

The price received by the Company for natural gas production from Western Canada is primarily driven by the NIT near-month contract price of natural gas, while the price received by the Company for production from Asia Pacific is largely set through fixed long-term sales contracts.

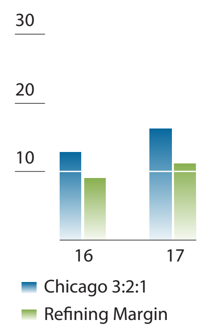
North American natural gas is consumed internally by the Company's Upstream and Downstream operations, helping to mitigate the impact of weak North American natural gas benchmark prices on the Company's results.

Refining Benchmarks

Chicago Average Crack Spread and Husky Realized U.S. Refining Margin
(US$/bbl)



Average Crack Spread
(US$/bbl)

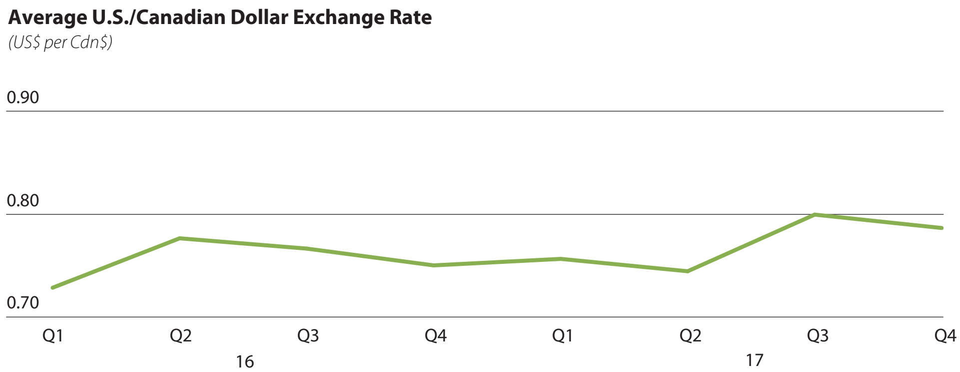


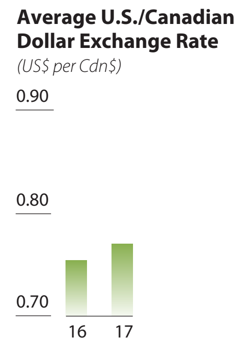
The Chicago 3:2:1 crack spread is the key indicator for U.S. refining margins and reflects refinery gasoline output that is approximately twice the distillate output, and is calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of distillate fuel less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not reflect the actual crude purchase costs or the product configuration of a specific refinery. The Chicago Regular Unleaded Gasoline and the Chicago Ultra-low Sulphur Diesel average benchmark prices are the standard products included in the Chicago 3:2:1 crack spread. The Chicago 3:2:1 crack spread is based on last in first out ("LIFO") accounting.

The cost of the U.S. Renewable Fuels Standard legislation has become a material economic factor for refineries in the U.S. The Chicago 3:2:1 crack spread is a gross margin based on the prices of unblended fuels. The cost of purchasing RINs or physical biofuel blending into a final gasoline or diesel has not been deducted from the Chicago 3:2:1 gross margin. The market value of gasoline or distillate that has been blended may be lower than the value of unblended petroleum products given the value a buyer of unblended petroleum can gain by generating a RIN through blending. The Company sells both blended fuels and unblended fuels with the goal of maximizing margins net of RINs purchases.

The Company's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil. The product slates produced at the Lima, BP-Husky Toledo and Superior refineries contain approximately 10 to 30 percent of other products that are sold at discounted market prices compared to gasoline and distillate. The Company's realized refining margins are accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

Foreign Exchange





The majority of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities and refined products whose prices are determined by reference to U.S. benchmark prices. The majority of the Company's non-hydrocarbon related expenditures are denominated in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, changes in foreign exchange rates impact the translation of U.S. Downstream and Asia Pacific operations and U.S. dollar-denominated debt. In 2017, the Canadian dollar averaged US$0.771 compared to US$0.755 in 2016.

The Company's long-term sales contracts in China are priced in Chinese Yuan ("RMB") and, therefore, an increase in the value of RMB relative to the Canadian dollar will increase the revenues received in Canadian dollars from the sale of these natural gas commodities in the region. The Canadian dollar averaged RMB 5.208 in 2017 compared to RMB 5.012 in 2016.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in 2017 on earnings before income taxes and net earnings. The table below reflects what the expected effect would have been on the financial results for 2017 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2017. Each separate item in the sensitivity analysis shows the approximate effect of an increase in that variable only; all other variables are held constant. While these sensitivities are indicative for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or upon greater magnitudes of change.

Sensitivity Analysis	2017 Average	Increase	Effect on Earnings before Income Taxes[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	**50.95**	*US$1.00/bbl*	**101**	**0.10**	**73**	**0.07**
NYMEX benchmark natural gas price[5]	**3.11**	*US$0.20/mmbtu*	**9**	**0.01**	**7**	**0.01**
WTI/Lloyd crude blend differential[6]	**11.76**	*US$1.00/bbl*	**(9)**	**(0.01)**	**(6)**	**(0.01)**
Canadian asphalt margins	**19.96**	*Cdn $1.00/bbl*	**10**	**0.01**	**7**	**0.01**
Canadian light oil margins	**0.052**	*Cdn $0.005/litre*	**13**	**0.01**	**10**	**0.01**
Chicago 3:2:1 crack spread	**16.31**	*US$1.00/bbl*	**123**	**0.12**	**78**	**0.08**
Exchange rate (US $ per Cdn $)[3][7]	**0.771**	*US$0.01*	**(64)**	**(0.06)**	**(46)**	**(0.05)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as of December 31, 2017.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent-based production.*
(5) *Includes impact of natural gas consumption.*
(6) *Revised to reflect the impact of Infrastructure and Marketing. Excludes impact on Canadian asphalt operations.*
(7) *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

4.0 Results of Operations

4.1 Segment Earnings

Segmented Earnings	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[1]	
($ millions)	**2017**	2016	**2017**	2016	**2017**	2016
Upstream						
Exploration and Production	**239**	(298)	**174**	(217)	**1,476**	872
Infrastructure and Marketing	**118**	1,430	**86**	1,308	**—**	54
Downstream						
Upgrading	**151**	241	**110**	175	**230**	51
Canadian Refined Products	**142**	151	**104**	110	**87**	52
U.S. Refining and Marketing	**371**	90	**234**	57	**313**	623
Corporate	**(597)**	(664)	**78**	(511)	**114**	53
Total	**424**	950	**786**	922	**2,220**	1,705

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

4.2 Upstream

Exploration and Production

Exploration and Production Earnings Summary *($ millions)*	**2017**	2016
Gross revenues	**4,978**	4,036
Royalties	**(363)**	(305)
Net revenues	**4,615**	3,731
Purchases of crude oil and products	**—**	32
Production, operating and transportation expenses	**1,650**	1,760
Selling, general and administrative expenses	**265**	232
Depletion, depreciation, amortization and impairment ("DD&A")	**2,237**	1,815
Exploration and evaluation expenses	**146**	188
Gain on sale of assets	**(42)**	(192)
Other – net	**6**	53
Share of equity investment (gain) loss	**(12)**	1
Financial items	**126**	140
Provisions for (recovery) of income taxes	**65**	(81)
Net earnings (loss)	**174**	(217)

Exploration and Production net revenues increased by $884 million in 2017 compared to 2016, primarily due to higher realized global commodity prices combined with increased production from the Company's thermal development projects and increased production in Asia Pacific. The increase was partially offset by lower oil and natural gas production in Western Canada due to the disposition of select legacy assets in 2016 and 2017.

Selling, general and administrative expenses increased by $33 million in 2017 compared to 2016 primarily due to an increase in employee costs and contract services.

Gain on sale of assets decreased by $150 million in 2017 compared to 2016 primarily due to the decrease in asset dispositions in 2017.

Provisions for income taxes increased by $146 million in 2017 compared to 2016 primarily due to higher earnings before income taxes in 2017 compared to 2016.

Average Sales Prices Realized

Average Sales Prices Realized	2017	2016
Crude oil and NGL *($/bbl)*		
Light & Medium crude oil	**67.36**	52.40
NGL	**44.18**	38.01
Heavy crude oil	**43.38**	30.50
Bitumen	**38.20**	27.63
Total crude oil and NGL average	**46.09**	35.78
Natural gas average *($/mcf)* [1]	**5.52**	4.40
Total average *($/boe)*	**42.47**	33.08

(1) *Reported average natural gas prices include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

The average sales prices realized by the Company for crude oil and NGL production increased by 29 percent in 2017 compared to 2016, reflecting an increase in global crude oil benchmarks.

The average sales prices realized by the Company for natural gas increased by 25 percent in 2017 compared to 2016. The increase was primarily due to a higher percentage of fixed-priced natural gas production from the Liwan and BD gas projects relative to total natural gas production.

Daily Gross Production

Daily Gross Production	2017	2016
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light & Medium crude oil	**12.1**	23.4
NGL	**10.5**	8.0
Heavy crude oil	**44.4**	54.1
Bitumen[1]	**119.1**	97.4
	186.1	182.9
Atlantic		
White Rose and satellite extensions – light crude oil	**30.0**	28.8
Terra Nova – light crude oil	**4.0**	4.3
	34.0	33.1
Asia Pacific		
Wenchang – light crude oil	**5.3**	6.6
Liwan and Wenchang – NGL[2]	**7.0**	6.0
Madura – NGL[3]	**0.6**	—
	12.9	12.6
	233.0	228.6
Natural gas *(mmcf/day)*		
Western Canada	**378.2**	442.4
Asia Pacific		
Liwan[2]	**152.9**	113.5
Madura[3]	**8.0**	—
	160.9	113.5
	539.1	555.9
Total *(mboe/day)*	**322.9**	321.2

(1) *Bitumen consists of production from thermal developments in Lloydminster, the Tucker Thermal Project located near Cold Lake, Alberta and the Sunrise Energy Project.*
(2) *Reported production volumes include Husky's working interest production from the Liwan Gas Project (49 percent).*
(3) *Reported production volumes include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

Crude Oil and NGL Production

Crude oil and NGL production increased by 4.4 mbbls/day, or two percent, in 2017 compared to 2016. The increase was primarily due to the continued production ramp-up at the Sunrise Energy Project, new production from the Edam West, Vawn and Edam East thermal developments, and increased NGL production in Asia Pacific and Western Canada. This was partially offset by lower crude oil production from Western Canada due to the disposition of select legacy assets in 2016 and 2017.

Natural Gas Production

Natural gas production decreased by 16.8 mmcf/day, or three percent, in 2017 compared to 2016. In Western Canada, natural gas production decreased by 64.2 mmcf/day, primarily due to the disposition of select legacy assets during 2016 and 2017, natural reservoir declines from mature properties and strategic shut-ins due to unfavourable economics. In Asia Pacific, natural gas production increased by 47.4 mmcf/day, primarily due to increased gas demand at the Liwan Gas Project and new production from the BD Project in 2017.

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	**2017**	2016
Crude oil and NGL		
Light & Medium crude oil	**25%**	32%
NGL	**6%**	5%
Heavy crude oil	**14%**	15%
Bitumen	**33%**	25%
Crude oil and NGL	**78%**	77%
Natural gas	**22%**	23%
Total	**100%**	100%

2018 Production Guidance and 2017 Actual

	Guidance	**Year ended December 31**	Guidance
Gross Production	2018	**2017**	2017
Canada			
Light & Medium crude oil *(mbbls/day)*	46 - 49	**46**	46 - 48
NGL *(mbbls/day)*	10 - 11	**10**	8 - 9
Heavy crude oil & bitumen *(mbbls/day)*	174 - 181	**164**	167 - 173
Natural gas *(mmcf/day)*	280 - 290	**378**	345 - 353
Canada total *(mboe/day)*	277 - 289	**283**	278 - 288
Asia Pacific			
Light crude oil *(mbbls/day)*	0 - 0	**5**	5 - 6
NGL *(mbbls/day)*	10 - 11	**8**	8 - 10
Natural gas *(mmcf/day)*(1)	200 - 210	**161**	171 - 182
Asia Pacific total *(mboe/day)*	43 - 46	**40**	42 - 46
Total *(mboe/day)*	320 - 335	**323**	320 - 335

(1) *Includes Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.*

Total production for the year ended December 31, 2017 was within the production guidance. The expected total production volumes in 2018 will remain comparable to 2017 after factoring in the Western Canada dispositions during the year. The 2018 production guidance reflects the ramp up of the Tucker Thermal Project, Sunrise Energy Project, and BD Project. The increases are anticipated to be offset by continued natural declines from mature properties in Atlantic and Western Canada, and decline in light crude oil production from Asia Pacific, as the PSC for the Wenchang field expired in 2017.

Factors that could potentially impact the Company's production performance in 2018 include, but are not limited to:

- changes in crude oil and natural gas prices such as increases in commodity pricing, which may result in the decision to accelerate near-term growth projects, or decreases in commodity pricing, which may result in the decision to temporarily shut-in production or delay capital expenditures.
- performance of recently commissioned facilities, new wells brought onto production and unanticipated reservoir response from existing fields.
- potential divestment of certain producing crude oil or natural gas properties in Western Canada.
- unplanned or extended maintenance and turnarounds at any of the Company's operated or non-operated facilities, upgrading, refining, pipeline or offshore assets.
- business interruptions due to unexpected events such as severe weather, fires, blowouts, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events.
- defaults by contracting parties whose services, goods or facilities are necessary for the Company's production.
- operations and assets which are subject to a number of political, economic and socio-economic risks.

Royalties

Royalty rates as a percentage of gross revenues averaged seven percent in 2017 compared to eight percent in 2016. Royalty rates in Western Canada averaged seven percent in both 2017 and 2016. Royalty rates in Atlantic averaged nine percent in 2017 compared to 15 percent in 2016, primarily due to production shifting to lower rate fields in 2017 combined with higher eligible costs. Royalty rates in Asia Pacific averaged six percent in both 2017 and 2016.

Operating Costs

Operating Costs *($ millions)*	**2017**	2016
Western Canada	**1,331**	1,413
Atlantic	**213**	224
Asia Pacific	**94**	92
Total	**1,638**	1,729
Per unit operating costs *($/boe)*	**13.93**	14.04

Total Exploration and Production operating costs were $1,638 million in 2017 compared to $1,729 million in 2016. Total Upstream unit operating costs averaged $13.93/boe in 2017 compared to $14.04/boe in 2016 with the decrease primarily attributable to lower unit operating costs per boe in Atlantic and Asia Pacific.

Per unit operating costs in Western Canada averaged $14.67/boe in 2017 compared to $14.21/boe in 2016. The increase in unit operating costs per boe was primarily attributable to higher energy costs and lower production in 2017, partially offset by cost savings initiatives realized in 2017.

Per unit operating costs in Atlantic averaged $17.12/boe in 2017 compared to $18.48/boe in 2016. The decrease in unit operating costs per boe was primarily due to higher production and lower subsea maintenance costs in 2017.

Per unit operating costs in Asia Pacific averaged $6.47/boe in 2017 compared to $8.01/boe in 2016. The decrease in unit operating costs per boe was primarily attributable to higher production at the Liwan Gas Project and cost saving initiatives.

Exploration and Evaluation Expenses

Exploration and Evaluation Expenses *($ millions)*	**2017**	2016
Seismic, geological and geophysical	**113**	78
Expensed drilling	**22**	66
Expensed land	**11**	44
Total	**146**	188

Exploration and evaluation expenses were $146 million in 2017 compared to $188 million in 2016. The increase in seismic, geological and geophysical expense of $35 million was primarily due to increased seismic operations in Asia Pacific. The decrease in expensed drilling was primarily attributable to lower daily drilling rates for the two unsuccessful exploration wells in the Flemish Pass in 2017 relative to 2016. The decrease in expensed land was primarily attributable to the 2016 pre-tax write off of $35 million of land in Western Canada.

Depletion, Depreciation, Amortization and Impairment

DD&A expense increased by $422 million in 2017 compared to 2016 primarily due to the recognition of a pre-tax impairment charge of $173 million on assets located in Western Canada due to changes in development plans and reinforced by market transactions in 2017. In 2016, the Company recognized a net pre-tax impairment reversal of $261 million on assets located in Western Canada due to the acceleration of forecasted production and revised operational economics, based on recent production performance and market transactions. In 2017, total DD&A excluding impairment averaged $17.61/boe compared to $17.67/boe in 2016.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were higher in 2017 compared to 2016 reflecting increased investment in thermal developments, Atlantic and Western Canada. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures(1) *($ millions)*	**2017**	2016
Exploration		
Western Canada	**63**	18
Thermal developments	**8**	6
Atlantic	**67**	18
Asia Pacific(2)	**10**	4
	148	46
Development		
Western Canada	**196**	116
Thermal developments	**534**	312
Non-thermal developments	**106**	51
Atlantic	**417**	226
Asia Pacific(2)	**2**	114
	1,255	819
Acquisitions		
Western Canada	**25**	—
Thermal developments	**48**	7
	73	7
	1,476	872

(1) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(2) *Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

Western Canada

During 2017, $284 million (19 percent) was invested in Western Canada compared to $134 million (15 percent) in 2016. Capital expenditures in 2017 related primarily to resource play development drilling targeting the Spirit River formation in the Ansell and Kakwa areas and the Montney formation in the Karr and Wembley areas.

Thermal Developments

During 2017, $590 million (40 percent) was invested in thermal developments compared to $325 million (37 percent) in 2016. Capital expenditures in 2017 related primarily to the Rush Lake 2 thermal development, a new 15-well pad at the Tucker Thermal Project and continued investment in the Sunrise Energy Project.

Non-Thermal Developments

During 2017, $106 million (seven percent) was invested in non-thermal developments compared to $51 million (six percent) in 2016. Capital expenditures in 2017 related primarily to sustainment activities.

Atlantic

During 2017, $484 million (33 percent) was invested in Atlantic compared to $244 million (28 percent) in 2016. Capital expenditures in 2017 related primarily to satellite extension developments at North Amethyst, the South White Rose Extension and the West White Rose Project as well as delineation drilling northwest of the main White Rose field.

Asia Pacific

During 2017, $12 million (one percent) was invested in Asia Pacific compared to $118 million (14 percent) in 2016. The decrease in capital expenditures in 2017 compared to 2016 reflects the installation of a second deepwater production pipeline at Liwan Gas Project in 2016.

Exploration and Production Wells Drilled

Onshore Drilling Activity

The following table discloses the number of wells drilled in thermal developments, non-thermal developments and Western Canada during 2017 and 2016:

	2017		2016	
Wells Drilled *(wells)*[1]	Gross	Net	Gross	Net
Thermal developments[2]	**64**	**64**	70	70
Non-thermal developments	**29**	**27**	5	5
Western Canada	**36**	**33**	3	2
	129	**124**	78	77

[1] *Excludes service/stratigraphic test wells for evaluation purposes.*
[2] *Includes producer and injector wells.*

Thermal developments consisted of drilling and completion activity related to the Rush Lake 2 development and a new 15-well pad at the Tucker Thermal Project. Western Canada drilling and completion activity increased due to the 16-well program targeting the Spirit River formation in the Ansell and Kakwa areas, as well as a drilling program targeting the Montney formation in the Karr and Wembley areas.

Offshore Drilling Activity

The following table discloses the Company's offshore drilling activity during 2017:

Region	Well	Working Interest	Well Type
Atlantic	North Amethyst G-25 10	68.875 percent	Development
Atlantic	South White Rose J-05 5	68.875 percent	Development
Atlantic	South White Rose J-05 7	72.500 percent	Development
Atlantic	White Rose A-78	93.232 percent	Exploration
Atlantic	Bonaventure O-96	35 percent	Exploration
Atlantic	Portugal Cove E-38	35 percent	Exploration

2018 Upstream Capital Expenditures Program

2018 Upstream Capital Expenditures Program *($ millions)*	
Thermal developments	**895 - 930**
Non-thermal developments	**85 - 90**
Western Canada	**270 - 285**
Atlantic	**750 - 775**
Asia Pacific[1]	**130 - 150**
Total Upstream capital expenditures	**2,130 - 2,230**

[1] *Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

The 2018 Upstream capital expenditures program reflects a focus on short and medium-cycle projects in the Integrated Corridor business, including further growing the Lloyd thermal bitumen portfolio and the Ansell resource play in Western Canada. In the Offshore business, the capital expenditures program will support the start of construction at the Liuhua 29-1 field offshore China and the West White Rose Project in Atlantic.

The Company has budgeted $895 - $930 million in thermal developments for 2018, primarily for the development of Rush Lake 2, Dee Valley, Spruce Lake North and Spruce Lake Central. Capital expenditures will also take place in support of environmental and regulatory work on Westhazel and Edam Central, which were projects sanctioned in the fourth quarter of 2017. The Company is making progress in its strategy to transition a greater percentage of production to long-life thermal bitumen production and the 2018 Upstream capital expenditures program will continue to build on this momentum.

The Company has budgeted $85 - $90 million in non-thermal developments for 2018, primarily for sustainment activities.

The Company has budgeted $270 - $285 million in Western Canada for 2018, primarily for the planned drilling activities in the Spirit River formation in the Ansell and Kakwa areas as well as the Montney formation.

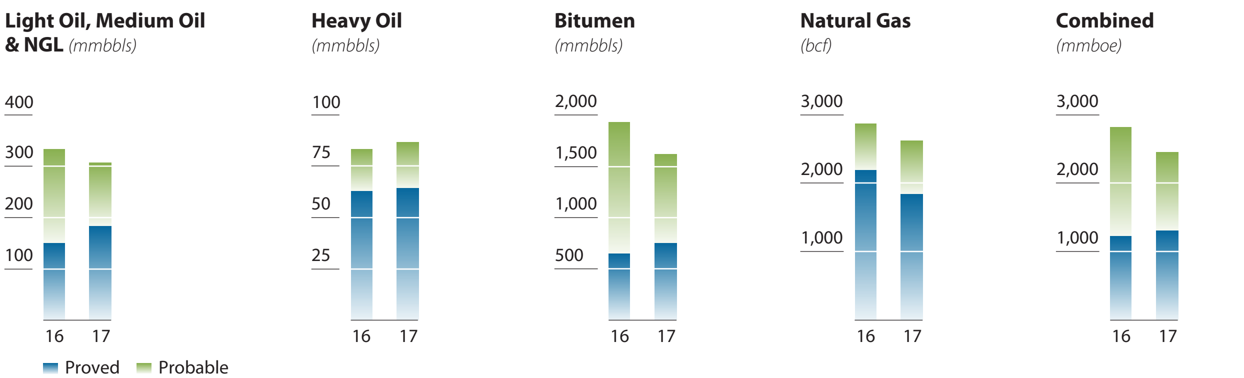
The Company has budgeted $750 - $775 million in Atlantic for 2018, primarily for the construction of the West White Rose Project.

The Company has budgeted $130 - $150 million in Asia Pacific in 2018, primarily for the continued development of the third field of the Liwan Gas Project, Liuhua 29-1.

Oil and Gas Reserves

The Company's reserves disclosure was prepared in accordance with Canadian Securities Administrators' National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") effective December 31, 2017 with a preparation date of January 31, 2018.

Proved and Probable Reserves at December 31:



Note: All Lloydminster thermal reserves are classified as bitumen.

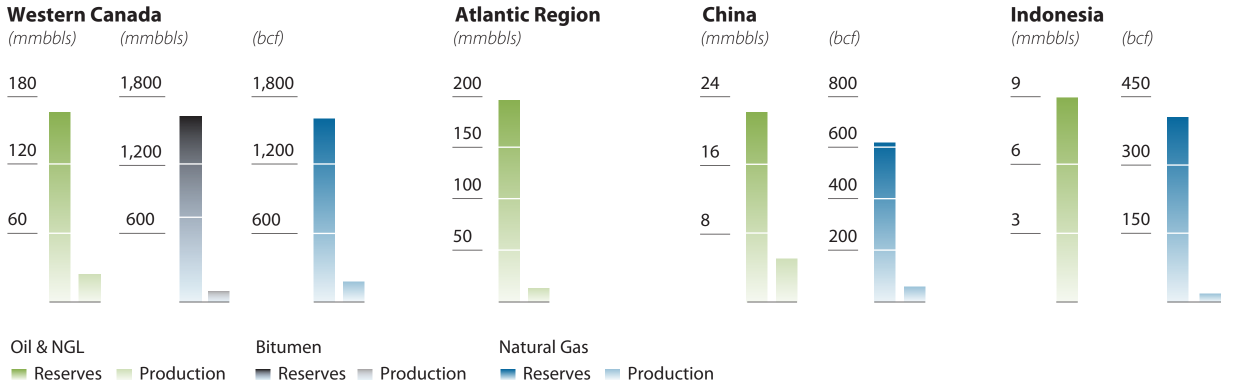
The Company's complete oil and gas reserves disclosure, prepared in accordance with NI 51-101 is contained in the Company's Annual Information Form, which is available at www.sedar.com, and certain supplementary oil and gas reserves disclosure prepared in accordance with U.S. disclosure requirements is contained in the Company's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com.

Sproule Associates Ltd. ("Sproule"), an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit of the Company's crude oil, natural gas and NGL reserves estimates. Sproule issued an audit opinion on January 31, 2018. stating that the Company's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions are, in aggregate, reasonable and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the Canadian Oil and Gas Evaluation Handbook.

At December 31, 2017, the Company's proved oil and gas reserves were 1,301 mmboe, compared to 1,224 mmboe at the end of 2016. The Company's 2017 reserves replacement ratio, defined as net additions divided by total production during the period, was 167 percent excluding economic revisions (165 percent including economic revisions). The 2017 reserves replacement ratio, excluding disposition/acquisition and economic factors, was 219 percent (217 percent including economic factors). Major changes to proved reserves in 2017 included:

- The disposition of Western Canada assets resulted in a total divestiture of 62 mmboe.
- Extensions and improved recovery additions of 220 mmbbls including 109 mmbbls for three new Lloyd thermal bitumen SAGD projects, 65 mmbbls with the sanctioning of the West White Rose Project, 27 mmbbls at the Sunrise Energy Project from new locations, and 14 mmboe in Ansell from new locations.
- Technical revisions of 36 mmboe including 12 mmboe in China due to strong gas performance, 20 mmbbls from improved CHOPS performance and Lloyd thermal bitumen performance additions of 3 mmbbls offset by negative performance of 6 mmboe for wells or facilities close to the end of their economic lives.

Proved Plus Probable Reserves and Production at December 31, 2017:



Reconciliation of Proved Reserves

	Canada					International		Total		
	Western Canada				Atlantic					
(forecast prices and costs before royalties)	Light/ Medium Crude Oil & NGL *(mmbbls)*	Heavy Crude Oil *(mmbbls)* [(1)]	Bitumen *(mmbbls)*[(1)]	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved reserves										
December 31, 2016	79	63	648	1,517	47	23	668	860	2,185	1,224
Technical revisions	4	17	6	—	(3)	3	53	27	53	36
Acquisitions	—	—	—	1	—	—	—	—	1	—
Dispositions	(12)	(1)	—	(294)	—	—	—	(13)	(294)	(62)
Discoveries, extensions and improved recovery	3	1	137	97	65	—	—	206	97	222
Economic factors	—	—	—	(9)	—	—	—	—	(9)	(2)
Production	(8)	(16)	(44)	(138)	(12)	(5)	(59)	(85)	(197)	(118)
Proved reserves December 31, 2017	**66**	**64**	**747**	**1,174**	**97**	**21**	**662**	**995**	**1,836**	**1,301**
Proved and probable reserves December 31, 2017	**80**	**86**	**1,609**	**1,597**	**196**	**31**	**1,014**	**2,002**	**2,611**	**2,437**
December 31, 2016	95	83	1,923	1,940	207	29	926	2,337	2,866	2,815

(1) *Lloydminster thermal property reserves are classified as bitumen.*

Reconciliation of Proved Developed Reserves

	Canada					International		Total		
	Western Canada				Atlantic					
(forecast prices and costs before royalties)	Light/ Medium Crude Oil & NGL *(mmbbls)*	Heavy Crude Oil *(mmbbls)* [(1)]	Bitumen *(mmbbls)*[(1)]	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved developed reserves										
December 31, 2016	75	63	160	1,183	42	23	567	363	1,750	654
Technical revisions	4	18	6	—	(2)	3	53	29	53	38
Transfer from proved undeveloped	1	—	40	55	5	—	—	46	55	55
Acquisitions	—	—	—	1	—	—	—	—	1	—
Dispositions	(12)	(1)	—	(294)	—	—	—	(13)	(294)	(62)
Discoveries, extensions and improved recovery	2	—	—	25	4	—	—	6	25	10
Economic factors	—	—	—	(9)	—	—	—	—	(9)	(2)
Production	(8)	(16)	(44)	(138)	(12)	(5)	(59)	(85)	(197)	(118)
December 31, 2017	**62**	**64**	**162**	**823**	**37**	**21**	**561**	**346**	**1,384**	**575**

(1) *Lloydminster thermal property reserves are classified as bitumen.*

Infrastructure and Marketing

Infrastructure and Marketing Earnings Summary *($ millions, except where indicated)*	**2017**	2016
Gross revenues	**1,976**	955
Purchases of crude oil and products	**1,855**	857
Infrastructure gross margin	**121**	98
Marketing and other	**(40)**	(88)
Total Infrastructure and Marketing gross margin	**81**	10
Production, operating and transportation expenses	**13**	20
Selling, general and administrative expenses	**4**	5
Depletion, depreciation, amortization and impairment	**2**	13
Loss (gain) on sale of assets	**1**	(1,439)
Other – net	**(8)**	(3)
Share of equity investment gain	**(49)**	(16)
Provisions for income taxes	**32**	122
Net earnings	**86**	1,308

Infrastructure and Marketing gross revenues and purchases of crude oil products increased by $1,021 million and $998 million, respectively, in 2017 compared to 2016, primarily due to increased volumes and prices.

Marketing and other loss decreased by $48 million in 2017 compared to 2016 primarily due to crude oil marketing gains from widening price differentials between Canada and the U.S. during 2017. This was partially offset by unrealized crude oil mark-to-market losses as a result of falling forward heavy differentials towards the end of 2017.

The Company recorded a loss on sale of assets of $1 million in 2017 compared to a gain of $1,439 million in 2016. The gain on sale of assets in 2016 was due to the sale of ownership interest in select midstream assets.

Share of equity investment gain increased by $33 million in 2017 compared to 2016 due to the pipeline spill costs incurred in 2016 and the formation of HMLP in mid-2016. Refer to Note 11 of the Consolidated Financial Statements.

Provisions for income taxes decreased by $90 million in 2017 compared to 2016 due to the tax associated with the sale of ownership interest in select midstream assets in 2016.

4.3 Downstream

Upgrading

Upgrading Earnings Summary *($ millions, except where indicated)*	2017	2016
Gross revenues	**1,440**	1,324
Purchases of crude oil and products	**983**	808
Gross margin	**457**	516
Production, operating and transportation expenses	**197**	168
Selling, general and administrative expenses	**9**	4
Depletion, depreciation, amortization and impairment	**99**	103
Other – net	**—**	(1)
Financial items	**1**	1
Provisions for income taxes	**41**	66
Net earnings	**110**	175
Upgrading throughput *(mbbls/day)*[(1)]	**68.5**	72.5
Total sales *(mbbls/day)*	**68.5**	72.8
Synthetic crude oil sales *(mbbls/day)*	**49.8**	55.2
Upgrading differential *($/bbl)*	**18.66**	20.74
Unit margin *($/bbl)*	**18.28**	19.37
Unit operating cost *($/bbl)*[(2)]	**7.88**	6.33

(1) *Throughput includes diluent returned to the field.*
(2) *Based on throughput.*

The Upgrading operations add value by processing heavy crude oil into high value synthetic crude oil and low sulphur distillates. The Upgrading profitability is primarily dependent on the differential between the cost of heavy crude oil feedstock and the sales price of synthetic crude oil.

Gross revenues increased by $116 million in 2017 compared to 2016 primarily due to higher realized prices for synthetic crude oil, partially offset by lower sales volumes resulting from a planned major turnaround in the second quarter of 2017. The price of Husky Synthetic Blend averaged $67.05/bbl in 2017 compared to $57.54/bbl in 2016. Sales volumes decreased by 4.3 mbbls/day, or five percent, and throughput decreased by 4.0 mbbls/day, or six percent, compared to 2016 due to the planned major turnaround in 2017.

Upgrading feedstock purchases increased by $175 million in 2017 compared to 2016 primarily due to higher Lloyd Heavy Blend pricing, which averaged $48.39/bbl in 2017 compared to $36.79/bbl in 2016.

Gross margin decreased by $59 million in 2017 compared to 2016 primarily due to the tightening light/heavy differentials, lowering the average upgrading differentials in 2017. The upgrading differential averaged $18.66/bbl in 2017, a decrease of $2.08/bbl or 10 percent compared to 2016. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend.

Production, operating and transportation expenses increased by $29 million in 2017 compared to 2016 primarily due to higher maintenance, labour and energy costs related to the planned major turnaround in the second quarter of 2017.

Provisions for income taxes decreased by $25 million in 2017 compared to 2016 primarily due to lower earnings before income taxes in 2017.

Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	2017	2016
Gross revenues	**2,787**	2,301
Purchases of crude oil and products	**2,219**	1,770
Gross margin	**568**	531
Fuel	**139**	136
Refining	**174**	123
Asphalt	**201**	217
Ancillary	**54**	55
	568	531
Production, operating and transportation expenses	**256**	241
Selling, general and administrative expenses	**53**	43
Depletion, depreciation, amortization and impairment	**111**	102
Gain on sale of assets	**(5)**	(3)
Other – net	**(1)**	(10)
Financial items	**12**	7
Provisions for income taxes	**38**	41
Net earnings	**104**	110
Number of fuel outlets[1]	**518**	481
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**7.3**	6.6
Fuel sales per outlet *(thousands of litres/day)*	**12.1**	11.8
Refinery throughput		
Prince George Refinery *(mbbls/day)*	**11.2**	9.4
Lloydminster Refinery *(mbbls/day)*	**26.8**	27.8
Ethanol production *(thousands of litres/day)*	**804.8**	820.6

(1) *Average number of fuel outlets for period indicated.*

Canadian Refined Products gross revenues increased by $486 million in 2017 compared to 2016 primarily due to higher commodity pricing, and higher sales volumes at the Prince George Refinery, where a major planned turnaround was completed in 2016. The increase was partially offset by lower throughput volumes at the Lloydminster Refinery, due to a planned turnaround in the second quarter of 2017, and lower asphalt margins due to market oversupply related to weather delays.

Purchases of crude oil and products increased by $449 million in 2017 compared to 2016 primarily due to higher commodity pricing, partially offset by the lower volumes at the Lloydminster Refinery due to a planned turnaround in the second quarter of 2017.

Refining gross margins increased by $51 million in 2017 compared to 2016 primarily due to higher sales volumes at the Prince George Refinery and the Minnedosa Ethanol Plant combined with higher ethanol pricing.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	2017	2016
Gross revenues	**9,355**	5,995
Purchases of crude oil and products	**8,059**	5,188
Gross margin	**1,296**	807
Production, operating and transportation expenses	**563**	535
Selling, general and administrative expenses	**15**	13
Depletion, depreciation, amortization and impairment	**354**	342
Other – net	**(21)**	(176)
Financial items	**14**	3
Provisions for income taxes	**137**	33
Net earnings	**234**	57
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**172.2**	138.2
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**76.6**	62.2
Superior Refinery throughput *(mbbls/day)*[1]	**5.5**	—
Refining margin *(US$/bbl crude throughput)*	**11.09**	8.94
Refinery inventory *(mmbbls)*[2]	**9.2**	10.8

(1) *The Superior Refinery was acquired on November 8, 2017.*
(2) *Feedstock and refined products are included in refinery inventory.*

U.S. Refining and Marketing gross revenues increased by $3,360 million in 2017 compared to 2016. The increase was primarily due to the higher finished goods sales prices and higher sales volume as a result of stronger operations in 2017, and scheduled major turnarounds at both the Lima and BP-Husky Toledo Refineries in 2016.

Purchases of crude oil and products increased by $2,871 million in 2017 compared to 2016 primarily due to higher crude oil feedstock costs and increased throughput at both the Lima and BP-Husky Toledo refineries. Throughput increased at the Lima Refinery by 34.0 mbbls/day and at the BP-Husky Toledo Refinery by 14.4 mbbls/day compared to 2016 primarily due to the planned major turnarounds at both the Lima and BP-Husky Toledo refineries in 2016 and the isocracker at Lima being fully in service in 2017.

Gross margin increased by $489 million in 2017 compared to 2016 primarily due to a higher Chicago 3:2:1 crack spread and higher sales volumes.

Other – net income decreased by $155 million in 2017 compared to 2016 primarily due to reduced insurance recoveries associated with the isocracker unit fire in 2016.

Provisions for income taxes increased by $104 million in 2017 compared to 2016 primarily due to higher earnings before income taxes in 2017.

The Chicago 3:2:1 crack spread benchmark is based on LIFO accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while crude oil feedstock costs included in realized margins are based on FIFO accounting, which reflects purchases made in previous months. The estimated FIFO impact was an increase in net earnings of approximately $58 million in 2017 compared to an increase of $50 million in 2016.

Downstream Capital Expenditures

In 2017, Downstream capital expenditures totalled $630 million compared to $726 million in 2016. The decrease in Downstream capital expenditures was primarily due to the completion of major planned turnarounds at the Lima and BP-Husky Toledo refineries and the feedstock optimization project in U.S. Refining and Marketing in 2016.

In Canada, capital expenditures of $317 million were primarily related to the scheduled major turnarounds at the Lloydminster Upgrader and Lloydminster Refinery in the second quarter of 2017.

In the U.S., capital expenditures of $313 million were primarily related to the crude oil flexibility project and various reliability, safety and environmental protection initiatives at the Lima Refinery. Capital expenditures of $95 million at the BP-Husky Toledo Refinery (Husky working interest) were primarily related to reliability, safety and environmental protection initiatives.

4.4 Corporate

Corporate Summary *($ millions) income (expense)*	**2017**	2016
Selling, general and administrative expenses	**(304)**	(247)
Depletion, depreciation, amortization and impairment	**(79)**	(87)
Other – net	**(6)**	(110)
Net foreign exchange gain (loss)	**(6)**	13
Finance income	**32**	12
Finance expense	**(234)**	(245)
Recovery of income taxes	**675**	153
Net earnings (loss)	**78**	(511)

The Corporate segment reported net earnings of $78 million in 2017 compared to a net loss of $511 million in 2016. Recovery of income taxes increased primarily due to the recognition of $436 million in deferred tax recovery related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018. Selling, general and administrative expenses increased by $57 million in 2017 primarily due to increases in employee costs and stock-based compensation expenses. Other – net expense decreased by $104 million in 2017 relates primarily to losses on the Company's short-term hedging program which concluded in June 2016. Finance income increased by $20 million primarily due to interest on short-term investments. Net foreign exchange gain (loss) decreased by $19 million due to the items noted below.

Foreign Exchange Summary *($ millions, except exchange rate amounts)*	**2017**	2016
Non-cash working capital gain (loss)	**(3)**	4
Other foreign exchange gain (loss)	**(3)**	9
Net foreign exchange gain (loss)	**(6)**	13
U.S./Canadian dollar exchange rates:		
At beginning of year	**US$0.745**	US$0.723
At end of year	**US$0.799**	US$0.745

Included in other foreign exchange gain (loss) are realized and unrealized foreign exchange gains and losses on working capital and intercompany financing. The foreign exchange gains and losses on these items can vary significantly due to the large volume and timing of transactions through these accounts in the period. The Company manages its exposure to foreign currency fluctuations in order to minimize the impact of foreign exchange gains and losses on the Consolidated Financial Statements.

Consolidated Income Taxes

Consolidated Income Taxes *($ millions)*	**2017**	2016
Provisions for (recovery of) income taxes	**(362)**	28
Cash income taxes received	**(41)**	(3)

Consolidated income taxes were a recovery of $362 million in 2017 compared to an income tax expense of $28 million in 2016. The recovery of consolidated income taxes was primarily due to the recognition of $436 million in deferred tax recovery related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018.

5.0 Risk and Risk Management

5.1 Enterprise Risk Management

The Company's enterprise risk management program supports decision-making via comprehensive and systematic identification and assessment of risks that could materially impact the results of the Company. Through this framework, the Company builds risk management and mitigation into strategic planning and operational processes for its business units through the adoption of standards and best practices. The Company has developed an enterprise risk matrix to identify risks to its people, the environment, its assets and its reputation, and to systematically mitigate these risks to an acceptable level.

The Company attempts to mitigate its financial, operational and strategic risks to an acceptable level through a variety of policies, systems and processes. The following provides a list of the most significant risks relating to the Company and its operations.

5.2 Significant Risk Factors

Operational, Environmental and Safety Incidents

The Company's businesses are subject to inherent operational risks with respect to safety and the environment that require continuous vigilance. The Company seeks to minimize these operational risks by carefully designing and building its facilities and conducting its operations in a safe and reliable manner using Husky Operational Integrity Management System, its integrated management system that considers environmental requirements and process and occupational safety. Failure to manage the risks effectively could result in potential fatalities, serious injury, interruptions to activities or use of assets, damage to assets, environmental impact or loss of licence to operate. Enterprise risk management, emergency preparedness, business continuity and security policies and programs are in place for all operating areas and are adhered to on an ongoing basis. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

Commodity Price Volatility

The Company's results of operations and financial condition are dependent on the prices received for its refined products, crude oil, NGL and natural gas production. Lower prices for crude oil, NGL and natural gas could adversely affect the value and quantity of the Company's oil and gas reserves. The Company's reserves include significant quantities of heavier grades of crude oil that trade at a discount to light crude oil. Heavier grades of crude oil are typically more expensive to produce, process, transport and refine into high value refined products. Refining and transportation capacity for heavy crude oil and bitumen is limited and planned increases of North American heavy crude oil and bitumen production may create the need for additional heavy oil and bitumen refining and transportation capacity. Wider price differentials between heavier and lighter grades of crude oil could have a material adverse effect on the Company's results of operations and financial condition, reduce the value and quantities of the Company's heavier crude oil reserves and delay or cancel projects that involve the development of heavier crude oil resources. There is no guarantee that pipeline development projects will provide sufficient transportation capacity and access to refining capacity to accommodate expected increases in North American heavy crude oil and bitumen production.

Prices for refined products and crude oil are based on world supply and demand. Supply and demand can be affected by a number of factors including, but not limited to, actions taken by OPEC, non-OPEC crude oil supply, social conditions in oil producing countries, the occurrence of natural disasters, general and specific economic conditions, technological developments, prevailing weather patterns, government regulation and policies and the availability of alternate sources of energy.

The Company's natural gas production is currently located in Western Canada and Asia Pacific. Western Canada's natural gas production is subject to North American market forces. North American natural gas supply and demand is affected by a number of factors including, but not limited to, the amount of natural gas available to specific market areas either from the well head of existing or accessible conventional or unconventional sources (such as from shale), or from storage facilities, technological developments, prevailing weather patterns, the U.S. and Canadian economies, the occurrence of natural disasters and pipeline restrictions.

In certain instances, the Company will use derivative instruments to manage exposure to price volatility on a portion of its refined product, oil and gas production, inventory or volumes in long-distance transit. The Company may also use firm commitments for the purchase or sale of crude oil and natural gas.

The fluctuations in refined products, crude oil and natural gas prices are beyond the Company's control and could have a material adverse effect on the Company's results of operations and financial condition.

Reservoir Performance Risk

Lower than projected reservoir performance on the Company's key growth projects could have a material adverse effect on the Company's results of operations, financial condition, business strategy and reserves. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and negatively affect the Company's reputation, investor confidence and the Company's ability to deliver on its growth strategy.

In order to maintain the Company's future production of crude oil, natural gas and NGL and maintain the value of the reserves portfolio, additional reserves must be added through discoveries, extensions, improved recovery, performance related revisions and acquisitions. The production rate of oil and gas properties tends to decline as reserves are depleted while the associated unit operating costs increase. In order to mitigate the effects of this, the Company must undertake successful exploration and development programs, increase the recovery factor from existing properties through applied technology and identify and execute strategic acquisitions of proved developed and undeveloped properties and unproved prospects. Maintaining an inventory of projects that can be developed depends upon, but is not limited to, obtaining and renewing rights to explore, develop and produce oil and natural gas, drilling success, completion of long lead time capital intensive projects on budget and on schedule and the application of successful exploitation techniques on mature properties.

Restricted Market Access and Pipeline Interruptions

The Company's results depend upon the Company's ability to deliver products to the most attractive markets. The Company's results of operations could be materially adversely affected by restricted market access resulting from a lack of pipeline or other transportation alternatives to attractive markets as well as regulatory and/or other marketplace barriers. Interruptions and restrictions may be caused by the inability of a pipeline to operate, or they can be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. With growing oil production across North America and the limited availability of infrastructure to carry the Company's products to the marketplace, oil and natural gas transportation capacity is expected to be restricted in the next few years. Restricted market access may potentially have a material adverse effect on the Company's results of operations, financial condition and business strategy. Unplanned shutdowns and closures of its refineries or Upgrader may limit the Company’s ability to deliver product with a material adverse effect on sales and results of operations.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact the Company’s personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or activist incident targeted at a facility, office or offshore vessel/installation owned or operated by the Company could result in the interruption or cessation of key elements of the Company's operations. Outcomes of such incidents could have a material adverse effect on the Company’s results of operations, financial condition and business strategy.

International Operations

International operations can expose the Company to uncertain political, economic and other risks. The Company's operations in certain jurisdictions may be materially adversely affected by political, economic or social instability or events. These events may include, but are not limited to, onerous fiscal policy, renegotiation or nullification of agreements and treaties, imposition of onerous regulation, changes in laws governing existing operations, financial constraints, including currency restrictions and exchange rate fluctuations, unreasonable taxation and behaviour of public officials, joint venture partners or third-party representatives that could result in lost business opportunities for the Company. This could materially adversely affect the Company's interest in its foreign operations, results of operations and financial condition.

Major Project Execution

The Company manages a variety of oil and gas projects ranging from Upstream to Downstream assets. The risks associated with project development and execution include, among others, the Company’s ability to obtain necessary environmental and regulatory approvals. This may result in extended stakeholder consultation, environmental assessments and public hearings. Additionally, there are risks involved with commissioning and integration of new assets to existing facilities. All of these and other risks can impact the economic feasibility of the Company's projects. Project risks can manifest through cost overruns, schedule delays and commodity price decreases. Some project risks can impact the Company’s safety and environmental records thereby negatively affecting the Company’s reputation.

Litigation, Administrative Proceedings and Regulatory Actions

The Company may be subject to litigation, claims, administrative proceedings and regulatory actions, which may be material. Such claims could relate to environmental damage, failure to comply with applicable laws and regulations, breach of contract, tax, bribery and employment matters, which could result in an unfavourable decision, including fines, sanctions, monetary damages, temporary suspensions of operations or the inability to engage in certain operations or transactions. The outcome of such claims can be difficult to assess or quantify and may have a material adverse effect on the Company’s reputation, financial condition and results of operations. The defence to such claims may be costly and could divert management’s attention away from day-to-day operations.

Partner Misalignment

Joint venture partners operate a portion of the Company's assets in which the Company has an ownership interest. This can reduce the Company's control and ability to manage risks. The Company is at times dependent upon its partners for the successful execution of various projects. If a dispute with partners were to occur over the development and operation of a project or if partners were unable to fund their contractual share of the capital expenditures, a project could be delayed and the Company could be partially or totally liable for its partner's share of the project.

Reserves Data, Future Net Revenue and Resource Estimates

The reserves data contained or referenced in the MD&A represent estimates only. The accurate assessment of oil and gas reserves is critical to the continuous and effective management of the Company's Upstream assets. Reserves estimates support various investment decisions about the development and management of oil and gas properties. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flow therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the effects of regulation by government agencies, including with respect to royalty payments, all of which may vary considerably from actual results. The Company uses all available information at the effective date of the evaluation and qualified reserves evaluators to prepare the reserves estimates. The Company also has a number of quality control measures in its reserves process including seeking the opinion of an independent reserves auditor on the Company's reserves. However, given the best technical information and evaluation techniques, all such estimates are still to some degree uncertain. All reserves estimates involve a degree of ambiguity and, at times, rely on indirect measurement techniques to estimate the size and recoverability of the resource. While new technologies have increased the accuracy of these techniques, there remains the potential for human or systemic error in recording and reporting the magnitude of the Company's oil and gas reserves. Estimates of the economically recoverable oil and gas reserves attributable to any particular property or group of properties, and estimates of future net revenues expected therefrom, may differ substantially from actual results even though the total company reserves are shown to be reliable through the historical total company technical reserves revisions. The Company has a diverse portfolio of assets by product type, reservoir type and location which is a factor in mitigating specific property risks. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and could have a material adverse effect on the Company's reputation, investor confidence and ability to deliver on its growth business strategy.

Government Regulation

Given the scope and complexity of the Company's operations, the Company is subject to regulation and intervention by governments at the federal, provincial, state and municipal levels in the countries in which it conducts its operations, development or exploratory activities. As these governments continually balance competing demands from different interest groups and stakeholders, the Company recognizes that the magnitude of regulatory risks has the potential to change over time. Changes in government policy, legislation or regulation could impact the Company's existing and planned projects as well as impose costs of compliance and increase capital expenditures and operating expenses. Examples of the Company's regulatory risks include, but are not limited to, uncertain or negative interactions with governments, uncertain energy policies, uncertain climate policies, uncertain environmental and safety policies, penalties, taxes, royalties, government fees, reserves access, limitations or increases in costs relating to the exportation of commodities, restrictions on the acquisition of exploration and production rights and land tenure, expropriation or cancellation of contract rights, limitations on control over the development and abandonment of fields and loss of licences to operate.

Environmental Regulation

Changes in environmental regulation could have a material adverse effect on the Company's results of operations, financial condition and business strategy by requiring increased capital expenditures and operating costs or by impacting the quality, formulation or demand of products, which may or may not be offset through market pricing.

The Company anticipates further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, increased compliance costs and approval delays for critical licences and permits, which could have a material adverse effect on the Company's results of operations, financial condition and business strategy through increased capital and operating costs.

Climate Change Regulation

Climate change regulations may become more onerous over time as governments implement policies to further reduce greenhouse gases ("GHG") emissions. As part of long range planning, the Company assesses future costs associated with regulation of GHG emissions in its operations and the evaluation of future projects, based on the Company's outlook for carbon pricing under current and pending regulations. Although the impact of emerging regulations is uncertain, they could have a material adverse effect on the Company's financial condition and results of operation through increased capital and operating costs and change in demand for refined products such as transportation fuels. The Company continues to monitor international and domestic efforts to address climate change, including international low carbon fuel standards and regulations and other emerging regulations in the jurisdictions in which the Company operates.

The Alberta Climate Leadership Plan began to be implemented in 2017. This plan includes an economy-wide carbon levy, rising to $30 per tonne in 2018 which applies to the Lloydminster Refinery as well as a Carbon Competitiveness Incentive Regulation ("CCIR") that will manage emissions at large final emitting facilities ("LFEs") including the Tucker Thermal Project and Sunrise Energy Project. Under the Specified Gas Emitters Regulation, which expired at the end of 2017, the Tucker Thermal Project generated over 250,000 tonnes of credits due to improved emission intensity performance. These credits are eligible to offset future compliance obligations under the CCIR. These regulations are not anticipated to have a material impact over the duration of the Company's five year long range plan. The CCIR is due for review in 2020, along with the federal "backstop". Uncertainty regarding future regulation, including carbon price and the details of implementing the oil sands emission limit, make it difficult to predict the potential future impact on the Company.

Saskatchewan's "Prairie Resilience" policy paper, released in December 2017, includes a number of proposals related to climate change including a performance standard for facilities which emit over 25kt of carbon dioxide equivalent each year. This would include the Company's Lloydminster Upgrader, ethanol plant and thermal projects. Climate change regulations are expected to be developed in 2018 and may materially adversely affect the Company's results of operations in the province. The impact on the Company is unknown at this time.

The cost of compliance with British Columbia's $30 per tonne carbon tax (increasing to $35 per tonne on April 1, 2018) and the Renewable and Low Carbon Fuel Requirements Regulation may materially adversely affect the Company's Prince George Refinery. Additionally, future regulations in support of British Columbia's commitment under its Climate Leadership Plan are uncertain.

Consultation continues regarding Manitoba's Climate and Green Plan with implementation expected in 2018. Resulting regulations are not yet certain but may materially adversely affect the Company's Minnedosa ethanol plant in Manitoba

Climate change regulations for the NL offshore are currently being developed as part of a consultation process involving the four offshore operators via Canadian Association of Petroleum Producers ("CAPP"). These regulations will have to meet equivalency standards with the Government of Canada. The details of the regulations are not yet known, and so the impact on the Company's operations offshore of NL is uncertain. Note that the Government of NL currently has no jurisdiction to regulate offshore GHG emissions, but discussions are underway to amend the Atlantic Accord to give NL jurisdiction to regulate offshore GHG emissions.

Within the mandate of the Pan-Canadian Framework on Clean Growth and Climate Change, in May 2017, the Government of Canada released a technical paper on the federal Carbon Pricing Backstop introducing two key elements: a carbon levy applied to gas that the Company uses at its facilities as well as retail fuel ($10 per tonne starting in 2018 and increasing by $10 annually to $50 per tonne in 2022), and an output-based pricing system for industrial facilities emitting GHGs above 50 kt per year. A federal Clean Fuel Standard Discussion Paper was also released in 2017. The impact of the Clean Fuel Standard is still uncertain.

The Company's U.S. refining business may be materially adversely affected by the implementation of the Environmental Protection Agency's ("EPA") climate change rules or, by future U.S. GHG legislation that applies to the oil and gas industry or the consumption of petroleum products and by other U.S. climate change statutes at the federal or state level or by regulations imposed by other federal agencies or at the state or local level. Such legislation or regulation could require the Company's U.S. refining operations to significantly reduce emissions and/or purchase emission credits, thereby increasing operating and capital costs, and could change the demand for refined products which may have a material adverse effect on the Company's financial condition and results of operation.

The U.S. Renewable Fuel Standard ("RFS") program, through the U.S. EPA specified renewable volume obligation ("RVO"), requires refiners to add annually increasing amounts of renewable fuels to their petroleum products or to purchase RINs in lieu of such blending. Due to regulatory uncertainty and in part due to the U.S. fuel supply reaching the "blend wall" (the 10 percent limit prescribed by most automobile warranties), the price and availability of RINs has been volatile.

The Company complies with the RFS program in the U.S. by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market. The Company cannot predict the future prices of RINs and renewable fuel blendstocks, and the costs to obtain the necessary RINs and blendstocks could be material. The Company's financial position and results of operations could be adversely affected if it is unable to pass the costs of compliance on to its customers and if the Company pays significantly higher prices for RINs or blendstocks to comply with the RFS mandated standards.

Competition

The energy industry is highly competitive with respect to gaining access to the resources required to increase oil and gas reserves and production, and gaining access to markets. The Company competes with others to acquire prospective lands, retain drilling capacity and field operating and construction services, obtain sufficient pipeline and other transportation capacity, gain access to and retain adequate markets for its products and services and gain access to capital markets. The Company's ability to successfully complete development projects could be materially adversely affected if it is unable to acquire economic supplies and services due to competition. Subsequent increases in the cost of or delays in acquiring supplies and services could result in uneconomic projects. The Company's competitors comprise all types of energy companies, some of which have greater resources.

General Economic Conditions

General economic conditions may have a material adverse effect on the Company's results of operations and financial condition. A decline in economic activity will reduce demand for petroleum products and adversely affect the price the Company receives for its commodities. The Company's cash flow could decline, assets could be impaired, future access to capital could be restricted and major development projects could be delayed or abandoned.

Cost or Availability of Oil and Gas Field Equipment

The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at reasonable prices. Without compromising safety, overall quality and environmental impacts, the Company continually develops its approved suppliers base to provide undisrupted access to materials, equipment and services, while maintaining a competitive cost baseline via cost escalation mitigation strategies.

Climatic Conditions

Extreme climatic conditions may have material adverse effects on financial condition and results of operations. Weather and climate affect demand, and therefore, the predictability of the demand for energy is affected to a large degree by the predictability of weather and climate. In addition, the Company's exploration, production and construction operations, and the operations of major customers and suppliers, can be affected by extreme weather. This may result in cessation or diminishment of production, delay of exploration and development activities or delay of plant construction.

The Company operates in some of the harshest environments in the world, including offshore in Atlantic. Climate change may increase the frequency of severe weather conditions in these locations including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased creation of icebergs. Icebergs off the coast of NL may threaten offshore oil production facilities, cause damage to equipment and possible production disruptions, spills, asset damage and human impacts. The Company has in place a number of policies to protect people, equipment and the environment in the event of extreme weather conditions and ice melt conditions.

The Company's Atlantic operations has a robust ice management program, which uses a range of resources including a dedicated ice surveillance aircraft, as well as synergistic relationships with government agencies including Environment and Climate Change Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commence in February and continue until the risk has abated. In addition, Atlantic operators employ a series of supply and support vessels to actively manage ice and icebergs. These vessels are equipped with a variety of ice management tools including towing ropes, towing nets and water cannons. The Company also maintains a series of ad-hoc relationships with contractors, allowing the quick mobilization of additional resources as required. The Company regularly assesses all aspects of its ice management program in order to ensure that the program continues to evolve as more information about the characteristics of ice and icebergs in the Atlantic becomes available and as new technologies are developed.

Financial Controls

While the Company has determined that its disclosure controls and procedures and internal controls over financial reporting are effective, such controls can only provide reasonable assurance with respect to financial statement preparation and disclosure. Failure to prevent, detect and correct misstatements could have a material adverse effect on the Company's results of operations and financial condition.

Cybersecurity Threats

As an oil and gas producer, the Company's ability to operate effectively is dependent upon developing and maintaining information systems and infrastructure that support the financial and general operating aspects of the business. Concurrently, the oil and gas industry has become the subject of increased levels of cybersecurity threats.

The Company has security measures, policies and controls designed to protect and secure the integrity of its information technology systems. The Company takes a proactive approach by continuing to invest in technology, processes and people to help minimize the impact of the changing cyber landscape and enhance the Company's resilience to cyber incidents. However, cybersecurity threats frequently change and require ongoing monitoring and detection capabilities. Such cybersecurity threats include unauthorized access to information technology systems due to hacking, viruses and other causes for purposes of misappropriating assets or sensitive information, corrupting data or causing operational disruption. Cyber-attacks could result in the loss or exposure of confidential information related to retail credit card information, personnel files, exploration activities, corporate actions, executive officer communications and financial results. The significance of any such event is difficult to quantify, but if the breach is material in nature, it could adversely affect the financial performance of the Company, its operations, its reputation and standing and expose it to regulatory consequences and claims of third-party damage, all of which could materially adversely affect the Company's results of operations and financial condition if the situation is not resolved in a timely manner, or if the financial impact of such adverse effects is not alleviated through insurance policies.

Although to date the Company has not experienced any material losses relating to cyber attacks or other information security breaches, there can be no assurance that the Company will not incur such losses in the future. The Company's risk and exposure to these matters cannot be fully mitigated because of, among other things, the evolving nature of these threats. The Audit Committee of the Company's Board of Directors has oversight of the Company's risk mitigation strategies related to cybersecurity.

Skilled Workforce Shortage
Successful execution of the Company's strategy is dependent on ensuring the Company's workforce possesses the appropriate skill level. There is a risk that the Company may have difficulty attracting and retaining personnel with the required skill levels. Failure to attract and retain personnel with the required skill levels could have a material adverse effect on the Company's financial condition and results of operations.

Aviation Incidents
The Company's offshore operations in Canada and China rely on regular travel by helicopter. There is a risk of a helicopter crash due to mechanical failure or human error resulting in a significant safety incident and subsequent facility shutdown and regulatory action. This risk is mitigated through a robust management process, maintenance program and regular auditing of Husky's aviation service providers. Helicopters chartered to support Husky offshore operations are designed to adapt to the anticipated environmental challenges i.e., anti-icing and floatation systems aligned to maximum sea height limits. Helicopters are also fitted with multiple redundant systems to address a wide range of in-flight emergencies. Pilots are trained to address these situations through regular real-time and simulator training aligned with and surpassing industry best practice.

5.3 Financial Risks

The Company's financial risks are largely related to commodity price risk, foreign currency risk, interest rate risk, counterparty credit risk and liquidity risk. From time to time, the Company uses derivative financial instruments to manage its exposure to these risks. These derivative financial instruments are not intended for trading or speculative purposes.

Fair Value of Financial Instruments
The Company's financial assets and liabilities that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon the fair value hierarchy. Level 1 fair value measurements are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair value measurements of assets and liabilities in Level 2 include valuations using inputs other than quoted prices but for which all significant outputs are observable, either directly or indirectly. Level 3 fair value measurements are based on inputs that are unobservable and significant to the overall fair value measurement.

The Company's financial instruments include cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, derivatives, portions of other assets and other long-term liabilities.

For the year ended December 31, 2017, the Company recognized a $46 million unrealized loss on its crude oil and natural gas risk management positions which was recorded in marketing and other. In addition, the Company recognized a $30 million realized loss recorded in net foreign currency forwards. Refer to Note 24 to the 2017 Consolidated Financial Statements.

Commodity Price Risk
The Company uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its crude oil and natural gas production, and it also uses firm commitments for the purchase or sale of crude oil and natural gas. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable, inventory, other assets, accounts payable and accrued liabilities and other long-term liabilities.

The Company's results will be impacted by a decrease in the price of crude oil and natural gas inventory. The Company has crude oil inventories that are feedstock, held at terminals or part of the in-process inventories at its refineries and at offshore sites. The Company also has natural gas inventory that could have an impact on earnings based on changes in natural gas prices. All these inventories are subject to a lower of cost or net realizable value test at each reporting period.

Foreign Currency Risk

The Company's results are affected by the exchange rates between various currencies including the Canadian and U.S. dollars. The majority of the Company's expenditures are in Canadian dollars while most of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in the Company's U.S. dollar-denominated debt and related interest expense, as expressed in Canadian dollars. The fluctuations in exchange rates are beyond the Company's control and could have a material adverse effect on the Company's results of operations and financial condition.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollar denominated revenue to hedge against these potential fluctuations. The Company also designates its U.S denominated debt as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.

Interest Rate Risk

Interest rate risk is the impact of fluctuating interest rates on financial condition. In order to manage interest rate risk and the resulting interest expense, the Company mitigates some of its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of its credit facilities and various financial instruments. The optimal mix maintained will depend on market conditions. The Company may also enter into interest rate swaps from time to time as an additional means of managing current and future interest rate risk.

Counterparty Credit Risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties in a transaction fail to meet or discharge their obligation to the Company. The Company actively manages this exposure to credit and contract execution risk from both a customer and a supplier perspective. Internal credit policies govern the Company's credit portfolio and limit transactions according to a counterparty's and a supplier's credit quality. Counterparties for financial derivatives transacted by the Company are generally major financial institutions or counterparties with investment grade credit ratings.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet 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. The Company's process for managing liquidity risk includes ensuring, to the extent possible, that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities and capacity to raise capital from various debt and equity capital markets under its shelf prospectuses. The availability of capital under its shelf prospectuses is dependent on market conditions at the time of sale.

Credit Rating Risk

Credit ratings affect the Company's ability to obtain both short-term and long-term financing and the cost of such financing. Additionally, the ability of the Company to engage in ordinary course derivative or hedging transactions and maintain ordinary course contracts with customers and suppliers on acceptable terms depends on the Company's credit ratings. A reduction in the current rating on the Company's debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to the Company's securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

The Company is committed to retaining investment grade credit ratings to support access to capital markets and currently has the following credit ratings:

	Standard and Poor's Rating Services	Moody's Investor Service ("Moody's")	Dominion Bond Rating Services Limited
Outlook/Trend	Stable	Stable	Stable
Senior Unsecured Debt	BBB+	Baa2	A(low)
Series 1 Preferred Shares	P-2(low)		Pfd-2(low)
Series 2 Preferred Shares	P-2(low)		Pfd-2(low)
Series 3 Preferred Shares	P-2(low)		Pfd-2(low)
Series 5 Preferred Shares	P-2(low)		Pfd-2(low)
Series 7 Preferred Shares	P-2(low)		Pfd-2(low)
Commercial Paper			R-1(low)

Debt Covenants

The Company's credit facilities include financial covenants, which contain a debt to capital covenant. If the Company does not comply with the covenants under these credit facilities, there is a risk that repayment could be accelerated.

6.0 Liquidity and Capital Resources

6.1 Summary of Cash Flow

Cash Flow Summary *($ millions)*	**2017**	2016
Cash flow		
Operating activities	**3,704**	1,971
Financing activities	**363**	(1,362)
Investing activities	**(2,789)**	632

Cash Flow from Operating Activities

Cash flow generated from operating activities increased by $1,733 million in 2017 compared to 2016. The increase was primarily due to higher realized global commodity prices combined with increased production from the Company's thermal bitumen developments and Asia Pacific operations, and a higher Chicago 3:2:1 crack spread and sales volumes in the U.S. Refining and Marketing operations.

Cash Flow from (used for) Financing Activities

Cash flow generated from financing activities increased by $1,725 million in 2017 compared to 2016. The increase was primarily due to the net issuance of $385 million in long-term debt in 2017, compared to the net repayment of $520 million of short-term debt and $768 million of long-term debt in 2016.

Cash Flow from (used for) Investing Activities

Cash flow used for investing activities increased by $3,421 million in 2017 compared to 2016. The increase was primarily due to increased capital expenditures and corporate acquisitions in 2017, compared to cash proceeds from asset sales of $2,935 million in 2016.

6.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2017, the Company's working capital was $2,109 million compared to $1,125 million at December 31, 2016. A reconciliation of the Company's working capital is as follows:

Working Capital *($ millions)*	**December 31, 2017**	December 31, 2016	Change
Cash and cash equivalents	**2,513**	1,319	1,194
Accounts receivable	**1,186**	1,036	150
Income taxes receivable	**164**	186	(22)
Inventories	**1,513**	1,558	(45)
Prepaid expenses	**145**	135	10
Restricted cash	**95**	84	11
Accounts payable and accrued liabilities	**(3,033)**	(2,226)	(807)
Short-term debt	**(200)**	(200)	—
Long-term debt due within one year	**—**	(403)	403
Contribution payable	**—**	(146)	146
Asset retirement obligations	**(274)**	(218)	(56)
Net working capital	**2,109**	1,125	984

The increase in cash and cash equivalents was primarily due to stronger operational performance resulting from the higher global commodity prices in 2017. Fluctuations in accounts receivable and accounts payable were due to the timing of settlements in 2017 compared to 2016. The decrease in income taxes receivable was due to the timing of expected tax refunds. The decrease in long-term debt due within one year was due to the timing of debt maturities. The decrease in contribution payable was due to the contribution being fully repaid in 2017.

6.3 Sources of Liquidity

Liquidity describes a company's ability to access cash. Sources of liquidity include funds from operations, proceeds from the issuance of equity, proceeds from the issuance of short and long-term debt, availability of short and long-term credit facilities and proceeds from asset sales. Since the Company operates in the Upstream oil and gas industry, it requires significant cash to fund capital programs necessary to maintain or increase production, develop reserves, acquire strategic oil and gas assets and repay maturing debt.

During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of short and long-term capital resources. The Company believes that it has sufficient liquidity to sustain its operations, fund capital programs and meet non-cancellable contractual obligations and commitments in the short and long-term principally by cash generated from operating activities, cash on hand, the issuance of equity, the issuance of debt, borrowings under committed and uncommitted credit facilities and cash proceeds from asset sales. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

At December 31, 2017, the Company had the following available credit facilities:

Credit Facilities *($ millions)*	Available	Unused
Operating facilities[(1)]	**850**	**428**
Syndicated credit facilities[(2)]	**4,000**	**3,800**
	4,850	**4,228**

(1) Consists of demand credit facilities and letter of credit.
(2) Commercial paper outstanding is supported by the Company's syndicated credit facilities.

At December 31, 2017, the Company had $4,228 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $428 million are short-term uncommitted credit facilities. A total of $422 million of the Company's short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $200 million of the Company's long-term committed borrowing credit facilities was used in support of commercial paper. At December 31, 2017, the Company had no direct borrowing against committed credit facilities. The Company's ability to renew existing bank credit facilities and raise new debt is dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. Credit ratings may be affected by the Company's level of debt, from time to time.

The Company's share capital is not subject to external restrictions. The Company's leverage covenant under both of its revolving syndicated credit facilities is debt to capital and calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. This covenant is used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2017, and assessed the risk of non-compliance to be low.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. There were no amounts drawn on this demand credit facility at December 31, 2017.

On December 22, 2015, the Company filed a universal short form base shelf prospectus (the "2015 U.S. Shelf Prospectus") with the Alberta Securities Commission and a related U.S. registration statement containing the 2015 U.S. Shelf Prospectus with the SEC that enabled the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the United States up to and including January 22, 2018. During the 25-month period that the 2015 U.S. Shelf Prospectus and the related U.S registration statement were effective, securities could be offered in amounts, at prices and on terms set forth in a prospectus supplement.

In March 2016, holders of 1,564,068 Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") exercised their option to convert their shares, on a one-for-one basis, to Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares") and receive a floating rate quarterly dividend. The dividend rate applicable to the Series 2 Preferred Shares for the three month period commencing September 30, 2017, to, but excluding December 31, 2017, is equal to the sum of the Government of Canada 90 day treasury bill rate on August 31, 2017, plus 1.73 percent, being 2.472 percent. The floating rate quarterly dividend applicable to the Series 2 Preferred Shares will be reset every quarter. The dividend rate applicable to the Series 1 Preferred Shares for the five year period commencing March 31, 2016, to, but excluding March 31, 2021, is equal to the sum of the Government of Canada five year bond yield on March 1, 2016, plus 1.73 percent, being 2.404 percent. Both rates were calculated in accordance with the articles of amendment of the Company creating the Series 1 Preferred Shares and Series 2 Preferred Shares dated March 11, 2011.

On March 9, 2016, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on December 14, 2016, was extended to March 9, 2020. In addition, the Company's leverage covenant under both of its revolving syndicated credit facilities ($2.0 billion maturing June 19, 2018, and $2.0 billion maturing March 9, 2020) was modified to a debt to capital covenant. At December 31, 2017, the Company was in compliance with the syndicated credit facility covenants and assesses the risk of non-compliance to be low.

On November 15, 2016, the Company repaid the maturing 7.55 percent notes issued under a trust indenture dated October 31, 1996. The amount paid to noteholders was $280 million, including $10 million of interest.

On March 10, 2017, the Company issued $750 million of 3.60 percent notes due March 10, 2027. The notes are redeemable at the option of the Company at any time, subject to a make-whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 10 and September 10 of each year, beginning September 10, 2017. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On March 30, 2017, the Company filed a universal short form base shelf prospectus (the "2017 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including April 30, 2019.

On September 15, 2017, the Company repaid the maturing 6.20 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to note holders was $365 million, including $11 million of interest.

At December 31, 2017, the Company had unused capacity of $3.0 billion under the 2017 Canadian Shelf Prospectus and US$3.0 billion in unused capacity under the 2015 U.S. Shelf Prospectus and related U.S. registration statement.

On January 29, 2018, the Company filed a universal short form base shelf prospectus (the "2018 U.S. Shelf Prospectus") with the Alberta Securities Commission. On January 30, 2018, the Company's related U.S. registration statement with the SEC containing the 2018 U.S. Shelf Prospectus became effective which enables the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the U.S. up to and including February 29, 2020. During the 25-month period that the 2018 U.S. Shelf Prospectus and the related U.S registration statement are effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement. The 2018 U.S. Shelf Prospectus replaced the 2015 U.S. Shelf Prospectus. The ability of the Company to utilize the capacity under the 2017 Canadian Shelf Prospectus and the 2018 U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

Net Debt

Net debt, a non-GAAP measure (see Section 9.3), is calculated as total debt less cash and cash equivalents. The Company had total debt of $5,440 million and cash and cash equivalents of $2,513 million at December 31, 2017 compared to total debt of $5,339 million and cash and cash equivalents of $1,319 million at December 31, 2016. The Company's net debt at December 31, 2017 decreased by $1,093 million when compared to December 31, 2016:

Net Debt[(1)] *($ millions)*	**December 31, 2017**	December 31, 2016
Net debt at beginning of period	**(4,020)**	(6,686)
Change in net debt due to:		
Funds from operations[(1)]	**3,306**	2,198
Capital expenditures	**(2,220)**	(1,705)
Corporate acquisitions	**(670)**	—
Cash dividends paid on preferred shares	**(34)**	(27)
Change in non-cash working capital	**570**	(568)
Proceeds from asset sales	**192**	2,935
Effect of exchange rates on cash and cash equivalents	**(84)**	8
Effect of exchange rates on long-term debt	**284**	130
Contribution payable	**(142)**	(193)
Contribution to joint ventures	**(81)**	(102)
Other	**(28)**	(10)
	1,093	2,666
Net debt at end of period	**(2,927)**	(4,020)

(1) *Net debt and funds from operations are non-GAAP measures. Refer to Section 9.3 for a reconciliation to the GAAP measure.*

During the years ended December 31, 2017 and 2016, the Company's capital expenditures were funded by funds from operations. The Company's funds from operations are dependent on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates. Management prepares capital expenditure budgets annually which are regularly monitored and updated to adapt to changes in market factors. In addition, the Company requires authorizations for capital expenditures on projects, which assists with the management of capital.

The common share dividend was suspended by the Board of Directors in respect of the fourth quarter of 2015 with the persistent downward pressure on oil prices and the extended "lower for longer" outlook to provide the Company with further financial flexibility to achieve its business and financial objectives. The Board of Directors carefully considers numerous factors including earnings, commodity price outlook, future capital requirements, and the financial condition of the Company when it reviews the Common

Share dividend policy. On February 28, 2018, the Board of Directors declared a quarterly dividend of $0.075 per common share for the three-month period ended December 31, 2017. The dividend will be payable on April 2, 2018 to shareholders of record at the close of business on March 20, 2018.

6.4 Capital Structure

Capital Structure

($ millions)	December 31, 2017 Outstanding
Total debt[1]	**5,440**
Shareholders' equity	**17,967**

[1] *Total debt is defined as long-term debt including long-term debt due within one year and short-term debt.*

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk, and to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes adjustments as economic conditions and the risk characteristics of its underlying assets change. The Company considers its capital structure to include shareholders' equity and debt, which was $23.4 billion at December 31, 2017 (December 31, 2016 – $23.0 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to funds from operations (refer to section 9.3). The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. At December 31, 2017, debt to capital employed was 23.2 percent (December 31, 2016 – 23.2 percent) and debt to funds from operations was 1.6 times (December 31, 2016 – 2.4 times), within the Company's targets.

The decrease in debt to funds from operations ratio as at December 31, 2017 was attributed to higher funds from operations due in large part to higher global commodity prices. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

6.5 Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Other Commercial Commitments

In the normal course of business, the Company is obligated to make future payments. The following summarizes known non-cancellable contracts and other commercial commitments:

Contractual Obligations

Payments due by period ($ millions)	2018	2019-2020	2021-2022	Thereafter	Total
Long-term debt and interest on fixed rate debt	260	2,122	911	3,661	6,954
Operating leases[1]	164	230	247	1,540	2,181
Firm transportation agreements[1]	451	929	945	4,306	6,631
Unconditional purchase obligations[2]	1,965	3,103	2,155	6,675	13,898
Lease rentals and exploration work agreements	94	139	136	973	1,342
Obligations to fund equity investee[3]	51	132	140	451	774
Finance lease obligations[4]	69	138	120	993	1,320
Asset retirement obligations[5]	274	330	304	8,763	9,671
	3,328	7,123	4,958	27,362	42,771

[1] *Included in the total of operating leases and firm transportation agreements are blending and storage agreements and transportation commitments of $0.9 billion and $2.0 billion respectively with HMLP.*

[2] *Includes processing services, distribution services, insurance premiums, drilling services, natural gas purchases and the purchase of refined petroleum products, which includes agreements entered into during the year totaling an incremental $385 million per year for a term of 15 years related to the expanded Canadian truck transportation network.*

[3] *Equity investee refers to the Company's investment in Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes*

[4] *Refer to Note 17 in the 2017 Consolidated Financial Statements.*

[5] *Asset retirement obligation amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets. The amounts are inclusive of $192 million of cash deposited into restricted accounts for funding of future asset retirement obligations in Asia Pacific.*

The Company updated its estimates for asset retirement obligations ("ARO") as outlined in Note 16 to the 2017 Consolidated Financial Statements. On an undiscounted and inflated basis, the ARO decreased from $11.4 billion as at December 31, 2016 to $9.7 billion as at December 31, 2017, primarily due to dispositions in Western Canada.

Other Obligations

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that decisions in any pending or threatened proceedings related to these and other matters, or any amount which it may be required to pay, would have a material adverse impact on its financial position, results of operations or liquidity.

The Company has income tax filings that are subject to audit and potential reassessment. The findings may impact the tax liability of the Company. The final results are not reasonably determinable at this time. Management believes that it has adequately provided for current and deferred income taxes.

During 2017, the Company completed a series of transactions related to the Canadian defined benefit pension plan, which was closed to new entrants in 1991. The Company recognized an $8 million loss on settlement related to the inactive plan members and a $3 million (net of tax of $1 million) loss in other comprehensive ("OCI") income for an annuity that was purchased to offset the defined benefit obligation for the active plan members. The Company also maintains a small defined benefit pension plan for the employees of the Superior Refinery which is closed to new entrants. Refer to Note 22 in the 2017 Consolidated Financial Statements.

In accordance with the provisions of the regulations of the People's Republic of China, the Company is required to deposit funds in separate accounts restricted to future decommissioning and disposal obligations. The funds will be used for decommissioning and disposal expenses upon the expiry or termination of the contracts for Asia Pacific. As at December 31, 2017, the Company has deposited funds of $192 million into the restricted cash accounts, of which $95 million relates to the Wenchang field and has been classified as current. The Company's participation in the Wenchang field expired in November 2017, and the amount of the decommissioning and disposal expenses was finalized in January 2018.

The Company is also subject to various contingent obligations that become payable only if certain events or rulings occur. The inherent uncertainty surrounding the timing and financial impact of these events or rulings prevents any meaningful measurement, which is necessary to assess their impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

The Company has a number of contingent environmental liabilities, which individually have been estimated to be immaterial. These contingent environmental liabilities are primarily related to the migration of contamination at fuel outlets and certain legacy sites where the Company had previously conducted operations. The contingent environmental liabilities involved have been considered in aggregate and based on reasonable estimates the Company does not believe they will result, in aggregate, in a material adverse effect on its financial position, results of operations or liquidity.

Off-Balance Sheet Arrangements

The Company does not believe it has any guarantees or off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the Company's financial condition, results of operations, liquidity or capital expenditures.

Standby Letters of Credit

On occasion, the Company issues letters of credit in connection with transactions in which the counterparty requires such security.

6.6 Transactions with Related Parties

The Company performs management services as the operator of the assets held by HMLP for which it earns a management fee. The Company is also the contractor for HMLP and constructs its assets on a cost recovery basis with certain restrictions. HMLP charges an access fee to the Company for the use of its pipeline systems in performing the Company's blending business, and the Company also pays for transportation and storage services. These transactions are related party transactions, as the Company has a 35 percent ownership interest in HMLP and the remaining ownership interests in HMLP belong to PAH and CKI, which are affiliates of one of the Company's principal shareholders. For the year ended December 31, 2017, the Company charged HMLP $412 million related to construction and management services. For the year ended December 31, 2017, the Company had purchases from HMLP of $203 million related to the use of the pipeline for the Company's blending activities, transportation and storage activities, received distributions of $25 million and paid capital contributions of $17 million. As at December 31, 2017, the Company had $67 million due from HMLP.

The Company sells natural gas to and purchases steam from the Meridian Limited Partnership ("Meridian"), owner of the Meridian cogeneration facility, for use at the facility, Upgrader and Lloydminster ethanol plant. In addition, the Company provides facilities services and personnel for the operations of the Meridian cogeneration facility, which are primarily measured and reimbursed at cost, which equates to fair value. These transactions are related party transactions, as Meridian is an affiliate of one of the Company's principal shareholders, and have been measured at fair value. For the year ended December 31, 2017, the amount of natural gas sales to Meridian totalled $45 million. For the year ended December 31, 2017, the amount of steam purchased by the Company from Meridian totalled $15 million. For the year ended December 31, 2017, the total cost recovery by the Company for facilities services was $11 million. At December 31, 2017, the Company had $1 million due from Meridian with respect to these transactions.

At December 31, 2017, $31 million of the May 11, 2009, 7.25 percent senior notes were held by a related party, Ace Dimension Limited, and are included in long-term debt in the Company's consolidated balance sheet. The related party transaction was measured at fair market value at the date of the transaction and has been carried out on the same terms as applied with unrelated parties.

6.7 Outstanding Share Data

Authorized:

- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 23, 2017

• common shares	1,005,120,012
• cumulative redeemable preferred shares, series 1	10,435,932
• cumulative redeemable preferred shares, series 2	1,564,068
• cumulative redeemable preferred shares, series 3	10,000,000
• cumulative redeemable preferred shares, series 5	8,000,000
• cumulative redeemable preferred shares, series 7	6,000,000
• stock options	22,158,469
• stock options exercisable	12,760,000

7.0 Critical Accounting Estimates and Key Judgments

The Company's consolidated financial statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Significant accounting policies are disclosed in Note 3 to the 2017 Consolidated Financial Statements. Certain of the Company's accounting policies require subjective judgment and estimation about uncertain circumstances.

7.1 Accounting Estimates

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and on a prospective basis. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained, and as the Company's operating environment changes. Specifically, amounts recorded for depletion, depreciation, amortization and impairment, asset retirement obligations, assets and liabilities measured at fair value, employee future benefits, income taxes and reserves and contingencies are based on estimates.

Depletion, Depreciation, Amortization and Impairment

Eligible costs associated with oil and gas activities are capitalized on a unit of measure basis. Depletion expense is subject to estimates including petroleum and natural gas reserves, future petroleum and natural gas prices, estimated future remediation costs, future interest rates as well as other fair value assumptions. The aggregate of capitalized costs, net of accumulated DD&A, less estimated salvage values, is charged to DD&A over the life of the proved developed reserves using the unit of production method, except in the case of assets whose useful life is shorter or longer than the lifetime of the proved developed reserves of that field, in which case the straight-line method or a unit-of-production method based on total proved plus probable reserves is applied.

Impairment and Reversals of Impairment of Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment or reversal of impairment. Determining whether there are any indications of impairment, or reversal of impairment, requires significant judgment of external factors, such as an extended change in prices or margins for oil and gas commodities or products, a significant change in an asset's market value, a significant change and revision of estimated volumes, revision of future development costs, a change in the entity's market capitalization or significant changes in the technological, market, economic or legal environment that would have an adverse impact on the entity. If impairment, or reversal of impairments, is indicated the amount by which the carrying value is different from the estimated fair value of the long-lived asset is charged to net earnings.

The determination of the recoverable amount for impairment, or reversal of impairment, involves the use of numerous assumptions and estimates. Estimates of future cash flows used in the evaluation of assets are made using management's forecasts of commodity prices, operating costs and future capital expenditures, marketing supply and demand, forecasted crack spreads, growth rate, discount rate and, in the case of oil and gas properties, expected production volumes. Expected production volumes take into account assessments of field reservoir performance and include expectations about proved and probable volumes and where applicable economically recoverable resources associated with interests in certain Husky properties which are risk-weighted utilizing geological, production, recovery, market price and economic projections. Either the cash flow estimates or the discount rate is risk-adjusted to reflect local conditions as appropriate. Future revisions to these assumptions impact the recoverable amount.

Impairment losses recognized for other assets in prior years are assessed at the end of each reporting period for indications that the impairment has decreased or no longer exists. An impairment loss is reversed only to the extent that the carrying amount of the asset or cash generating units ("CGUs") does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

Asset Retirement Obligations

Estimating ARO requires that the Company estimates costs that are many years in the future. Restoration technologies and costs are constantly changing, as are regulatory, political, environment, safety and public relations considerations. Inherent in the calculation of ARO are numerous assumptions and estimates, including the ultimate settlement amounts, future third-party pricing, inflation factors, credit-adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in changes to the ARO.

Fair Value of Financial Instruments

The fair values of derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. These estimates are also subject to change with fluctuations in commodity prices, interest rates, foreign currency exchange rates and estimates of non-performance. The actual settlement of a derivative instrument could differ materially from the fair value recorded and could impact future results.

Employee Future Benefits

The determination of the cost of the defined benefit pension plan and the other post-retirement benefit plans reflects a number of estimates that affect expected future benefit payments. These estimates include, but are not limited to, attrition, mortality, the rate of return on pension plan assets, salary escalations for the defined benefit pension plan and expected health care cost trends for the post-retirement health and dental care plan. The fair value of the plan assets is used for the purposes of calculating the expected return on plan assets.

Income Taxes

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Estimates that require significant judgments are also made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where the transaction and calculations for which the ultimate tax determination are uncertain. All tax filings are subject to audit and potential reassessment, often after the passage of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Legal, Environmental Remediation and Other Contingent Matters

The Company is required to determine both whether a loss is probable based on judgment and interpretation of laws and regulations and whether the loss can be reasonably estimated. When a loss is determined it is charged to net earnings. The Company must continually monitor known and potential contingent matters and make appropriate provisions by charges to net earnings when warranted by circumstances.

7.2 Key Judgments

Management makes judgments regarding the application of IFRS for each accounting policy. Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include determination of technical feasibility and commercial viability, impairment assessments, the determination of CGUs, changes in reserve estimates, the determination of a joint arrangement, the designation of the Company's functional currency and the fair value of related party transactions.

Exploration and Evaluation Costs

Costs directly associated with an exploration well are initially capitalized as exploration and evaluation assets. Expenditures related to wells that do not find reserves or where no future activity is planned are expensed as exploration and evaluation expenses. Exploration and evaluation costs are excluded from costs subject to depletion until technical feasibility and commercial viability is assessed or production commences. At that time, costs are either transferred to property, plant and equipment or their value is impaired. Impairment is charged directly to net earnings. Drilling results, required operating costs and capital expenditure and estimated reserves are important judgments when making this determination and may change as new information becomes available.

Impairment of Financial Assets

A financial asset is assessed at the end of each reporting period to determine whether it is impaired based on objective evidence indicating that one or more events have had a negative effect on the estimated future cash flows of that asset. Objective evidence used by the Company to assess impairment of financial assets includes quoted market prices for similar financial assets and historical collection rates for loans and receivables. The calculations for the net present value of estimated future cash flows related to derivative financial assets requires the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and expected production volumes, and it is possible that the assumptions may change, which may require a material adjustment to the carrying value of financial assets.

Cash Generating Units

The Company's assets are grouped into respective CGUs, which is the smallest identifiable group of assets, liabilities and associated goodwill that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The determination of the Company's CGUs is subject to management's judgment.

Reserves

Oil and gas reserves are evaluated internally and audited by independent qualified reserve engineers. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty. Changes in reserve estimates can have an impact on reported net earnings through revisions to depletion, depreciation and amortization expense, in addition to determining possible impairments and reversal of impairments of property, plant and equipment.

Net reserves represent the Company's undivided gross working interest in total reserves after deducting crown, freehold and overriding royalty interests. Assumptions reflect market and regulatory conditions, as applicable, as at the balance sheet date and could differ significantly from other points in time throughout the year or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Joint Arrangements
Joint arrangements represent activities where the Company has joint control established by a contractual agreement. Joint control requires unanimous consent for financial and operational decisions. A joint arrangement is either a joint operation, whereby the parties have rights to the assets and obligations for the liabilities, or a joint venture, whereby the parties have rights to the net assets.

Classification of a joint arrangement as either joint operation or joint venture requires judgment. Management's considerations include, but are not limited to, determining if the arrangement is structured through a separate vehicle and whether the legal form and contractual arrangements give the entity direct rights to the assets and obligations for the liabilities within the normal course of business. Other facts and circumstances are also assessed by management, including the entity's rights to the economic benefits of assets and its involvement and responsibility for settling liabilities associated with the arrangement.

Functional and Presentation Currency
Functional currency is the currency of the primary economic environment in which the Company and its subsidiaries operate and is normally the currency in which the entity primarily generates and expends cash. The designation of the Company's functional currency is a management judgment based on the composition of revenues and costs in the locations in which it operates.

Related Party Judgments and Estimates
The Company entered into transactions and agreements in the normal course of business with certain related parties, joint arrangements and associates. These transactions are on terms equivalent to those that prevail in arm's-length transactions. Proceeds for disposition of assets to related parties are recognized at fair value, based on discounted cash flow forecast from those assets. Independent opinions of the fair value may be obtained. Changes in the assumptions used to determine these fair values may result in a material difference in the proceeds and any gain or loss on disposition.

8.0 Recent Accounting Standards and Changes in Accounting Policies

Recent Accounting Standards

The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Leases

In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet while operating leases are recognized in the Consolidated Statements of Income when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expense upon implementation. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 Revenue from Contracts with Customers, has been applied, or is applied at the same date as IFRS 16.

Implementation of IFRS 16 consists of four phases:

- Project awareness and engagement - This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 16 to stakeholders, and creating a project steering committee.
- Scoping - This phase focuses on identifying and categorizing the Company's contracts, performing a high-level impact assessment and determining the adoption approach and which optional recognition exemptions will be applied by the Company. This phase also includes identifying the systems impacted by the new accounting standard and evaluating potential system solutions.
- Detailed analysis and solution development - This phase includes assessing which agreements contain leases and determining the expected conversion differences for leases currently accounted for as operating leases under the existing standard. This phase also includes selection of the system solution.
- Implementation - This phase includes implementing the changes required for compliance with IFRS 16. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the execution of customized training programs and preparation of disclosures under IFRS 16.

The Company is currently in the detailed analysis and solutions development phase of implementing IFRS 16. The impact on the Company's consolidated financial statements upon adoption of IFRS 16 is currently being assessed.

Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. 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. Early adoption is permitted.

Implementation of IFRS 15 consists of four phases:

- Project awareness and engagement – This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 15 to stakeholders.
- Scoping – This phase focuses on identifying the Company's major revenue streams, determining how and when revenue is currently recognized and determination of whether any changes are expected upon adoption.
- Detailed analysis and solution development – Steps in this phase include addressing any potential differences in revenue recognition identified in the scoping phase, according to the priority assigned. This involves detailed analysis of the IFRS 15 revenue recognition criteria, review of contracts with customers to ensure revenue recognition practices are in accordance with IFRS 15 and evaluating potential changes to revenue processes and systems.
- Implementation – This phase includes implementing the changes required for compliance with IFRS 15. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the execution of customized training programs and preparation of disclosures under IFRS 15.

The Company has completed the assessment of IFRS 15 and is currently in the implementation phase. The Company will retrospectively adopt the standard on January 1, 2018. The adoption of IFRS 15 does not require any material changes to the amounts recorded in the consolidated financial statements; however, it will require additional disclosures.

Financial Instruments

In July 2014, the IASB issued IFRS 9, "Financial Instruments" to replace IAS 39, which provides a single model for classification and measurement 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 instruments. For financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. IFRS 9 includes a new, forward-looking 'expected loss' impairment model that will result in a more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard is effective for annual periods beginning on or after January 1, 2018, with required retrospective application and early adoption permitted.

Implementation of IFRS 9 consists of four phases:

- Project awareness and engagement – This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 9 to stakeholders.
- Scoping – This phase focuses on identifying the Company's financial instruments, determining accounting treatment for in-scope financial instruments under IFRS 9, and determination of whether any changes are expected upon adoption.
- Detailed analysis and solution development – This phase includes addressing differences in accounting for financial instruments. Steps in this phase involve detailed analysis of the IFRS 9 recognition impacts, measurement and disclosure requirements, and evaluating potential changes to accounting processes.
- Implementation – This phase includes implementing the changes required for compliance with IFRS 9. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the preparation of disclosures under IFRS 9.

The Company has completed the assessment of IFRS 9 and is currently in the implementation phase. The Company will retrospectively adopt the standard on January 1, 2018. The adoption of IFRS 9 does not require any material changes to the consolidated financial statements.

Amendments to the IFRS 2 Share-based Payment

In June 2016, the IASB issued amendments to IFRS 2 to be applied prospectively for annual periods beginning on or after January 1, 2018 with early adoption permitted. The amendments clarify how to account for certain types of share-based payment arrangements. The adoption of the amendments does not have a material impact on the Company's consolidated financial statements.

Change in Accounting Policy

The Company has applied the following amendments to accounting standards issued by the IASB for the first time for the annual reporting period commencing January 1, 2017:

Amendments to IAS 7 Statement of Cash Flows

The amendments require disclosure of information enabling users of financial statements to evaluate changes in liabilities arising from financing activities. The adoption of this amended standard resulted in the disclosure of a reconciliation to changes in liabilities from financing activities. Refer to Note 15 of the Consolidated Financial Statements.

Amendments to IAS 12

The amendments clarify the recognition of deferred tax assets for unrealized losses on debt instruments measured at fair value. The adoption of the amendments has no material impact on the Company's consolidated financial statements.

9.0 Reader Advisories

9.1 Forward-Looking Statements

Certain statements in this document are forward-looking statements and information (collectively, "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this document are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "is estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "scheduled" and "outlook"). In particular, forward-looking statements in this document include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; the Company's 2018 production guidance, including guidance for specified areas and product types; the Company's objective of maintaining stated debt to funds from operations and debt to capital employed ratio targets; and the Company's 2018 Upstream capital expenditure program;
- with respect to the Company's thermal developments: anticipated timing of first production from and design capacity of the Company's Rush Lake 2 thermal development and its three Lloyd thermal projects at Dee Valley, Spruce Lake North and Spruce Lake Central; the timing of commencement of construction at Dee Valley; the timing of commencement of site clearing and construction at Spruce Lake Central and Spruce Lake North; the expected timing of first production from, and design capacity of, the two new thermal projects at Westhazel and Edam Central; the expected volume of long-life thermal production expected to be brought on by the Company in the next four years; the expected timing of ramp up of production and expected 2018 production volumes from the Tucker Thermal Project; and expected timing to reach nameplate capacity at the Sunrise Energy Project;
- with respect to the Company's Western Canada resource plays: the Company's strategic and drilling plans for its Western Canada portfolio; and expected timing that six wells in the Spirit River formation and two wells at Wembley will start production;
- with respect to the Company's Offshore business in Asia Pacific: the expected timing of commencement of construction at, and first production from, Liuhua 29-1; the Company's drilling plans at Block 15/33 and Block 16/25 offshore China; expected total gross daily sales volumes of natural gas and NGL once production is fully ramped up at the BD Project and the MDA-MBH and MDK fields; the expected timing of drilling of five MDA field production wells and two MBH field production wells, and the expected timing of first gas therefrom; and the expected timing of tie-in of the additional MDK shallow water field;
- with respect to the Company's Offshore business in the Atlantic: the expected timing of first oil and the expected timing and volume of gross peak production at the West White Rose Project; and the potential new development at Northwest White Rose;
- with respect to the Company's Infrastructure and Marketing business, the expected timing of completion of construction of HMLP's new 150-kilometre pipeline system; and
- with respect to the Company's Downstream operating segment: the expected timing of a final investment decision on the potential expansion of the Company's Lloydminster Asphalt Refinery; the expected timing of completion of the crude oil flexibility project at the Lima Refinery; and the expected timing of completion of a project to increase the heavy oil processing capacity at the Superior Refinery.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserves and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this document are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events, including the timing of regulatory approvals, that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third party consultants, suppliers and regulators, among others.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to the Company.

The Company's Annual Information Form for the year ended December 31, 2017 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

New factors emerge from time to time and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

9.2 Oil and Gas Reserves Reporting

Disclosure of Oil and Gas Reserves and Other Oil and Gas Information

Unless otherwise indicated: (i) reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, have an effective date of December 31, 2017 and represent the Company's working interest share; (ii) projected and historical production volumes provided represent the Company's working interest share before royalties; and (iii) historical production volumes provided are for the year ended December 31, 2017.

The Company uses the term barrels of oil equivalent ("boe"), which is consistent with other oil and gas companies' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies but does not represent value equivalency at the wellhead.

The Company uses the term reserves replacement ratio, which is consistent with other oil and gas companies' disclosures. Reserves replacement ratios for a given period are determined by taking the Company's incremental proved reserves additions for that period divided by the Company's Upstream gross production for the same period. The reserves replacement ratio measures the amount of reserves added to a company's reserves base during a given period relative to the amount of oil and gas produced during that same period. A company's reserves replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserves replacement ratio only measures the amount of reserves added to a company's reserve base during a given period. Reserves replacement ratios that exclude economic factors will exclude the impacts that changing oil and gas prices have.

Note to U.S. Readers

The Company reports its reserves information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101, "Standards of Disclosure for Oil and Gas Disclosure",adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves information in accordance with Canadian disclosure requirements, it may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the Securities and Exchange Commission (the "SEC") .

9.3 Non-GAAP Measures

Disclosure of non-GAAP Measures

The Company uses measures primarily based on IFRS and also uses some secondary non-GAAP measures. The non-GAAP measures included in this MD&A and related disclosures are: adjusted net earnings (loss), funds from operations, free cash flow, net debt, operating netback, debt to capital employed, debt to funds from operations and LIFO. None of these measures is used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for operating netback, debt to capital employed or debt to funds from operations. These are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity. The non-GAAP measures do not have standardized meanings prescribed by IFRS and therefore are unlikely to be comparable to similar measures presented by other issuers. They are common in the reports of other companies but may differ by definition and application. All non-GAAP measures are defined below.

Adjusted Net Earnings (Loss)

Adjusted net earnings (loss) is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "net earnings (loss)" as determined in accordance with IFRS, as an indicator of financial performance. Adjusted net earnings (loss) is comprised of net earnings (loss) and excludes items such as after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on sale of assets which are not considered to be indicative of the Company's ongoing financial performance. Adjusted net earnings (loss) is a complementary measure used in assessing the Company's financial performance through providing comparability between periods. Adjusted net earnings (loss) was redefined in the second quarter of 2016. Previously, adjusted net earnings (loss) was defined as net earnings (loss) plus after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs.

The following table shows the reconciliation of net earnings (loss) to adjusted net earnings (loss) for the three months and years ended December 31:

Adjusted Net Earnings	Three months ended Dec. 31,		Year ended Dec. 31,		
($ millions)	**2017**	2016	**2017**	2016	2015
Net earnings (loss)	**672**	186	**786**	922	(3,850)
Impairment (impairment reversal) of property, plant and equipment, net of tax	**3**	(202)	**126**	(190)	3,664
Impairment of goodwill	**—**	—	**—**	—	160
Exploration and evaluation asset write-downs, net of tax	**—**	41	**4**	63	177
Inventory write-downs, net of tax	**—**	6	**—**	6	14
Gain on sale of assets, net of tax	**(10)**	(37)	**(34)**	(1,456)	(16)
Adjusted net earnings (loss)	**665**	(6)	**882**	(655)	149

Debt to Capital Employed

Debt to capital employed is a non-GAAP measure and is equal to long-term debt, long-term debt due within one year, and short-term debt divided by capital employed. Capital employed is equal to long-term debt, long-term debt due within one year, short-term debt and shareholders' equity. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

Debt to Funds from Operations

Debt to funds from operations is a non-GAAP measure and is equal to long-term debt, long-term debt due within one year and short-term debt divided by funds from operations. Funds from operations is equal to cash flow – operating activities plus change in non-cash working capital. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

The following table shows the calculation of debt to funds from operations for the periods ended December 31, 2017, 2016 and 2015:

Debt to Funds from Operations *($ millions)*	**December 31, 2017**	December 31, 2016	December 31, 2015
Total debt	**5,440**	5,339	6,756
Funds from operations	**3,306**	2,198	3,333
Debt to funds from operations	**1.6**	2.4	2.0

Funds from Operations and Free Cash Flow

Funds from operations is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Funds from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance of the Company in the stated period. Funds from operations equals cash flow – operating activities plus change in non-cash working capital.

Funds from operations has been restated in the second quarter of 2017 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the removal of adjustments for settlement of asset retirement obligations and deferred revenue. Prior periods have been restated to conform to current presentation.

Free cash flow is a non-GAAP measure, which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Free cash flow is presented to assist management and investors in analyzing operating performance by the business in the stated period. Free cash flow equals funds from operations less capital expenditures.

The following table shows the reconciliation of cash flow – operating activities to funds from operations and free cash flow, and related per share amounts for the three months and years ended December 31:

Reconciliation of Cash Flow	Three months ended Dec. 31,		Year ended Dec. 31,		
($ millions)	**2017**	2016	**2017**	2016	2015
Net earnings (loss)	**672**	186	**786**	922	(3,850)
Items not affecting cash:					
Accretion	**28**	30	**112**	126	121
Depletion, depreciation, amortization and impairment	**647**	405	**2,882**	2,462	8,644
Inventory write-down to net realizable value	**—**	9	**—**	9	22
Exploration and evaluation expenses	**—**	56	**6**	86	242
Deferred income taxes (recoveries)	**(360)**	45	**(359)**	29	(1,827)
Foreign exchange (gain) loss	**1**	(29)	**(4)**	(4)	27
Stock-based compensation	**25**	3	**45**	33	(39)
Gain on sale of assets	**(13)**	(52)	**(46)**	(1,634)	(22)
Unrealized market to market loss (gain)	**57**	26	**56**	38	(14)
Share of equity investment loss (gain)	**(1)**	(38)	**(61)**	(15)	5
Other	**8**	29	**16**	24	20
Settlement of asset retirement obligations	**(45)**	(31)	**(136)**	(87)	(98)
Deferred revenue	**(5)**	23	**(16)**	209	102
Distribution from joint ventures	**25**	—	**25**	—	—
Change in non-cash working capital	**337**	(18)	**398**	(227)	427
Cash flow – operating activities	**1,376**	644	**3,704**	1,971	3,760
Change in non-cash working capital	**(337)**	18	**(398)**	227	(427)
Funds from operations	**1,039**	662	**3,306**	2,198	3,333
Capital expenditures	**(745)**	(391)	**(2,220)**	(1,705)	(3,005)
Free cash flow	**294**	271	**1,086**	493	328
Funds from operations – basic	**1.03**	0.66	**3.29**	2.19	3.39
Funds from operations – diluted	**1.03**	0.66	**3.29**	2.19	3.39

LIFO

The Chicago 3:2:1 market crack spread benchmark is based on LIFO inventory costing, a non-GAAP measure, which assumes that crude oil feedstock costs are based on the current month price of WTI, while on a FIFO basis, the comparable GAAP measure, crude oil feedstock costs included in realized margins reflect purchases made in previous months. Management believes that comparisons between LIFO and FIFO inventory costing assist management and investors in assessing differences in the Company's realized refining margins compared to the Chicago 3:2:1 market crack spread benchmark.

Net Debt

Net debt is a non-GAAP measure that equals total debt less cash and cash equivalents. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

The following table shows the reconciliation of total debt to net debt as at December 31, 2017, 2016 and 2015:

Net Debt *($ millions)*	**December 31, 2017**	December 31, 2016	December 31, 2015
Short-term debt	**200**	200	720
Long-term debt due within one year	**—**	403	277
Long-term debt	**5,240**	4,736	5,759
Total debt	**5,440**	5,339	6,756
Cash and cash equivalents	**(2,513)**	(1,319)	(70)
Net debt	**2,927**	4,020	6,686

Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. Management believes this measurement assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. Operating netback is calculated as gross revenue less royalties, production and operating and transportation costs on a per unit basis.

9.4 Additional Reader Advisories

Intention of Management's Discussion and Analysis

This Management's Discussion and Analysis is intended to provide an explanation of financial and operational performance compared with prior periods and the Company's prospects and plans. It provides additional information that is not contained in the Company's Consolidated Financial Statements.

Review by the Audit Committee

This Management's Discussion and Analysis was reviewed by the Company's Audit Committee and approved by the Board of Directors on February 28, 2018. Any events subsequent to that date could materially alter the veracity and usefulness of the information contained in this document.

Additional Husky Documents Filed with Securities Commissions

This Management's Discussion and Analysis dated February 28, 2018, should be read in conjunction with the 2017 Consolidated Financial Statements and related notes. Readers are also encouraged to refer to the Company's interim reports filed for 2017, which contain Management's Discussion and Analysis and Consolidated Financial Statements, and the Company's Annual Information Form for the year ended December 31, 2017, filed separately with Canadian regulatory agencies, and annual Form 40-F filed with the SEC, the U.S. federal securities regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and www.huskyenergy.com. Husky's Management's Discussion and Analysis for the interim period ended December 31, 2017, is incorporated herein by reference.

Use of Pronouns and Other Terms

"Husky" and "the Company" refer to Husky Energy Inc. on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, comparisons of results are for the years ended December 31, 2017 and 2016 and the Company's financial position at December 31, 2017 and 2016.

Reclassifications and Materiality for Disclosures

Certain prior year amounts have been reclassified to conform to current year presentation. Materiality for disclosures is determined on the basis of whether the information omitted or misstated would cause a reasonable investor to change his or her decision to buy, sell or hold Husky's securities.

Additional Reader Guidance

Unless otherwise indicated:

- Financial information is presented in accordance with IFRS as issued by the IASB.
- All dollar amounts are in Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represents the Company's working interest share before royalties.
- Prices are presented before the effect of hedging.

Terms

Adjusted Net Earnings (Loss)	*Net earnings (loss) before after-tax property, plant and equipment impairment charges (reversals), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on the sale of assets*
Asia Pacific	*Includes Upstream oil and gas exploration and production activities located offshore China and Indonesia*
Atlantic	*Includes Upstream oil and gas exploration and production activities located offshore Newfoundland and Labrador*
Bitumen	*Bitumen is a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds or 10,000 centipoise measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods*
Capital Employed	*Long-term debt, long-term debt due within one year, short-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and short-term debt divided by capital employed*
Debt to Funds from Operations	*Long-term debt, long-term debt due within one year and short-term debt divided by funds from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil and bitumen to facilitate transmissibility of the oil through a pipeline*
Feedstock	*Raw materials which are processed into petroleum products*
Free Cash Flow	*Funds from operations less capital expenditures*
Funds from Operations	*Cash flow - operating activities plus change in non-cash working capital*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Heavy crude oil	*Crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity*
high-TAN	*A measure of acidity. Crude oils with a high content of naphthenic acids are referred to as high total acid number (TAN) crude oils or high acid crude oil. The TAN value is defined as the milligrams of Potassium Hydroxide required to neutralize the acidic group of one gram of the oil sample. Crude oils in the industry with a TAN value greater than 1 are referred to as high-TAN crudes*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
Light crude oil	*Crude oil with a relative density greater than 31.1 degrees API gravity*
Medium crude oil	*Crude oil with a relative density that is greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity*
Net Debt	*Total debt less cash and cash equivalents*
Net Revenue	*Gross revenues less royalties*
NOVA Inventory Transfer ("NIT")	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Oil sands	*Sands and other rock materials that contain crude bitumen and include all other mineral substances in association therewith*
Operating Netback	*Gross revenue less royalties, operating costs and transportation costs on a per unit basis*
Plan of Development	*As it relates to the Company's operations in Indonesia, a Plan of Development represents development planning on one or more oil and gas fields in an integrated and optimal plan for the production of hydrocarbon reserves considering technical, economical and environmental aspects. An initial Plan of Development in a development area needs both SKK Migas and the Minister of Energy and Mineral Resources approvals. Subsequent Plans of Development in the same development area only need SKK Migas approval*
Probable reserves	*Those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves*

Proved developed reserves	*Those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing*
Proved reserves	*Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves*
Proved undeveloped reserves	*Those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned*
Seismic survey	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
Shareholders' Equity	*Common shares, preferred shares, contributed surplus, retained earnings, accumulated other comprehensive income and non-controlling interest*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Thermal	*Use of steam injection into the reservoir in order to enable heavy oil and bitumen to flow to the well bore.*
Total Debt	*Long-term debt including long-term debt due within one year and short-term debt*
Turnaround	*Performance of scheduled plant or facility maintenance requiring the complete or partial shutdown of the plant or facility operations*
Western Canada	*Includes Upstream oil and gas exploration and development activities located in Alberta, Saskatchewan and British Columbia*

Units of Measure

bbls	*barrels*	*mboe*	*thousand barrels of oil equivalent*
bbls/day	*barrels per day*	*mboe/day*	*thousand barrels of oil equivalent per day*
bcf	*billion cubic feet*	*mcf*	*thousand cubic feet*
boe	*barrels of oil equivalent*	*mcfge*	*million cubic feet of gas equivalent*
boe/day	*barrels of oil equivalent per day*	*mmbbls*	*million barrels*
GJ	*gigajoule*	*mmboe*	*million barrels of oil equivalent*
mbbls	*thousand barrels*	*mmbtu*	*million British Thermal Units*
mbbls/day	*thousand barrels per day*	*mmcf*	*million cubic feet*
mbbls	*thousand barrels*	*mmcf/day*	*million cubic feet per day*
mbbls/day	*thousand barrels per day*	*m3*	*cubic meter*

9.5 Disclosure Controls and Procedures

Disclosure Controls and Procedures

Husky's management, under supervision of the Chief Executive Officer and the Chief Financial Officer, have evaluated the effectiveness of Husky's disclosure controls and procedures (as defined in the rules of the SEC and the Canadian Securities Administrators ("CSA")) as at December 31, 2017, and have concluded that such disclosure controls and procedures are effective.

Management's Annual Report on Internal Control over Financial Reporting

The following report is provided by management in respect of Husky's internal controls over financial reporting (as defined in the rules of the SEC and the CSA):

1) Husky's management, under the supervision of the Chief Executive Officer and Chief Financial Officer, is responsible for designing, establishing and maintaining adequate internal control over financial reporting for Husky. All 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.

2) Husky's management has used the Committee of Sponsoring Organizations of the Treadway Commission framework to evaluate the effectiveness of Husky's internal control over financial reporting.

3) As at December 31, 2017, management, under the supervision of the Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective.

4) KPMG LLP, who has audited the Consolidated Financial Statements of Husky for the year ended December 31, 2017, has also issued a report on internal controls over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States) that attests to Husky's internal controls over financial reporting.

Changes in Internal Control over Financial Reporting

There have been no changes in Husky's internal control over financial reporting during the year ended December 31, 2017, that have materially affected or are reasonably likely to materially affect its internal control over financial reporting.

10.0 Selected Quarterly Financial and Operating Information

10.1 Summary of Quarterly Results

Fourth Quarter Results Summary *($ millions, except where indicated)*	Three months ended **Dec. 31 2017**	 Dec. 31 2016
Gross revenues and Marketing and other		
Upstream		
Exploration and Production	**1,355**	1,215
Infrastructure and Marketing	**633**	186
Downstream		
Upgrading	**452**	340
Canadian Refined Products	**815**	603
U.S. Refining and Marketing	**2,755**	1,890
Corporate and Eliminations	**(476)**	(369)
Total gross revenues and marketing and other	**5,534**	3,865
Net earnings (loss)		
Upstream		
Exploration and Production	**170**	198
Infrastructure and Marketing	**(27)**	18
Downstream		
Upgrading	**48**	32
Canadian Refined Products	**39**	8
U.S. Refining and Marketing	**129**	19
Corporate and Eliminations	**313**	(89)
Net earnings	**672**	186
Per share – Basic	**0.66**	0.19
Per share – Diluted	**0.66**	0.19
Adjusted net earnings (loss)[(1)]	**665**	(6)
Cash flow – operating activities	**1,376**	644
Funds from operations[(1)]	**1,039**	662
Per share – Basic	**1.03**	0.66
Per share – Diluted	**1.03**	0.66
Upstream		
Daily gross production		
Crude oil and NGL production *(mbbls/day)*[(3)]	**231.2**	234.5
Natural gas production *(mmcf/day)*[(3)]	**534.9**	555.4
Total production *(mboe/day)*	**320.4**	327.0
Average sales prices realized *($/boe)*		
Crude oil and NGL *($/bbl)*[(3)]	**51.06**	42.27
Natural gas *($/mcf)*[(3)]	**5.89**	5.65
Total average sales prices realized *($/boe)*	**46.69**	39.90
Downstream		
Refinery throughput		
Lloydminster Upgrader *(mbbls/day)*	**78.2**	66.5
Lloydminster Refinery *(mbbls/day)*	**30.1**	28.4
Prince George Refinery *(mbbls/day)*	**11.3**	11.8
Lima Refinery *(mbbls/day)*	**164.5**	165.1
BP-Husky Toledo Refinery *(mbbls/day)*	**81.0**	78.8
Superior Refinery *(mbbls/day)*[(2)]	**22.0**	—
Total throughput *(mbbls/day)*	**387.1**	350.6

Fourth Quarter Results Summary (continued)	Three months ended	
($ millions, except where indicated)	**Dec. 31 2017**	Dec. 31 2016
Upgrading unit margin *($/bbl)*	**20.65**	18.85
Upgrading synthetic crude oil sales *(mbbls/day)*	**56.5**	50.0
Upgrading total sales *(mbbls/day)*	**77.9**	66.9
Retail fuel sales *(million of litres/day)*	**8.0**	6.6
Canadian light oil margins *($/litre)*	**0.052**	0.057
Lloydminster Refinery asphalt margin *($/bbl)*	**15.79**	20.80
U.S. Refining Margin *(US$/bbl crude throughput)*	**14.71**	9.86
U.S./Canadian dollar exchange rate *(US$)*	**0.786**	0.750

(1) *Adjusted net earnings (loss) and funds from operations are non-GAAP measures. Refer to Section 9.3 for a reconciliation to the GAAP measures.*
(2) *The Superior Refinery was acquired on November 8, 2017.*
(3) *Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*

Gross Revenue and Marketing and Other

The Company's consolidated gross revenues and marketing and other increased by $1,669 million in the fourth quarter of 2017 compared to the fourth quarter of 2016.

In the Upstream business segment, Exploration and Production gross revenues increased primarily due to higher commodity pricing in the fourth quarter of 2017, which was partially offset by a higher Canadian dollar. Infrastructure and Marketing gross revenues and marketing and other increased primarily due to increased volumes and prices.

In the Downstream business segment, Upgrading gross revenues increased primarily due to higher realized prices for synthetic crude oil and higher sales volumes in 2017, as the Upgrader was in plant maintenance in the fourth quarter of 2016. Canadian Refined Products gross revenues increased primarily due to higher fuel sales volumes. U.S. Refining and Marketing gross revenues increased primarily due to higher sales volumes and higher realized product pricing in the fourth quarter of 2017 compared to the same period in 2016.

Net Earnings

The Company's consolidated net earnings increased by $486 million in the fourth quarter of 2017 compared to the same period in 2016.

In the Upstream business segment, Exploration and Production net earnings decreased primarily due to the 2016 net after-tax impairment reversal of $202 million on assets located in Western Canada. The decrease was partially offset by higher commodity pricing in the fourth quarter of 2017, compared to the fourth quarter of 2016.

In the Downstream business segment, Upgrading and Canadian Refined Products net earnings increased primarily due to the same factors which impacted gross revenues and marketing and other. U.S. Refining and Marketing net earnings increased primarily due to the higher Chicago 3:2:1 crack spread in the fourth quarter of 2017 compared to the same period in 2016. The Company recorded FIFO gains of $45 million during the fourth quarter of 2017 compared to FIFO gains of $25 million during the fourth quarter of 2016.

In the fourth quarter of 2017, the Company recognized $436 million in deferred tax recovery related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018.

Adjusted Net Earnings (Loss)

Adjusted net earnings (loss), which excludes after-tax property, plant and equipment impairment (reversal), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and losses (gains) on sale of assets, increased by $671 million in the fourth quarter of 2017 compared to the fourth quarter of 2016. The increase was primarily attributable to the same factors which impacted net earnings.

Cash Flow – Operating Activities and Funds from Operations

Cash flow – operating activities and funds from operations increased by $732 million and $377 million, respectively, in the fourth quarter of 2017 compared to the fourth quarter of 2016 primarily due to the same factors which impacted adjusted net earnings (loss). Funds from operations is a non-GAAP measure; refer to section 9.3.

Daily Gross Production

Production decreased by 6.6 mbbls/day during the fourth quarter of 2017 compared to the fourth quarter of 2016 as a result of:
- Decreased production from Western Canada primarily due to the disposition of select legacy assets in 2016 and 2017.

Partially offset by:
- Increased production from thermal bitumen developments;
- Increased natural gas and NGL production from the Liwan Gas Project; and
- Increased natural gas production due to new production from the BD Project.

Segmented Operational Information

Segmented Operational Information ($ millions, except where indicated)	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Gross revenues and Marketing and other								
Upstream								
Exploration and Production	**1,355**	**1,157**	**1,215**	**1,251**	1,215	941	1,044	836
Infrastructure and Marketing	**633**	**509**	**425**	**369**	186	280	288	113
Downstream								
Upgrading	**452**	**377**	**227**	**384**	340	334	369	281
Canadian Refined Products	**815**	**802**	**602**	**568**	603	678	585	435
U.S. Refining and Marketing[1]	**2,755**	**2,292**	**2,135**	**2,173**	1,890	1,642	1,337	1,126
Corporate and Eliminations	**(476)**	**(424)**	**(253)**	**(397)**	(369)	(355)	(362)	(213)
Total gross revenues and marketing and other	**5,534**	**4,713**	**4,351**	**4,348**	3,865	3,520	3,261	2,578
Net earnings (loss)								
Upstream								
Exploration and Production	**170**	**28**	**(67)**	**43**	198	63	(228)	(250)
Infrastructure and Marketing	**(27)**	**10**	**33**	**70**	18	1,306	35	(51)
Downstream								
Upgrading	**48**	**9**	**5**	**48**	32	27	58	58
Canadian Refined Products	**39**	**38**	**12**	**15**	8	55	36	11
U.S. Refining and Marketing	**129**	**114**	**12**	**(21)**	19	(16)	61	(7)
Corporate and Eliminations	**313**	**(63)**	**(88)**	**(84)**	(89)	(45)	(158)	(219)
Net earnings (loss)	**672**	**136**	**(93)**	**71**	186	1,390	(196)	(458)
Per share – Basic	**0.66**	**0.13**	**(0.10)**	**0.06**	0.19	1.37	(0.20)	(0.47)
Per share – Diluted	**0.66**	**0.13**	**(0.10)**	**0.06**	0.19	1.37	(0.20)	(0.47)
Adjusted net earnings (loss)[2]	**665**	**136**	**10**	**71**	(6)	(100)	(91)	(458)
Funds from operations[2]	**1,039**	**891**	**715**	**661**	662	619	505	412
Per share – Basic	**1.03**	**0.89**	**0.71**	**0.66**	0.66	0.62	0.50	0.41
Per share – Diluted	**1.03**	**0.89**	**0.71**	**0.66**	0.66	0.62	0.50	0.41
U.S./Canadian dollar exchange rate (US$)	**0.786**	**0.799**	**0.744**	**0.756**	0.750	0.766	0.776	0.728
Exploration and Production								
Daily production, before royalties								
Crude oil & NGL production *(mbbls/day)*								
Light & Medium crude oil	**46.6**	**42.7**	**56.0**	**60.7**	54.9	47.6	69.4	80.9
NGL[3]	**21.4**	**19.3**	**17.2**	**14.2**	15.9	13.4	12.8	14.0
Heavy crude oil	**42.3**	**44.1**	**43.1**	**48.0**	48.4	49.5	57.5	61.5
Bitumen	**120.9**	**117.7**	**117.4**	**120.6**	115.3	103.6	88.0	81.8
Total crude oil & NGL production *(mbbls/day)*	**231.2**	**223.8**	**233.7**	**243.5**	234.5	214.1	227.7	238.2
Natural gas *(mmcf/day)*[3]	**534.9**	**563.4**	**514.8**	**543.1**	555.4	521.3	528.8	618.6
Total production *(mboe/day)*	**320.4**	**317.7**	**319.5**	**334.0**	327.0	301.0	315.8	341.3
Average sales prices								
Light & Medium crude oil *($/bbl)*	**77.05**	**63.13**	**63.27**	**66.70**	64.12	54.91	56.11	39.65
NGL *($/bbl)*[7]	**51.19**	**37.83**	**38.00**	**49.64**	46.47	35.62	36.68	31.89
Heavy crude oil *($/bbl)*	**48.64**	**41.89**	**42.06**	**41.28**	36.30	35.04	34.88	18.12
Bitumen *($/bbl)*	**41.88**	**38.14**	**37.46**	**35.20**	33.80	29.53	30.95	12.83
Natural gas *($/mcf)*[3]	**5.89**	**5.25**	**5.59**	**5.35**	5.65	3.99	3.46	4.41
Operating costs *($/boe)*	**13.20**	**14.12**	**14.65**	**13.75**	13.92	15.15	13.90	13.31
Operating netbacks[3][4]								
Lloydminster Thermal *($/bbl)*[5]	**33.98**	**27.38**	**24.14**	**24.88**	22.02	19.72	24.61	10.02
Lloydminster Non-Thermal *($/boe)*[5]	**19.36**	**12.46**	**12.70**	**14.80**	11.58	11.28	15.05	0.50
Tucker Thermal *($/bbl)*[5]	**31.79**	**28.35**	**24.09**	**23.53**	21.34	20.04	26.55	5.28
Sunrise Energy Project *($/bbl)*[5]	**16.50**	**16.05**	**11.67**	**2.24**	5.42	0.90	(26.52)	(53.29)
Western Canada – Crude Oil *($/bbl)*[5]	**12.99**	**3.64**	**12.03**	**19.18**	5.06	11.37	18.95	(1.94)
Western Canada – NGL & natural gas *($/mcf)*[6]	**0.15**	**0.12**	**1.01**	**1.05**	1.36	0.45	(0.56)	0.36
Atlantic – Light Oil *($/bbl)*[5]	**59.00**	**35.86**	**42.08**	**44.39**	40.49	22.83	28.55	27.82
Asia Pacific – Light Oil, NGL & natural gas *($/boe)*[3][5]	**65.31**	**61.81**	**61.90**	**64.43**	61.09	47.77	59.21	61.11
Total *($/boe)*[5]	**30.00**	**23.25**	**23.53**	**24.17**	22.32	15.70	17.30	9.68

Segmented Operational Information (continued)	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Upgrading								
Synthetic crude oil sales *(mbbls/day)*	**56.5**	**58.2**	**30.3**	**54.1**	50.0	53.3	59.8	57.7
Total sales *(mbbls/day)*	**77.9**	**79.4**	**40.3**	**76.2**	66.9	69.7	76.5	78.3
Upgrading differential *($/bbl)*	**21.46**	**13.60**	**18.70**	**20.88**	20.36	19.45	20.85	22.23
Canadian Refined Products								
Fuel sales *(millions of litres/day)*	**8.0**	**8.1**	**6.5**	**6.4**	6.6	6.8	6.8	6.2
Refinery throughput								
Lloydminster Refinery *(mbbls/day)*	**30.1**	**30.0**	**19.5**	**28.0**	28.4	26.7	28.2	28.0
Prince George Refinery *(mbbls/day)*	**11.3**	**11.9**	**9.7**	**11.8**	11.8	9.7	5.1	11.0
U.S. Refining and Marketing								
Refinery throughput								
Lima Refinery *(mbbls/day)*	**164.5**	**178.3**	**174.1**	**172.0**	165.1	155.6	103.9	127.5
BP-Husky Toledo Refinery *(mbbls/day)*	**81.0**	**77.3**	**71.1**	**77.0**	78.8	58.4	41.2	69.4
Superior Refinery *(mbbls/day)*(7)	**22.0**	**—**	**—**	**—**	—	—	—	—

(1) *During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings.*
(2) *Adjusted net earnings (loss) and funds from operations are non-GAAP measures. Refer to Section 9.3 for a reconciliation to the GAAP measures.*
(3) *Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*
(4) *Operating netback is a non-GAAP measure. Refer to Section 9.3.*
(5) *Includes associated co-products converted to boe.*
(6) *Includes associated co-products converted to mcfge.*
(7) *The Superior Refinery was acquired on November 8, 2017.*

Significant Items Impacting Gross Revenues, Net Earnings (Loss) and Funds from Operations

Variations in the Company's gross revenues, net earnings (loss) and funds from operations (non-GAAP measure) are primarily driven by changes in production volumes, commodity prices, commodity price differentials, refining crack spreads, foreign exchange rates and planned turnarounds. Stronger crude oil and North American natural gas prices throughout 2017, resulted in an increase to Company's gross revenues, net earnings and funds from operations (non-GAAP measure). Other significant items which impacted gross revenues, net earnings and funds from operations (non-GAAP measure) over the last eight quarters include:

2017
Q4:
- On November 8, 2017, the Company completed the purchase of the Superior Refinery, a 50,000 bbls/day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet for $670 million (US$527 million) in cash, which includes $108 million (US$85 million) of working capital, subject to final adjustments.
- At the Tucker Thermal Project, drilling of the new 15-well pad was completed in the second quarter and steaming commenced in the fourth quarter of 2017.
- At the Sunrise Energy Project production continued to ramp up and the 14 previously drilled well pairs were tied in and are producing.
- Production from 10 wells of the 16-well program in the Ansell and Kakwa areas was achieved. Due to improved operating efficiencies, drilling times were reduced by 30 percent during 2017, contributing to a 22 percent reduction in per-well drilling costs.
- At Karr in the Montney formation, two wells were drilled in the third quarter and production was achieved in the fourth quarter.
- Production continued to ramp up at the BD Project. The first lifting of NGL occurred mid-October.
- An additional infill well was completed at the main White Rose field, which was tied back to the *SeaRose* FPSO, providing for improved capital efficiencies.
- The sale of select assets in Western Canada to third parties was completed, representing approximately 17,600 boe/day for gross proceeds of approximately $65 million resulting in an after-tax gain of $9 million.
- The recognition of $436 million in deferred tax recovery related to the reduction in the U.S. Federal corporate tax rate that will take effect in 2018.

Q3:
- First production was achieved at the BD Project in the Madura Strait. NGL were produced and stored on the FPSO.
- Nine wells of a 16-well program in the Ansell and Kakwa areas were completed by the third quarter.
- Production from one well at Wembley in the Montney formation commenced.
- At South White Rose, an oil production well and a supporting water injection well were completed.
- The consolidation of a single expanded truck transport network of approximately 160 sites was completed during the quarter.

Q2:

- The Company recognized an after-tax impairment expense of $123 million related to crude oil and natural gas assets located in Western Canada in the Upstream Exploration and Production segment. The impairment charges were the result of changes in the development plans and reinforced by market transactions.
- Lloydminster Upgrader and Lloydminster Asphalt Refinery throughput and sales volumes were lower due to major planned turnarounds at the Lloydminster Upgrader and Lloydminster Asphalt Refinery.
- The sale of select assets in Western Canada to third parties was completed, representing approximately 2,600 boe/day for gross proceeds of approximately $123 million, resulting in an after-tax gain of $23 million.

Q1:

- First oil was achieved at the Tucker Thermal Project's new eight-well pad.
- First oil was achieved from a North Amethyst infill well.

2016

Q4:

- Insurance recoveries of $176 million were accrued for business interruption and property damage associated with a fire that damaged the Company's isocracker unit at Lima during the first quarter of 2015. As at December 31, 2016, the Company had recorded a total of $411 million in insurance recoveries.
- After-tax property, plant and equipment net impairment reversal charges of $202 million were recognized and related to crude oil and natural gas assets located in Western Canada. The impairment reversal was due to an acceleration of forecasted production and revised operational economics, based on recent production performance and market transactions. In addition, the Company recorded an exploration and evaluation land after-tax write-down of $41 million primarily related to oil sands assets.
- The sale of select assets in southern Alberta was completed representing approximately 4,700 boe/day for gross proceeds of $24 million and after-tax gains of $37 million.
- An additional well was brought into production at the South White Rose drill centre.

Q3:

- The Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash and an after-tax gain of $1.32 billion. The assets included approximately 1,900 kilometres of pipeline in the Lloydminster region, 4.1 mmbbls of storage capacity at Hardisty and Lloydminster and other ancillary assets. The assets are held by a newly-formed limited partnership, of which the Company owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent.
- The sale of several packages was completed for select legacy Western Canada crude and natural gas assets in Saskatchewan and Alberta representing approximately 5,000 boe/day for total gross proceeds of approximately $299 million, resulting in an after-tax gain of $167 million.
- The Company's China subsidiary signed a Heads of Agreement ("HOA") with CNOOC and relevant companies for the price adjustment of natural gas from the Liwan 3-1 and Liuhua 34-2 fields to set the price at Cdn. $12.50- Cdn. $15.00 per mcf at the exchange rates existing in the third quarter of 2016. Gross take-or-pay volumes from the fields remained unchanged in the range of 300-330 mmcf/day. Liquids production, net to Husky, was also expected to remain in the range of 5,000 - 6,000 bbls/day. The price adjustment under the HOA is effective as of November 20, 2015, and the settlement of outstanding payment was calculated from that date.
- First production was achieved at the North Amethyst Hibernia formation well.
- First oil was achieved at the 4,500 bbls/day Edam West heavy oil thermal development.

Q2:

- U.S. Refining and Marketing throughput and sales volumes were lower due to major planned turnarounds at both the Lima and BP-Husky Toledo Refineries.
- Prince George Refinery gross margins were lower due to a planned turnaround.
- Demand for natural gas in North America was lower due to unseasonably mild weather conditions coupled with a temporary decline in natural gas demand from Canadian oil sands operations due to the wildfires in the Fort McMurray region of Alberta.
- The Company recorded an exploration and evaluation land after-tax write-down of $22 million relating to two exploration wells drilled in the Flemish Pass Basin which did not encounter economic quantities of hydrocarbons.
- The sale of several packages of select legacy Western Canada crude oil and natural gas assets in Saskatchewan and Alberta was completed, representing approximately 20,500 boe/day for total gross proceeds of approximately $791 million. As a part of one of the transactions, the Company obtained interests in lands with thermal development potential in the Lloydminster region. The Company recorded an after-tax loss of $184 million for the sale.
- The sale of royalty interests was completed representing approximately 1,700 boe/day of Western Canada production. Proceeds included $165 million in cash and other considerations, including the transfer to the Company of royalty and working interests in select heavy oil properties in the Lloydminster area. The Company recorded an after-tax gain of $119 million for the sale.
- First oil was achieved at the 10,000 bbls/day Vawn heavy oil thermal development.
- First oil was achieved at the 10,000 bbls/day Edam East heavy oil thermal development.
- First oil was achieved from the Colony formation at the Tucker Thermal Project.

Q1:

- Upgrading throughput decreased primarily due to unscheduled maintenance.

Segmented Financial Information

2017 *($ millions)*	Upstream								Downstream			
	Exploration and Production[1]				Infrastructure and Marketing				Upgrading			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	**1,355**	1,157	1,215	1,251	**704**	513	426	333	**452**	377	227	384
Royalties	**(97)**	(71)	(91)	(104)	**—**	—	—	—	**—**	—	—	—
Marketing and other	**—**	—	—	—	**(71)**	(4)	(1)	36	**—**	—	—	—
Revenues, net of royalties	**1,258**	1,086	1,124	1,147	**633**	509	425	369	**452**	377	227	384
Expenses												
Purchases of crude oil and products	**(1)**	—	1	—	**657**	495	408	295	**304**	287	144	248
Production, operating and transportation expenses	**390**	413	430	417	**7**	1	2	3	**49**	45	54	49
Selling, general and administrative expenses	**84**	63	61	57	**1**	1	1	1	**3**	1	3	2
Depletion, depreciation, amortization and impairment	**471**	514	705	547	**—**	1	1	—	**30**	31	19	19
Exploration and evaluation expenses	**38**	31	56	21	**—**	—	—	—	**—**	—	—	—
Loss (gain) on sale of assets	**(13)**	3	(33)	1	**—**	—	—	1	**—**	—	—	—
Other – net	**37**	(7)	(39)	15	**(6)**	10	(9)	(3)	**—**	—	—	—
	1,006	1,017	1,181	1,058	**659**	508	403	297	**386**	364	220	318
Earnings from operating activities	**252**	69	(57)	89	**(26)**	1	22	72	**66**	13	7	66
Share of equity investment gain (loss)	**13**	(1)	(1)	1	**(12)**	13	24	24	**—**	—	—	—
Net foreign exchange gains (losses)	**—**	—	—	—	**—**	—	—	—	**—**	—	—	—
Finance income	**1**	2	1	1	**—**	—	—	—	**—**	—	—	—
Finance expenses	**(33)**	(31)	(35)	(32)	**—**	—	—	—	**—**	(1)	—	—
	(32)	(29)	(34)	(31)	**—**	—	—	—	**—**	(1)	—	—
Earnings (loss) before income tax	**233**	39	(92)	59	**(38)**	14	46	96	**66**	12	7	66
Provisions for (recovery of) income taxes												
Current	**(8)**	(25)	12	(13)	**—**	—	—	—	**24**	12	4	23
Deferred	**71**	36	(37)	29	**(11)**	4	13	26	**(6)**	(9)	(2)	(5)
	63	11	(25)	16	**(11)**	4	13	26	**18**	3	2	18
Net earnings (loss)	**170**	28	(67)	43	**(27)**	10	33	70	**48**	9	5	48
Capital expenditures[4]	**525**	355	307	289	**—**	—	—	—	**14**	27	168	21
Total assets	**17,920**	18,021	18,275	18,802	**1,364**	1,447	1,338	1,422	**1,263**	1,261	1,179	1,129

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*
(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*
(3) *During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings.*
(4) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period. Includes Exploration and Production assets acquired through acquisition, and excludes assets acquired through corporation acquisition.*

Downstream (continued)								Corporate and Eliminations[2]				Total			
Canadian Refined Products				U.S. Refining and Marketing[3]											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
815	802	602	568	2,755	2,292	2,135	2,173	(476)	(424)	(253)	(397)	5,605	4,717	4,352	4,312
—	—	—	—	—	—	—	—	—	—	—	—	(97)	(71)	(91)	(104)
—	—	—	—	—	—	—	—	—	—	—	—	(71)	(4)	(1)	36
815	802	602	568	2,755	2,292	2,135	2,173	(476)	(424)	(253)	(397)	5,437	4,642	4,260	4,244
647	650	477	445	2,316	1,876	1,894	1,973	(476)	(424)	(253)	(397)	3,447	2,884	2,671	2,564
66	63	67	60	151	135	137	140	—	—	—	—	663	657	690	669
19	12	11	11	4	4	3	4	121	61	63	59	232	142	142	134
28	27	27	29	90	82	93	89	28	18	17	16	647	673	862	700
—	—	—	—	—	—	—	—	—	—	—	—	38	31	56	21
—	(5)	—	—	—	—	—	—	—	—	—	—	(13)	(2)	(33)	2
(1)	—	—	—	(14)	10	(14)	(3)	(3)	12	(3)	—	13	25	(65)	9
759	747	582	545	2,547	2,107	2,113	2,203	(330)	(333)	(176)	(322)	5,027	4,410	4,323	4,099
56	55	20	23	208	185	22	(30)	(146)	(91)	(77)	(75)	410	232	(63)	145
—	—	—	—	—	—	—	—	—	—	—	—	1	12	23	25
—	—	—	—	—	—	—	—	5	2	(11)	(2)	5	2	(11)	(2)
—	—	—	—	—	—	—	—	10	9	8	5	11	11	9	6
(3)	(3)	(3)	(3)	(4)	(4)	(3)	(3)	(59)	(58)	(62)	(55)	(99)	(97)	(103)	(93)
(3)	(3)	(3)	(3)	(4)	(4)	(3)	(3)	(44)	(47)	(65)	(52)	(83)	(84)	(105)	(89)
53	52	17	20	204	181	19	(33)	(190)	(138)	(142)	(127)	328	160	(145)	81
18	11	6	10	(4)	5	1	—	(14)	(31)	(18)	(16)	16	(28)	5	4
(4)	3	(1)	(5)	79	62	6	(12)	(489)	(44)	(36)	(27)	(360)	52	(57)	6
14	14	5	5	75	67	7	(12)	(503)	(75)	(54)	(43)	(344)	24	(52)	10
39	38	12	15	129	114	12	(21)	313	(63)	(88)	(84)	672	136	(93)	71
25	14	37	11	122	88	52	51	59	27	16	12	745	511	580	384
1,548	1,533	1,516	1,503	7,580	6,676	6,769	7,035	3,252	3,219	3,295	3,003	32,927	32,157	32,372	32,894

	Upstream								Downstream			
	Exploration and Production[(1)]				Infrastructure and Marketing				Upgrading			
2016 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	1,215	941	1,044	836	195	275	270	215	340	334	369	281
Royalties	(105)	(56)	(90)	(54)	—	—	—	—	—	—	—	—
Marketing and other	—	—	—	—	(9)	5	18	(102)	—	—	—	—
Revenues, net of royalties	1,110	885	954	782	186	280	288	113	340	334	369	281
Expenses												
Purchases of crude oil and products	—	6	14	12	186	273	227	171	224	225	222	137
Production, operating and transportation expenses	438	429	442	451	3	2	7	8	49	43	40	36
Selling, general and administrative expenses	81	57	52	42	2	1	1	1	2	—	1	1
Depletion, depreciation, amortization and impairment	237	474	542	562	—	1	6	6	21	27	27	28
Exploration and evaluation expenses	78	17	76	17	—	—	—	—	—	—	—	—
Loss (gain) on sale of assets	(55)	(236)	96	2	3	(1,442)	—	—	—	—	—	—
Other – net	29	18	9	(2)	4	(3)	(1)	(3)	—	—	(1)	—
	808	765	1,231	1,084	198	(1,168)	240	183	296	295	289	202
Earnings from operating activities	302	120	(277)	(302)	(12)	1,448	48	(70)	44	39	80	79
Share of equity investment gain (loss)	2	(1)	(1)	(1)	36	(20)	—	—	—	—	—	—
Net foreign exchange gains (losses)	—	—	—	—	—	—	—	—	—	—	—	—
Finance income	2	3	—	—	—	—	—	—	—	—	—	—
Finance expenses	(34)	(35)	(36)	(40)	—	—	—	—	—	(1)	—	—
	(32)	(32)	(36)	(40)	—	—	—	—	—	(1)	—	—
Earnings (loss) before income taxes	272	87	(314)	(343)	24	1,428	48	(70)	44	38	80	79
Provisions for (recovery of) income taxes												
Current	12	(9)	6	(109)	—	—	—	—	—	—	—	—
Deferred	62	33	(92)	16	6	122	13	(19)	12	11	22	21
	74	24	(86)	(93)	6	122	13	(19)	12	11	22	21
Net earnings (loss)	198	63	(228)	(250)	18	1,306	35	(51)	32	27	58	58
Capital expenditures[(3)(4)]	274	173	250	175	3	(5)	24	32	19	13	13	6
Total assets	19,098	18,654	19,008	20,454	1,582	1,407	1,732	1,647	1,076	1,082	1,151	1,131

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*

(3) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

Downstream (continued)								Corporate and Eliminations[2]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
603	678	585	435	1,890	1,642	1,337	1,126	(369)	(355)	(362)	(213)	3,874	3,515	3,243	2,680
—	—	—	—	—	—	—	—	—	—	—	—	(105)	(56)	(90)	(54)
—	—	—	—	—	—	—	—	—	—	—	—	(9)	5	18	(102)
603	678	585	435	1,890	1,642	1,337	1,126	(369)	(355)	(362)	(213)	3,760	3,464	3,171	2,524
475	516	440	339	1,617	1,448	1,083	1,040	(369)	(355)	(362)	(213)	2,133	2,113	1,624	1,486
66	62	64	49	144	127	127	137	—	—	—	—	700	663	680	681
23	6	7	7	4	3	3	3	63	39	82	63	175	106	146	117
27	26	25	24	96	88	77	81	24	22	20	21	405	638	697	722
—	—	—	—	—	—	—	—	—	—	—	—	78	17	76	17
—	(2)	(1)	—	—	—	—	—	—	—	—	—	(52)	(1,680)	95	2
(1)	(8)	—	(1)	(1)	—	(50)	(125)	(4)	(17)	65	66	27	(10)	22	(65)
590	600	535	418	1,860	1,666	1,240	1,136	(286)	(311)	(195)	(63)	3,466	1,847	3,340	2,960
13	78	50	17	30	(24)	97	(10)	(83)	(44)	(167)	(150)	294	1,617	(169)	(436)
—	—	—	—	—	—	—	—	—	—	—	—	38	(21)	(1)	(1)
—	—	—	—	—	—	—	—	8	1	(9)	13	8	1	(9)	13
—	—	—	—	—	—	—	—	5	2	—	5	7	5	—	5
(2)	(2)	(1)	(2)	(1)	—	(1)	(1)	(63)	(60)	(58)	(64)	(100)	(98)	(96)	(107)
(2)	(2)	(1)	(2)	(1)	—	(1)	(1)	(50)	(57)	(67)	(46)	(85)	(92)	(105)	(89)
11	76	49	15	29	(24)	96	(11)	(133)	(101)	(234)	(196)	247	1,504	(275)	(526)
—	—	—	—	—	—	—	—	4	24	23	48	16	15	29	(61)
3	21	13	4	10	(8)	35	(4)	(48)	(80)	(99)	(25)	45	99	(108)	(7)
3	21	13	4	10	(8)	35	(4)	(44)	(56)	(76)	23	61	114	(79)	(68)
8	55	36	11	19	(16)	61	(7)	(89)	(45)	(158)	(219)	186	1,390	(196)	(458)
12	3	29	8	67	107	267	182	16	18	12	7	391	309	595	410
1,410	1,419	1,458	1,399	7,017	6,822	6,866	6,444	2,077	2,179	763	821	32,260	31,563	30,978	31,896

Management's Report

The management of Husky Energy Inc. ("the Company") is responsible for the financial information and operating data presented in this financial document.

The consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this financial document has been prepared on a basis consistent with that in the consolidated financial statements.

The Company maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that the Company's internal control over financial reporting was effective as of December 31, 2017. The system of internal controls is further supported by an internal audit function.

The Audit Committee of the Board of Directors, composed of independent non-management directors, meets regularly with management, internal auditors as well as the external auditors, to discuss audit (external, internal and joint venture), internal controls, accounting policy and financial reporting matters as well as the reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board. The Committee is also responsible for the appointment of the external auditors for the Company.

The consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with Canadian Auditing Standards and the standards of the Public Company Accounting Oversight Board (United States) on behalf of the shareholders. KPMG LLP has full and free access to the Audit Committee.

Robert J. Peabody
President & Chief Executive Officer

Jonathan M. McKenzie
Chief Financial Officer

Calgary, Canada
February 28, 2018

Independent Auditors' Report

To the Shareholders and the Board of Directors of Husky Energy Inc.

We have audited the accompanying consolidated financial statements of Husky Energy Inc., which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Husky Energy Inc. as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 28, 2018

Consolidated Financial Statements

Consolidated Balance Sheets

(millions of Canadian dollars)	**December 31, 2017**	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents *(note 4)*	**2,513**	1,319
Accounts receivable *(notes 5, 24)*	**1,186**	1,036
Income taxes receivable	**164**	186
Inventories *(note 6)*	**1,513**	1,558
Prepaid expenses	**145**	135
Restricted cash *(notes 7, 16)*	**95**	84
	5,616	4,318
Restricted cash *(note 7, 16)*	**97**	72
Exploration and evaluation assets *(note 8)*	**838**	1,066
Property, plant and equipment, net *(note 9)*	**24,078**	24,593
Goodwill *(note 10)*	**633**	679
Investment in joint ventures *(note 11)*	**1,238**	1,128
Long-term income taxes receivable	**242**	232
Other assets *(note 12)*	**185**	172
Total Assets	**32,927**	32,260
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities *(note 14)*	**3,033**	2,226
Short-term debt *(note 15)*	**200**	200
Long-term debt due within one year *(note 15)*	**—**	403
Contribution payable due within one year *(note 11)*	**—**	146
Asset retirement obligations *(note 16)*	**274**	218
	3,507	3,193
Long-term debt *(note 15)*	**5,240**	4,736
Other long-term liabilities *(note 17)*	**1,237**	1,020
Asset retirement obligations *(note 16)*	**2,252**	2,573
Deferred tax liabilities *(note 18)*	**2,724**	3,111
Total Liabilities	**14,960**	14,633
Shareholders' equity		
Common shares *(note 19)*	**7,293**	7,296
Preferred shares *(note 19)*	**874**	874
Contributed surplus	**2**	—
Retained earnings	**9,207**	8,457
Accumulated other comprehensive income	**580**	989
Non-controlling interest	**11**	11
Total Shareholders' Equity	**17,967**	17,627
Total Liabilities and Shareholders' Equity	**32,927**	32,260

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

Robert J. Peabody
Director

William Shurniak
Director

Consolidated Statements of Income

(millions of Canadian dollars, except share data)	Year ended December 31, **2017**	2016
Gross revenues	**18,986**	13,312
Royalties	**(363)**	(305)
Marketing and other	**(40)**	(88)
Revenues, net of royalties	**18,583**	12,919
Expenses		
Purchases of crude oil and products	**11,566**	7,356
Production, operating and transportation expenses *(note 20)*	**2,679**	2,724
Selling, general and administrative expenses *(note 20)*	**650**	544
Depletion, depreciation, amortization and impairment *(notes 9, 10)*	**2,882**	2,462
Exploration and evaluation expenses *(note 8)*	**146**	188
Gain on sale of assets *(note 9)*	**(46)**	(1,634)
Other – net	**(18)**	(27)
	17,859	11,613
Earnings from operating activities	**724**	1,306
Share of equity investment gain *(note 11)*	**61**	15
Financial items *(note 21)*		
Net foreign exchange gains (losses)	**(6)**	13
Finance income	**37**	17
Finance expenses	**(392)**	(401)
	(361)	(371)
Earnings before income taxes	**424**	950
Provisions for (recovery of) income taxes *(note 18)*		
Current	**(3)**	(1)
Deferred	**(359)**	29
	(362)	28
Net earnings	**786**	922
Earnings per share *(note 19)*		
Basic	**0.75**	0.88
Diluted	**0.75**	0.88
Weighted average number of common shares outstanding *(note 19)*		
Basic *(millions)*	**1,005.3**	1,004.9
Diluted *(millions)*	**1,005.3**	1,004.9

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Comprehensive Income

	Year ended December 31,	
(millions of Canadian dollars)	**2017**	2016
Net earnings	**786**	922
Other comprehensive loss		
Items that will not be reclassified into earnings, net of tax:		
Remeasurements of pension plans *(note 22)*	**(7)**	(18)
Items that may be reclassified into earnings, net of tax:		
Derivatives designated as cash flow hedges *(note 24)*	**(2)**	(2)
Equity investment – share of other comprehensive income	**3**	2
Exchange differences on translation of foreign operations	**(653)**	(247)
Hedge of net investment *(note 24)*	**243**	113
Other comprehensive loss	**(416)**	(152)
Comprehensive income	**370**	770

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Changes in Shareholders' Equity

	Attributable to Equity Holders							
					AOCI [1]			
(millions of Canadian dollars)	Common Shares	Preferred Shares	Contributed Surplus	Retained Earnings	Foreign Currency Translation	Hedging	Non-Controlling Interest	Total Shareholders' Equity
Balance as at December 31, 2015	7,000	874	—	7,589	1,103	20	—	16,586
Net earnings	—	—		922	—	—	—	922
Other comprehensive income (loss)								
Remeasurements of pension plans (net of tax recovery of $6 million) *(notes 18, 22)*	—	—	—	(18)	—	—	—	(18)
Derivatives designated as cash flow hedges (net of tax recovery of less than $1 million) *(notes 18, 24)*	—	—	—	—	—	(2)	—	(2)
Equity investment – share of other comprehensive income	—	—	—	—	—	2	—	2
Exchange differences on translation of foreign operations (net of tax recovery of $40 million) *(note 18)*	—	—	—	—	(247)	—	—	(247)
Hedge of net investment (net of tax loss of $17 million) *(notes 18, 24)*	—	—	—	—	113	—	—	113
Total comprehensive income (loss)	—	—	—	904	(134)	—	—	770
Transactions with owners recognized directly in equity:								
Stock dividends paid *(note 19)*	296	—		—	—	—	—	296
Dividends declared on preferred shares *(note 19)*	—	—		(36)	—	—	—	(36)
Non-controlling interest	—	—	—	—	—	—	11	11
Balance as at December 31, 2016	7,296	874	—	8,457	969	20	11	17,627
Net earnings	**—**	**—**		**786**	**—**	**—**	**—**	**786**
Other comprehensive income (loss)								
Remeasurements of pension plans (net of tax recovery of $4 million) *(notes 18, 22)*	**—**	**—**		**(7)**	**—**	**—**	**—**	**(7)**
Derivatives designated as cash flow hedges (net of tax expense of less than $1 million) *(notes 18, 24)*	**—**	**—**		**—**	**—**	**(2)**	**—**	**(2)**
Equity investment – share of other comprehensive income	**—**	**—**		**—**	**—**	**3**	**—**	**3**
Exchange differences on translation of foreign operations (net of tax recovery of $82 million) *(note 18)*	**—**	**—**		**—**	**(653)**	**—**	**—**	**(653)**
Hedge of net investment (net of tax loss of $38 million) *(notes 18, 24)*	**—**	**—**		**—**	**243**	**—**	**—**	**243**
Total comprehensive income (loss)	**—**	**—**	**—**	**779**	**(410)**	**1**	**—**	**370**
Transactions with owners recognized directly in equity:								
Dividends declared on preferred shares *(note 19)*	**—**	**—**	**—**	**(34)**	**—**	**—**	**—**	**(34)**
Share cancellation *(note 19)*	**(3)**	**—**	**2**	**5**	**—**	**—**	**—**	**4**
Balance as at December 31, 2017	**7,293**	**874**	**2**	**9,207**	**559**	**21**	**11**	**17,967**

[1] *Accumulated other comprehensive income.*

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows

	Year ended December 31,	
(millions of Canadian dollars)	**2017**	2016
Operating activities		
Net earnings	**786**	922
Items not affecting cash:		
Accretion *(note 21)*	**112**	126
Depletion, depreciation, amortization and impairment *(note 9)*	**2,882**	2,462
Inventory write-down to net realizable value *(note 6)*	**—**	9
Exploration and evaluation expenses *(note 8)*	**6**	86
Deferred income taxes *(note 18)*	**(359)**	29
Foreign exchange	**(4)**	(4)
Stock-based compensation *(notes 19, 20)*	**45**	33
Gain on sale of assets *(note 9)*	**(46)**	(1,634)
Unrealized mark to market loss	**56**	38
Share of equity investment gain *(note 11)*	**(61)**	(15)
Other	**16**	24
Settlement of asset retirement obligations *(note 16)*	**(136)**	(87)
Deferred revenue *(note 17)*	**(16)**	209
Distribution from joint ventures *(note 11)*	**25**	—
Change in non-cash working capital *(note 23)*	**398**	(227)
Cash flow – operating activities	**3,704**	1,971
Financing activities		
Long-term debt issuance *(note 15)*	**750**	6,181
Long-term debt repayment *(note 15)*	**(365)**	(6,949)
Short-term debt repayment *(note 15)*	**—**	(520)
Debt issue costs *(note 15)*	**(6)**	—
Dividends on preferred shares *(note 19)*	**(34)**	(27)
Other	**18**	21
Change in non-cash working capital *(note 23)*	**—**	(68)
Cash flow – financing activities	**363**	(1,362)
Investing activities		
Capital expenditures	**(2,220)**	(1,705)
Corporate acquisition *(note 9)*	**(670)**	—
Proceeds from asset sales *(note 9)*	**192**	2,935
Contribution payable payment *(note 11)*	**(142)**	(193)
Contribution to joint ventures *(note 11)*	**(81)**	(102)
Other	**(40)**	(30)
Change in non-cash working capital *(note 23)*	**172**	(273)
Cash flow – investing activities	**(2,789)**	632
Increase in cash and cash equivalents	**1,278**	1,241
Effect of exchange rates on cash and cash equivalents	**(84)**	8
Cash and cash equivalents at beginning of year	**1,319**	70
Cash and cash equivalents at end of year	**2,513**	1,319
Supplementary cash flow information		
Net interest paid	**(334)**	(344)
Income taxes received	**41**	3

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to the Consolidated Financial Statements

Note 1 Description of Business and Segmented Disclosures

Husky Energy Inc. ("Husky" or "the Company") is an international integrated energy company incorporated under the Business Corporations Act (Alberta). The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and the Cumulative Redeemable Preferred Shares, Series 1, Cumulative Redeemable Preferred Shares, Series 2, Cumulative Redeemable Preferred Shares, Series 3, Cumulative Redeemable Preferred Shares, Series 5 and Cumulative Redeemable Preferred Shares, Series 7 are listed under the symbols, "HSE.PR.A","HSE.PR.B", "HSE.PR.C", "HSE.PR.E" and "HSE.PR.G", respectively. The registered office is located at 707, 8th Avenue S.W., PO Box 6525, Station D, Calgary, Alberta, T2P 3G7.

Management has identified segments for the Company's business based on differences in products, services and management responsibility. The Company's business is conducted predominantly through two major business segments – Upstream and Downstream.

Upstream operations in the Integrated Corridor and Offshore include exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids ("NGL") ("Exploration and Production") and marketing of the Company's and other producers' crude oil, natural gas, NGLs, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and natural gas, and storage of crude oil, diluent and natural gas ("Infrastructure and Marketing"). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Alberta, Saskatchewan, and British Columbia ("Western Canada"), offshore east coast of Canada ("Atlantic") and offshore China and offshore Indonesia ("Asia Pacific").

Downstream operations in the Integrated Corridor include upgrading of heavy crude oil feedstock into synthetic crude oil in Canada ("Upgrading"), refining crude oil in Canada, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol ("Canadian Refined Products"). It also includes refining in the U.S. of primarily crude oil to produce and market asphalt, gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards ("U.S. Refining and Marketing"). Upgrading, Canadian Refined Products and U.S. Refining and Marketing all process and refine natural resources into marketable products and are grouped together as the Downstream business segment due to the similar nature of their products and services.

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[(1)]		Infrastructure and Marketing[(2)]		Total	
Year ended December 31,	**2017**	2016	**2017**	2016	**2017**	2016
Gross revenues	**4,978**	4,036	**1,976**	955	**6,954**	4,991
Royalties	**(363)**	(305)	**—**	—	**(363)**	(305)
Marketing and other	**—**	—	**(40)**	(88)	**(40)**	(88)
Revenues, net of royalties	**4,615**	3,731	**1,936**	867	**6,551**	4,598
Expenses						
Purchases of crude oil and products	**—**	32	**1,855**	857	**1,855**	889
Production, operating and transportation expenses	**1,650**	1,760	**13**	20	**1,663**	1,780
Selling, general and administrative expenses	**265**	232	**4**	5	**269**	237
Depletion, depreciation, amortization and impairment	**2,237**	1,815	**2**	13	**2,239**	1,828
Exploration and evaluation expenses	**146**	188	**—**	—	**146**	188
Loss (gain) on sale of assets	**(42)**	(192)	**1**	(1,439)	**(41)**	(1,631)
Other – net	**6**	53	**(8)**	(3)	**(2)**	50
	4,262	3,888	**1,867**	(547)	**6,129**	3,341
Earnings (loss) from operating activities	**353**	(157)	**69**	1,414	**422**	1,257
Share of equity investment gain (loss)	**12**	(1)	**49**	16	**61**	15
Financial items						
Net foreign exchange gain (loss)	**—**	—	**—**	—	**—**	—
Finance income	**5**	5	**—**	—	**5**	5
Finance expenses	**(131)**	(145)	**—**	—	**(131)**	(145)
	(126)	(140)	**—**	—	**(126)**	(140)
Earnings (loss) before income taxes	**239**	(298)	**118**	1,430	**357**	1,132
Provisions for (recovery of) income taxes						
Current	**(34)**	(100)	**—**	—	**(34)**	(100)
Deferred	**99**	19	**32**	122	**131**	141
	65	(81)	**32**	122	**97**	41
Net earnings (loss)	**174**	(217)	**86**	1,308	**260**	1,091
Intersegment revenues	**1,250**	988	**—**	—	**1,250**	988

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Includes $280 million of revenue (2016 - nil) and $234 million of associated costs (2016 - nil) for construction contracts, inclusive of $259 million of revenue (2016 - nil) and $236 million of costs (2016 - nil) for contracts in progress accounted for under the percentage of completion method.*

(3) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices. Segment results include transactions between business segments.*

Downstream								Corporate and Eliminations[3]		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2017	2016	2017	2016	2017	2016	2017	2016	2017	2016	2017	2016
1,440	1,324	2,787	2,301	9,355	5,995	13,582	9,620	(1,550)	(1,299)	18,986	13,312
—	—	—	—	—	—	—	—	—	—	(363)	(305)
—	—	—	—	—	—	—	—	—	—	(40)	(88)
1,440	1,324	2,787	2,301	9,355	5,995	13,582	9,620	(1,550)	(1,299)	18,583	12,919
983	808	2,219	1,770	8,059	5,188	11,261	7,766	(1,550)	(1,299)	11,566	7,356
197	168	256	241	563	535	1,016	944	—	—	2,679	2,724
9	4	53	43	15	13	77	60	304	247	650	544
99	103	111	102	354	342	564	547	79	87	2,882	2,462
—	—	—	—	—	—	—	—	—	—	146	188
—	—	(5)	(3)	—	—	(5)	(3)	—	—	(46)	(1,634)
—	(1)	(1)	(10)	(21)	(176)	(22)	(187)	6	110	(18)	(27)
1,288	1,082	2,633	2,143	8,970	5,902	12,891	9,127	(1,161)	(855)	17,859	11,613
152	242	154	158	385	93	691	493	(389)	(444)	724	1,306
—	—	—	—	—	—	—	—	—	—	61	15
—	—	—	—	—	—	—	—	(6)	13	(6)	13
—	—	—	—	—	—	—	—	32	12	37	17
(1)	(1)	(12)	(7)	(14)	(3)	(27)	(11)	(234)	(245)	(392)	(401)
(1)	(1)	(12)	(7)	(14)	(3)	(27)	(11)	(208)	(220)	(361)	(371)
151	241	142	151	371	90	664	482	(597)	(664)	424	950
63	—	45	—	2	—	110	—	(79)	99	(3)	(1)
(22)	66	(7)	41	135	33	106	140	(596)	(252)	(359)	29
41	66	38	41	137	33	216	140	(675)	(153)	(362)	28
110	175	104	110	234	57	448	342	78	(511)	786	922
192	157	108	154	—	—	300	311	—	—	1,550	1,299

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2017**	2016	**2017**	2016	**2017**	2016
Expenditures on exploration and evaluation assets[2]	**148**	46	**—**	—	**148**	46
Expenditures on property, plant and equipment[2]	**1,328**	826	**—**	54	**1,328**	880
As at December 31,						
Exploration and evaluation assets	**838**	1,066	**—**	—	**838**	1,066
Developing and producing assets at cost	**41,804**	44,790	**—**	—	**41,804**	44,790
Accumulated depletion, depreciation, amortization and impairment	**(26,014)**	(27,984)	**—**	—	**(26,014)**	(27,984)
Other property, plant and equipment at cost	**—**	—	**89**	140	**89**	140
Accumulated depletion, depreciation and amortization	**—**	—	**(50)**	(99)	**(50)**	(99)
Total exploration and evaluation assets and property, plant and equipment, net	**16,628**	17,872	**39**	41	**16,667**	17,913
Total assets	**17,920**	19,098	**1,364**	1,582	**19,284**	20,680

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the year. Includes Exploration and Production assets acquired through acquisition, but excludes assets acquired through corporation acquisition.*

Geographical Financial Information

($ millions)	Canada		United States	
Year ended December 31,	**2017**	2016	**2017**	2016
Gross revenues[1]	**8,599**	6,510	**9,355**	5,995
Royalties	**(303)**	(261)	**—**	—
Marketing and other	**(40)**	(88)	**—**	—
Revenue, net of royalties	**8,256**	6,161	**9,355**	5,995
As at December 31,				
Restricted cash – non-current	**—**	—	**—**	—
Exploration and evaluation assets	**831**	654	**—**	—
Property, plant and equipment, net	**15,478**	16,112	**5,595**	5,341
Goodwill	**—**	—	**633**	679
Investment in joint ventures	**685**	640	**—**	—
Long-term income tax receivable	**242**	232	**—**	—
Other assets	**64**	43	**21**	23
Total non-current assets	**17,300**	17,681	**6,249**	6,043

(1) *Sales to external customers are based on the location of the seller.*

Downstream								Corporate and Eliminations		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2017	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**148**	46
230	51	**87**	52	**313**	623	**630**	726	**114**	53	**2,072**	1,659
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**838**	1,066
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**41,804**	44,790
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**(26,014)**	(27,984)
2,600	2,367	**2,704**	2,500	**8,300**	7,897	**13,604**	12,764	**1,124**	1,011	**14,817**	13,915
(1,463)	(1,363)	**(1,466)**	(1,344)	**(2,705)**	(2,556)	**(5,634)**	(5,263)	**(845)**	(766)	**(6,529)**	(6,128)
1,137	1,004	**1,238**	1,156	**5,595**	5,341	**7,970**	7,501	**279**	245	**24,916**	25,659
1,263	1,076	**1,548**	1,410	**7,580**	7,017	**10,391**	9,503	**3,252**	2,077	**32,927**	32,260

China		Other International		Total	
2017	2016	**2017**	2016	**2017**	2016
1,032	807	**—**	—	**18,986**	13,312
(60)	(44)	**—**	—	**(363)**	(305)
—	—	**—**	—	**(40)**	(88)
972	763	**—**	—	**18,583**	12,919
97	72	**—**	—	**97**	72
3	407	**4**	5	**838**	1,066
3,005	3,139	**—**	1	**24,078**	24,593
—	—	**—**	—	**633**	679
—	—	**553**	488	**1,238**	1,128
—	—	**—**	—	**242**	232
78	83	**22**	23	**185**	172
3,183	3,701	**579**	517	**27,311**	27,942

Note 2 Basis of Presentation

a) Basis of Measurement and Statement of Compliance

The consolidated financial statements have been prepared by management on a historical cost basis with some exceptions, as detailed in the accounting policies set out below in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). These accounting policies have been applied consistently for all periods presented in these consolidated financial statements.

These consolidated financial statements were approved and signed by the Chair of the Audit Committee and the Chief Executive Officer on February 28, 2018 having been duly authorized to do so by the Board of Directors.

Certain prior years' amounts have been reclassified to conform with current presentation.

b) Principles of Consolidation

The consolidated financial statements include the accounts of Husky Energy Inc. and its subsidiaries. Subsidiaries are defined as any entities, including unincorporated entities such as partnerships, for which the Company has the power to govern their financial and operating policies to obtain benefits from their activities. The Company's accounts reflect the proportionate share of the assets, liabilities, revenues, expenses and cash flows from the Company's activities that are conducted jointly with third parties. Intercompany balances, net earnings and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements. A portion of the Company's activities relate to joint ventures (see Note 11), which are accounted for using the equity method.

c) Use of Estimates, Judgments and Assumptions

The timely preparation of the consolidated financial statements requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenue and expenses during the period. Actual results may differ from these estimates, judgments and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and on a prospective basis. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained, and as the Company's operating environment changes. Specifically, amounts recorded for depletion, depreciation, amortization and impairment, asset retirement obligations, assets and liabilities measured at fair value, employee future benefits, income taxes and reserves and contingencies are based on estimates.

Management makes judgments regarding the application of IFRS for each accounting policy. Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include determination of technical feasibility and commercial viability, impairment assessments, the determination of cash generating units ("CGUs"), changes in reserve estimates, the determination of a joint arrangement, the designation of the Company's functional currency and the fair value of related party transactions.

Significant estimates, judgments and assumptions made by management in the preparation of these consolidated financial statements are outlined in detail in Note 3.

d) Functional and Presentation Currency

The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is presented in millions of Canadian dollars, except per share amounts and unless otherwise stated.

The designation of the Company's functional currency is a management judgment based on the currency of the primary economic environment in which the Company operates.

Note 3 Significant Accounting Policies

a) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand less outstanding cheques and deposits with an original maturity of less than three months at the time of purchase. When outstanding cheques are in excess of cash on hand and short-term deposits, and the Company has the ability to net settle, the excess is reported in bank operating loans.

Cash and cash equivalents held that are not available for use are classified as restricted cash. When restricted cash is not expected to be used within 12 months, it is classified as a non-current asset.

b) Inventories

Crude oil, natural gas, refined petroleum products and sulphur inventories are valued at the lower of cost or net realizable value. Cost is determined using average cost or on a first-in, first-out basis, as appropriate. Materials, parts and supplies are valued at the lower of average cost or net realizable value. Cost consists of raw material, labour, direct overhead, operating costs, transportation and depreciation, depletion and amortization. Commodity inventories held for trading purposes are carried at fair value and measured at fair value less costs to sell based on Level 2 observable inputs, refer to policy Note 3 (m). Any changes in commodity inventory fair value are included as gains or losses in marketing and other in the consolidated statements of income, during the period of change. Previous inventory impairment provisions are reversed when there is a change in the condition that caused the impairment and the inventory remains on hand. Unrealized intersegment net earnings on inventory sales are eliminated.

c) Precious Metals

The Company uses precious metals in conjunction with a catalyst as part of the downstream upgrading and refining processes. These precious metals remain intact; however, there is a loss during the reclamation process. The estimated loss is amortized to production and operating expenses over the period that the precious metal is in use, which is approximately two to five years. After the reclamation process, the actual loss is compared to the estimated loss and any difference is recognized in net earnings. Precious metals are included in other assets on the balance sheet.

d) Exploration and Evaluation Assets and Property, Plant and Equipment

i) Cost

Oil and gas properties and other property, plant and equipment are recorded at cost, including expenditures that are directly attributable to the purchase or development of an asset. Borrowing costs directly attributable to the acquisition, construction or production of a qualifying asset are included in the asset cost. Capitalization ceases when substantially all activities necessary to prepare the qualifying asset for its intended use are complete.

ii) Exploration and Evaluation Costs

The accounting treatment of costs incurred for oil and natural gas exploration, evaluation and development is determined by the classification of the underlying activities as either exploratory or developmental. The results from an exploration drilling program can take considerable time to analyze, and the determination that commercial reserves have been discovered requires determination of technical feasibility, commercial viability and industry experience. Exploration activities can fluctuate from year to year, due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in exploratory drilling and the degree of risk associated with drilling in particular areas. Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance.

Costs incurred after the legal right to explore an area has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as exploration and evaluation assets. These costs include costs to acquire acreage and exploration rights, legal and other professional fees and land brokerage fees. Pre-license costs and geological and geophysical costs associated with exploration activities are expensed in the period incurred. Costs directly associated with an exploration well are initially capitalized as an exploration and evaluation asset until the drilling of the well is complete and the results have been evaluated. If extractable hydrocarbons are found and are likely to be developed commercially, but are subject to further appraisal activity, which may include the drilling of wells, the costs continue to be carried as an exploration and evaluation asset while sufficient and continued progress is made in assessing the commercial viability of the hydrocarbons. Capitalized exploration and evaluation costs or assets are not depreciated and are carried forward until technical feasibility and commercial viability of the area is determined or the assets are determined to be impaired. Management determines technical feasibility and commercial viability when exploration and evaluation assets are reclassified to property, plant and equipment. This decision considers several factors, including the existence of reserves, establishing commercial and technical feasibility and whether the asset can be developed using a proved development concept and has received internal approval. Upon the determination of technical feasibility and commercial viability, capitalized exploration and evaluation assets are then transferred to property, plant and equipment. All such carried costs are subject to technical, commercial and management review, as well as review for impairment indicators, at least every reporting period to confirm the continued intent to develop or otherwise extract value from the discovery. These costs are also tested for impairment when transferred to property, plant and equipment. Capitalized exploration and evaluation expenditures related to wells that do not find reserves, or where no future activity is planned, are expensed as exploration and evaluation expenses.

The application of the Company's accounting policy for exploration and evaluation costs 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. Judgments may change as new information becomes available.

iii) Development Costs

Expenditures, including borrowing costs, on the construction, installation and completion of infrastructure facilities, such as platforms, pipelines and the drilling of development wells, are capitalized as oil and gas properties. Costs incurred to operate and maintain wells and equipment to lift oil and gas to the surface are expensed as production and operating expenses.

iv) Other Property, Plant and Equipment

Repair and maintenance costs, other than major turnaround costs, are expensed as incurred. Major turnaround costs are capitalized as part of property, plant and equipment when incurred and are amortized over the estimated period of time to the anticipated date of the next turnaround.

v) Depletion, Depreciation and Amortization

Oil and gas properties are depleted on a unit-of-production basis over the proved developed reserves of the particular field, except in the case of assets whose useful life is shorter or longer than the lifetime of the proved developed reserves of that field, in which case the straight-line method or a unit-of-production method based on total proved plus probable reserves is applied. The unit-of-production rate for the depletion of oil and gas properties related to total proved plus probable reserves takes into account expenditures incurred to date together with sanctioned future development expenditures required to develop the field.

Oil and gas reserves are evaluated internally and audited by independent qualified reserve engineers. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty. Changes in reserve estimates can have an impact on reported net earnings through revisions to depletion, depreciation and amortization expense, in addition to determining possible impairments and reversal of impairments of property, plant and equipment.

Net reserves represent the Company's undivided gross working interest in total reserves after deducting crown, freehold and overriding royalty interests. Assumptions reflect market and regulatory conditions, as applicable, as at the balance sheet date and could differ significantly from other points in time throughout the year or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Depreciation for substantially all other property, plant and equipment is provided using the straight-line method based on the estimated useful lives of assets, which range from five to forty-five years, less any estimated residual value. The useful lives of assets are estimated based upon the period the asset is expected to be available for use by the Company. Residual values are based upon the estimated amount that would be obtained on disposal, net of any costs associated with the disposal. Other property, plant and equipment held under finance leases are depreciated over the shorter of the lease term and the estimated useful life of the asset.

Depletion, depreciation and amortization rates for all capitalized costs associated with the Company's activities are reviewed at least annually, or when events or conditions occur that impact capitalized costs, reserves and estimated service lives.

vi) Finance Leases

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the lease property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

All other leases are accounted for as operating leases and the lease costs are expensed as incurred.

e) Joint Arrangements

Joint arrangements represent activities where the Company has joint control established by a contractual agreement. Joint control requires unanimous consent for financial and operational decisions. A joint arrangement is either a joint operation, whereby the parties have rights to the assets and obligations for the liabilities, or a joint venture, whereby the parties have rights to the net assets.

For a joint operation, the consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of the joint arrangement. The Company reports items of a similar nature to those on the financial statements of the joint arrangement, on a line-by-line basis, from the date that joint control commences until the date that joint control ceases.

Joint ventures are accounted for using the equity method of accounting and recognized at cost and adjusted thereafter for the post-acquisition change in the Company's share of the joint venture's net assets. The Company's consolidated financial statements include its share of the joint venture's profit or loss and other comprehensive income ("OCI") included in investment in joint ventures, until the date that joint control ceases.

Classification of a joint arrangement as either joint operation or joint venture requires judgment. Management's considerations include, but are not limited to, determining if the arrangement is structured through a separate vehicle and whether the legal form and contractual arrangements give the entity direct rights to the assets and obligations for the liabilities within the normal course of business. Other facts and circumstances are also assessed by management, including the entity's rights to the economic benefits of assets and its involvement and responsibility for settling liabilities associated with the arrangement.

f) Investments in Associates

An associate is an entity for which the Company has significant influence and thereby has the power to participate in the financial and operational decisions but does not control or jointly control the investee. Investments in associates are accounted for using the equity method of accounting and are recognized at cost and adjusted thereafter for the post-acquisition change in the Company's share of the investee's net assets. The Company's consolidated financial statements include its share of the investee's profit or loss and OCI until the date that significant influence ceases.

g) Business Combinations

Business combinations are accounted for using the acquisition method. Determining whether an acquisition meets the definition of a business combination or represents an asset purchase requires judgment on a case-by-case basis. If the acquisition meets the definition of a business combination, the assets and liabilities are recognized based on the contractual terms, economic conditions, the Company's operating and accounting policies and other factors that exist on the acquisition date, which is the date on which control is transferred to the Company. The identifiable assets and liabilities are measured at their fair values on the acquisition date with limited exceptions. Any additional consideration payable, contingent upon the occurrence of a future event, is recognized at fair value on the acquisition date; subsequent changes in the fair value of the liability are recognized in net earnings. Acquisition costs incurred are expensed and included in selling, general and administrative expenses in the consolidated statements of income.

h) Goodwill

Goodwill is the excess of the purchase price paid over the recognized amount of net assets acquired through business combinations, which is inherently imprecise as judgment is required in the determination of the fair value of assets and liabilities. Goodwill, which is not amortized, is assigned to appropriate CGUs or groups of CGUs. Goodwill is tested for impairment annually and when circumstances indicate that the carrying value may be impaired. Impairment losses are recognized in net earnings and are not subject to reversal. On the disposal or termination of a previously acquired business, any remaining balance of associated goodwill is included in the determination of the gain or loss on disposal.

i) Impairment and Reversals of Impairment on Non-Financial Assets

The carrying amounts of the Company's non-financial assets, other than inventories and deferred tax assets, are reviewed at the end of each reporting period to determine whether there is an indication of impairment or reversal of impairment. If such indication exists, the recoverable amount is estimated.

Determining whether there are any indications of impairment or impairment reversals requires significant judgment of external factors, such as an extended change in prices or margins for oil and gas commodities or products, a significant change in an asset's market value, a significant revision of estimated volumes, revision of future development costs, a change in the entity's market capitalization or significant changes in the technological, market, economic or legal environment that would have an impact on the Company's CGUs. If any indication of impairment or impairment reversals exist, an estimate of the asset's recoverable amount is calculated as the higher of the fair value less costs to sell ("FVLCS") and the asset's value in use ("VIU") for an individual asset or CGU. If the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, the asset is tested as part of a CGU, which is the smallest identifiable group of assets, liabilities and associated goodwill that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. Determination of the Company's CGUs is subject to management's judgment.

FVLCS is the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCS is generally determined as the net present value of the estimated future cash flows expected to arise from a CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted using a rate that would be applied by a market participant to arrive at a net present value of the CGU.

VIU is the net present value of the estimated future cash flows expected to arise from the continued use of the asset in its present form and its eventual disposal. VIU is determined by applying assumptions specific to the Company's continued use and can only take into account sanctioned future development costs. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, operating costs and future capital expenditures, forecasted crack spreads, growth rate, discount rate and, in the case of oil and gas properties, expected production volumes. Expected production volumes take into account assessments of field reservoir performance and include expectations about proved and probable volumes and where applicable economically recoverable resources associated with interests in certain Husky properties which are risk-weighted utilizing geological, production, recovery, market price and economic projections. Either the cash flow estimates or the discount rate is risk-adjusted to reflect local conditions as appropriate.

Given that the calculations for recoverable amounts require the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and in the case of oil and gas properties, expected production volumes, it is possible that the assumptions may change, which may impact the estimated life of the CGU and may require a material adjustment to the carrying value of goodwill and non-financial assets.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses recognized with respect to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the CGU or group of CGUs on a pro rata basis. Impairment losses are recognized in depletion, depreciation, amortization and impairment in the consolidated statements of income.

Impairment losses recognized in prior years are assessed at the end of each reporting period for indications that the impairment has decreased or no longer exists. An impairment loss is reversed only to the extent that the carrying amount of the asset or CGU does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

j) Asset Retirement Obligations ("ARO")

A liability is recognized for future legal or constructive retirement obligations associated with the Company's assets. The Company has significant obligations to remove tangible assets and restore land after operations cease and the Company retires or relinquishes the asset. The retirement of Upstream and Downstream assets consists primarily of plugging and abandoning wells, abandoning surface and subsea plant and equipment and facilities and restoring land to a state required by regulation or contract. The amount recognized is the net present value of the estimated future expenditures determined in accordance with local conditions, current technology and current regulatory requirements. The obligation is calculated using the current estimated costs to retire the asset inflated to the estimated retirement date and then discounted using a credit-adjusted risk-free discount rate. The liability is recorded in the period in which an obligation arises with a corresponding increase to the carrying value of the related asset. The liability is progressively accreted over time as the effect of discounting unwinds, creating an expense recognized in finance expenses. The costs capitalized to the related assets are amortized in a manner consistent with the depletion, depreciation and amortization of the underlying assets. Actual retirement expenditures are charged against the accumulated liability as incurred.

Liabilities for ARO are adjusted every reporting period for changes in estimates. These adjustments are accounted for as a change in the corresponding capitalized cost, except where a reduction in the provision is greater than the undepreciated capitalized cost of the related assets, in which case the capitalized cost is reduced to nil and the remaining adjustment is recognized in net earnings. Changes to the amount of capitalized costs will result in an adjustment to future depletion, depreciation and amortization, and to finance expenses.

Estimating the ARO requires significant judgment as restoration technologies and costs are constantly changing, as are regulatory, political, environmental and safety considerations. Inherent in the calculation of the ARO are numerous assumptions including the ultimate settlement amounts, future third-party pricing, inflation factors, risk-free discount rates, credit risk, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in material changes to the ARO liability. Adjustments to the estimated amounts and timing of future ARO cash flows are a regular occurrence in light of the significant judgments and estimates involved.

k) Legal and Other Contingent Matters

Provisions and liabilities for legal and other contingent matters are recognized in the period when the circumstance becomes probable that a future cash outflow resulting from past operations or events will occur and the amount of the cash outflow can be reasonably estimated. The timing of recognition and measurement of the provision requires the application of judgment to existing facts and circumstances, which can be subject to change, and the carrying amounts of provisions and liabilities are reviewed regularly and adjusted accordingly. The Company is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations, and determine that the loss can be reasonably estimated. When a loss is recognized, it is charged to net earnings. The Company continually monitors known and potential contingent matters and makes appropriate disclosure and provisions when warranted by the circumstances present.

l) Share Capital

Preferred shares are classified as equity since they are cancellable and redeemable only at the Company's option and dividends are discretionary and payable only if declared by the Board of Directors. Incremental costs directly attributable to the issuance of shares and stock options are recognized as a deduction from equity, net of tax. Common share dividends are paid out in common shares, or in cash, and preferred share dividends are paid in cash. Both common and preferred share dividends are recognized as distributions within equity.

m) Financial Instruments

Financial instruments are any contracts that give rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial instruments are initially recognized at fair value, and subsequently measured based on classification in one of the following categories: loans and receivables, held to maturity investments, other financial liabilities, fair value through profit or loss ("FVTPL") or available-for-sale ("AFS") financial assets.

Financial instruments classified as FVTPL or AFS are measured at fair value at each reporting date; any transaction costs associated with these types of instruments are expensed as incurred. Unrealized gains and losses on AFS financial assets are recognized in OCI (see policy note o) and transferred to net earnings when the asset is derecognized. Unrealized gains and losses on FVTPL financial instruments related to trading activities are recognized in marketing and other in the consolidated statements of income, and unrealized gains and losses on all other FVTPL financial instruments are recognized in other - net.

Financial instruments classified as loans or receivables, held to maturity investments and other financial liabilities are initially measured at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs that are directly attributable to the acquisition or issue of a financial instrument are measured at amortized cost and added to the fair value initially recognized.

Financial instruments subsequently revalued at fair value are further categorized using a three-level hierarchy that reflects the significance of the inputs used in determining fair value. Level 1 fair value is determined by reference to quoted prices in active markets for identical assets and liabilities. Level 2 fair value is based on inputs that are independently observable for similar assets or liabilities. Level 3 fair value is not based on independently observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value.

n) Derivative Instruments and Hedging Activities

Derivatives are financial instruments for which the fair value changes in response to market risks, require little or no initial investment and are settled at a future date. Derivative instruments are utilized by the Company to manage various market risks including volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company may enter into swap and other derivative transactions to hedge or mitigate the Company's commercial risk, including derivatives that reduce risks that arise in the ordinary course of the Company's business. The Company may choose to apply hedge accounting to derivative instruments.

The fair values of derivatives are determined using valuation models that require assumptions concerning the amount and timing of future cash flows and discount rates. These estimates are also subject to change with fluctuations in commodity prices, interest rates, foreign currency exchange rates and estimates of non-performance. The actual settlement of a derivative instrument could differ materially from the fair value recorded and could impact future results.

i) Derivative Instruments

All derivative instruments, other than those designated as effective hedging instruments or certain non-financial derivative contracts that meet the Company's own use requirements, are classified as held for trading and are recorded at fair value. Gains and losses on these instruments are recorded in the consolidated statements of income in the period they occur.

The Company may enter into commodity price contracts in order to offset fixed or floating prices with market rates to manage exposures to fluctuations in commodity prices. The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The related inventory is measured at fair value based on exit prices. Gains and losses from these derivative contracts, which are not designated as effective hedging instruments, are recognized in revenues or purchases of crude oil and products and are initially recorded at settlement date. Derivative instruments that have been designated as effective hedging instruments are further classified as either fair value or cash flow hedges (see "Hedging Activities").

ii) Embedded Derivatives

Derivatives embedded in a host contract are recorded separately when the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract and the host contract is not measured at FVTPL. The definition of an embedded derivative is the same as freestanding derivatives. Embedded derivatives are measured at fair value with gains and losses recognized in net earnings.

iii) Hedging Activities

At the inception of a derivative transaction, if the Company elects to use hedge accounting, formal designation and documentation is required. The documentation must include: identification of the hedged item or transaction, the hedging instrument, the nature of the risk being hedged, the Company's risk management objective and strategy for undertaking the hedge and how the Company will assess the hedging instrument's effectiveness in offsetting the exposure to changes in the hedged item.

A hedge is assessed at inception and at the end of each reporting period to ensure that it is highly effective in offsetting changes in fair values or cash flows of the hedged item. For a fair value hedge, the gain or loss from remeasuring the hedging instrument at fair value is recognized immediately in net earnings with the offsetting gain or loss on the hedged item. When fair value hedge accounting is discontinued, the carrying amount of the hedging instrument is deferred and amortized to net earnings over the remaining maturity of the hedged item.

For a cash flow hedge, the effective portion of the gain or loss is recorded in OCI. Any hedge or portion of a hedge that is ineffective is immediately recognized in net earnings. Hedge accounting is discontinued on a prospective basis when the hedging relationship no longer qualifies for hedge accounting. Any gain or loss on the hedging instrument resulting from the discontinuation of a cash flow hedge is deferred in OCI until the forecasted transaction date. If the forecasted transaction date is no longer expected to occur, the gain or loss is recognized in net earnings in the period of discontinuation.

A net investment hedge of a foreign operation is accounted for similarly to a cash flow hedge. The Company may designate certain U.S. dollar denominated debt as a hedge of its net investment in foreign operations for which the U.S. dollar is the functional currency. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in OCI, net of tax, and are limited to the translation gain or loss on the net investment.

o) Comprehensive Income

Comprehensive income consists of net earnings and OCI. OCI is comprised of the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge or net investment hedge, the unrealized gains and losses on AFS financial assets, the exchange gains and losses arising from the translation of foreign operations with a functional currency that is not Canadian dollars and the actuarial gains and losses on defined benefit pension plans. Amounts included in OCI are shown net of tax. Other reserves is an equity category comprised of the cumulative amounts of OCI, relating to foreign currency translation and hedging.

p) Impairment of Financial Assets

A financial asset is assessed at the end of each reporting period to determine whether it is impaired, based on objective evidence indicating that one or more events have had a negative effect on the estimated future cash flows of that asset. Objective evidence used by the Company to assess impairment of financial assets includes quoted market prices for similar financial assets and historical collection rates for loans and receivables.

An impairment loss with respect to a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the net present value of the estimated future cash flows discounted at the original effective interest rate. A revaluation with respect to an AFS financial asset is calculated by reference to its fair value and any amounts in OCI are transferred to net earnings.

Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net earnings. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

Given that the calculations for the net present value of estimated future cash flows related to derivative financial assets require the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and expected production volumes, it is possible that the assumptions may change, which may require a material adjustment to the carrying value of financial assets.

q) Pensions and Other Post-employment Benefits

In Canada, the Company provides a defined contribution pension plan and other post-retirement benefits to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. In the United States, the Company provides two defined contribution pension plans (401(k)) and one other post-retirement benefits plan. The Company also maintains a small defined benefit pension plan for the employees of the Superior Refinery.

The cost of the pension benefits earned by employees in the defined contribution pension plans is expensed as incurred. The cost of the benefits earned by employees in the defined benefit pension plans is determined using the projected unit credit funding method. Actuarial gains and losses are recognized in retained earnings as incurred.

The defined benefit asset or liability is comprised of the fair value of plan assets from which the obligations are to be settled and the present value of the defined benefit obligation. Plan assets are measured at fair value based on the closing bid price when there is a quoted price in an active market. Plan assets are assets that are held by a long-term employee benefit fund or qualifying insurance policies. Plan assets are not available to the Company's creditors. The value of any defined benefit asset is restricted to the sum of any past service costs and the present value of refunds from and reductions in future contributions to the plan. Defined benefit obligations are estimated by discounting expected future payments using the year-end market rate of interest for high-quality corporate debt instruments with cash flows that match the timing and amount of expected benefit payments.

Post-retirement medical benefits are also provided to qualifying retirees. In some cases the benefits are provided through medical care plans to which the Company, the employees, the retirees and covered family members contribute. In some plans there is no funding of the benefits before retirement. These plans are recognized on the same basis as described above for the defined benefit pension plan.

The determination of the cost of the defined benefit pension plan and the other post-retirement benefit plans reflects a number of assumptions that affect the expected future benefit payments. The valuation of these plans is prepared by an independent actuary engaged by the Company. These assumptions include, but are not limited to, the estimate of expected plan investment performance, salary escalation, retirement age, attrition, future health care costs and mortality. The fair value of the plan assets is used for the purposes of calculating the expected return on plan assets.

The assumptions for each country are reviewed each year and are adjusted where necessary to reflect changes in fund experience and actuarial recommendations. Mortality rates are based on the latest available standard mortality tables for the individual countries concerned. The rate of return on pension plan assets is based on a projection of real long-term bond yields and an equity risk premium, which are combined with local inflation assumptions and applied to the actual asset mix of each plan. The amount of the expected return on plan assets is calculated using the expected rate of return for the year and the fair value of assets at the beginning of the year. Future salary increases are based on expected future inflation rates for the individual countries.

r) Income Taxes

Current income tax is recognized in net earnings in the period unless it relates to items recognized directly to equity, including OCI, in which case the deferred income tax is also recorded in equity. Any interest and penalties on income taxes are recognized in interest expense and interest payable. Management periodically evaluates positions taken in the Company's tax returns with respect to situations in which applicable tax regulations are subject to interpretation and reassessment and establishes provisions where appropriate.

Deferred tax is measured using the liability method on temporary differences at the reporting date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax assets and liabilities are recognized at expected tax rates in effect in the year when the asset is expected to be realized or the liability settled, based on tax rates and tax laws that have been enacted or substantively enacted at the reporting date. 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 unless it relates to items recognized directly to equity, including OCI, in which case the deferred income tax is also recorded in equity. Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to set off current tax assets against current income tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Estimates that require significant judgments are also made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where the transaction and calculations for which the ultimate tax determination are uncertain. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

s) Asset Exchange Transactions

Asset exchange transactions are measured at cost if the transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. Otherwise, asset exchange transactions are measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. If the acquired item is not measured at fair value, its cost is measured at the carrying amount of the asset given up. Gains and losses are recorded in other - net in the consolidated statements of income in the period they occur.

t) Revenue Recognition

Revenue from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured. Revenues associated with the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recognized when the title passes to the customer. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided. Revenues from construction contracts are recognized using the percentage of completion method based upon costs incurred and may be recorded on a net or gross basis dependent on whether the Company is acting as an agent or principal, respectively.

Under take or pay contracts, the Company makes a long-term supply commitment in return for a commitment from the buyer to pay for minimum quantities, whether or not the customer takes delivery. If a buyer has a right to get a "make-up" delivery at a later date, revenue is deferred and recognized only when the product is delivered or the make-up product can no longer be taken. If no such option exists within the contractual terms, revenue is recognized when the take-or-pay penalty is triggered.

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods or services provided in the normal course of business, net of discounts, customs duties and sales taxes. Crude oil and natural gas sold below or above the Company's working interest share of production results in production underlifts or overlifts. Underlifts are recorded as a receivable at cost with a corresponding decrease to production and operating expense, while overlifts are recorded as a payable at fair value with a corresponding increase to production and operating expense.

Physical exchanges of inventory are reported on a net basis for swaps of similar items, as are sales and purchases made with a common counterparty as part of an arrangement similar to a physical exchange.

Finance income is recognized as the interest accrues using the effective interest rate, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset.

u) Foreign Currency

Functional currency is the currency of the primary economic environment in which the Company and its subsidiaries operate and is normally the currency in which the entity primarily generates and expends cash. The financial statements of Husky's subsidiaries are translated into Canadian dollars, which is the presentation and functional currency of the Company. The assets and liabilities of subsidiaries whose functional currencies are other than Canadian dollars are translated into Canadian dollars at the foreign exchange rate at the balance sheet date, while revenues and expenses of such subsidiaries are translated using average monthly foreign exchange rates, which approximate the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation are included in OCI.

The Company's transactions in foreign currencies are translated to the appropriate functional currency at the foreign exchange rate on the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency at the foreign exchange rate at the balance sheet date and differences arising on translation are recognized in net earnings. Non-monetary assets that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the dates of the transactions.

v) Share-based Payments

In accordance with the Company's stock option plan, stock options to acquire common shares may be granted to officers and certain other employees. The Company records compensation expense over the vesting period based on the fair value of options granted. Compensation expense is recorded in net earnings as part of selling, general and administrative expenses.

The Company's stock option plan is a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. A liability for the stock options is accrued over their vesting period and measured at fair value using the Black-Scholes option pricing model. The liability is revalued each reporting period until it is settled to reflect changes in the fair value of the options. The net change is recognized in net earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital.

The Company's Performance Share Unit Plan provides a time-vested award to certain officers and employees of the Company. Performance Share Units ("PSU") entitle participants to receive cash based on the Company's share price at the time of vesting. The amount of cash payment is contingent on the Company's total shareholder return relative to a peer group of companies and achieving a return on capital in use ("ROCIU") target. ROCIU equals net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not in use. Net earnings is adjusted for the difference between actual realized and budgeted commodity prices and foreign exchange rates and other actual and budgeted exceptional items. A liability for expected cash payments is accrued over the vesting period of the PSUs and is revalued at each reporting date based on the market price of the Company's common shares and the expected vesting percentage. Upon vesting, a cash payment is made to the participants and the outstanding liability is reduced by the payment amount.

w) Earnings per Share

The number of basic common shares outstanding is the weighted average number of common shares outstanding for each period. Shares issued during the period are included in the weighted average number of shares from the date consideration is received. The calculation of basic earnings per common share is based on net earnings attributable to common shareholders divided by the weighted average number of common shares outstanding.

The number of diluted common shares outstanding is calculated using the treasury stock method, which assumes that any proceeds received from in-the-money stock options would be used to buy back common shares at the average market price for the period. The calculation of diluted earnings per share is based on net earnings attributable to common shareholders divided by the weighted average number of common shares outstanding adjusted for the effects of all potential dilutive common share issuances, which are comprised of common shares issuable upon exercise of stock options granted to employees. Stock options granted to employees provide the holder with the ability to settle in cash or equity. For the purposes of the diluted earnings per share calculation, the Company must adjust the numerator for the more dilutive effect of cash-settlement versus equity-settlement despite how the stock options are accounted for in net earnings. As a result, net earnings reported based on accounting of cash-settled stock options may be adjusted for the results of equity-settlements for the purposes of determining the numerator for the diluted earnings per share calculation.

x) Government Grants

Government grants are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be complied with. If a grant is received but reasonable assurance and compliance with conditions is not achieved, the grant is recognized as a deferred liability until such conditions are fulfilled. When the grant relates to an expense item, it is recognized as income in the period in which the costs are incurred. Where the grant relates to an asset, it is recognized as a reduction to the net book value of the related asset and recognized in net earnings in equal amounts over the expected useful life of the related asset through lower depletion, depreciation and amortization.

y) Related Party Judgments and Estimates

The Company enters into transactions and agreements in the normal course of business with certain related parties, joint arrangements and associates. These transactions are on terms equivalent to those that prevail in arm's length transactions. Proceeds for disposition of assets to related parties are recognized at fair value, based on discounted cash flow forecast from those assets. Independent opinions of the fair value may be obtained. Changes in the assumptions used to determine these fair values may result in a material difference in the proceeds and any gain or loss on disposition. See Note 25.

z) Recent Accounting Standards

The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Leases

In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet while operating leases are recognized in the Consolidated Statements of Income when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expense upon implementation. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 Revenue from Contracts with Customers, has been applied, or is applied at the same date as IFRS 16.

Implementation of IFRS 16 consists of four phases:

- Project awareness and engagement - This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 16 to stakeholders, and creating a project steering committee.
- Scoping - This phase focuses on identifying and categorizing the Company's contracts, performing a high-level impact assessment and determining the adoption approach and which optional recognition exemptions will be applied by the Company. This phase also includes identifying the systems impacted by the new accounting standard and evaluating potential system solutions.
- Detailed analysis and solution development - This phase includes assessing which agreements contain leases and determining the expected conversion differences for leases currently accounted for as operating leases under the existing standard. This phase also includes selection of the system solution.
- Implementation - This phase includes implementing the changes required for compliance with IFRS 16. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the execution of customized training programs and preparation of disclosures under IFRS 16.

The Company is currently in the detailed analysis and solutions development phase of implementing IFRS 16. The impact on the Company's consolidated financial statements upon adoption of IFRS 16 is currently being assessed.

Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. 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. Early adoption is permitted.

Implementation of IFRS 15 consists of four phases:

- Project awareness and engagement – This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 15 to stakeholders.
- Scoping – This phase focuses on identifying the Company's major revenue streams, determining how and when revenue is currently recognized and determination of whether any changes are expected upon adoption.
- Detailed analysis and solution development – Steps in this phase include addressing any potential differences in revenue recognition identified in the scoping phase, according to the priority assigned. This involves detailed analysis of the IFRS 15 revenue recognition criteria, review of contracts with customers to ensure revenue recognition practices are in accordance with IFRS 15 and evaluating potential changes to revenue processes and systems.
- Implementation – This phase includes implementing the changes required for compliance with IFRS 15. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the execution of customized training programs and preparation of disclosures under IFRS 15.

The Company has completed the assessment of IFRS 15 and is currently in the implementation phase. The Company will retrospectively adopt the standard on January 1, 2018. The adoption of IFRS 15 does not require any material changes to the amounts recorded in the consolidated financial statements; however, it will require additional disclosures.

Financial Instruments

In July 2014, the IASB issued IFRS 9, "Financial Instruments" to replace IAS 39, which provides a single model for classification and measurement 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 instruments. For 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. IFRS 9 includes a new, forward-looking 'expected loss' impairment model that will result in a more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard is effective for annual periods beginning on or after January 1, 2018, with required retrospective application and early adoption permitted.

Implementation of IFRS 9 consists of four phases:

- Project awareness and engagement – This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 9 to stakeholders.
- Scoping – This phase focuses on identifying the Company's financial instruments, determining accounting treatment for in-scope financial instruments under IFRS 9, and determination of whether any changes are expected upon adoption.
- Detailed analysis and solution development – This phase includes addressing differences in accounting for financial instruments. Steps in this phase involve detailed analysis of the IFRS 9 recognition impacts, measurement and disclosure requirements, and evaluating potential changes to accounting processes.
- Implementation – This phase includes implementing the changes required for compliance with IFRS 9. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the preparation of disclosures under IFRS 9.

The Company has completed the assessment of IFRS 9 and is currently in the implementation phase. The Company will retrospectively adopt the standard on January 1, 2018. The adoption of IFRS 9 does not require any material changes to the consolidated financial statements.

Amendments to IFRS 2 Share-based Payment

In June 2016, the IASB issued amendments to IFRS 2 to be applied prospectively for annual periods beginning on or after January 1, 2018 with early adoption permitted. The amendments clarify how to account for certain types of share-based payment arrangements. The adoption of the amendments does not have a material impact on the Company's consolidated financial statements.

aa) Change in Accounting Policy

The Company has applied the following amendments to accounting standards issued by the IASB for the first time for the annual reporting period commencing January 1, 2017:

Amendments to IAS 7 Statement of Cash Flows

The amendments require disclosure of information enabling users of financial statements to evaluate changes in liabilities arising from financing activities. The adoption of this amended standard resulted in the disclosure of a reconciliation to changes in liabilities from financing activities. See Note 15.

Amendments to IAS 12

The amendments clarify the recognition of deferred tax assets for unrealized losses on debt instruments measured at fair value. The adoption of the amendments has no material impact on the Company's consolidated financial statements.

Note 4 Cash and Cash Equivalents

Cash and cash equivalents at December 31, 2017 included $280 million of cash (December 31, 2016 – $271 million) and $2,233 million of short-term investments with original maturities less than three months at the time of purchase (December 31, 2016 – $1,048 million).

Note 5 Accounts Receivable

Accounts Receivable

($ millions)	**December 31, 2017**	December 31, 2016
Trade receivables	**1,170**	1,019
Allowance for doubtful accounts	**(34)**	(32)
Derivatives due within one year	**17**	9
Other	**33**	40
End of year	**1,186**	1,036

Note 6 Inventories

Inventories

($ millions)	**December 31, 2017**	December 31, 2016
Crude oil, natural gas and sulphur	**539**	523
Refined petroleum products	**548**	433
Trading inventories measured at fair value less costs to sell	**237**	399
Materials, supplies and other	**189**	203
End of year	**1,513**	1,558

Impairment of inventory to net realizable value for the year ended December 31, 2017 was nil (December 31, 2016 – $9 million).

Trading inventories measured at fair value less costs to sell consist of natural gas inventories and crude oil inventories. The fair value measurement incorporates exit commodity prices and adjustments for quality and location. Refer to Note 24.

Note 7 Restricted Cash

In accordance with the provisions of the regulations of the People's Republic of China, the Company is required to deposit funds into separate accounts restricted to the funding of future asset retirement obligations in offshore China. As at December 31, 2017, the Company had deposited funds of $192 million (2016 – $156 million), of which $95 million (December 31, 2016 - $84 million) relates to the Wenchang field and has been classified as current. The remaining balance of $97 million (December 31, 2016 - $72 million) has been classified as non-current.

The Company's participation in the Wenchang field expired in November 2017, and the amount of the decommissioning and disposal expenses was finalized in January 2018.

Note 8 Exploration and Evaluation Costs

Exploration and Evaluation Assets

($ millions)	**2017**	2016
Beginning of year	**1,066**	1,091
Additions	**224**	95
Disposals	**—**	(6)
Transfers to oil and gas properties *(note 9)*	**(377)**	(18)
Expensed exploration expenditures previously capitalized	**(6)**	(86)
Exchange adjustments	**(69)**	(10)
End of year	**838**	1,066

The following exploration and evaluation expenses for the years ended December 31, 2017 and 2016 relate to activities associated with the exploration for and evaluation of crude oil and natural gas resources and were recorded in the Upstream Exploration and Production business.

Exploration and Evaluation Expense Summary

($ millions)	**2017**	2016
Seismic, geological and geophysical	**113**	78
Expensed drilling	**22**	66
Expensed land	**11**	44
	146	188

Note 9 Property, Plant and Equipment

Property, Plant and Equipment

($ millions)	Oil and Gas Properties	Processing, Transportation and Storage	Upgrading	Refining	Retail and Other	Total
Cost						
December 31, 2015	50,388	1,465	2,313	8,136	2,688	64,990
Additions	818	55	51	712	61	1,697
Acquisitions	67	—	—	—	—	67
Transfers from exploration and evaluation *(note 8)*	18	—	—	—	—	18
Changes in asset retirement obligations *(note 16)*	231	—	3	11	9	254
Disposals and derecognition	(6,590)	(1,383)	—	—	(3)	(7,976)
Exchange adjustments	(131)	—	—	(214)	—	(345)
December 31, 2016	44,801	137	2,367	8,645	2,755	58,705
Additions[1]	**1,371**	**11**	**230**	**561**	**140**	**2,313**
Acquisitions	**29**	**—**	**—**	**577**	**—**	**606**
Transfers from exploration and evaluation *(note 8)*	**377**	**—**	**—**	**—**	**—**	**377**
Intersegment transfers	**48**	**(61)**	**—**	**—**	**13**	**—**
Changes in asset retirement obligations *(note 16)*	**150**	**—**	**2**	**13**	**23**	**188**
Disposals and derecognition	**(4,702)**	**—**	**—**	**(39)**	**—**	**(4,741)**
Exchange adjustments	**(259)**	**(1)**	**—**	**(566)**	**(1)**	**(827)**
December 31, 2017	**41,815**	**86**	**2,599**	**9,191**	**2,930**	**56,621**
Accumulated depletion, depreciation, amortization and impairment						
December 31, 2015	(31,300)	(574)	(1,260)	(2,676)	(1,546)	(37,356)
Depletion, depreciation, amortization and impairment	(1,806)	(23)	(103)	(380)	(150)	(2,462)
Disposals and derecognition	5,082	501	—	13	4	5,600
Exchange adjustments	38	—	—	68	—	106
December 31, 2016	(27,986)	(96)	(1,363)	(2,975)	(1,692)	(34,112)
Depletion, depreciation, amortization and impairment	**(2,238)**	**(2)**	**(99)**	**(406)**	**(137)**	**(2,882)**
Intersegment transfers	**(37)**	**50**	**—**	**—**	**(13)**	**—**
Disposals and derecognition	**4,124**	**—**	**—**	**16**	**—**	**4,140**
Exchange adjustments	**121**	**1**	**—**	**189**	**—**	**311**
December 31, 2017	**(26,016)**	**(47)**	**(1,462)**	**(3,176)**	**(1,842)**	**(32,543)**
Net book value						
December 31, 2016	16,815	41	1,004	5,670	1,063	24,593
December 31, 2017	**15,799**	**39**	**1,137**	**6,015**	**1,088**	**24,078**

(1) *Additions include assets under finance lease.*

Included in depletion, depreciation, amortization and impairment expense for the year ended December 31, 2017 is a pre-tax impairment expense of $173 million related to crude oil and natural gas assets, primarily in the Ram River and Foothills CGU's in the Upstream Exploration and Production segment (December 31, 2016 – a pre-tax net impairment reversal of $261 million). The impairment charges were a result of changes in the development plan and reinforced by market transactions. The associated assets were sold on December 20, 2017 for gross proceeds of $65 million, thereby representing the recoverable amounts of these assets. The recoverable amount was determined to be FVLCS based upon the observed market transaction (Level 1).

Costs of property, plant and equipment, including major development projects, not subject to depletion, depreciation and amortization as at December 31, 2017 were $2.8 billion (December 31, 2016 – $2.0 billion) including undeveloped land assets of $57 million as at December 31, 2017 (December 31, 2016 – $95 million).

The net book values of assets held under finance lease within property, plant and equipment are as follows:

Assets Under Finance Lease

($ millions)	Refining	Oil and Gas Properties	Total
December 31, 2016	24	255	279
December 31, 2017	**152**	**335**	**487**

Assets Dispositions

On May 25, 2016, the Company completed the sale of royalty interests representing approximately 1,700 boe/day of Western Canada production for gross proceeds of $165 million, resulting in a pre-tax gain of $163 million and an after-tax gain of $119 million.

On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The Company also recognized an investment of $621 million for its 35 percent retained interest. This transaction resulted in a change of control and the recognition of a pre-tax gain of $1.44 billion and an after-tax gain of $1.32 billion. The assets and related liabilities were recorded in the Upstream Infrastructure and Marketing segment. The assets are held by a newly formed limited partnership, Husky Midstream Limited Partnership ("HMLP"), of which the Company owns 35 percent, Power Assets Holding Ltd. ("PAH") owns 48.75 percent and CK Infrastructure Holdings Ltd. ("CKI") owns 16.25 percent. Husky remains operator of the assets.

During 2016, the Company completed the sale of approximately 30,200 boe/day of legacy crude oil and gas assets in Western Canada for gross proceeds of $1.12 billion. The Company recognized a pre-tax gain of $35 million and an after-tax gain of $25 million.

During 2017, the Company completed the sale of select assets in Western Canada to third parties for gross proceeds of approximately $185 million, resulting in a pre-tax gain of $46 million and an after-tax gain of $36 million. The assets and related liabilities were recorded in the Upstream Exploration and Production segment.

Assets Acquisitions

On November 8, 2017, the Company completed the purchase of the Superior Refinery, a 50,000 bbls/day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet Specialty Products Partners, L.P. ("Calumet") for $670 million (US$527 million) in cash, which includes $108 million (US$85 million) of working capital, subject to final adjustments.

The acquisition has been accounted for as a business combination using the acquisition method. The purchase price allocation is based on management's best estimates of fair values of acquired assets and liabilities as at November 8, 2017:

Purchase Price Allocation

($ millions)	**USD**	**CAD**
Working capital	85	108
Property, plant and equipment	454	577
Asset retirement obligation	(7)	(9)
Other long-term liabilities	(5)	(6)
Net assets acquired	**527**	**670**

The fair values of accounts receivable and accounts payable approximate their carrying values due to their short-term nature. The fair value of inventory was determined using quoted prices. The fair values of property, plant and equipment were determined based on a cost and future cash flow approach. For the cost approach, key assumptions included the cost to construct the assets and the remaining useful life. For the cash flow approach, key assumptions were the discount rate and future commodity prices. The decommissioning provision was based on the fair value of estimated future reclamation costs. Key assumptions included discount rates, cost estimates and timeline to abandon and reclaim the refinery.

The acquisition of Superior Refinery contributed $163 million to gross revenues and a loss of $13 million to consolidated net earnings from the acquisition date to December 31, 2017.

Had the acquisition occurred on January 1, 2017, the Superior Refinery would have contributed $1.1 billion to gross revenues and $93 million to consolidated net earnings, which would have resulted in gross revenues of $19.9 billion and consolidated net earnings of $892 million for the year ended December 31, 2017.

Acquisition costs of $8 million have been charged to selling, general and administrative expenses in the consolidated statements of income for the year ended December 31, 2017.

Note 10 Goodwill

Goodwill

($ millions)	**December 31, 2017**	December 31, 2016
Beginning of year	**679**	700
Exchange adjustments	**(46)**	(21)
End of year	**633**	679

As at December 31, 2017, the Company's goodwill balance related entirely to the Lima Refinery. For impairment testing purposes, the recoverable amount of the Lima Refinery CGU was estimated using the higher of FVLCS and VIU methodology based on cash flows expected over a 50-year period and discounted using a pre-tax discount rate of 8 percent (2016 – 8 percent).

The value-in-use calculation for the Lima Refinery CGU is sensitive to changes in discount rate, forecasted crack spreads and growth rate. The discount rate is derived from the Company's post-tax weighted average cost of capital with appropriate adjustments made to reflect the risks specific to the refinery. Forecasted crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel, and are consistent with crack spreads used in the Company's long range plan.

Cash flow projections for the initial 10-year period are based on long range plan future cash flows and inflated by a 2 percent long-term growth rate for the remaining 40-year period. The inflation rate was based upon an average expected inflation rate for the U.S. of 2 percent (2016 – 2 percent). As at December 31, 2017, the recoverable amount exceeded the carrying amount and no impairment was identified.

The Company used the market capitalization and comparative market multiplier to corroborate discounted cash flow results.

Note 11 Joint Arrangements

Joint Operations

BP-Husky Refining LLC

The Company holds a 50 percent ownership interest in BP-Husky Refining LLC, which owns and operates the BP-Husky Toledo Refinery in Ohio. On March 31, 2008, the Company completed a transaction with BP whereby BP contributed the BP-Husky Toledo Refinery plus inventories and other related net assets and the Company contributed US$250 million in cash and a contribution payable of US $2.6 billion.

The Company's proportionate share of the contribution payable included in the consolidated balance sheets is as follows:

Contribution Payable

($ millions)	**December 31, 2017**	December 31, 2016
Beginning of year	**146**	348
Accretion *(note 21)*	**2**	6
Paid	**(142)**	(193)
Foreign exchange	**(6)**	(15)
End of year	**—**	146

The Company amended the terms of payment of the Company's contribution payable with BP-Husky Refining LLC in the first quarter of 2015. In accordance with the amendment, US$1 billion of the net contribution payable was paid on February 2, 2015. Subsequent to the payment, BP-Husky Refining LLC distributed US$1 billion to each of the joint arrangement partners, which resulted in the creation of a deferred tax asset and deferred tax recovery of $203 million. As a result of the prepayment, the accretion rate was reduced from 6 percent to 2.5 percent for the future term of the agreement and the remaining maturity date was extended to December 31, 2017. The remaining net contribution payable amount of approximately US$110 million (CDN $142 million) was repaid in 2017.

Summarized below is the Company's proportionate share of operating results and financial position in the BP-Husky Refining LLC joint operation that have been included in the consolidated statements of income and the consolidated balance sheets in U.S. Refining and Marketing in the Downstream segment:

Results of Operations

($ millions)	2017	2016
Revenues	**2,239**	1,521
Expenses	**(2,215)**	(1,570)
Proportionate share of net earnings (loss)	**24**	(49)

Balance Sheets

($ millions)	December 31, 2017	December 31, 2016
Current assets	**424**	395
Non-current assets	**2,195**	2,446
Current liabilities	**(324)**	(324)
Non-current liabilities	**(467)**	(535)
Proportionate share of net assets	**1,828**	1,982

Sunrise Oil Sands Partnership

The Company holds a 50 percent interest in the Sunrise Oil Sands Partnership, which is engaged in operating an oil sands project in Northern Alberta.

Summarized below is the Company's proportionate share of operating results and financial position in the Sunrise Oil Sands Partnership that have been included in the consolidated statements of income and the consolidated balance sheets in Exploration and Production in the Upstream segment:

Results of Operations

($ millions)	2017	2016
Revenues	**259**	106
Expenses	**(261)**	(220)
Financial items	**(28)**	(28)
Proportionate share of net loss	**(30)**	(142)

Balance Sheets

($ millions)	December 31, 2017	December 31, 2016
Current assets	**76**	57
Non-current assets	**2,756**	3,147
Current liabilities	**(129)**	(98)
Non-current liabilities	**(275)**	(274)
Proportionate share of net assets	**2,428**	2,832

Joint Venture

Husky-CNOOC Madura Ltd.

The Company currently holds 40 percent joint control in Husky-CNOOC Madura Ltd., which is engaged in the exploration for and production of oil and gas resources in Indonesia. Results of the joint venture are included in the consolidated statements of income in Exploration and Production in the Upstream segment.

Summarized below is the financial information for Husky-CNOOC Madura Ltd. accounted for using the equity method:

Results of Operations

($ millions, except share of equity investment)	**2017**	2016
Revenues	**97**	—
Expenses	**(80)**	(32)
Net earnings (loss)	**17**	(32)
Share of equity investment *(percent)*	**40%**	40%
Proportionate share of equity investment	**12**	(1)

Balance Sheets

($ millions, except share of equity investment)	**December 31, 2017**	December 31, 2016
Current assets[(1)]	**152**	67
Non-current assets	**1,993**	1,111
Current liabilities	**(1,021)**	(134)
Non-current liabilities	**(898)**	(836)
Net assets	**226**	208
Share of net assets *(percent)*	**40%**	40%
Carrying amount in balance sheet	**553**	488

(1) *Current assets include cash and cash equivalents of $26 million (2016 – $7 million).*

The Company's share of equity investment and carrying amount of share of net assets does not equal the 40 percent joint control of the expenses and net assets of Husky-CNOOC Madura Ltd. due to differences in the accounting policies of the joint venture and the Company and non-current liabilities of the joint venture which are not included in the Company's carrying amount of net assets due to equity accounting.

Husky Midstream Limited Partnership

On July 15, 2016, the Company completed the sale of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan. The assets are held by a newly-formed limited partnership, HMLP, of which Husky owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent. Results of the joint venture are included in the consolidated statements of income in Infrastructure and Marketing in the Upstream segment.

Summarized below is the financial information for HMLP accounted for using the equity method:

Results of Operations

($ millions, except share of equity investment)	**2017**	2016
Revenues	**294**	138
Expenses	**(107)**	(97)
Net income	**187**	41
Share of equity investment *(percent)*	**35%**	35%
Proportionate share of equity investment	**49**	16

Balance Sheet

($ millions, except share of net assets)	**December 31, 2017**	December 31, 2016
Current assets[(1)]	**152**	55
Non-current assets	**2,617**	2,403
Current liabilities	**(75)**	(44)
Non-current liabilities	**(690)**	(590)
Net assets	**2,004**	1,824
Share of net assets *(percent)*	**35%**	35%
Carrying amount in balance sheet	**685**	640

(1) *Current assets include cash and cash equivalents of $28 million (2016 – $23 million).*

The Company's share of equity investment and carrying amount of share of net assets does not equal the 35 percent joint control of the net income and net assets of HMLP due to the potential fluctuation in the partnership profit structure.

Note 12 Other Assets

Other Assets

($ millions)	**December 31, 2017**	December 31, 2016
Long-term receivables	**144**	117
Leasehold incentives	**2**	13
Precious metals	**21**	23
Other	**18**	19
End of period	**185**	172

Note 13 Bank Operating Loans

At December 31, 2017, the Company had unsecured short-term borrowing lines of credit with banks totalling $850 million[(1)] (December 31, 2016 – $670 million) and letters of credit under these lines of credit totalling $422 million (December 31, 2016 – $378 million). As at December 31, 2017, bank operating loans were nil (December 31, 2016 – nil). Interest payable is based on Bankers' Acceptance, CAD Prime Rate, U.S. LIBOR, or U.S. Base Rates.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million (December 31, 2016 – $10 million) available for general purposes. The Company's proportionate share of the liability for any drawings under this credit facility is $5 million (December 31, 2016 – $5 million). As at December 31, 2017, there was no balance outstanding under this credit facility (December 31, 2016 – nil).

(1) *Includes $75 million demand facility available specifically for letters of credit only.*

Note 14 Accounts Payable and Accrued Liabilities

Accounts Payable and Accrued Liabilities

($ millions)	**December 31, 2017**	December 31, 2016
Trade payables	**950**	762
Accrued liabilities	**1,791**	1,275
Dividend payable *(note 19)*	**9**	9
Stock-based compensation	**30**	17
Derivatives due within one year	**115**	61
Other	**138**	102
End of year	**3,033**	2,226

Note 15 Debt and Credit Facilities

Short-term Debt

($ millions)	**December 31, 2017**	December 31, 2016
Commercial paper[1]	**200**	200

[1] *The commercial paper is supported by the Company's syndicated credit facilities and the Company is authorized to issue commercial paper up to a maximum of $1.0 billion having a term not to exceed 365 days. The weighted average interest rate as at December 31, 2017 was 1.40 percent per annum (December 31, 2016 – 0.93 percent).*

Long-term Debt

		Canadian $ Amount		U.S. $ Denominated	
($ millions)	Maturity	**December 31, 2017**	December 31, 2016	**December 31, 2017**	December 31, 2016
Long-term debt					
6.15% notes[1][3]	2019	**376**	403	**300**	300
7.25% notes[1][4]	2019	**939**	1,007	**750**	750
5.00% notes[5]	2020	**400**	400	**—**	—
3.95% notes[1][4]	2022	**626**	671	**500**	500
4.00% notes[1][4]	2024	**939**	1,007	**750**	750
3.55% notes[5]	2025	**750**	750	**—**	—
3.60% notes[5]	2027	**750**	—	**—**	—
6.80% notes[1][4]	2037	**484**	519	**387**	387
Debt issue costs[2]		**(24)**	(23)	**—**	—
Unwound interest rate swaps *(note 24)*[6]		**—**	2	**—**	—
Long-term debt		**5,240**	4,736	**2,687**	2,687
Long-term debt due within one year					
6.20% notes[1][4]	2017	**—**	403	**—**	300
Long-term debt due within one year		**—**	403	**—**	300

[1] *All of the Company's U.S. dollar denominated debt is designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency. Refer to Note 24 for Foreign Currency Risk Management.*
[2] *Calculated using the effective interest rate method.*
[3] *The 6.15% notes represent unsecured securities under a trust indenture dated June 14, 2002.*
[4] *The 7.25%, the 3.95%, the 4.00%, the 6.80% and the 6.20% notes represent unsecured securities under a trust indenture dated September 11, 2007.*
[5] *The 5.00%, the 3.55% and the 3.60% notes represent unsecured securities under a trust indenture dated December 21, 2009.*
[6] *Unwound interest rate swaps as at December 31, 2017 was less than $1 million.*

During the year ended December 31, 2017, the Company had a net cumulative long-term debt issuance of $385 million (2016 – net cumulative long-term debt repayments of $768 million) towards the Company's long-term debt.

Credit Facilities

On November 30, 2017, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facility, previously set to expire on June 19, 2018, was extended to June 19, 2022.

As at December 31, 2017 the covenant under the Company's syndicated credit facilities was a debt to capital covenant, calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. This covenant is used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2017, and assessed the risk of non-compliance to be low. As at December 31, 2017, the Company had no borrowings under its $2.0 billion facility expiring March 9, 2020 (December 31, 2016 – no borrowings) and no borrowings under its $2.0 billion facility expiring June 19, 2022 (December 31, 2016 – no borrowings).

There continues to be no difference between the terms of these facilities, other than their maturity dates. Interest payable is based on Bankers' Acceptance, CAD Prime Rate, U.S. LIBOR, or U.S. Base Rates, depending on the borrowing option selected and credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt.

Notes

On November 15, 2016, the Company repaid the maturing 7.55 percent notes issued under a trust indenture dated October 31, 1996. The amount paid to noteholders was $280 million, including $10 million of interest.

On March 10, 2017, the Company issued $750 million of 3.60 percent notes due March 10, 2027. This was completed by way of a prospectus supplement dated March 7, 2017, to the Company's universal short form base shelf prospectus dated February 23, 2015 (the "2015 Canadian Shelf Prospectus"). The notes are redeemable at the option of the Company at any time, subject to a make-whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 10 and September 10 of each year, beginning September 10, 2017. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On March 30, 2017, the Company filed a universal short form base shelf prospectus (the "2017 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including April 30, 2019. The 2017 Canadian Shelf Prospectus replaces the 2015 Canadian Shelf Prospectus, which expired on March 23, 2017.

On September 15, 2017, the Company repaid the maturing 6.20 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to note holders was $365 million, including $11 million of interest.

At December 31, 2017, the Company had unused capacity of $3.0 billion under its 2017 Canadian Shelf Prospectus and US$3.0 billion under its 2015 U.S. Shelf Prospectus and related U.S. registration statement.

On January 29, 2018, the Company filed a universal short form base shelf prospectus (the "2018 U.S. Shelf Prospectus") with the Alberta Securities Commission. On January 30, 2018, the Company's related U.S. registration statement with the SEC containing the 2018 U.S. Shelf Prospectus became effective which enables the Company to offer up to US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the U.S. up to and including February 29, 2020. During the 25-month period that the 2018 U.S. Shelf Prospectus and the related U.S registration statement are effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement. The 2018 U.S. Shelf Prospectus replaced the 2015 U.S. Shelf Prospectus.

The Company's notes, credit facilities and short-term lines of credit rank equally in right of payment.

Reconciliation of Changes of Liabilities to Cash Flows from Financing Activities

	Liabilities			
($ millions)	Short-term debt	Long-term debt due within one year	Long-term debt	Other long-term liabilities
December 31, 2016	200	403	4,736	1,020
Changes from financing cash flows				
Long-term debt issuance	**—**	**—**	**750**	**—**
Long-term debt repayment	**—**	**(365)**	**—**	**—**
Debt issue costs	**—**	**—**	**(6)**	**—**
Other	**—**	**—**	**—**	**18**
Total change from financing cash flows	**—**	**(365)**	**744**	**18**
Other changes – liability-related				
Foreign exchange	**—**	**(38)**	**—**	**(28)**
Fair value changes	**—**	**—**	**—**	**3**
Addition of finance lease obligations	**—**	**—**	**—**	**269**
Payment of finance lease obligations	**—**	**—**	**—**	**(29)**
Deferred revenue	**—**	**—**	**—**	**(16)**
Amortization of debt issuance costs	**—**	**—**	**3**	**—**
Foreign exchange recognized in OCI	**—**	**—**	**(243)**	**—**
Total other changes – liability related	**—**	**(38)**	**(240)**	**199**
December 31, 2017	**200**	**—**	**5,240**	**1,237**

Note 16 Asset Retirement Obligations

At December 31, 2017, the estimated total undiscounted inflation-adjusted amount required to settle the Company's ARO was $9.7 billion (December 31, 2016 – $11.4 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 42 years (December 31, 2016 – 41 years) into the future. This amount has been discounted using credit-adjusted risk-free rates of 2.9 percent to 4.8 percent (December 31, 2016 – 2.8 percent to 5.3 percent) and an inflation rate of 2 percent (December 31, 2016 – 2 percent). Obligations related to future environmental remediation and cleanup of oil and gas assets are included in the estimated ARO.

The change in the provision in 2017 is primarily due to the disposition of select legacy Western Canada crude oil and natural gas assets in 2017 and 2016.

While the provision is based on management's best estimates of future costs, discount rates and the economic lives of the assets, there is uncertainty regarding the amount and timing of incurring these costs.

A reconciliation of the carrying amount of asset retirement obligations at December 31, 2017 and 2016 is set out below:

Asset Retirement Obligations

($ millions)	**2017**	2016
Beginning of year	**2,791**	2,984
Additions	**47**	16
Liabilities settled	**(136)**	(87)
Liabilities disposed	**(420)**	(452)
Change in discount rate	**143**	205
Change in estimates	**(2)**	25
Exchange adjustment	**(9)**	(26)
Accretion *(note 21)*	**112**	126
End of year	**2,526**	2,791
Expected to be incurred within 1 year	**274**	218
Expected to be incurred beyond 1 year	**2,252**	2,573

The Company had deposited funds of $192 million (2016 – $156 million) into the restricted cash account, of which $95 million relates to the Wenchang field and have been classified as current and the remaining balance of $97 million have been classified as non-current. The Company's participation in the Wenchang field expired in November 2017, and resolution on the decommissioning and disposal expenses was finalized in January 2018.

Note 17 Other Long-term Liabilities

Other Long-term Liabilities

($ millions)	**December 31, 2017**	December 31, 2016
Employee future benefits *(note 22)*	**248**	208
Finance lease obligations	**498**	288
Stock-based compensation	**32**	14
Deferred revenue	**284**	321
Leasehold incentives	**101**	104
Other	**74**	85
End of year	**1,237**	1,020

Finance lease obligations

The Company, on behalf of the Sunrise Oil Sands Partnership, entered into an arrangement for the construction and use of pipeline and storage facilities in its oil sands operations for a minimum period of 20 years with options to renew.

During the year ended December 31, 2017, the Company entered into an arrangement to lease a supply vessel to support the West White Rose Project and other Atlantic operations for a minimum period of 10 years with options to renew. The Company also entered into a five year refining feedstock transportation arrangement and an 18 year hydrogen supply arrangement. The substance of these arrangements have been determined to be finance lease obligations.

The future minimum lease payments under existing finance leases are payable as follows:

	Within 1 year		After 1 year but no more than 5 years		More than 5 years		Total	
($ millions)	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Future minimum lease payments	**69**	35	**258**	140	**993**	764	**1,320**	939
Interest	**48**	30	**174**	112	**594**	505	**816**	647
Present value of minimum lease payments	**66**	33	**194**	102	**244**	153	**504**	288

Note 18 Income Taxes

The major components of income tax expense for the years ended December 31, 2017 and 2016 were as follows:

Income Tax Expense (Recovery)

($ millions)	**2017**	2016
Current income tax		
Current income tax charge	**28**	90
Adjustments to current income tax estimates	**(31)**	(91)
	(3)	(1)
Deferred income tax		
Relating to origination and reversal of temporary differences	**83**	(121)
Adjustments to deferred income tax estimates	**(442)**	150
	(359)	29

Deferred Tax Items in OCI

($ millions)	2017	2016
Deferred tax items expensed (recovered) directly in OCI		
Derivatives designated as cash flow hedges	**—**	(1)
Remeasurement of pension plans	**(4)**	(6)
Exchange differences on translation of foreign operations	**(82)**	(40)
Hedge of net investment	**38**	17
	(48)	(30)

The provision for income taxes in the consolidated statements of income reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31, 2017 and 2016 were accounted for as follows:

Reconciliation of Effective Tax Rate

($ millions, except tax rate)	2017	2016
Earnings before income taxes		
Canada	**(440)**	615
United States	**301**	5
Other foreign jurisdictions	**563**	330
	424	950
Statutory Canadian income tax rate *(percent)*	**27.1%**	27.2%
Expected income tax	**115**	258
Effect on income tax resulting from:		
Foreign jurisdictions	**20**	(3)
Non-taxable items	**(1)**	(272)
Adjustments with respect to previous year	**(473)**	59
Revaluation of foreign tax pools	**(8)**	(11)
Other – net	**(15)**	(3)
Income tax expense (recovery)	**(362)**	28

The statutory tax rate is 27.1 percent in 2017 (2016 – 27.2 percent). The 2017 to 2016 tax rates were similar due to no significant changes to tax rates.

Effective January 1, 2018, the U.S. Federal corporate tax rate will be reduced from 35 percent to 21 percent. Included in income tax expense for the year ended December 31, 2017 is a $436 million deferred income tax recovery related to the revaluation of the U.S. deferred tax liabilities.

The following reconciles the movements in the deferred income tax liabilities and assets:

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2017	Recognized in Earnings	Recognized in OCI	Other	December 31, 2017
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(3,998)	**187**	**104**	**(20)**	**(3,727)**
Foreign exchange gains taxable on realization	(224)	**85**	**(38)**	**—**	**(177)**
Debt issue costs	(2)	**(1)**	**—**	**—**	**(3)**
Other temporary differences	(21)	**(69)**	**—**	**—**	**(90)**
Deferred tax assets					
Pension plans	32	**4**	**4**	**—**	**40**
Asset retirement obligations	693	**(8)**	**(6)**	**—**	**679**
Loss carry-forwards	389	**150**	**(16)**	**—**	**523**
Financial assets at fair value	20	**11**	**—**	**—**	**31**
	(3,111)	**359**	**48**	**(20)**	**(2,724)**

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2016	Recognized in Earnings	Recognized in OCI	Other	December 31, 2016
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(4,233)	187	48	—	(3,998)
Foreign exchange gains taxable on realization	(42)	(166)	(16)	—	(224)
Debt issue costs	(1)	(1)	—	—	(2)
Other temporary differences	141	(162)	—	—	(21)
Deferred tax assets					
Pension plans	43	(17)	6	—	32
Asset retirement obligations	892	(196)	(3)	—	693
Loss carry-forwards	75	319	(5)	—	389
Financial assets at fair value	13	7	—	—	20
	(3,112)	(29)	30	—	(3,111)

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At December 31, 2017, the Company has nil deferred tax liabilities in respect to these investments (December 31, 2016 – nil).

At December 31, 2017, the Company had $2,031 million (December 31, 2016 – $1,257 million) of tax losses that will expire between 2030 and 2037. The Company has recorded deferred tax assets in respect of these losses, as there are sufficient taxable temporary differences in the various jurisdictions to utilize these losses.

Note 19 Share Capital

Common Shares

The Company is authorized to issue an unlimited number of no par value common shares.

Common Shares	Number of Shares	Amount ($ millions)
December 31, 2015	984,328,915	7,000
Stock dividends	21,122,939	296
December 31, 2016	1,005,451,854	7,296
Share cancellation	**(331,842)**	**(3)**
December 31, 2017	**1,005,120,012**	**7,293**

Quarterly dividends may be declared in an amount expressed in dollars per common share or could be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume-weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume-weighted average trading price of the common shares is calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares.

The quarterly common share dividend was suspended by the Board of Directors in respect of the fourth quarter of 2015. At December 31, 2017, the Company had no common share dividends payable (December 31, 2016 – nil).

On February 28, 2018, the Board of Directors have reinstated the quarterly common share dividend and declared cash dividends of $0.075 per common share, for the fourth quarter of 2017. The dividends are payable on April 2, 2018 to shareholders of record at the close of business on March 20, 2018.

Preferred Shares

The Company is authorized to issue an unlimited number of no par value preferred shares.

Cumulative Redeemable Preferred Shares	Number of Shares	Amount ($ millions)
December 31, 2015	36,000,000	874
Series 1 shares converted to Series 2 shares	(1,564,068)	(38)
Series 2 shares converted from Series 1 shares	1,564,068	38
December 31, 2016	36,000,000	874
December 31, 2017	**36,000,000**	**874**

Cumulative Redeemable Preferred Shares Dividends	**2017**		2016	
($ millions)	Declared	Paid	Declared	Paid
Series 1 Preferred Shares	**6**	**6**	9	7
Series 2 Preferred Shares[1]	**1**	**1**	—	—
Series 3 Preferred Shares	**11**	**11**	11	8
Series 5 Preferred Shares	**9**	**9**	9	7
Series 7 Preferred Shares	**7**	**7**	7	5
	34	**34**	36	27

(1) *Series 2 Preferred Share dividends declared and paid in the year ended December 31, 2016 was less than $1 million.*

At December 31, 2017 there were $9 million of Preferred Share dividends payable (December 31, 2016 - $9 million).

Holders of the Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") are entitled to receive a cumulative quarterly fixed dividend yielding 2.40 percent annually for a five year period ending March 31, 2021, as and when declared by the Company's Board of Directors. Thereafter, the dividend rate will be reset every five years at a rate equal to the five-year Government of Canada bond yield plus 1.73 percent. Holders of Series 1 Preferred Shares have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares"), subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter.

Holders of the Series 2 Preferred Shares are entitled to receive a cumulative quarterly floating rate dividend that is reset every quarter for a five year period ending March 31, 2021, as and when declared by the Company's Board of Directors. The dividend rate applicable to the Series 2 Preferred Shares, for the three month period commencing September 30, 2017 but excluding December 31, 2017, was 2.472 percent based on the sum of the Government of Canada 90 day Treasury bill rate on August 31, 2017 plus 1.73 percent. Holders of Series 2 Preferred Shares have the right, at their option, to convert their shares into Series 1 Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter.

Holders of the Cumulative Redeemable Preferred Shares, Series 3 (the "Series 3 Preferred Shares") are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending December 31, 2019 as and when declared by the Company's Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.13 percent. Holders of Series 3 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 4 (the "Series 4 Preferred Shares"), subject to certain conditions, on December 31, 2019 and on December 31 every five years thereafter. Holders of the Series 4 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.13 percent.

Holders of the Cumulative Redeemable Preferred Shares, Series 5 (the "Series 5 Preferred Shares") are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending March 31, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every 5 years at the rate equal to the five-year Government of Canada bond yield plus 3.57 percent. Holders of Series 5 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 6 (the "Series 6 Preferred Shares"), subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Holders of the Series 6 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.57 percent.

Holders of the Cumulative Redeemable Preferred Shares, Series 7 (the "Series 7 Preferred Shares") are entitled to receive a cumulative fixed dividend yielding 4.60 percent annually for the initial period ending June 30, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every 5 years at the rate equal to the five-year Government of Canada bond yield plus 3.52 percent. Holders of the Series 7 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 8 (the "Series 8 Preferred Shares"), subject to certain conditions, on June 30, 2020 and on June 30 every 5 years thereafter. Holders of the Series 8 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.52 percent.

Stock Option Plan

Pursuant to the Incentive Stock Option Plan (the "Option Plan"), the Company may grant from time to time to officers and employees of the Company options to purchase common shares of the Company. The term of each option is five years, and vests one-third on each of the first three anniversary dates from the grant date. The Option Plan provides the option holder with the right to exercise the option to acquire one common share at the exercise price or surrender the option for a cash payment. The exercise price of the option is equal to the weighted average trading price of the Company's common shares during the five trading days prior to the grant date. When the stock option is surrendered to the Company, the cash payment is equal to the excess of the aggregate fair market value of the common shares able to be purchased pursuant to the vested and exercisable portion of such stock options on the date of surrender over the aggregate exercise price for those common shares pursuant to those stock options. The fair market value of common shares is calculated as the closing price of the common shares on the date on which board lots of common shares have traded immediately preceding the date a holder of the stock options provides notice to the Company that he or she wishes to surrender his or her stock options to the Company in lieu of exercise.

Included in accounts payable and accrued liabilities and other long-term liabilities in the consolidated balance sheets at December 31, 2017 was $21 million (December 31, 2016 – $8 million) representing the estimated fair value of options outstanding. The total expense recognized in selling, general and administrative expenses in the consolidated statements of income for the Option Plan for the year ended December 31, 2017 was $13 million (2016 – $7 million). At December 31, 2017, stock options exercisable for cash had an intrinsic value of $12 million (December 31, 2016 – $1 million).

The following options to purchase common shares have been awarded to officers and certain other employees:

Outstanding and Exercisable Options	**2017**		2016	
	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
Outstanding, beginning of year	**25,459**	**26.26**	27,621	28.79
Granted[1]	**5,544**	**16.13**	5,381	15.67
Expired or forfeited	**(8,358)**	**25.62**	(7,543)	27.94
Outstanding, end of year	**22,645**	**23.96**	25,459	26.26
Exercisable, end of year	**12,946**	**28.91**	15,662	29.03

[1] *Options granted during the year ended December 31, 2017 were attributed a fair value of $2.01 per option (2016 – $2.26) at grant date.*

Outstanding and Exercisable Options	Outstanding Options			Exercisable Options	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
$14.20 – $29.99	14,281	18.89	3.3	4,582	22.18
$30.00 – $36.20	8,364	32.60	0.72	8,364	32.60
December 31, 2017	**22,645**	**23.96**	**2.35**	**12,946**	**28.91**

The fair value of the share options is estimated at each reporting date using the Black-Scholes option pricing model, taking into account the terms and conditions upon which the share options are granted and for the performance options, the current likelihood of achieving the specified target. The following table lists the assumptions used in the Black-Scholes option pricing model for the share options and performance options:

Black-Scholes Assumptions	December 31, 2017	December 31, 2016
	Tandem Options	Tandem Options
Dividend per option	**0.72**	0.96
Range of expected volatilities used *(percent)*	**16.7 - 32.9**	24.9 - 39.6
Range of risk-free interest rates used *(percent)*	**0.9 - 1.9**	0.4 - 1.1
Expected life of share options from vesting date *(years)*	**1.95**	1.91
Expected forfeiture rate *(percent)*	**9.0%**	9.3%
Weighted average exercise price	**25.46**	27.72
Weighted average fair value	**1.15**	0.37

The expected life of the share options is based on historical data and current expectations and is not necessarily indicative of exercise patterns that may occur. The expected volatility reflects the assumption that the historical volatility over a period similar to the expected life of the options is indicative of future trends, which may also not necessarily be the actual outcome.

Performance Share Units

In February 2010, the Compensation Committee of the Board of Directors of the Company established the Performance Share Unit Plan for executive officers and certain employees of the Company. The term of each PSU is three years, and the PSU vests on the second and third anniversary dates of the grant date in percentages determined by the Compensation Committee based on the Company's total shareholder return relative to a peer group of companies and achieving a ROCIU target set by the Company. ROCIU equals net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not in use. Net earnings is adjusted for the difference between actual realized and budgeted commodity prices and foreign exchange rates and other actual and budgeted exceptional items. Upon vesting, PSU holders receive a cash payment equal to the number of vested PSUs multiplied by the weighted average trading price of the Company's common shares for the five preceding trading days. As at December 31, 2017, the carrying amount of the liability relating to PSUs was $41 million (December 31, 2016 – $24 million). The total expense recognized in selling, general and administrative expenses in the consolidated statements of income for the PSUs for the year ended December 31, 2017 was $32 million (2016 – $26 million). The Company paid out $15 million (2016 – $18 million) for performance share units which vested in the year. The weighted average contractual life of the PSUs at December 31, 2017 was two years (December 31, 2016 – one and a half years).

The number of PSUs outstanding was as follows:

Performance Share Units	2017	2016
Beginning of year	**4,863,690**	5,122,626
Granted	**5,667,970**	2,250,110
Exercised	**(966,932)**	(1,167,256)
Forfeited	**(1,202,810)**	(1,341,790)
Outstanding, end of year	**8,361,918**	4,863,690
Vested, end of year	**2,262,954**	1,490,243

Earnings per Share

Earnings per Share

($ millions)	2017	2016
Net earnings	**786**	922
Effect of dividends declared on preferred shares in the year	**(34)**	(36)
Net earnings – basic	**752**	886
Dilutive effect of accounting for stock options as cash-settled[1]	**4**	(3)
Net earnings – diluted	**756**	883

(millions)		
Weighted average common shares outstanding – basic and diluted	**1,005.3**	1,004.9

Earnings per share – basic *($/share)*	**0.75**	0.88
Earnings per share – diluted *($/share)*	**0.75**	0.88

[1] *Stock-based compensation expense was $13 million based on cash-settlement for the year ended December 31, 2017 (2016 – $7 million). Stock-based compensation expense would have been $9 million based on equity-settlement for the year ended December 31, 2017 (2016 – $10 million). For the year ended December 31, 2017, cash-settlement of stock options was used to calculate diluted earnings per share as it was considered more dilutive than equity-settlement.*

For the year ended December 31, 2017, 23 million tandem options (2016 – 25 million) were excluded from the calculation of diluted earnings per share as these options were anti-dilutive.

Note 20 Production, Operating and Transportation and Selling, General and Administrative Expenses

The following table summarizes production, operating and transportation expenses in the consolidated statements of income for the years ended December 31, 2017 and 2016:

Production, Operating and Transportation Expenses

($ millions)	2017	2016
Services and support costs	**930**	983
Salaries and benefits	**664**	631
Materials, equipment rentals and leases	**248**	259
Energy and utility	**453**	413
Licensing fees	**200**	246
Transportation	**26**	30
Other	**158**	162
Total production, operating and transportation expenses	**2,679**	2,724

The following table summarizes selling, general and administrative expenses in the consolidated statements of income for the years ended December 31, 2017 and 2016:

Selling, General and Administrative Expenses

($ millions)	**2017**	2016
Employee costs[(1)]	**395**	319
Stock-based compensation expense[(2)]	**45**	33
Contract services	**100**	85
Equipment rentals and leases	**37**	36
Maintenance and other	**73**	71
Total selling, general and administrative expenses	**650**	544

(1) *Employee costs are comprised of salary and benefits earned during the year, plus cash bonuses awarded during the year. Annual bonus awards settled in shares are included in stock-based compensation expense.*

(2) *Stock-based compensation expense represents the cost to the Company for participation in share-based payment plans.*

Note 21 Financial Items

Financial Items

($ millions)	**2017**	2016
Foreign exchange		
Non-cash working capital gains (losses)	**(3)**	4
Other foreign exchange gains (losses)	**(3)**	9
Net foreign exchange gains (losses)	**(6)**	13
Finance income	**37**	17
Finance expenses		
Long-term debt	**(342)**	(330)
Contribution payable *(note 11)*	**(2)**	(6)
Other	**(4)**	(17)
	(348)	(353)
Interest capitalized[(1)]	**68**	78
	(280)	(275)
Accretion of asset retirement obligations *(note 16)*	**(112)**	(126)
Finance expenses	**(392)**	(401)
Total Financial Items	**(361)**	(371)

(1) *Interest capitalized on project costs is calculated using the Company's annualized effective interest rate of 5 percent (2016 – 5 percent).*

Note 22 Pensions and Other Post-employment Benefits

The Company currently provides defined contribution pension plans for all qualified employees and two other post-employment benefit plans to its retirees. The other post-employment benefit plans provide certain retired employees with health care and dental benefits. The Company also maintains two defined benefit pension plans, which are closed to new entrants. The defined benefit pension plans provide pension benefits to certain employees based on years of service and final average earnings. The amount and timing of funding of these plans is subject to the funding policy as approved by the Board of Directors.

The measurement date of all plan assets and the accrued benefit obligations was December 31, 2017. The Company is required to file an actuarial valuation of its defined benefit pension with the provincial or state regulator at least every three years. The most recent actuarial valuation was December 31, 2016 for the Canadian defined benefit plan. The most recent actuarial valuation was December 31, 2014 for the Canadian Other Post-employment benefit plan. The most recent actuarial valuation of the U.S. Other Post-employment benefit plan was December 31, 2015.

Defined Contribution Pension Plan

During the year ended December 31, 2017, the Company recognized a $46 million expense (2016 – $46 million) for the defined contribution plan and the two U.S. 401(k) plans in net earnings.

Defined Benefit Pension Plan ("DB Pension Plan") and Other Post-employment Benefit Plans ("OPEB Plans")

Defined Benefit Obligation	DB Pension Plan		OPEB Plans	
($ millions)	**2017**	2016	**2017**	2016
Beginning of year	**178**	177	**213**	180
Current service cost	**1**	1	**15**	13
Interest cost	**4**	6	**8**	7
Benefits paid	**(9)**	(11)	**(4)**	(3)
Settlements	**(140)**	—	**—**	—
Increase due to business combinations[1]	**34**	—	**—**	—
Remeasurements				
Actuarial (gain) loss – experience	**3**	(1)	**—**	(1)
Actuarial loss – financial assumptions	**5**	6	**12**	17
End of year	**76**	178	**244**	213

[1] *The Superior Refinery DB pension plan was transferred from Calumet GP.LLC to Husky Energy Inc. effective November 2017. Please refer to Note 9 for business combination.*

Fair Value of Plan Assets	DB Pension Plan		OPEB Plans	
($ millions)	**2017**	2016	**2017**	2016
Beginning of year	**183**	181	**—**	—
Contributions by employer	**6**	2	**—**	—
Benefits paid	**(9)**	(11)	**—**	—
Interest income	**4**	6	**—**	—
Return on plan assets greater than discount rate	**4**	5	**—**	—
Settlements	**(148)**	—	**—**	—
Increase due to business combinations[1]	**27**	—	**—**	—
End of year	**67**	183	**—**	—

[1] *The Superior Refinery DB pension plan was transferred from Calumet GP.LLC to Husky Energy Inc. effective November 2017. Please refer to Note 9 for business combination.*

Funded status	DB Pension Plan		OPEB Plans	
($ millions)	**2017**	2016	**2017**	2016
Net asset (liability)	**(9)**	5	**(244)**	(213)

The Company has accrued the total net liability for the DB Pension Plan and the OPEB Plans in the consolidated balance sheets in other long-term liabilities.

On July 27, 2017, the Company completed a series of transactions related to the Canadian DB Pension Plan. The most recent actuarial valuation at the transaction date was at December 31, 2016. Defined benefit assets and accrued obligations were remeasured immediately prior to the transactions. DB Pension Plan assets of $148 million, including a one-time cash contribution by the Company of $5 million, were used to settle $140 million of the defined benefit obligation related to the inactive plan members. This resulted in the Company recognizing a $8 million loss on settlement in Other – net expense.

As part of a risk management strategy the Company also purchased a $48 million annuity to offset the related $42 million defined benefit obligation for the active plan members. This resulted in a $3 million actuarial loss (net of tax of $1 million) on plan assets recorded in other comprehensive income.

The Company will continue to accrue service costs for the active plan members and the contribution to the plan for the next annual reporting period.

In November 2017, the Company also acquired a small defined benefit pension plan for the employees of the Superior Refinery which is closed to new entrants.

The composition of the DB Pension Plan assets at December 31, 2017 and 2016 was as follows:

DB Pension Plan Assets

(percent)	Target allocation range	**2017**	2016
Money market type funds	—	**0.2**	0.6
Equity securities	—	**—**	43.8
Debt securities	100	**99.8**	55.6

The following table summarizes amounts recognized in net earnings and OCI for the DB Pension Plan and the OPEB Plans for the years ended December 31, 2017 and 2016:

	DB Pension Plan		OPEB Plans	
($ millions)	**2017**	2016	**2017**	2016
Amounts recognized in net earnings				
Current service cost	**1**	1	**15**	13
Past service cost	**1**	—	**—**	—
Net Interest cost	**—**	—	**8**	7
Settlement loss	**8**	—	**—**	—
Benefit cost	**10**	1	**23**	20
Remeasurements				
Actuarial (gain) loss due to liability experience	**3**	(1)	**—**	(1)
Actuarial loss due to liability assumption changes	**5**	6	**12**	17
Gain on plan assets	**(4)**	(5)	**—**	—
Remeasurement effects recognized in OCI	**4**	—	**12**	16

The following long-term assumptions were used to estimate the value of the defined benefit obligations, the plan assets and the OPEB Plans:

Assumptions

	DB Pension Plan		OPEB Plans	
(percent)	**2017**	2016	**2017**	2016
Discount rate for benefit expense and obligation	**3.4 - 3.5**	3.5 - 3.8	**3.4 - 3.9**	3.7 - 4.1
Rate of compensation expense	**3.5**	3.5	**N/A**	N/A

The average health care cost trend rate used for the benefit expense for the Canadian OPEB Plan was 7.0 percent for 2017, grading 0.5 percent per year for 4 years to 5.0 percent in 2021 and thereafter. The average health care cost trend rate used for the obligation related to the Canadian OPEB Plan was 6.5 percent for 2017, grading 0.4 percent per year for 4 years to 5.0 percent in 2021 and thereafter.

The average health care cost trend rate used for the benefit expense for the U.S. OPEB Plan was 6.5 percent for 2017, grading 0.30 percent per year for 5 years to 5.0 percent per year in 2022 and thereafter. The average health care cost trend rate used for the obligation related to the U.S. OPEB Plan was 6.0 percent for 2017, grading 0.20 percent per year for 5 years to 5.0 percent in 2022 and thereafter.

The sensitivity of the defined benefit and OPEB obligation to changes in relevant actuarial assumption is shown below:

Sensitivity Analysis

	DB Pension Plan		OPEB Plans	
($ millions)	1% increase	1% decrease	1% increase	1% decrease
Discount rate	(9)	11	(41)	47
Health care cost trend rate	N/A	N/A	47	(36)

Note 23 Cash Flows – Change in Non-cash Working Capital

Non-cash Working Capital

($ millions)	2017	2016
Decrease (increase) in non-cash working capital		
Accounts receivable	**(329)**	(332)
Inventories	**(264)**	(334)
Prepaid expenses	**(38)**	131
Accounts payable and accrued liabilities	**1,201**	(33)
Change in non-cash working capital	**570**	(568)
Relating to:		
Operating activities	**398**	(227)
Financing activities	**—**	(68)
Investing activities	**172**	(273)

Note 24 Financial Instruments and Risk Management

Financial Instruments

The Company's financial instruments include cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, derivatives, portions of other assets and other long-term liabilities.

The following table summarizes the Company's financial instruments that are carried at fair value in the consolidated balance sheets:

Financial Instruments at Fair Value

($ millions)	December 31, 2017	December 31, 2016
Commodity contracts – fair value through profit or loss ("FVTPL")		
Natural gas[(1)]	**(13)**	5
Crude oil[(2)]	**(57)**	(30)
Foreign currency contracts – FVTPL		
Foreign currency forwards	**1**	—
Other assets – FVTPL	**1**	1
Hedge of net investment[(3)(4)]	**(584)**	(827)
End of year	**(652)**	(851)

(1) *Natural gas contracts includes a $3 million decrease at December 31, 2017 (December 31, 2016 – $11 million increase) to the fair value of held-for-trading inventory, recognized in the consolidated balance sheets, related to third party physical purchase and sale contracts for natural gas held in storage. Total fair value of the related natural gas storage inventory was $5 million at December 31, 2017 (December 31, 2016 – $45 million).*

(2) *Crude oil contracts includes an $5 million increase at December 31, 2017 (December 31, 2016 – $17 million increase) to the fair value of held-for-trading inventory, recognized in the consolidated balance sheets, related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory was $232 million at December 31, 2017 (December 31, 2016 – $354 million).*

(3) *Hedging instruments are presented net of tax.*

(4) *Represents the translation of the Company's U.S. dollar denominated long-term debt designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.*

The Company's other financial instruments that are not related to derivatives, contingent consideration or hedging activities are included in cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, and portions of other assets and other long-term liabilities. These financial instruments are classified as loans and receivables or other financial liabilities and are carried at amortized cost. Excluding long-term debt, the carrying values of these financial instruments and cash and cash equivalents approximate their fair values.

The fair value of long-term debt represents the present value of future cash flows associated with the debt. Market information, such as treasury rates and credit spreads, are used to determine the appropriate discount rates. These fair value determinations are compared to quotes received from financial institutions to ensure reasonability. At December 31, 2017, the carrying value of the Company's long-term debt was $5.2 billion and the estimated fair value was $5.6 billion (December 31, 2016 carrying value of $5.1 billion, estimated fair value of $5.5 billion).

The estimation of the fair value of commodity derivatives and held-for-trading inventories incorporates exit prices and adjustments for quality and location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability. The estimation of the fair value of the net investment hedge incorporates foreign exchange rates and market interest rates from financial institutions. All financial assets and liabilities are classified as Level 2 measurements.

Risk Management Overview

The Company is exposed to risks related to the volatility of commodity prices, foreign exchange rates and interest rates. It is also exposed to financial risks related to liquidity and credit and contract risks. In certain instances, the Company uses derivative instruments to manage the Company's exposure to these risks. Derivative instruments are recorded at fair value in accounts receivable, inventory, other assets and accounts payable and accrued liabilities in the consolidated balance sheets. The Company has crude oil and natural gas inventory held in storage related to commodity price risk management contracts that is recognized at fair value. The Company employs risk management strategies and policies designed to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels.

Responsibility for risk management is held by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

a) Market Risk

i) Commodity Price Risk Management

All derivative instruments, other than those designated as effective hedging instruments or certain non-financial derivative contracts that meet the Company's own use requirements, are classified as held for trading and are recorded at fair value. Gains and losses on these instruments are recorded in the consolidated statements of income in the period they occur.

The Company uses derivative commodity instruments from time to time to manage exposure to price volatility on a portion of its crude oil and natural gas production, and it also uses firm commitments for the purchase or sale of crude oil and natural gas. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable, inventory, other assets, accounts payable and accrued liabilities and other long-term liabilities.

The Company's results will be impacted by a decrease in the price of crude oil and natural gas inventory. The Company has crude oil inventories that are feedstock, held at terminals or part of the in-process inventories at its refineries and at offshore sites. The Company also has natural gas inventory that could have an impact on earnings based on changes in natural gas prices. All these inventories are subject to a lower of cost or net realizable value test at each reporting period.

Foreign Exchange Risk Management

The Company's results are affected by the exchange rates between various currencies, including the Canadian and U.S. dollar. The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. The majority of the Company's expenditures are in Canadian dollars. The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. revenue dollars to hedge against these fluctuations and to mitigate its exposure to foreign exchange risk.

A change in the value of the Canadian dollar against the U.S. dollar will also result in an increase or decrease in the Company's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as the related finance expense. In order to mitigate the Company's exposure to long-term debt affected by the U.S./Canadian dollar exchange rate, the Company may enter into cash flow hedges using cross currency debt swap arrangements. In addition, the Company's U.S. dollar denominated debt has been designated as a hedge of a net investment in a foreign operation that has a U.S. dollar functional currency. The unrealized foreign exchange gain or loss related to this hedge is recorded in OCI.

At December 31, 2017, the Company had designated US$2.7 billion denominated debt as a hedge of the Company's selected net investments in its foreign operations with a U.S. dollar functional currency (December 31, 2016 – US$3.0 billion). For the year ended December 31, 2017, the unrealized gain arising from the translation of the debt was $243 million (December 31, 2016 – unrealized gain of $113 million), net of tax loss of $38 million (December 31, 2016 – loss of $17 million), which was recorded in hedge of net investment within OCI.

Interest Rate Risk Management

Interest rate risk is the impact of fluctuating interest rates on earnings, cash flows and valuations. To mitigate risk related to interest rates, the Company may enter into fair value or cash flow hedges using interest rate swaps.

At December 31, 2017, the balance in long-term debt related to deferred gains resulting from unwound interest rate swaps that had previously been designated as a fair value hedge was less than $1 million (December 31, 2016 – $2 million). The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $1 million for the year ended December 31, 2017 (December 31, 2016 – $2 million).

At December 31, 2017, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was $15 million (December 31, 2016 – $18 million), net of tax of $5 million (December 31, 2016 – net of tax of $6 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in an offset to finance expense of $2 million for the year ended December 31, 2017 (December 31, 2016 – $2 million).

ii) Earnings Impact of Market Risk Management Contracts

The realized and unrealized gains (losses) recognized on other risk management positions for the years ended December 31, 2017 and 2016 are set out below:

Earnings Impact *($ millions)*	2017 Marketing and Other	 Other – Net	 Net Foreign Exchange
Commodity Price			
Natural gas	**(18)**	**—**	**—**
Crude oil	**(28)**	**—**	**—**
	(46)	**—**	**—**
Foreign Currency			
Foreign currency forwards	**—**	**—**	**(30)**
	(46)	**—**	**(30)**

Earnings Impact *($ millions)*	2016 Marketing and Other	 Other – Net	 Net Foreign Exchange
Commodity Price			
Natural gas	(1)	—	—
Crude oil	(38)	—	—
Crude oil call options	—	(67)	—
Crude oil put options	—	(54)	—
	(39)	(121)	—
Foreign Currency			
Foreign currency forwards	—	—	10
	(39)	(121)	10

Offsetting Financial Assets and Liabilities

The tables below outline the financial assets and financial liabilities that are subject to set-off rights and related arrangements, and the effect of those rights and arrangements on the consolidated balance sheets:

Offsetting Financial Assets and Liabilities *($ millions)*	As at December 31, 2017 Gross Amount	 Amount Offset	 Net Amount
Financial Assets			
Financial derivatives	**150**	**(111)**	**40**
Normal purchase and sale agreements	**639**	**(280)**	**359**
End of year	**789**	**(391)**	**399**
Financial Liabilities			
Financial derivatives	**(246)**	**122**	**(123)**
Normal purchase and sale agreements	**(933)**	**353**	**(581)**
End of year	**(1,179)**	**475**	**(704)**

Offsetting Financial Assets and Liabilities *($ millions)*	As at December 31, 2016 Gross Amount	 Amount Offset	 Net Amount
Financial Assets			
Financial derivatives	57	(38)	19
Normal purchase and sale agreements	529	(199)	330
End of year	586	(237)	349
Financial Liabilities			
Financial derivatives	(161)	70	(91)
Normal purchase and sale agreements	(644)	234	(410)
End of year	(805)	304	(501)

Market Risk Sensitivity Analysis

A sensitivity analysis for commodities, foreign currency exchange and interest rate risks has been calculated by increasing or decreasing commodity prices, foreign currency exchange rates or interest rates, as appropriate. These sensitivities represent the increase or decrease in earnings before income taxes resulting from changing the relevant rates, with all other variables held constant. These sensitivities have only been applied to financial instruments held at fair value. The Company's process for determining these sensitivities has not changed during the year.

Commodity Price Risk[(1)] *($ millions)*	10% price increase	10% price decrease
Crude oil price	(10)	10
Natural gas price	(8)	8

Foreign Exchange Rate[(2)] *($ millions)*	Canadian dollar $0.01 increase	Canadian dollar $0.01 decrease
U.S. dollar per Canadian dollar	1	(1)

(1) *Based on average crude oil and natural gas market prices as at December 31, 2017.*
(2) *Based on the U.S./Canadian dollar exchange rate as at December 31, 2017.*

b) Financial Risk

i) Liquidity Risk Management

Liquidity risk is the risk that the Company will not be able to meet 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. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and capacity to raise capital from various debt and equity capital markets under its shelf prospectuses. The Company prepares annual capital expenditure budgets, which are monitored and updated as required. In addition, the Company requires authorizations for expenditures on projects, which assists with the management of capital.

Since the Company operates in the Upstream oil and gas industry, it requires significant cash to fund capital programs necessary to maintain or increase production, develop reserves, acquire strategic oil and gas assets and repay maturing debt. The Company's Upstream capital programs are funded principally by cash provided from operating activities and issuances of debt and equity. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow of maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of short and long-term capital resources. Occasionally, the Company will economically hedge a portion of its production to protect cash flow in the event of commodity price declines.

The Company had the following available credit facilities as at December 31, 2017:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[(1)] *(note 13)*	**850**	**428**
Syndicated bank facilities[(2)] *(note 15)*	**4,000**	**3,800**
End of year	**4,850**	**4,228**

(1) *Consists of demand credit facilities and a letter of credit facility.*
(2) *Commercial paper outstanding is supported by the Company's Syndicated credit facilities.*

In addition to the credit facilities listed above, the Company had unused capacity under the Canadian Shelf Prospectus of $3.0 billion and unused capacity under the U.S Shelf Prospectus and related U.S registration statement of US$3.0 billion. The ability of the Company to raise additional capital utilizing these Shelf Prospectuses is dependent on market conditions.

The Company believes it has sufficient funding through the use of these facilities and access to the capital markets to meet its future capital requirements.

ii) Credit and Contract Risk Management

Credit and contract risk represent the financial loss that the Company would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms. The Company actively manages its exposure to credit and contract execution risk from both a customer and a supplier perspective. The Company's accounts receivables are broad based with customers in the energy industry and midstream and end user segments and are subject to normal industry risks. The Company's policy to mitigate credit risk includes granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of all accounts. The Company had one external customer that constituted more than 10 percent of gross revenues during the years ended December 31, 2017 and December 31, 2016. Sales to this customer were approximately $3,290 million for the year ended December 31, 2017 (December 31, 2016 – $1,832 million).

Cash and cash equivalents include cash bank balances and short-term deposits maturing in less than three months. The Company manages the credit exposure related to short-term investments by monitoring exposures daily on a per issuer basis relative to predefined investment limits.

The carrying amounts of cash and cash equivalents, accounts receivable and restricted cash represent the Company's maximum credit exposure.

The Company’s accounts receivable was aged as follows at December 31, 2017:

Accounts Receivable Aging

($ millions)	**December 31, 2017**
Current	**1,161**
Past due (1 – 30 days)	**5**
Past due (31 – 60 days)	**15**
Past due (61 – 90 days)	**1**
Past due (more than 90 days)	**38**
Allowance for doubtful accounts	**(34)**
	1,186

The Company recognizes a valuation allowance when collection of accounts receivable is in doubt. Accounts receivable are impaired directly when collection of accounts receivable is no longer expected. For the year ended December 31, 2017, the Company wrote off $1 million (December 31, 2016 – $3 million) of uncollectible receivables.

Note 25 Related Party Transactions

The following table lists the Company's significant subsidiaries and jointly-controlled entities and their respective places of incorporation, continuance or organization, as the case may be, and the Company's percentage equity interest (to the nearest whole number) as at December 31, 2017. All of the entities listed below, except as otherwise indicated, are 100 percent beneficially owned, or controlled or directed, directly or indirectly, by the Company.

Significant Subsidiaries and Joint Operations	%	Jurisdiction
Husky Oil Operations Limited	100	Alberta
Husky Energy International Corporation	100	Alberta
Lima Refining Company	100	Delaware
Husky Marketing and Supply Company	100	Delaware
Husky Oil Limited Partnership	100	Alberta
Husky Terra Nova Partnership	100	Alberta
Husky Downstream General Partnership	100	Alberta
Husky Energy Marketing Partnership	100	Alberta
Sunrise Oil Sands Partnership	50	Alberta
BP-Husky Refining LLC	50	Delaware

Each of the related party transactions described below was made on terms equivalent to those that prevail in arm’s length transactions.

The Company performs management services as the operator of the assets held by HMLP for which it earns a management fee. The Company is also the contractor for HMLP and constructs its assets on a cost recovery basis with certain restrictions. HMLP charges an access fee to the Company for the use of its pipeline systems in performing the Company's blending business, and the Company also pays for transportation and storage services. These transactions are related party transactions, as the Company has a 35 percent ownership interest in HMLP and the remaining ownership interests in HMLP belong to PAH and CKI, which are affiliates of one of the Company's principal shareholders. For the year ended December 31, 2017, the Company charged HMLP $412 million (December 31, 2016 – $133 million) related to construction and management services. For the year ended December 31, 2017, the Company had purchases from HMLP of $203 million (December 31, 2016 – $79 million) related to the use of the pipeline for the Company's blending activities, transportation and storage activities, received distributions of $25 million (December 31, 2016 – nil) and paid capital contributions of $17 million (December 31, 2016 – nil). As at December 31, 2017, the Company had $67 million due from HMLP (December 31, 2016 – $26 million).

The Company sells natural gas to and purchases steam from the Meridian Limited Partnership ("Meridian"), owner of the Meridian cogeneration facility, for use at the facility, Upgrader and Lloydminster ethanol plant. In addition, the Company provides facilities services and personnel for the operations of the Meridian cogeneration facility, which are primarily measured and reimbursed at cost, which equates fair value. These transactions are related party transactions, as Meridian is an affiliate of one of the Company's principal shareholders, and have been measured at fair value. For the year ended December 31, 2017, the amount of natural gas sales to Meridian totalled $45 million (December 31, 2016 – $41 million). For the year ended December 31, 2017, the amount of steam purchased by the Company from Meridian totalled $15 million (December 31, 2016 – $13 million). For the year ended December 31, 2017, the total cost recovery by the Company for facilities services was $11 million (December 31, 2016 – $12 million). At December 31, 2017 the Company had $1 million due from Meridian with respect to these transactions (December 31, 2016 – under $1 million).

At December 31, 2017, $31 million of the May 11, 2009, 7.25 percent senior notes were held by a related party, Ace Dimension Limited, and are included in long-term debt in the Company's consolidated balance sheet. The related party transaction was measured at fair market value at the date of the transaction and has been carried out on the same terms as applied with unrelated parties.

Key management includes Directors (executive and non-executive), Executive Officers and Senior Vice – Presidents of the Company. The amounts disclosed in the table below are the amounts recognized as an expense during the reporting period related to key management personnel:

Compensation of Key Management Personnel

($ millions)	**2017**	2016
Short-term employee benefits[(1)]	**16**	16
Stock-based compensation[(2)]	**31**	22
	47	38

[(1)] *Short-term employee benefits are comprised of salary and benefits earned during the year, plus cash bonuses awarded during the year. Annual bonus awards settled in shares are included in stock-based compensation expense.*

[(2)] *Stock-based compensation expense represents the cost to the Company for participation in share-based payment plans.*

Note 26 Commitments and Contingencies

At December 31, 2017, the Company had commitments that require the following minimum future payments, which are not accrued in the consolidated balance sheets:

Minimum Future Payments for Commitments

($ millions)	Within 1 year	After 1 year but not more than 5 years	More than 5 years	Total
Operating leases[(1)]	164	477	1,540	2,181
Firm transportation agreements[(1)]	451	1,874	4,306	6,631
Unconditional purchase obligations[(2)]	1,965	5,258	6,675	13,898
Lease rentals and exploration work agreements	94	275	973	1,342
Obligations to fund equity investee[(3)]	51	272	451	774
	2,725	8,156	13,945	24,826

[(1)] *Included in operating leases and firm transportation agreements are blending and storage agreements and transportation commitments of $0.9 billion and $2.0 billion respectively with HMLP.*

[(2)] *Includes processing services, distribution services, insurance premiums, drilling services, natural gas purchases and the purchase of refined petroleum products, which includes agreements entered into during the year totaling an incremental $385 million per year for a term of 15 years related to the expanded Canadian truck transportation network.*

[(3)] *Equity investee refers to the Company's investment in Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for consolidated financial statement purposes.*

The Company has income tax and royalty filings that are subject to audit and potential reassessment. The findings may impact the liabilities of the Company. The final results are not reasonably determinable at this time, and management believes that it has adequately provided for current and deferred income taxes.

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters would have a material adverse impact on its financial position, results of operations or liquidity.

Note 27 Capital Disclosures

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk, and to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes adjustments as economic conditions and the risk characteristics of its underlying assets change. The Company considers its capital structure to include shareholders' equity and debt which was $23.4 billion as at December 31, 2017 (December 31, 2016 – $23.0 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to funds from operations. Debt to capital employed is defined as long-term debt, long-term debt due within one year, and short-term debt divided by capital employed which is equal to long-term debt, long-term debt due within one year, short-term debt and shareholders' equity. Debt to funds from operations is defined as long-term debt, long-term debt due within one year and short-term debt divided by funds from operations which is equal to cash flow – operating activities plus change in non-cash working capital.

The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. At December 31, 2017, debt to capital employed was 23.2 percent (December 31, 2016 – 23.2 percent) which was within the Company's target and debt to funds from operations was 1.6 times (December 31, 2016 – 2.4 times), which was within Company's target. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company's share capital is not subject to external restrictions; however, the syndicated credit facilities include a debt to capital covenant, calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. This covenant is used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2017, and assessed the risk of non-compliance to be low.

There were no changes in the Company's approach to capital management from the previous year.

Supplemental Financial and Operating Information

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	**2017**	2016	2015	2014	2013	2012[1]	2011[1]	2010[2][3]	2009[2][3]	2008[2][3]
Financial Highlights										
Gross Revenues and Marketing and Other	**18,946**	13,224	16,801	25,122	24,181	22,948	22,829	18,085	15,935	26,744
Net earnings (loss)	**786**	922	(3,850)	1,258	1,829	2,022	2,224	947	1,416	3,751
Earnings (loss) per share										
Basic	**0.75**	0.88	(3.95)	1.26	1.85	2.06	2.40	1.11	1.67	4.42
Diluted	**0.75**	0.88	(4.01)	1.20	1.85	2.06	2.34	1.05	1.67	4.42
Capital expenditures[4]	**2,220**	1,705	3,005	5,023	5,028	4,701	4,618	3,571	2,797	4,108
Total debt[8]	**5,440**	5,339	6,756	5,292	4,119	3,918	3,911	4,187	3,229	1,957
Debt to capital employed *(percent)*[5]	**23.2**	23.2	28.9	20.0	17.0	17.0	18.0	22.0	18.0	12.0
Upstream										
Daily production, before royalties										
Crude oil & NGLs *(mboe/day)*	**233.0**	228.6	230.9	236.6	226.5	209.2	211.3	202.6	216.2	256.8
Natural gas *(mmcf/day)*	**539.1**	559.9	689.0	621.0	512.7	554.0	607.0	506.8	541.7	594.4
Total production *(mboe/day)*	**322.9**	321.2	345.7	340.1	312.0	301.5	312.5	287.1	306.5	355.9
Total proved reserves, before royalties *(mmboe)*[6]	**1,301**	1,224	1,324	1,279	1,265	1,192	1,172	1,081	933	896
Downstream										
Upgrading										
Synthetic crude oil sales *(mbbls/day)*	**49.8**	55.2	51.1	53.3	50.5	60.4	55.3	54.1	61.8	58.7
Upgrading differential *($/bbl)*	**18.66**	20.74	18.66	21.80	29.14	22.34	27.34	14.52	11.89	28.77
Canadian Refined Products										
Fuel sales *(million of litres/day)*[7]	**7.3**	6.6	7.6	8.0	8.1	8.7	9.5	8.2	7.6	7.9
Refinery throughput										
Prince George Refinery *(mbbls/day)*	**11.2**	9.4	10.7	11.7	10.3	11.1	10.6	10.0	10.3	10.1
Lloydminster Refinery *(mbbls/day)*	**26.8**	27.8	28.1	28.8	26.4	28.3	28.1	27.8	24.1	26.1
U.S. Refining and Marketing										
Refinery throughput										
Lima Refinery *(mbbls/day)*	**172.2**	138.2	136.1	141.6	149.4	150.0	144.3	136.6	114.6	136.6
BP-Husky Toledo Refinery *(mbbls/day)*[9]	**76.6**	62.2	68.2	63.2	65.0	60.6	63.9	64.4	64.9	60.6
Superior Refinery *(mbbls/day)*[10]	**5.5**	—	—	—	—	—	—	—	—	—
Refining margin *(U.S. $/bbl crude throughput)*	**11.09**	8.94	10.09	9.37	15.06	17.48	17.60	7.29	11.37	(0.86)

(1) *Gross revenues and U.S. refining margin have been recast for 2012 and 2011 to reflect a change in the classification of certain trading transactions.*
(2) *Results reported for 2010 and previous years have not been adjusted for the change in presentation of the former Midstream.*
(3) *Results are reported in accordance with previous Canadian GAAP. Certain reclassifications have been made to conform with current presentation.*
(4) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(5) *The financial ratios constitute non-GAAP measures. Refer to Section 9.3 of the Management's Discussion and Analysis for disclosures on non-GAAP measures.*
(6) *Total proved reserves, before royalties for 2010 onwards were prepared in accordance with the Canadian Securities Administrators' National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Prior to 2010, reserves were prepared in accordance with the rules of the United States Securities and Exchange Commission guidelines and the United States Financial Accounting Standards Board. Refer to Section 9.2 of the Management's Discussion and Analysis for a discussion.*
(7) *Fuel sales have been recast to exclude non-retail products, results reported for 2010 and previous years have not been adjusted for the change in presentation.*
(8) *Total debt includes long-term debt, long-term debt due within one year and short-term debt.*
(9) *BP-Husky Toledo Refinery throughput was revised in the first quarter of 2016 to reflect total throughput. Prior periods reflected crude throughput only and 2015 has been restated to conform with current presentation. Results reported for 2014 and prior have not been adjusted for the change in presentation.*
(10) *Superior Refinery was acquired in November 2017.*

Segmented Financial Information

	Upstream										Downstream				
	Exploration and Production					Infrastructure and Marketing					Upgrading				
($ millions)	**2017**	2016	2015	2014	2013	**2017**	2016	2015	2014	2013	**2017**	2016	2015	2014	2013
Year ended December 31															
Gross revenues	**4,978**	4,036	5,374	8,634	7,333	**1,976**	955	1,264	2,202	2,134	**1,440**	1,324	1,319	2,212	2,023
Royalties	**(363)**	(305)	(432)	(1,030)	(864)	**—**	—	—	—	—	**—**	—	—	—	—
Marketing and other	**—**	—	—	—	—	**(40)**	(88)	38	70	312	**—**	—	—	—	—
Revenues, net of royalties	**4,615**	3,731	4,942	7,604	6,469	**1,936**	867	1,302	2,272	2,446	**1,440**	1,324	1,319	2,212	2,023
Expenses															
Purchase of crude oil and products	**—**	32	41	96	91	**1,855**	857	1,123	2,056	2,004	**983**	808	922	1,676	1,378
Production, operating and transportation expenses	**1,650**	1,760	2,076	2,172	2,016	**13**	20	37	32	21	**197**	168	169	180	161
Selling, general and administrative expenses	**265**	232	237	253	240	**4**	5	7	8	12	**9**	4	4	9	7
Depletion, depreciation, amortization and impairment	**2,237**	1,815	7,993	3,434	2,515	**2**	13	25	25	20	**99**	103	106	108	96
Exploration and evaluation expenses	**146**	188	447	214	246	**—**	—	—	—	—	**—**	—	—	—	—
Loss (gain) on sale of assets	**(42)**	(192)	(17)	(39)	(19)	**1**	(1,439)	—	—	—	**—**	—	—	—	—
Other – net	**6**	53	(34)	(21)	(16)	**(8)**	(3)	(5)	(2)	(3)	**—**	(1)	(11)	11	(27)
Total Expenses	**4,262**	3,888	10,743	6,109	5,073	**1,867**	(547)	1,187	2,119	2,054	**1,288**	1,082	1,190	1,984	1,615
Earnings (loss) from operating activities	**353**	(157)	(5,801)	1,495	1,396	**69**	1,414	115	153	392	**152**	242	129	228	408
Share of equity investment gain (loss)	**12**	(1)	(5)	(6)	(10)	**49**	16	—	—	—	**—**	—	—	—	—
Net financial items	**(126)**	(140)	(139)	(152)	(103)	**—**	—	—	—	—	**(1)**	(1)	(1)	(1)	(7)
Earnings (loss) before income tax	**239**	(298)	(5,945)	1,337	1,283	**118**	1,430	115	153	392	**151**	241	128	227	401
Current income taxes	**(34)**	(100)	(41)	386	162	**—**	—	222	99	222	**63**	—	(17)	47	19
Deferred income taxes	**99**	19	(1,566)	(41)	169	**32**	122	(191)	(60)	(122)	**(22)**	66	52	12	85
Total income tax provision (recovery)	**65**	(81)	(1,607)	345	331	**32**	122	31	39	100	**41**	66	35	59	104
Net earnings (loss)	**174**	(217)	(4,338)	992	952	**86**	1,308	84	114	292	**110**	175	93	168	297
Total assets as at December 31	**17,920**	19,098	21,103	26,035	24,653	**1,364**	1,582	1,699	1,969	1,670	**1,263**	1,076	1,141	1,243	1,355

[1] *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*

Downstream										Corporate and Eliminations[1]					Total				
Canadian Refined Products					U.S. Refining and Marketing														
2017	2016	2015	2014	2013	2017	2016	2015	2014	2013	2017	2016	2015	2014	2013	2017	2016	2015	2014	2013
2,787	2,301	2,886	4,020	3,737	9,355	5,995	7,345	10,663	10,728	(1,550)	(1,299)	(1,425)	(2,679)	(2,086)	18,986	13,312	16,763	25,052	23,869
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	(363)	(305)	(432)	(1,030)	(864)
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	(40)	(88)	38	70	312
2,787	2,301	2,886	4,020	3,737	9,355	5,995	7,345	10,663	10,728	(1,550)	(1,299)	(1,425)	(2,679)	(2,086)	18,583	12,919	16,369	24,092	23,317
2,219	1,770	2,281	3,319	3,134	8,059	5,188	6,455	9,941	9,546	(1,550)	(1,299)	(1,425)	(2,679)	(2,086)	11,566	7,356	9,397	14,409	14,067
256	241	238	263	227	563	535	474	472	420	—	—	—	—	—	2,679	2,724	2,994	3,119	2,845
53	43	31	44	26	15	13	10	9	4	304	247	53	139	217	650	544	342	462	506
111	102	103	102	90	354	342	333	268	233	79	87	84	73	51	2,882	2,462	8,644	4,010	3,005
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	146	188	447	214	246
(5)	(3)	(5)	(1)	(8)	—	—	—	4	—	—	—	—	—	—	(46)	(1,634)	(22)	(36)	(27)
(1)	(10)	1	1	3	(21)	(176)	(236)	(4)	—	6	110	(2)	(5)	(17)	(18)	(27)	(287)	(20)	(60)
2,633	2,143	2,649	3,728	3,472	8,970	5,902	7,036	10,690	10,203	(1,161)	(855)	(1,290)	(2,472)	(1,835)	17,859	11,613	21,515	22,158	20,582
154	158	237	292	265	385	93	309	(27)	525	(389)	(444)	(135)	(207)	(251)	724	1,306	(5,146)	1,934	2,735
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	61	15	(5)	(6)	(10)
(12)	(7)	(6)	(5)	(5)	(14)	(3)	(3)	(3)	(3)	(208)	(220)	(71)	17	21	(361)	(371)	(220)	(144)	(97)
142	151	231	287	260	371	90	306	(30)	522	(597)	(664)	(206)	(190)	(230)	424	950	(5,371)	1,784	2,628
45	—	6	80	65	2	—	15	1	18	(79)	99	121	104	103	(3)	(1)	306	717	589
(7)	41	55	(7)	1	135	33	(106)	(12)	165	(596)	(252)	(71)	(83)	(88)	(359)	29	(1,827)	(191)	210
38	41	61	73	66	137	33	(91)	(11)	183	(675)	(153)	50	21	15	(362)	28	(1,521)	526	799
104	110	170	214	194	234	57	397	(19)	339	78	(511)	(256)	(211)	(245)	786	922	(3,850)	1,258	1,829
1,548	1,410	1,448	1,676	1,788	7,580	7,017	6,784	5,788	5,537	3,252	2,077	881	2,137	1,901	32,927	32,260	33,056	38,848	36,904

Upstream Operating Information

	2017	2016	2015	2014	2013
Daily Production, before royalties					
Light & Medium crude oil *(mbbls/day)*	**51.4**	63.1	80.5	91.2	95.1
NGL *(mbbls/day)*[3]	**18.1**	14.0	18.2	14.0	9.2
Heavy crude oil *(mbbls/day)*	**44.4**	54.1	69.1	76.8	74.5
Bitumen *(mbbls/day)*[3]	**119.1**	97.4	63.1	54.6	47.7
	233.0	228.6	230.9	236.6	226.5
Natural gas *(mmcf/day)*	**539.1**	555.9	689.0	621.0	512.7
Total production *(mboe/day)*	**322.9**	321.2	345.7	340.1	312.0
Average sales prices					
Light & Medium crude oil *($/bbl)*	**67.36**	52.40	57.55	96.59	106.48
NGL *($/bbl)*[3]	**44.18**	38.01	45.88	72.61	70.49
Heavy crude oil *($/bbl)*	**43.38**	30.50	37.16	71.91	63.44
Bitumen *($/bbl)*	**38.20**	27.63	34.47	70.57	61.68
Natural gas *($/mcf)*[3]	**5.52**	4.40	5.80	5.99	3.19
Operating costs *($/boe)*	**13.93**	14.04	15.14	16.12	16.28
Operating netbacks[1][2][3]					
Light & Medium crude oil *($/bbl)*	**39.83**	23.82	29.40	59.63	65.50
NGL *($/bbl)*	**27.05**	22.99	32.10	50.01	39.60
Heavy crude oil *($/bbl)*	**15.33**	9.25	14.56	41.95	34.61
Bitumen *($/bbl)*	**24.85**	15.21	15.41	51.17	43.92
Natural gas *($/mcf)*	**3.67**	2.51	3.93	3.79	1.06

(1) *The operating netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing. Operating netback is a non-GAAP measure. Refer to Section 9.3 of the Management's Discussion and Analysis for disclosures on non-GAAP measures.*
(2) *Includes associated co-products converted to boe.*
(3) *Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.*

Supplemental Upstream Operating Statistics[6]

Operating Netback Analysis[1]	2017	2016	2015
Total Upstream[9]			
Crude Oil Equivalent *($/boe)*[2]			
Sales volume *(mboe/day)*	**322.9**	321.2	345.7
Gross revenue *($/boe)*[7]	**42.47**	33.08	41.06
Royalties *($/boe)*	**3.07**	2.60	3.43
Production and operating costs *($/boe)*[7]	**13.93**	14.04	15.14
Transportation *($/boe)*[3]	**0.22**	0.25	0.49
Operating netback *($/boe)*	**25.25**	16.19	22.00
Depletion, depreciation, amortization and impairment *($/boe)*	**19.08**	15.45	63.34
Administration expenses and other *($/boe)*	**3.13**	2.62	2.56
Earnings (loss) before taxes *($/boe)*	**3.04**	(1.88)	(43.90)
Operating netbacks by commodity			
Crude Oil & NGL's Total			
Sales volume *(mboe/day)*	**233.0**	228.6	230.9
Gross revenue *($/boe)*[7]	**46.09**	35.78	44.18
Royalties *($/boe)*	**3.92**	3.36	4.48
Production and operating costs *($/boe)*[7]	**15.36**	15.42	17.47
Offshore transportation *($/boe)*[3]	**0.31**	0.36	0.74
Operating netback *($/boe)*	**26.50**	16.64	21.49
Natural Gas Total[9]			
Sales volume *(mmcf/day)*	**539.1**	555.9	689.0
Gross revenue *($/mcf)*[7]	**5.52**	4.40	5.80
Royalties *($/mcf)*	**0.15**	0.12	0.13
Production and operating costs *($/mcf)*[7]	**1.70**	1.77	1.74
Operating netback *($/mcf)*	**3.67**	2.51	3.93

Operating Netback Analysis (continued)	2017	2016	2015
Thermal Development			
Lloydminster Thermal			
Bitumen			
Sales volumes *(mbbls/day)*	**77.1**	65.5	48.4
Gross revenue *($/bbl)*(7)	**40.53**	30.22	36.29
Royalties *($/bbl)*	**2.76**	1.98	3.60
Production and operating costs *($/bbl)*(7)	**10.21**	8.72	9.00
Operating netback *($/bbl)*	**27.56**	19.52	23.69
Tucker Thermal			
Bitumen			
Sales volumes *(mbbls/day)*	**21.9**	19.1	11.5
Gross revenue *($/bbl)*(7)	**37.73**	27.57	31.43
Royalties *($/bbl)*	**0.90**	0.50	0.73
Production and operating costs *($/bbl)*(7)	**9.84**	8.11	17.70
Operating netback *($/bbl)*	**26.99**	18.96	13.00
Sunrise Energy Project			
Bitumen			
Sales volumes *(mbbls/day)*	**20.1**	12.8	3.2
Gross revenue *($/bbl)*(7)	**29.79**	14.46	17.72
Royalties *($/bbl)*	**0.77**	0.40	0.57
Production and operating costs *($/bbl)*(7)	**16.91**	26.56	95.18
Transportation *($/bbl)*(3)	**—**	—	23.71
Operating netback *($/bbl)*	**12.11**	(12.50)	(101.74)
Thermal Development Bitumen Total			
Sales volumes *(mbbls/day)*	**119.1**	97.4	63.1
Gross revenue *($/bbl)*(7)	**38.20**	27.63	34.46
Royalties *($/bbl)*	**2.08**	1.48	2.92
Production and operating costs *($/bbl)*(7)	**11.27**	10.94	14.96
Transportation *($/bbl)*(3)	**—**	—	1.20
Operating netback *($/bbl)*	**24.85**	15.21	15.38

Operating Netback Analysis (continued)	2017	2016	2015
Non - Thermal Development[8]			
Medium Oil			
Sales volumes *(mbbls/day)*	**2.1**	2.1	2.1
Gross revenue *($/bbl)*[7]	**48.30**	36.97	41.89
Royalties *($/bbl)*	**2.41**	1.80	1.89
Heavy Oil			
Sales volumes *(mbbls/day)*[8]	**43.5**	44.9	54.8
Gross revenue *($/bbl)*[7]	**43.41**	31.13	37.71
Royalties *($/bbl)*	**4.42**	2.44	4.28
Natural Gas			
Sales volumes *(mmcf/day)*[8]	**24.6**	17.7	17.5
Gross revenue *($/mcf)*[7]	**2.02**	1.76	2.26
Royalties ($/mcf)	**0.11**	0.09	0.19
Non - Thermal Development Medium Oil, Heavy Oil & Natural Gas Total[2]			
Sales volumes *(mboe/day)*	**49.7**	50.0	59.8
Gross revenue *($/boe)*[7]	**41.04**	30.17	36.69
Royalties *($/boe)*	**4.03**	2.34	4.04
Production and operating costs *($/boe)*[7]	**22.21**	18.52	18.36
Operating netback *($/boe)*	**14.80**	9.31	14.29
Western Canada[8]			
Crude Oil			
Light & Medium Oil			
Sales volumes *(mbbls/day)*	**10.0**	21.3	34.3
Gross revenue *($/bbl)*[7]	**54.13**	41.35	48.87
Royalties *($/bbl)*	**6.97**	4.04	5.50
Heavy Oil			
Sales volumes *(mbbls/day)*[8]	**0.9**	9.2	14.3
Gross revenue *($/bbl)*[7]	**42.14**	27.39	35.09
Royalties *($/bbl)*	**4.86**	3.60	5.09
Western Canada Crude Oil Total			
Sales volumes *(mbbls/day)*	**10.9**	30.5	48.6
Gross revenue *($/bbl)*[7]	**53.15**	37.14	44.81
Royalties *($/bbl)*	**6.80**	3.91	5.38
Production and operating costs *($/bbl)*[7]	**33.69**	25.16	24.47
Operating netback *($/bbl)*	**12.66**	8.07	14.96
Natural Gas & NGLs			
NGLs			
Sales volumes *(mbbls/day)*	**10.5**	8.0	8.8
Gross revenue *($/bbl)*[7]	**32.08**	31.14	34.08
Royalties *($/bbl)*	**10.16**	7.59	7.75
Natural Gas			
Sales volumes *(mmcf/day)*[8]	**353.6**	424.7	496.4
Gross revenue *($/mcf)*[4][7]	**2.31**	2.06	2.68
Royalties *($/mcf)*[4][5]	**(0.12)**	(0.04)	(0.08)
Western Canada Natural Gas and NGL Total[2]			
Sales volumes *(mmcfe/day)*	**416.6**	472.7	549.2
Gross revenue *($/mcfe)*[7]	**2.77**	2.37	2.97
Royalties *($/mcfe)*	**0.15**	0.08	0.05
Production and operating costs *($/mcfe)*[7]	**2.02**	1.90	2.04
Operating netback *($/mcfe)*	**0.60**	0.39	0.88

Operating Netback Analysis (continued)	**2017**	2016	2015
Atlantic			
Light Oil			
Sales volumes *(mbbls/day)*	**34.0**	33.1	36.8
Gross revenue *($/bbl)*	**71.69**	60.01	65.89
Royalties *($/bbl)*	**6.75**	8.70	7.43
Production and operating costs *($/bbl)*	**17.12**	18.48	16.76
Offshore transportation *($/bbl)*(3)	**2.13**	2.46	2.58
Operating netback *($/bbl)*	**45.69**	30.37	39.12
Asia Pacific – China			
Light Oil			
Sales volumes *(mbbls/day)*	**5.3**	6.6	7.3
Gross revenue *($/bbl)*	**72.08**	54.98	60.80
Royalties *($/bbl)*	**5.08**	3.68	3.12
NGLs			
Sales volumes *(mbbls/day)*	**7.0**	6.0	9.4
Gross revenue *($/bbl)*	**59.50**	47.14	56.99
Royalties *($/bbl)*	**3.38**	2.65	3.19
Natural Gas			
Sales volumes *(mmcf/day)*	**152.9**	113.5	175.1
Gross revenue *($/mcf)*	**13.29**	13.58	14.98
Royalties *($/mcf)*	**0.74**	0.72	0.81
Asia Pacific – China Light Oil, NGLs & Natural Gas Total(2)			
Sales volumes *(mboe/day)*	**37.8**	31.5	45.9
Gross revenue *($/boe)*	**74.94**	69.40	78.49
Royalties *($/boe)*	**4.33**	3.84	4.24
Production and operating costs *($/boe)*	**6.16**	8.01	5.78
Operating netback *($/boe)*	**64.45**	57.55	68.47

Operating Netback Analysis (continued)	2017	2016	2015
Asia Pacific – Indonesia[9]			
NGLs			
Sales volumes *(mbbls/day)*	**0.6**	—	—
Gross revenue *($/bbl)*	**77.79**	—	—
Royalties *($/bbl)*	**12.32**	—	—
Natural Gas			
Sales volumes *(mmcf/day)*	**8.0**	—	—
Gross revenue *($/mcf)*	**9.51**	—	—
Royalties *($/mcf)*	**1.03**	—	—
Asia Pacific – Indonesia NGLs & Natural Gas Total[2]			
Sales volumes *(mboe/day)*	**1.9**	—	—
Gross revenue *($/boe)*	**63.46**	—	—
Royalties *($/boe)*	**8.08**	—	—
Production and operating costs *($/boe)*	**12.59**	—	—
Operating netback *($/boe)*	**42.79**	—	—
Asia Pacific – Total[9]			
Light Oil			
Sales volumes *(mbbls/day)*	**5.3**	6.6	7.3
Gross revenue *($/bbl)*	**72.08**	54.98	60.80
Royalties *($/bbl)*	**5.08**	3.68	3.12
NGLs			
Sales volumes *(mbbls/day)*	**7.6**	6.0	9.4
Gross revenue *($/bbl)*	**60.94**	47.14	56.99
Royalties *($/bbl)*	**4.08**	2.65	3.19
Natural Gas			
Sales volumes *(mmcf/day)*	**160.9**	113.5	175.1
Gross revenue *($/mcf)*	**13.10**	13.58	14.98
Royalties *($/mcf)*	**0.76**	0.72	0.81
Asia Pacific Light Oil, NGLs & Natural Gas Total[2]			
Sales volumes *(mboe/day)*	**39.7**	31.5	45.9
Gross revenue *($/boe)*	**74.38**	69.40	78.49
Royalties *($/boe)*	**4.52**	3.84	4.24
Production and operating costs *($/boe)*	**6.47**	8.01	5.78
Operating netback *($/boe)*	**63.39**	57.55	68.47

(1) The operating netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing. Operating netback is a non-GAAP measure. Refer to Section 9.3 of the Management's Discussion and Analysis for disclosures on non-GAAP measures.
(2) Includes associated co-products converted to boe and mcf.
(3) Includes offshore transportation costs shown separately from price received. During the first quarter of 2016, the Company reclassified Sunrise Energy Project transportation costs to net against price received. Prior periods have not been restated.
(4) Includes sulphur sales revenues/royalties.
(5) Alberta Gas Cost Allowance reported exclusively as gas royalties.
(6) In the third quarter of 2016, Husky completed the sale of its ownership interest in select midstream assets. These assets are held by HMLP, of which Husky has a 35 percent investment in. Husky's investment is considered a joint venture and is prospectively being accounted for using the equity method.
(7) Transportation expenses for Western Canada, Non - Thermal Development and Thermal Development has been deducted from both gross revenue and production and operating costs to reflect the actual price received at the oil and gas lease.
(8) In the first quarter of 2017, approximately 6.0 mboe/day equivalent of heavy oil and natural gas production was transferred from Western Canada to Non - Thermal Development.
(9) Reported production volumes and associated per unit values include Husky's working interest production from the BD Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.

Advisories

Forward-Looking Statements and Information

Certain statements in this annual report are forward-looking statements and information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this annual report are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "schedules" and "outlook"). In particular, forward-looking statements in this annual report include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally, the Company's general strategic plans and growth strategies; expectation of continued generation of free cash flow; anticipated annual average production growth through 2021; target net debt to funds from operations; and per year amount of future reductions in cash taxes;
- with respect to the Company's thermal developments in the Integrated Corridor: the expected increase in overall thermal production over the next four years; the expected design capacity for the Rush Lake 2, Dee Valley, Spruce Lake North, Spruce Lake Central, Edam Central and West Hazel thermal developments, and the expected timing for bringing such developments online; the expected volume and timing of design capacity to be added by the Edam Central and Westhazel projects; the expected timing to reach 30,000 bbls/day at the Tucker Thermal Project; and the expected timing to reach full capacity at the Sunrise Energy Project;
- with respect to the Company's Offshore business in the Asia Pacific region: the expected timing of first gas at Liuhua 29-1; the expected timing of drilling of, and first gas at, seven production wells at the MDA-MBH fields; the expected timing of tie-in of a third well at the MDK field; expected combined sales volumes from the BD, MDA-MBH and MDK fields once production is fully ramped up; and the expected timing to drill exploration wells at Block 15/33 and Block 16/25; and
- with respect to the Company's Offshore business in the Atlantic region, the expected timing of construction and first oil, and expected gross peak production, at the West White Rose Project.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserve and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this annual report are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third-party consultants, suppliers and regulators, among others.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to Husky.

The Company's Annual Information Form for the year ended December 31, 2017 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

New factors emerge from time to time and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management's assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

Non-GAAP Measures

This annual report contains certain terms which do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS") and are therefore unlikely to be comparable to similar measures presented by other issuers. The non-GAAP measures included in this annual report are: funds from operations, free cash flow, adjusted net earnings (loss), net debt and operating netback. For further details on these non-GAAP measures, please refer to "Non-GAAP Measures" and "Additional Reader Advisories" in sections 9.3 and 9.4, respectively, of the Company's Management's Discussion and Analysis for the year ended December 31, 2017, which sections are incorporated herein by reference.

Disclosure of Oil and Gas Information

Unless otherwise indicated: (i) reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, have an effective date of December 31, 2017 and represent the Company's working interest share; (ii) projected and historical production volumes provided represent the Company's working interest share before royalties; and (iii) historical production volumes provided are for the year ended December 31, 2017.

The Company uses the term "barrels of oil equivalent" (or "boe"), which is consistent with other oil and gas companies' disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not represent value equivalency at the wellhead.

The Company uses the term "reserves replacement ratio", which is consistent with other oil and gas companies' disclosures. Reserves replacement ratios for a given period are determined by taking the Company's incremental proved reserve additions for that period divided by the Company's upstream gross production for the same period. The reserves replacement ratio measures the amount of reserves added to a company's reserve base during a given period relative to the amount of oil and gas produced during that same period. A company's reserves replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserves replacement ratio only measures the amount of reserves added to a company's reserves base during a given period. Reserves replacement ratios presented as excluding economic factors exclude the impact that changing oil and gas prices have on reserves amounts.

Note to U.S. Readers

The Company reports its reserves and resources information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves and resources information in accordance with Canadian disclosure requirements, it may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the U.S. Securities and Exchange Commission.

All currency is expressed in Canadian dollars unless otherwise indicated.

Corporate Information

Board of Directors

Victor T.K. Li
Co-Chairman

Canning K.N. Fok
Co-Chairman(2)

William Shurniak
Deputy Chairman(1)

Robert J. Peabody
President & Chief Executive Officer

Stephen E. Bradley(1)(3)

Asim Ghosh

Martin J.G. Glynn(2)(3)

Poh Chan Koh

Eva L. Kwok(2)(3)

Stanley T.L. Kwok(4)

Frederick S.H. Ma(1)(4)

George C. Magnus(1)

Neil D. McGee(4)

Colin S. Russel(1)(4)

Wayne E. Shaw(1)(3)

Frank J. Sixt(2)

(1) Audit Committee
(2) Compensation Committee
(3) Corporate Governance Committee
(4) Health, Safety & Environment Committee

The Management Information Circular and the Annual Information Form contain additional information regarding the Directors.

Executives

Robert J. Peabody
President & Chief Executive Officer

Jonathan M. McKenzie
Chief Financial Officer

Robert W.P. Symonds
Chief Operating Officer

Gerald F. Alexander
Senior Vice President, Western Canada Production

Bradley H. Allison
Senior Vice President, Exploration

Janet E. Annesley
Senior Vice President, Corporate Affairs

Robert I. Baird
Senior Vice President, Downstream

P. Andrew Dahlin
Senior Vice President, Heavy Oil

Nancy F. Foster
Senior Vice President, Human & Corporate Resources

David A. Gardner
Senior Vice President, Business Development

James D. Girgulis
Senior Vice President, General Counsel & Secretary

Robert M. Hinkel
Chief Operating Officer, Asia Pacific

Trevor Pritchard
Senior Vice President, Atlantic Region

Terry J. Manning
Senior Vice President, Safety, Engineering & Procurement

John W.G. Myer
Senior Vice President, Oil Sands

Investor Information

Common Share Information

Year ended December 31		**2017**	2016	2015
Share price *(dollars)*	High	**17.83**	18.10	29.48
	Low	**13.39**	11.34	14.03
	Close at December 31	**17.75**	16.29	14.31
Average daily trading volumes *(thousands)*		**1,022**	1,430	1,196
Number of common shares outstanding *(thousands)*		**1,005,120**	1,005,452	984,329
Weighted average number of common shares outstanding *(thousands)*				
	Basic	**1,005,309**	1,004,875	984,067
	Diluted	**1,005,310**	1,004,875	984,067

Trading in the common shares of Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite Index, S&P/TSX Capped Energy Index and S&P/TSX 60 Index.

Toronto Stock Exchange Listing
HSE, HSE.PR.A, HSE.PR.B, HSE.PR.C, HSE.PR.E and HSE.PR.G (at December 31, 2017)

Outstanding Shares
The number of common shares outstanding at December 31, 2017 was 1,005,120,012.

Transfer Agent and Registrar
Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company N.A. Share certificates may be transferred at Computershare's principal offices in Calgary, Toronto, Montreal and Vancouver, and at Computershare's principal office in Canton, Massachusetts in the United States.

Queries regarding share certificates, dividends and estate transfers should be directed to Computershare Trust Company at 1-800-564-6253 (in Canada and the United States) and 1-514-982-7555 (outside Canada and the United States).

Auditors
KPMG LLP
3100, 205 - 5th Avenue S.W.
Calgary, Alberta T2P 4B9

Annual Meeting
The Annual Meeting of Shareholders will be held at 10:30 a.m. on Thursday, April 26 in the Performance Hall at Studio Bell, 850 - 4th Street S.E., Calgary, Alberta, Canada.

Additional Publications
The following publications are available on our website:

- Annual Information Form, filed with Canadian securities regulators
- Form 40-F, filed with the U.S. Securities and Exchange Commission
- Quarterly Reports

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Please recycle. The paper, paper mill, and printer are all Forest Stewardship Council certified, which is an international network that promotes environmentally appropriate and socially beneficial management of the world's forests.

Design and Production: One Design
Printing: CBN Commercial Solutions
This report was printed in Canada.