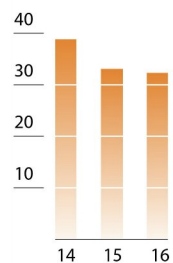


MANAGEMENT'S DISCUSSION AND ANALYSIS

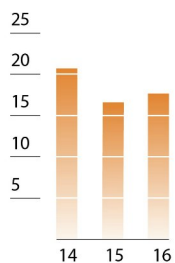
1.0 Financial Summary

1.1 Financial Position

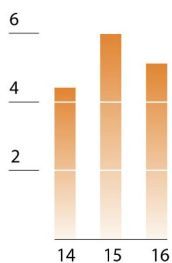
Total Assets
(\$ billions)



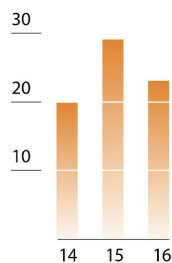
Total Equity
(\$ billions)



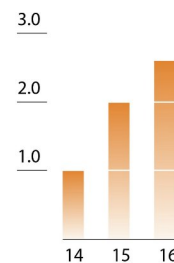
Total Long-term Debt (\$ billions)



Debt to Capital Employed⁽¹⁾ (%)

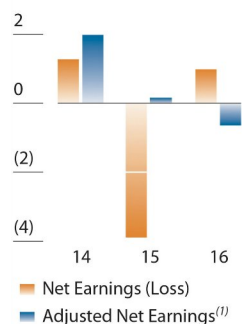


Debt to Funds from Operations⁽¹⁾
(times)

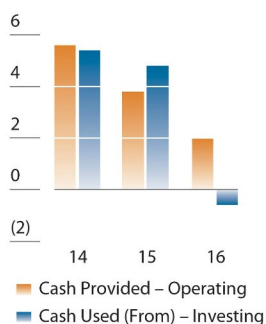


1.2 Financial Performance

Net Earnings
(\$ billions)



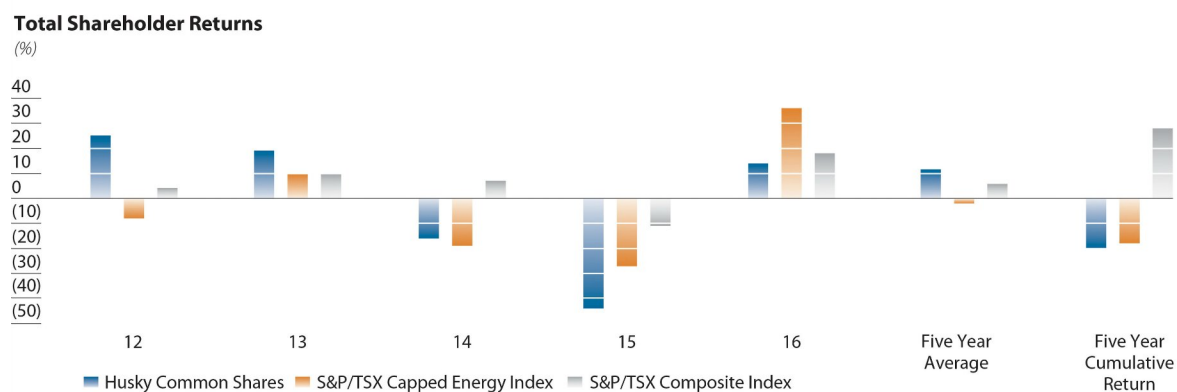
Cash Flow
(\$ billions)



⁽¹⁾ Debt to capital employed, debt to funds from operations and adjusted net earnings are non-GAAP measures. Adjusted net earnings was redefined in the second quarter of 2016 to equal net earnings before after-tax property, plant and equipment impairment (reversal), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on sale of assets. Prior periods have been revised to conform with the current period presentation. Refer to Section 11.3 for a reconciliation to the GAAP measures.

1.3 Total Shareholder Returns

The following graph shows the total shareholder returns compared with the Standard and Poor's ("S&P") and the Toronto Stock Exchange ("TSX") energy and composite indices.



1.4 Selected Annual Information

(\$ millions, except where indicated)

	2016	2015	2014
Gross revenues and Marketing and other	13,224	16,801	25,122
Net earnings (loss) by business segment			
Upstream	1,091	(4,254)	1,106
Downstream	342	660	363
Corporate	(511)	(256)	(211)
Net earnings (loss)	922	(3,850)	1,258
Net earnings (loss) per share – basic	0.88	(3.95)	1.26
Net earnings (loss) per share – diluted	0.88	(4.01)	1.20
Adjusted net earnings (loss) ⁽¹⁾	(655)	149	1,992
Funds from operations ⁽¹⁾	2,076	3,329	5,535
Ordinary dividends per common share ⁽²⁾	—	0.90	1.20
Dividends per cumulative redeemable preferred share, series 1	0.73	1.11	1.11
Dividends per cumulative redeemable preferred share, series 2	0.42	—	—
Dividends per cumulative redeemable preferred share, series 3	1.13	1.19	—
Dividends per cumulative redeemable preferred share, series 5	1.25	0.90	—
Dividends per cumulative redeemable preferred share, series 7	1.15	0.62	—
Total assets	32,260	33,056	38,848
Net debt ⁽³⁾	4,020	6,686	4,025

⁽¹⁾ Adjusted net earnings and funds from operations are non-GAAP measures. Adjusted net earnings was redefined in the second quarter of 2016 to equal net earnings before after-tax property, plant and equipment impairment (reversal), goodwill impairment charges, exploration and evaluation asset write-downs, inventory write-downs and loss (gain) on sale of assets. Prior periods have been revised to conform with the current period presentation. Refer to Section 11.3 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 the fourth quarter of 2015.

⁽³⁾ Net debt is a non-GAAP measure. Refer to Section 11.3 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. The Company's balanced growth strategy focuses on consistent execution, disciplined financial management and safe and reliable operations.

2.1 Upstream

Upstream includes 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, 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, offshore East Coast of Canada (Atlantic Region) and offshore China and offshore Indonesia (Asia Pacific Region).

Profile and highlights of the Upstream segment include:

Heavy Oil

- The heavy oil thermal portfolio, including the Tucker Thermal Project, averaged 84,600 bbls/day in 2016, compared to 59,900 bbls/day in 2015;
- First oil was achieved at the 10,000 bbls/day Edam East heavy oil thermal development in the second quarter of 2016. Production averaged 14,900 bbls/day in December, exceeding its design capacity;
- First oil was achieved at the 10,000 bbls/day Vawn heavy oil thermal development in the second quarter of 2016. Production averaged 11,400 bbls/day in December, exceeding its design capacity;
- First oil was achieved at the 4,500 bbls/day Edam West heavy oil thermal development in the third quarter of 2016. Production averaged 4,200 bbls/day in December;
- First oil was achieved from the Colony formation at the Tucker Thermal Project in the Cold Lake region of Alberta in the second quarter of 2016. Total production from the Tucker Thermal Project averaged 21,700 bbls/day in December;
- Development continues at the 10,000 bbls/day Rush Lake 2 heavy oil thermal development, with first production expected in the first half of 2019; and
- Three new Lloyd thermal projects with total design capacity of about 30,000 bbls/day have been sanctioned at Dee Valley, Spruce Lake North and Spruce Lake Central. Subject to regulatory approval, first production for all three is expected in 2020.

Oil Sands

- Gross production from the Sunrise Energy Project continued to ramp-up in 2016, averaging 25,600 bbls/day (12,800 bbls/day net Husky share) during 2016, with average annual production in 2017 expected to be in the range of 40,000 to 44,000 bbls/day (20,000 to 22,000 bbls/day net Husky share).

Asia Pacific Region

- The Liwan Gas Project, the first deepwater development offshore China, consists of three deepwater natural gas fields: Liwan 3-1, Liuhua 34-2 and Liuhua 29-1. The Company holds a 49 percent working interest in the production sharing contract ("PSC") at the Liwan Gas Project and operates the deepwater infrastructure;
- Combined gross production from Liwan 3-1 and Liuhua 34-2 averaged 48,800 boe/day (24,800 boe/day net Husky share) in 2016, compared to 62,300 boe/day (38,400 boe/day net Husky share) in 2015. The decrease in the overall production is due to issues within the buyer's onshore pipeline network in the first quarter of 2016 and reduced buyer gas demand in 2016. The decrease in the Company's net share of production was also due to the entitlement share of production volumes reverting back to 49 percent in the second quarter of 2015 following the completion of exploration cost recoveries from the Liwan 3-1 field;
- During the third quarter of 2016, the Company's China subsidiary signed a Heads of Agreement ("HOA") with China National Offshore Oil Corporation ("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 current exchange rates. Gross take-or-pay volumes from the fields remain unchanged in the range of 300-330 mmcf/day. Liquids production, net to Husky, is 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;
- The second 22-inch subsea pipeline connecting the deepwater pipeline to the central platform has been completed, tested and placed in service. This pipeline provides operating flexibility for the deepwater infrastructure and completes the Liwan facilities to its full design specification;
- Negotiations for the sale of gas and liquids from Liuhua 29-1, the third deepwater field, are being pursued together with CNOOC;

- The Company holds a 40 percent working interest in the Wenchang oil field, located in the Pearl River Mouth Basin approximately 400 kilometres southwest of the Hong Kong Special Administrative Region. The PSC will expire in the fourth quarter of 2017, after which the Company will not have a working interest in this field;
- In 2015, the Company signed a PSC for the 15/33 exploration block offshore China. The 15/33 block covers approximately 155 square kilometres and is located in the Pearl River Mouth Basin in the South China Sea, approximately 140 kilometres southeast of the Hong Kong Special Administrative Region, in water depths of approximately 80 - 100 metres. The Company is the operator of the block during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, its partner CNOOC may assume a working interest of up to 51 percent during the development and production phase. The corresponding CNOOC share of exploration cost recovery from production would be allocated to the Company;
- The Company holds a 40 percent working interest in a joint venture company that holds the PSC for the Madura Strait Block covering approximately 622,000 acres, offshore Indonesia. It is focused on the development of the BD, MDA, MBH, MDK and MAC fields;
- The liquids-rich BD field, which is the first gas development the Company is advancing in Indonesia, remains on target for first production in 2017 and is scheduled to ramp up to its full gas sales rate by the second half of 2017;
- At the MDA, MBH and MDK gas fields, the Company has secured a gas sales agreement for the MDA and MBH fields, which will be developed in tandem. Production from the MDA, MBH and MDK gas fields is expected in the 2018 - 2019 timeframe;
- Combined net sales volumes from the BD, MDA, MBH and MDK fields are expected to be about 100 mmcf/day of gas and 2,400 boe/day of associated NGL once fully ramped up;
- Longer term, the MAC field is proceeding with front-end engineering and design ("FEED") for development and the Company has three additional discoveries in the Madura Strait Block that are under evaluation for development;
- The Company has a 100 percent interest in the rights to the Anugerah exploration block covering approximately two million acres. The Anugerah exploration block is located in the East Java Basin, Indonesia approximately 150 kilometres east of the Madura Strait Block; and
- The Company and its joint venture partner CPC Corporation have rights to an exploration block in the South China Sea covering approximately 7,700 square kilometres located southwest of the island of Taiwan. The Company holds a 75 percent working interest during exploration, while CPC Corporation has the right to participate in the development program up to a 50 percent interest.

Atlantic Region

- The Company is the operator of the White Rose field with a 72.5 percent working interest in the core field and a 68.875 percent working interest in satellite tiebacks, including the North Amethyst, South White Rose and West White Rose extensions. The Company has a 13 percent non-operated interest in the Terra Nova oil field;
- First production was achieved from the North Amethyst Hibernia formation well in the third quarter of 2016 and an additional well was brought into production at the South White Rose drill centre in the fourth quarter of 2016;
- Engineering design and subsurface evaluation work continues at West White Rose to increase capital efficiency and improve resource capture. The project will be considered for sanction in 2017;
- In November 2016, the Canada-Newfoundland and Labrador Petroleum Board announced that the Company was the successful bidder on two parcels of land in its 2016 land sale. The lands cover an area of 211,574 hectares and brought the Company's Exploration Licenses ("ELs") in the region to eight. The southwest parcel is adjacent to the White Rose field and satellite extensions, while the other is northeast of the field and adjacent to other Company operated ELs in the Jeanne d'Arc Basin; and
- The Company has a 35 percent non-operated working interest in five discoveries in the Flemish Pass: Bay du Nord, Bay de Verde, Baccaieu, Harpoon and Mizzen.

Western Canada Resource Play Development

- Expertise and experience exploring and developing the natural gas potential in the Alberta Deep Basin, Foothills and Northwest Plains of Alberta and British Columbia.

Infrastructure and Marketing

- The Infrastructure and Marketing business supports Upstream production while providing integration with the Company's Downstream assets through optimization of market access;
- The Infrastructure and Marketing business manages the sale and transportation of the Company's Upstream and Downstream production and third-party commodity trading volumes through access to capacity on third-party pipelines and storage facilities in both Canada and the United States; and
- Plans to expand export pipeline access and production storage opportunities to enhance market access for the Company's heavy oil production are being evaluated.

2.2 Downstream

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil in Canada (Upgrading), refining in Canada of crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol (Canadian Refined Products) and refining in the U.S. of primarily crude oil to produce and market 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 therefore are grouped together as the Downstream business segment due to the similar nature of their products and services.

Profile and highlights of the Downstream segment include:

Upgrading

- Heavy oil upgrading facility located in Lloydminster, Saskatchewan with a throughput capacity of 82 mbbbls/day.

Canadian Refined Products

- Largest marketer of paving asphalt in Western Canada with a 29 mbbbls/day capacity asphalt refinery located in Lloydminster, Alberta integrated with the local heavy oil production, transportation and upgrading infrastructure;
- Largest producer of ethanol in Western Canada with a combined 260 million litres per year of capacity at plants located in Lloydminster, Saskatchewan and Minnedosa, Manitoba;
- Refinery at Prince George, British Columbia with throughput capacity of 12 mbbbls/day producing low sulphur gasoline and ultra low sulphur diesel;
- Major regional motor fuel marketer with an average of 481 retail marketing locations in 2016, including bulk plants and travel centres with strategic land positions in Western Canada and Ontario. The Company also entered into a contractual agreement with Imperial Oil to create a single expanded truck transport network of approximately 160 sites. The agreement was approved by Canada's Competition Bureau in June 2016 and contract closing conditions were met late in the fourth quarter 2016. Progress continues to be made on the implementation of the agreement, and the consolidation of the two networks is expected in the second half of 2017; and
- The Company has started the pre-FEED work on a potential 30,000 bbls/day expansion of its asphalt processing capacity in Lloydminster. This business continues to show strong returns through the cycle and its expansion would provide an additional outlet for the Company's growing heavy oil thermal production.

U.S. Refining and Marketing

- Refinery in Lima, Ohio with a gross crude oil throughput capacity of 165,000 bbls/day and operating capacity of 140,000 – 165,000 bbls/day on its current crude slate. The Company continues to work on a crude oil flexibility project designed to improve reliability at the facility and allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada. Current heavy crude oil feedstock capability is up to 10,000 bbls/day. The full scope of the project is expected to be completed in 2018; and
- A 50 percent interest in the BP-Husky Refinery in Toledo, Ohio with a nameplate capacity of 160,000 bbls/day and operating capacity of 135,000 – 145,000 bbls/day on its current crude slate. The Company and its partner completed a feedstock optimization project at the BP-Husky Toledo Refinery in mid-July 2016. The Refinery is now able to process approximately 65,000 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 remains unchanged at 160,000 bbls/day.

2.3 Divestitures

- 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;
- 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 include 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, Husky Midstream Limited Partnership ("HMLP"), of which the Company owns 35 percent, Power Assets Holdings Limited ("PAH") owns 48.75 percent and Cheung Kong Infrastructure Holdings Limited ("CKI") owns 16.25 percent. The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets; and
- During 2016, the company completed the sale of approximately 30,200 boe/day of legacy crude oil and natural gas assets in Western Canada for gross proceeds of \$1.12 billion.

2.4 Saskatchewan Pipeline Spill Recovery Efforts

- During the third quarter of 2016, a pipeline leak occurred on the south shore of the North Saskatchewan River, spilling approximately 225 m³ (+/- 10 percent) of heavy oil and diluent. Approximately 210 m³ was recovered in cleanup operations completed in 2016; and
- As at December 31, 2016, total gross costs incurred in response to the spill were approximately \$107 million, for which \$88 million has been recovered through insurance proceeds. Both the spill costs and insurance recoveries have been incurred by HMLP. The Company is the operator of the assets within HMLP and holds a 35 percent interest.

3.0 The 2016 Business Environment

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

- The imbalance between global crude oil supply and demand, led primarily by the growth in U.S. unconventional and the Organization of the Petroleum Exporting Countries ("OPEC") production, lower economic growth forecasts from emerging markets and corresponding growth in global crude oil inventories, resulted in the continued weakness of key crude oil benchmarks. However, in late 2016, OPEC came to an agreement to reduce production by 1.2 mmbbls/day from their daily production, which has led to crude oil benchmarks showing signs of recovery in the fourth quarter;
- North American natural gas benchmarks continued to be weak in 2016 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 Canadian dollar continued to be weak relative to the U.S. dollar in 2016;
- In early 2016, the Alberta government adopted the recommendation of its Royalty Review Panel. The new royalty framework preserves the existing royalty structure and rates for oil sands. It also creates a harmonized royalty formula for crude oil, natural gas and NGL that emulates a revenue minus cost system. The new rates will be calibrated to match rates of returns that could be expected under the existing system. The royalty changes will take effect in 2017 and only apply to new wells. Royalties on existing wells will remain in place for 10 years;
- Reduced production from the Western Canadian oil sands resulting from a temporary production interruption in May due to the Fort McMurray wildfire;
- Industry advancement in alternative and improved extraction methods have rapidly evolved in North American and international onshore and offshore activity;
- A continuing emphasis on environmental, health and safety, enterprise risk management, resource sustainability and corporate social responsibility;
- 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;
- The increasing targets in the U.S. Renewable Fuel Standard ("RFS") program have led to an increase in the price of Renewable Identification Number ("RIN") credits for U.S. refiners;
- The convergence of North American and International crude oil prices has led to a decrease in crack spreads for North American refiners; and
- Continued global economic uncertainty has led to a tightening of investment from historical norms, creating greater competition among companies within capital markets and the postponement of various capital projects.

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

The Company is exposed to a number of risks inherent to 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 7.0 and the 2016 Annual Information Form.

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

Average Benchmarks Summary		2016	2015
West Texas Intermediate ("WTI") crude oil ⁽¹⁾	(U.S. \$/bbl)	43.32	48.80
Brent crude oil ⁽²⁾	(U.S. \$/bbl)	43.69	52.46
Light sweet at Edmonton	(\$/bbl)	52.99	57.21
Daqing ⁽³⁾	(U.S. \$/bbl)	40.86	49.26
Western Canada Select at Hardisty ⁽⁴⁾	(U.S. \$/bbl)	29.48	35.28
Lloyd heavy crude oil at Lloydminster	(\$/bbl)	32.61	39.15
WTI/Lloyd crude blend differential	(U.S. \$/bbl)	13.70	13.43
Condensate at Edmonton	(U.S. \$/bbl)	42.47	47.36
NYMEX natural gas ⁽⁵⁾	(U.S. \$/mmbtu)	2.46	2.66
Nova Inventory Transfer ("NIT") natural gas	(\$/GJ)	1.98	2.62
Chicago Regular Unleaded Gasoline	(U.S. \$/bbl)	56.07	67.11
Chicago Ultra-low Sulphur Diesel	(U.S. \$/bbl)	56.48	68.02
Chicago 3:2:1 crack spread	(U.S. \$/bbl)	12.74	18.62
U.S./Canadian dollar exchange rate	(U.S. \$)	0.755	0.783
Canadian Equivalents⁽⁶⁾			
WTI crude oil	(\$/bbl)	57.38	62.32
Brent crude oil	(\$/bbl)	57.87	67.00
Daqing	(\$/bbl)	54.12	62.91
Western Canada Select at Hardisty	(\$/bbl)	39.05	45.06
WTI/Lloyd crude blend differential	(\$/bbl)	18.15	17.15
NYMEX natural gas	(\$/mmbtu)	3.26	3.40

⁽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.

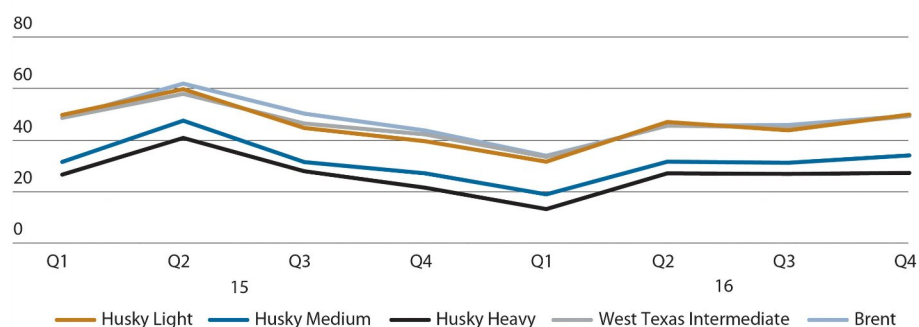
As an integrated producer, the Company's profitability is largely determined by realized prices for crude oil and natural gas, marketing margins on committed pipeline capacity and refinery margins, as well as the effect of changes in the U.S./Canadian dollar exchange rate. All of Husky's crude oil production 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, predominantly in the United States. In the Asia Pacific Region, natural gas is sold to a specific buyer with long-term contracts. For the Liwan 3-1 gas field, a price profile has been fixed for five years and then will be linked to local benchmark pricing for the years following subject to a floor and ceiling. For the Liuhua 34-2 field, the price is fixed with a single escalation step during the contract delivery period.

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. 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 52 percent heavy crude oil 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 at rack prices or from production from the Husky Prince George Refinery.

Crude Oil Benchmarks

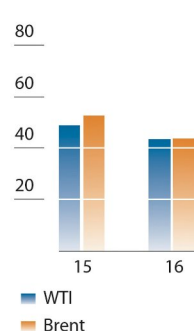
WTI, Brent and Husky Average Crude Oil Prices

(U.S. \$/bbl)



Average WTI and Brent

(U.S. \$/bbl)



Global crude oil benchmarks remained weak during 2016 due to the continued market imbalance between supply and demand. While crude oil production in the U.S. has declined relative to 2015, it remained at near record levels. Towards the end of 2016, OPEC members and some key non-OPEC producers agreed to reduce production in 2017 which has improved the outlook for global crude oil benchmarks. West Texas Intermediate ("WTI") reached a low of U.S. \$26.21/bbl in the first quarter of 2016 and subsequently increased to an average of U.S. \$49.29/bbl during the fourth quarter of 2016. WTI averaged U.S. \$43.32/bbl in 2016, which was weaker compared to 2015 when WTI averaged U.S. \$48.80/bbl. Brent averaged U.S. \$43.69/bbl in 2016 compared to U.S. \$52.46/bbl in 2015.

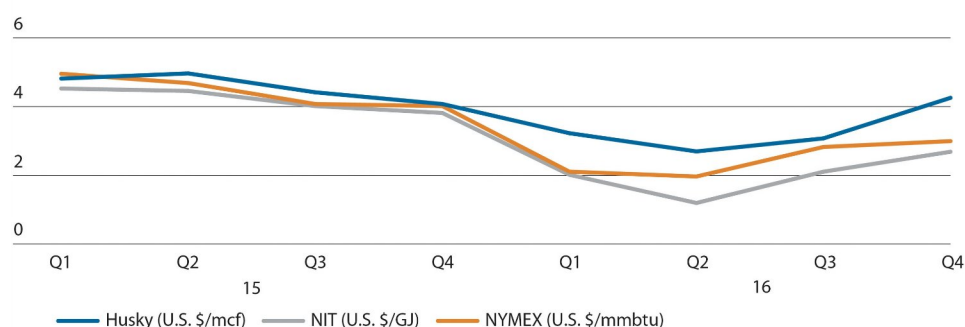
The price received by the Company for crude oil production from Western Canada is primarily driven by the price of WTI, adjusted to Western Canada. The price received by the Company for crude oil production from the Atlantic Region is primarily driven by the price of Brent and the price received by the Company for crude oil and NGL production from the Asia Pacific Region is primarily driven by the price of Daqing. A portion 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 2016, 66 percent of the Company's crude oil and NGLs production was heavy crude oil or bitumen compared to 57 percent in 2015.

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 decreased in 2016 primarily due to lower expected demand growth from oil sands and declining market benchmarks for energy commodities.

Natural Gas Benchmarks

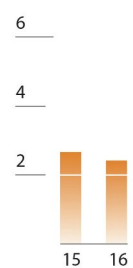
NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices

(U.S. \$/mcf)



Average NYMEX

(U.S. \$/mmbtu)



North American natural gas benchmarks continued to be weak in 2016 due to an oversupply of natural gas in North America, which is largely the result of technological advances in horizontal drilling and hydraulic fracturing which have unlocked significant reserves that were not economical under previously applied extraction methods. The Nova Inventory Transfer ("NIT") natural gas benchmark observed a temporary decline in the second quarter of 2016 due to reduced demand from Canadian oil sands operations, which were impacted by the Fort McMurray wildfire.

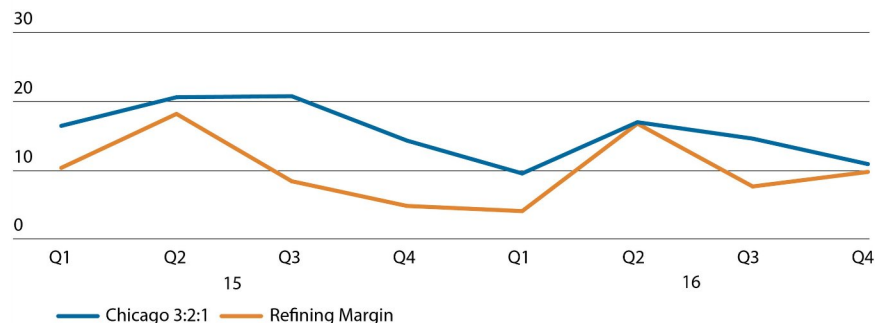
The price received by the Company for natural gas production from Western Canada is primarily driven by the NIT near-month contract price of natural gas, while the price received by the Company for production from the Asia Pacific Region are covered by fixed long-term sales contracts.

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

Refining Benchmarks

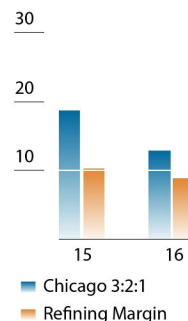
Chicago Average Crack Spread and Husky Realized U.S. Refining Margin

(U.S. \$/bbl)



Average Crack Spread

(U.S. \$/bbl)



The 3:2:1 crack spread is the key indicator for refining margins and reflects refinery gasoline output that is approximately twice the distillate output. This crack spread 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 nor 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 market crack spread benchmark.

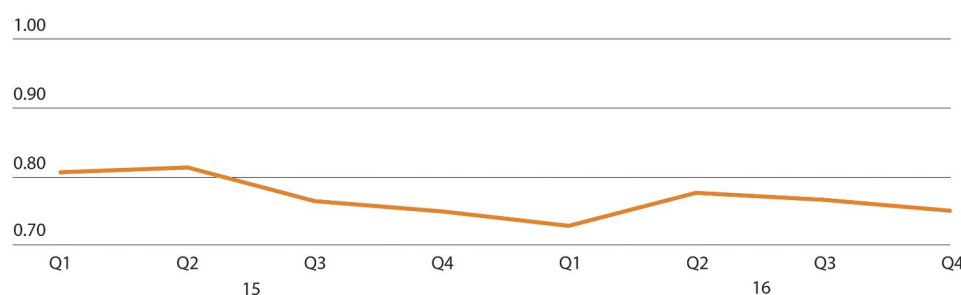
The cost of the Renewable Fuels Standard legislation has become a material economic factor for refineries in the U.S. as the market value of RINs has risen. The 3:2:1 crack spread is a gross margin based on the prices of unblended fuels that will be blended with biofuel. The cost of purchasing RINs or 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. Husky sells both blended fuels and unblended fuels with the goal of maximizing revenue 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 and BP-Husky Toledo Refineries contain approximately 10 to 15 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

Average U.S./Canadian Dollar Exchange Rate

(U.S. \$ per Cdn \$)



Average U.S./Canadian Dollar Exchange Rate

(U.S. \$ per Cdn \$)



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. The Company's earnings benefited from the weakening of the Canadian dollar in 2016, which averaged U.S. \$0.755 compared to U.S. \$0.783 in 2015.

The Company's fixed long-term sales contracts in the Asia Pacific Region 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 natural gas commodities in the region. The Canadian dollar averaged RMB 5.01 in 2016 compared to RMB 4.92 in 2015.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in 2016 on earnings before income taxes and net earnings. The table below reflects what the expected effect would have been on the financial results for 2016 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2016. 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	2016		Effect on Earnings before Income Taxes ⁽¹⁾		Effect on Net Earnings ⁽¹⁾	
	Average	Increase	(\$ millions)	(\$/share) ⁽²⁾	(\$ millions)	(\$/share) ⁽²⁾
WTI benchmark crude oil price ⁽³⁾⁽⁴⁾	43.32	U.S. \$1.00/bbl	101	0.10	73	0.07
NYMEX benchmark natural gas price ⁽⁵⁾	2.46	U.S. \$0.20/mmbtu	14	0.01	11	0.01
WTI/Lloyd crude blend differential ⁽⁶⁾	13.70	U.S. \$1.00/bbl	(56)	(0.06)	(42)	(0.04)
Canadian light oil margins	0.057	Cdn \$0.005/litre	12	0.01	9	0.01
Asphalt margins	20.80	Cdn \$1.00/bbl	10	0.01	8	0.01
Chicago 3:2:1 crack spread	12.74	U.S. \$1.00/bbl	80	0.08	51	0.05
Exchange rate (U.S. \$ per Cdn \$) ⁽³⁾⁽⁷⁾	0.755	U.S. \$0.01	(45)	(0.04)	(33)	(0.03)

⁽¹⁾ Excludes mark to market accounting impacts.

⁽²⁾ Based on 1,005.5 million common shares outstanding as of December 31, 2016.

⁽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⁾ Excludes impact on 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 Strategic Plan

The Company's strategy is to continue to develop a higher return production base, which will further lower its cost structure and drive free cash flow growth.

The Company is building on its thermal expertise through its expanding Lloyd heavy oil thermal developments, the Tucker Thermal Project and the Sunrise Energy Project. The integrated Downstream business maximizes margins from this thermal production while helping shield the Company from volatile differentials. In the Asia Pacific Region, Husky continues to develop its fixed-price natural gas business offshore China and Indonesia, further insulating the Company from commodity price instability. The Western Canada and Atlantic Region portfolios are being rejuvenated with a balance of short to long-term opportunities that provide for higher return production growth.

The Company's strategic direction by business segment is summarized as follows:

4.1 Upstream

The Company's heavy oil strategy is focused on expanding its long life, higher return Lloyd thermal production. The Company advanced the development of its heavy oil thermal assets in 2016 with the addition of three new thermal projects with a combined nameplate capacity of 24,500 bbls/day and is currently developing the 10,000 bbls/day Rush Lake 2 project, with expected first production in the first half of 2019. The Company also sanctioned three new Lloyd thermal projects with a total design capacity of about 30,000 bbls/day, which are subject to regulatory approval, with expected first production for all three in 2020.

The Asia Pacific Region consists of the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields on Block 29/26 located offshore China, the Wenchang oil field, the Madura Strait block BD, MDA, MBH, MDK and MAC development fields, three discoveries offshore Indonesia and rights to additional exploration blocks in the South China Sea, offshore Taiwan and offshore Indonesia. The Liwan Gas Project, located approximately 300 kilometres southeast of the Hong Kong Special Administrative Region, is an important component of the Company's near term production growth strategy and a key step in accessing the burgeoning energy markets in the Hong Kong Special Administrative Region and Mainland China. The Company, and its partner CNOOC, achieved first gas production from the Liwan 3-1 gas field in March 2014 and from the Liuhua 34-2 gas field in December 2014. At the Liwan Gas Project, the second 22-inch subsea pipeline connecting the deepwater pipeline to the central platform has been completed, tested and placed in service. This pipeline provides operating flexibility for the deepwater infrastructure and completes the Liwan facilities to its full design specification. Negotiations for the sale of gas and liquids from the Liuhua 29-1 gas field are ongoing. At the BD development, the project is on target for first production in the 2017 timeframe and is scheduled to ramp up to its full gas sales rate by the second half of 2017.

The Sunrise Energy Project achieved steady production ramp-up, despite wildfires temporarily impacting production in the second quarter of 2016. Total production averaged 25,600 bbls/day (12,800 bbls/day net Husky share) in 2016 with annual average production in 2017 expected to be in the range of 40,000 to 44,000 bbls/day (20,000 to 22,000 bbls/day net Husky share).

In the Atlantic Region, the Company holds interests in eight Production Licences, eight Exploration Licences and 23 Significant Discovery Areas. Development activity continued to advance at the White Rose core field and its satellites, with first oil achieved at the North Amethyst Hibernia formation well and an additional well brought into production at the South White Rose drill centre. Engineering design and subsurface evaluation work continues at the West White Rose extension to increase capital efficiency and improve resource capture, with the project being considered for sanction in 2017. In the Flemish Pass, the Company holds a 35 percent non-operated working interest in the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. The Company and its partner continue to assess the commercial potential of these discoveries. In November 2016, the Canada-Newfoundland and Labrador Petroleum Board announced that the Company was the successful bidder on two parcels of land in its 2016 land sale. The lands cover an area of 211,574 hectares and brought the Company's ELs in the region to eight. The southwest parcel is adjacent to the White Rose field and satellite extensions, while the other is northeast of the field and adjacent to other Company operated ELs in the Jeanne d'Arc Basin.

The Company's Western Canada resource play strategy is to advance developments in the Spirit River (predominantly Wilrich), Montney and Duvernay formations.

The Infrastructure and Marketing business supports Upstream production while providing integration with the Company's Downstream assets through optimization of market access. The Company plans to expand export pipeline access and product storage opportunities to enhance market access. 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 retains a 35 percent ownership interest and remains the operator of the assets, which will provide the takeaway capacity for another eight heavy oil thermal developments. Strategically, the deal facilitates both the expansion of Husky Lloydminster area production and the expansion of third-party tariff business.

4.2 Downstream

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 refined product pricing for its Western Canada heavy oil, bitumen and light oil production and assists in mitigating market volatility.

Downstream operations include upgrading and refining crude oil and marketing gasoline, diesel, jet fuel, asphalt, ethanol and related products in Canada and the United States.

The Company's strategic plans emphasize safe, reliable, cost effective operations. To enhance crude oil processing optionality at the Lima Refinery, the Company continued to make progress on the crude oil flexibility project targeted for completion in 2018. The project will allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada, enabling the Lima Refinery to swing between light and heavy crude oil feedstock and strengthening the Company's integration model. The first stage of the project is now complete and the Refinery can currently process up to 10,000 bbls/day of heavy crude oil feedstock.

At the BP-Husky Toledo Refinery, the Company and its partner completed a feedstock optimization project in 2016. The Refinery is now able to process approximately 65,000 bbls/day of High-TAN crude oil to support production from the Sunrise Energy Project. The Refinery's overall nameplate capacity remains unchanged at 160,000 bbls/day.

4.3 Financial

The Company is committed to ensuring sufficient liquidity, financial flexibility and access to long-term capital to fund the Company's 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 to maintain a healthy balance sheet to provide financial flexibility. The Company's target is to maintain a debt to funds from operations ratio of under 2.0 times and a debt to capital employed ratio of under 25 percent, which are both non-GAAP measures (refer to Sections 8.4 and 11.3). 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 this commodity down cycle which include, but are not limited to, a reduction of budgeted capital spending, the suspension of the quarterly common share dividend, the sale of royalty interests in Western Canada production, the sale of non-core assets in Western Canada, a strategic disposition of select midstream assets and the continued transition to lower sustaining and higher return Lloyd thermal projects. Refer to Section 8.0 for additional information on the Company's liquidity and capital resources.

5.0 Key Growth Highlights

The 2016 Capital Program enabled the Company to advance its near-term profitable growth projects while maintaining prudent capital management in a weak commodity price environment.

5.1 Upstream

Heavy Oil

Heavy Oil Thermal Developments

The Company continued to advance its inventory of heavy oil thermal developments in 2016. These long-life developments are built with modular, repeatable designs and require low sustaining capital once brought online.

The following table lists the design capacity, percentage completion and status for the Company's near-term heavy oil thermal developments:

Heavy Oil Thermal Developments

Development	Design Capacity (bbls/day)	Percentage Completion	Status	2016 Exit Production (bbls/day) ⁽¹⁾
Edam East	10,000	100%	On production	14,900
Vawn	10,000	100%	On production	11,400
Edam West	4,500	100%	On production	4,200

⁽¹⁾ Exit production is the average production for the month of December.

Total heavy oil thermal production, including the Tucker Thermal Project averaged 84,600 bbls/day in 2016 compared to 59,900 bbls/day in 2015, a 41 percent increase. The increase is primarily attributed to new production from the Edam East, Vawn, and Edam West heavy oil thermal developments in addition to steady production from the balance of the Company's other heavy oil thermal developments, including the Tucker Thermal Project.

Total heavy oil thermal production reached an average production of 102,400 bbls/day in December.

First oil was achieved from the Colony formation at the Tucker Thermal Project in the Cold Lake region of Alberta on April 19, 2016. Total production from the Tucker Thermal Project averaged 21,700 bbls/day in December.

Development continues at the 10,000 bbls/day Rush Lake 2 heavy oil thermal development, with first production expected in the first half of 2019.

The Company sanctioned three new Lloyd thermal projects with total design capacity of about 30,000 bbls/day at Dee Valley, Spruce Lake North and Spruce Lake Central. Subject to regulatory approval, first production for all three is expected in 2020.

Oil Sands

Sunrise Energy Project

Production from the Sunrise Energy Project averaged 25,600 bbls/day (12,800 bbls/day net Husky share) in 2016. Production was temporarily impacted by the wildfire in the second quarter and averaged approximately 35,000 bbls/day (17,500 bbls/day net Husky share) in December. The Company has introduced higher operating pressures, as approved by the Alberta Energy Regulator ("AER"), contributing to higher steam-oil ratio ("SOR") in the short term. As a result, the Company expects improved well conformance and production rates over the next two years.

Production is expected to continue to ramp up in 2017 with average annual production in the range of 40,000 to 44,000 bbls/day (20,000 to 22,000 bbls/day net Husky share).

Asia Pacific Region

China

Block 29/26

Combined gross production from Liwan 3-1 and Liuhua 34-2 averaged 48,800 boe/day (24,800 boe/day net Husky share) in 2016, consisting of gross natural gas production of 224 mmcf/day and NGL production of 11.5 mbbls/day compared to 62,300 boe/day (38,400 boe/day net Husky share) in 2015, consisting of gross natural gas production of 286 mmcf/day and NGL production of 14.6 mbbls/day. The decrease in production in 2016 was due to issues within the buyer's onshore pipeline network in the first quarter, reduced demand throughout the year and the Company's share of production volumes reverted back to 49 percent in the second quarter of 2015 following the completion of exploration cost recoveries from the Liwan 3-1 field. The second 22-inch subsea pipeline connecting the deepwater pipeline to the central platform has been completed, tested and placed in service. This pipeline provides operating flexibility for the deepwater infrastructure and completes the Liwan facilities to its full design specification.

Negotiations for the sale of gas and liquids from the Liuhua 29-1 gas field are ongoing.

Block 15/33

On the 15/33 block located offshore China, the Company is continuing to plan for exploration activities and expects to drill two wells in the 2017-2018 timeframe.

Offshore Taiwan

Analysis of the two-dimensional seismic survey data acquired in 2014 has been completed and a number of significant prospects have been identified. The Company plans to acquire three-dimensional seismic survey data on the most attractive prospects during 2017.

Indonesia

Madura Strait

Progress continued on the shallow water gas developments during 2016. At the liquids-rich BD field, development well drilling, completion and testing of all four wells has been completed. The facilities construction project is approximately 97 percent complete including the installation and testing of the shallow water platform, the subsea pipeline to shore and the onshore gas metering station. The FPSO vessel construction has been completed and the vessel is now moored at the field location in preparation for in-situ testing and commissioning. The project is on target for first production in the 2017 timeframe and is scheduled to ramp up to its full gas sales rate by the second half of 2017.

The Company has secured a gas sales agreement for the MDA and MBH fields, which will be developed in tandem. Negotiations of additional gas sales agreements for the MDA, MBH and MDK gas fields are in progress. A re-tendering process for a floating production vessel has been completed and the winning bidder was approved by SKK Migas. The vessel lease contract is being finalized and is planned to be signed in early 2017. Tendering is also underway for related engineering, procurement, construction and installation contracts. Production from the MDA, MBH and MDK fields is expected in the 2018 - 2019 timeframe. Combined net sales volumes from the BD, MDA, MBH and MDK fields are expected to be approximately 100 mmcf/day of natural gas and 2,400 bbls/day of associated NGLs once production is fully ramped up.

Anugerah

During 2015, the Company acquired two-dimensional and three-dimensional seismic survey data on the contract area. Results from analysis of the data is being evaluated to confirm whether the Company will accept a future drilling commitment.

Atlantic Region

White Rose Field and Satellite Extensions

In 2016, the Henry Goodrich rig resumed operations at North Amethyst. First production was achieved from the North Amethyst Hibernia formation well on September 15, 2016. An additional well was brought into production at the South White Rose drill centre on November 29, 2016. The rig has since drilled an infill well at North Amethyst.

Engineering design and subsurface evaluation work continues at West White Rose to increase capital efficiency and improve resource capture. The project will be considered for sanction in 2017.

Atlantic Exploration

The exploration and appraisal drilling program at the Bay du Nord discovery in the Flemish Pass Basin was completed during 2016. Since the program commenced in the fourth quarter of 2014, Husky has participated in three appraisal and four exploration wells in and around Bay du Nord, leading to two new oil discoveries at Bay de Verde and Baccalieu and two unsuccessful wells at Bay d'Espoir and Bay du Loup. The Company holds a 35 percent non-operated working interest in the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. The Company and its partner continue to assess the commercial potential of these discoveries.

In November 2016, the Canada-Newfoundland and Labrador Petroleum Board announced that the Company was the successful bidder on two parcels of land in its 2016 land sale. The lands cover an area of 211,574 hectares and brought the Company's ELs in the region to eight. The southwest parcel is adjacent to the White Rose field and satellite extensions, while the other is northeast of the field and adjacent to other Company operated ELs in the Jeanne d'Arc Basin.

Western Canada Resource Play Development

Oil and Natural Gas Resource Plays

Overall resource play production in Western Canada averaged approximately 34,500 boe/day in 2016, with current development primarily focused on the Ansell multi-zone natural gas resource play.

The Company is pursuing liquids-rich natural gas development opportunities within the existing asset portfolio primarily in the Ansell and Kakwa areas.

5.2 Downstream

Canadian Refined Products

The Company and Imperial Oil received regulatory approval from the Canadian Competition Bureau during the second quarter of 2016 to create a single expanded truck transport network of approximately 160 sites. The agreement was approved by Canada's Competition Bureau in June 2016 and contract closing conditions were met late in the fourth quarter 2016. Progress continues to be made on the implementation of the agreement and the consolidation of the two networks is expected in the second half of 2017.

Lima Refinery

The Company continued work on a crude oil flexibility project in 2016. The project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada providing the Refinery with the ability to swing between light and heavy crude oil feedstock. The first stage of the project was completed in 2016 and the Refinery can currently process up to 10,000 bbls/day of heavy crude oil feedstock. The full scope of the project is expected to be completed in 2018.

BP-Husky Toledo Refinery

The Company and its partner completed a feedstock optimization project at the BP-Husky Toledo Refinery in mid-July 2016. The Refinery is now able to process approximately 65,000 bbls/day of High-TAN crude oil to support production from the Sunrise Energy Project.

Lloydminster Asphalt Expansion

The Company has started pre-FEED work on a potential 30,000 bbls/day expansion of its asphalt processing capacity in Lloydminster with sanctioning expected in 2017. This business continues to show strong returns through the cycle and its expansion would provide an additional outlet for the Company's growing heavy oil thermal production.

6.0 Results of Operations

6.1 Segment Earnings

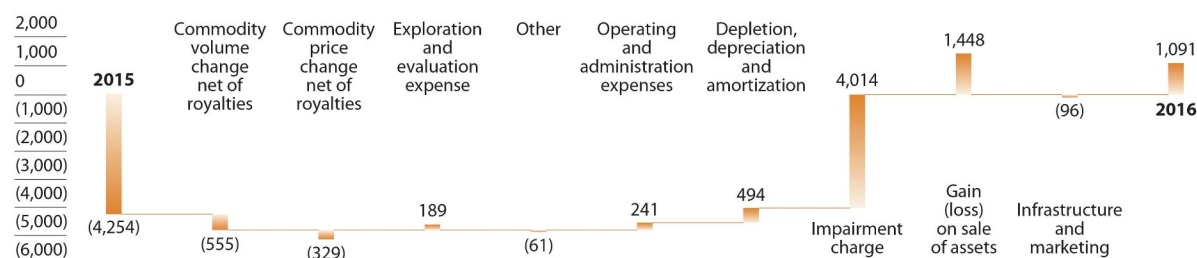
(\$ millions)	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures ⁽¹⁾	
	2016	2015	2016	2015	2016	2015
Upstream						
Exploration and Production	(298)	(5,945)	(217)	(4,338)	872	2,269
Infrastructure and Marketing	1,430	115	1,308	84	54	168
Downstream						
Upgrading	241	128	175	93	51	46
Canadian Refined Products	151	231	110	170	52	30
U.S. Refining and Marketing	90	306	57	397	623	425
Corporate	(664)	(206)	(511)	(256)	53	67
Total	950	(5,371)	922	(3,850)	1,705	3,005

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

6.2 Upstream

After Tax Earnings Variance Analysis

(\$ millions)



Exploration and Production

Exploration and Production Earnings Summary (\$ millions)

	2016	2015
Gross revenues	4,036	5,374
Royalties	(305)	(432)
Net revenues	3,731	4,942
Purchases of crude oil and products	32	41
Production, operating and transportation expenses	1,760	2,076
Selling, general and administrative expenses	232	237
Depletion, depreciation, amortization and impairment	1,815	7,993
Exploration and evaluation expenses	188	447
Gain on sale of assets	(192)	(17)
Other – net	53	(34)
Share of equity investment loss	1	5
Financial items	140	139
Recovery of income taxes	(81)	(1,607)
Net earnings (loss)	(217)	(4,338)

Exploration and Production net revenues decreased by \$1,211 million in 2016 compared to 2015, primarily due to lower global crude oil benchmark prices, lower crude oil and natural gas production in North America due to the disposition of select legacy Western Canada crude oil and natural gas assets and lower natural gas production in the Asia Pacific Region due to lower demand and the reversion of the Company's entitlement share of production at Liwan 3-1 to 49 percent, from approximately 76 percent in the second quarter of 2015. The factors affecting the decline in Exploration and Production net revenues were partially offset by higher heavy oil thermal production and lower royalties.

Production, operating, and transportation costs decreased by \$316 million in 2016 compared to 2015 primarily due to cost savings initiatives and lower energy costs.

Depletion, depreciation, amortization ("DD&A") and impairment expense decreased by \$6,178 million in 2016 compared to 2015 primarily due to the recognition of a pre-tax impairment charge of \$5,181 million on crude oil and natural gas assets in 2015, which reduced the carrying value of the Company's depletable asset base in 2016 and the recognition of a pre-tax net impairment reversal of \$261 million in 2016 related to Western Canada assets.

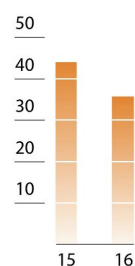
Exploration and evaluation expenses decreased by \$259 million in 2016 compared to 2015. The decrease is primarily due to a \$277 million write-down of certain Western Canada resource play assets including associated unfulfilled work commitment penalties in the third quarter of 2015, compared to an \$86 million write-off in 2016 primarily due to two unsuccessful exploration wells in the Atlantic Region and a decision by management to not pursue further evaluation of certain Oil Sands assets at this time.

Gain on sale of assets increased by \$175 million in 2016 compared to 2015 due to the sale of royalty interests and select legacy Western Canada crude oil and natural gas assets.

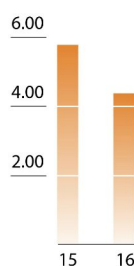
Recovery of income taxes decreased by \$1,526 million primarily due to a \$1,357 million deferred income tax recovery associated with impairment charges recognized on crude oil and natural gas assets located in Western Canada in 2015.

Average Sales Prices Realized

Average Price Realized
Crude Oil and NGL
(\$/bbl)



Average Price Realized
Natural Gas
(\$/mcf)



Average Sales Prices Realized	2016	2015
Crude oil and NGL (\$/bbl)		
Light & Medium crude oil	52.40	57.55
NGL	38.01	45.88
Heavy crude oil	30.50	37.16
Bitumen	27.63	34.47
Total crude oil and NGL average	35.78	44.18
Natural gas average (\$/mcf)	4.40	5.80
Total average (\$/boe)	33.08	41.06

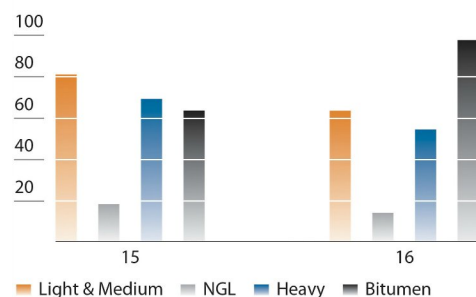
The average sales prices realized by the Company declined by 19 percent for crude oil and NGL in 2016 compared to 2015 reflecting significant declines in global crude oil benchmarks.

The average sales prices realized by the Company for natural gas declined by 24 percent in 2016 compared to 2015. The decrease in realized natural gas pricing was primarily due to lower fixed priced natural gas production from the Liwan Gas Project relative to total natural gas production and a price adjustment for natural gas from the Liwan 3-1 and Liuhua 34-2 fields, per the Heads of Agreement ("HOA") signed by the Company with CNOOC Limited in the third quarter of 2016. The price adjustment under the HOA is effective as of November 2015 and a retroactive adjustment was recognized in the third quarter of 2016. Asia Pacific natural gas production was also lower in 2016 due to reduced buyer demand, temporary production shut-in for the gas buyer's onshore gas pipeline infrastructure in the first quarter of 2016 and the Company's share of production volumes reverted back to 49 percent in the second quarter of 2015 following the completion of exploration cost recoveries from the Liwan 3-1 field.

Daily Gross Production

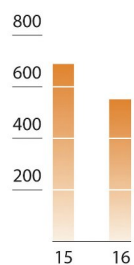
Production

Oil & NGL
(mmbbls/day)



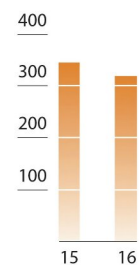
Production

Natural Gas
(mmcf/day)



Production

Combined
(mboe/day)



Daily Gross Production

2016

2015

Crude oil and NGL (mmbbls/day)

Western Canada

Light & Medium crude oil

23.4

36.4

NGL

8.0

8.8

Heavy crude oil

54.1

69.1

Bitumen⁽¹⁾

84.6

59.9

170.1

174.2

Oil Sands

Sunrise – bitumen

12.8

3.2

Atlantic Region

White Rose and Satellite Fields – light crude oil

28.8

32.1

Terra Nova – light crude oil

4.3

4.7

33.1

36.8

Asia Pacific Region

Wenchang – light crude oil

6.6

7.3

Liwan and Wenchang – NGL⁽²⁾

6.0

9.4

12.6

16.7

228.6

230.9

Natural gas (mmcf/day)

Western Canada

442.4

513.9

Asia Pacific Region⁽²⁾

113.5

175.1

555.9

689.0

Total (mboe/day)

321.2

345.7

⁽¹⁾ Bitumen consists of production from heavy oil thermal developments and the Tucker Thermal Project located near Cold Lake, Alberta. Heavy oil thermal average daily gross production was 65.4 mmbbls/day and 48.4 mmbbls/day for the years ended December 31, 2016 and 2015, respectively.

⁽²⁾ Reported production volumes include Husky's net working interest production from the Liwan Gas Project (49 percent) and an incremental share of production volumes allocated to Husky for exploration cost recoveries. The incremental share of production volumes ceased during the second quarter of 2015 reflecting the completion of exploration cost recoveries from the Liwan 3-1 field.

Crude Oil and NGL Production

Crude oil and NGL production decreased by 2.3 mbbbls/day or one percent compared to 2015 primarily due to divestitures of select legacy Western Canada crude oil and natural gas assets in 2016 and natural reservoir declines from mature properties in Western Canada and the Atlantic Region. The decreases were partially offset by strong performance from new and existing heavy oil thermal developments and production ramp-up at the Sunrise Energy Project.

Natural Gas Production

Natural gas production decreased by 133.1 mmcf/day or 19 percent compared to 2015. In the Asia Pacific Region, natural gas production decreased by 61.6 mmcf/day due to reduced buyer demand, temporary production shut-in for the connection of a second deepwater pipeline and an unscheduled isolation and temporary repair in the Liwan 3-1 field related to the gas buyer's onshore gas pipeline infrastructure in the first quarter of 2016. Additionally, the Company's entitlement share of production volumes reverted back to 49 percent in late May 2015 following the completion of exploration cost recoveries from the Liwan 3-1 field.

In Western Canada, natural gas production decreased by 71.5 mmcf/day primarily due to divestitures of select legacy Western Canada crude oil and natural gas assets, reduced investment, natural reservoir declines from mature properties, strategic shut-ins due to unfavourable economics and third-party pipeline restrictions.

Exploration and Production Revenue Mix (Percentage of Upstream Net Revenues)	2016	2015
Crude oil and NGL		
Light & Medium crude oil	32%	33%
NGL	5%	6%
Heavy crude oil	15%	18%
Bitumen	25%	15%
Crude oil and NGL	77%	72%
Natural gas	23%	28%
Total	100%	100%

2017 Production Guidance and 2016 Actual

	Guidance	Year ended December 31	Guidance ⁽¹⁾
	2017	2016	2016
Gross Production			
Canada			
Light & Medium crude oil (mbbls/day)	46 - 48	56	66 - 68
NGL (mboe/day)	8 - 9	8	7 - 8
Heavy crude oil & bitumen (mbbls/day)	167 - 173	151	142 - 157
Natural gas (mmcf/day)	345 - 353	442	380 - 430
Canada total (mboe/day)	278 - 288	289	279 - 305
Asia Pacific			
Light crude oil (mbbls/day)	5 - 6	7	6 - 7
NGL (mboe/day)	8 - 10	6	7 - 8
Natural gas (mmcf/day)	171 - 182	114	140 - 150
Asia Pacific total (mboe/day)	42 - 46	32	36 - 40
Total (mboe/day)	320 - 335	321	315 - 345

⁽¹⁾ 2016 production guidance does not reflect the impact of asset dispositions in Western Canada.

The Company's total production for the year ended December 31, 2016 was within the production guidance. The Company expects that total production volumes in 2017 will be comparable to 2016. The 2017 production guidance reflects increasing thermal heavy oil production along with increasing bitumen production from the Sunrise Energy Project and initial production from the BD Liquids rich gas field in Indonesia. The increases are anticipated to be offset by continued natural declines from mature properties in the Atlantic Region and Western Canada and reflects the Company's decision to reduce the amount of capital in Western Canada.

Factors that could potentially impact the Company's production performance in 2017 include, but are not limited to:

- potential divestment of certain producing crude oil or natural gas properties in Western Canada;
- declines in crude oil and natural gas prices which may result in the decision to temporarily shut-in production or delay capital expenditures;
- increases in crude oil and natural gas prices which may result in the decision to accelerate near-term growth projects;
- performance on recently commissioned facilities, new wells brought onto production and unanticipated reservoir response from existing fields;
- 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 or facilities are necessary for the Company's production; and
- 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 were consistent in 2016 and 2015 at eight percent. Royalty rates in Western Canada averaged seven percent in 2016 compared to nine percent in 2015 primarily due to a higher percentage of production from thermal projects, which are at a lower royalty rate and due to lower commodity prices, which affect royalties on a sliding scale of price sensitivity. Royalty rates in the Atlantic Region averaged 15 percent in 2016 compared to 11 percent in 2015 due to lower eligible royalty costs. Royalty rates in the Asia Pacific Region averaged six percent in 2016 compared to five percent in 2015.

Operating Costs

<i>(\$ millions)</i>	2016	2015
Western Canada	1,413	1,692
Atlantic Region	224	225
Asia Pacific	92	97
Total	1,729	2,014
Per unit operating costs <i>(\$/boe)</i>	14.04	15.14

Total Exploration and Production operating costs were \$1,729 million in 2016 compared to \$2,014 million in 2015. Total Upstream unit operating costs averaged \$14.04/boe in 2016 compared to \$15.14/boe in 2015 with the decrease primarily attributable to lower unit operating costs per boe in Western Canada.

Per unit operating costs in Western Canada averaged \$14.21/boe in 2016 compared to \$16.55/boe in 2015. The decrease in unit operating costs per boe was primarily attributable to cost savings initiatives, lower energy costs and divestitures of higher operating cost assets.

Per unit operating costs in the Atlantic Region averaged \$18.48/boe in 2016 compared to \$16.76/boe in 2015. The increase in unit operating costs per boe was primarily attributable to a decrease in production.

Per unit operating costs in the Asia Pacific Region averaged \$8.01/boe in 2016 compared to \$5.78/boe in 2015. The increase in unit operating costs per boe was primarily attributable to lower production at the Liwan Gas Project, partially offset by cost saving initiatives.

Exploration and Evaluation Expenses

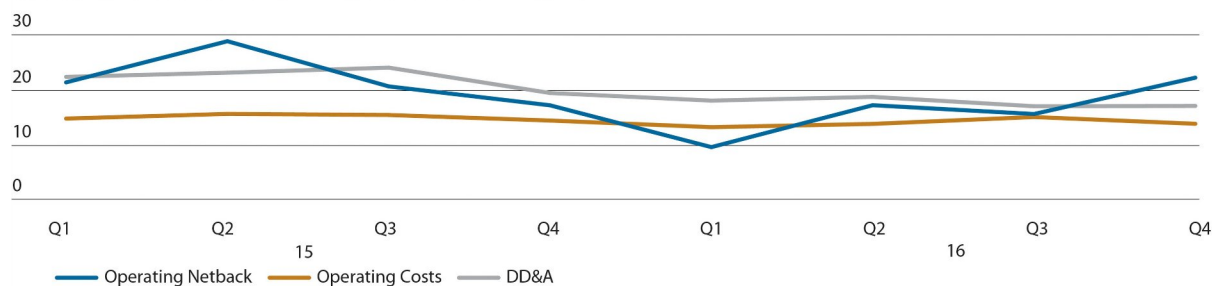
<i>(\$ millions)</i>	2016	2015
Seismic, geological and geophysical	78	103
Expensed drilling	66	297
Expensed land	44	47
Total	188	447

Exploration and evaluation expenses in 2016 were \$188 million compared to \$447 million in 2015. The decrease in expense drilling is primarily attributable to a \$277 million write-down of certain Western Canada resource play assets including associated unfulfilled work commitment penalties in the third quarter of 2015. Included in expensed land and drilling in 2016 is a pre-tax write-off of \$86 million mainly related to Oil Sands and Atlantic Region assets. The decrease in seismic, geological and geophysical costs resulted from lower seismic activity across the portfolio.

Depletion, Depreciation, Amortization and Impairment

DD&A and impairment expense decreased by \$6,178 million in 2016 compared to 2015 primarily due to the recognition of a pre-tax impairment charge of \$5,181 million on crude oil and natural gas assets, including associated goodwill, located in Western Canada during the third quarter of 2015. The impairment charge reduced the carrying value of the Company's depletable asset base and resulted in a lower DD&A expense per unit of production in 2016. 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. Additionally, in 2016, production was lower from the Liwan Gas Project, which carries a higher per unit of production DD&A expense. In 2016, total DD&A excluding impairment averaged \$17.67/boe compared to \$22.28/boe in 2015.

Operating Netback⁽¹⁾, Unit Operating Costs and DD&A⁽²⁾ (\$/boe)



⁽¹⁾ Operating netback is a non-GAAP measure and is equal to gross revenue less royalties, production and operating costs and transportation costs on a per unit basis. Refer to section 11.3.

⁽²⁾ DD&A excludes impairment and impairment reversals.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were lower in 2016 compared to 2015 and reflect the Company's prudent capital management in a low commodity price environment. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures ⁽¹⁾ (\$ millions)	2016	2015
Exploration		
Western Canada	18	24
Heavy Oil	6	12
Atlantic Region	18	169
Asia Pacific Region	4	—
	46	205
Development		
Western Canada	116	420
Heavy Oil	335	899
Oil Sands	28	264
Atlantic Region	226	379
Asia Pacific Region	114	46
	819	2,008
Acquisitions		
Western Canada	—	2
Heavy Oil	7	54
	7	56
	872	2,269

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

Western Canada

During 2016, \$134 million (15 percent) was invested in Western Canada conventional and resource plays, compared to \$446 million (20 percent) in 2015. Capital expenditures in 2016 relate primarily to sustainment and maintenance activities and the development of the Rainbow Lake NGL project. The decrease in capital expenditures in 2016 compared to 2015 is due to the low commodity price environment.

Heavy Oil

During 2016, \$348 million (40 percent) was invested in Heavy Oil, compared to \$965 million (42 percent) in 2015. Capital expenditures in 2016 relate primarily to the development of the Edam East, Edam West and Vawn heavy oil thermal developments in addition to the Colony formation at the Tucker Thermal Project. The decrease in capital expenditures in 2016 compared to 2015 reflects the completion of thermal projects.

Oil Sands

During 2016, \$28 million (three percent) was invested in Oil Sands, compared to \$264 million (12 percent) in 2015. Capital expenditures in 2016 and 2015 relate primarily to the Sunrise Energy Project. The decrease in capital expenditures in 2016 compared to 2015 reflects the completion of Phase 1 of the Sunrise Energy Project in the third quarter of 2015.

Atlantic Region

During 2016, \$244 million (28 percent) was invested in the Atlantic Region, compared to \$548 million (24 percent) in 2015. Capital expenditures in 2016 relate primarily to the development of the White Rose extension projects, including North Amethyst and South White Rose satellite fields and further exploration and appraisal drilling in the Flemish Pass Basin. The decrease in capital expenditures in 2016 compared to 2015 reflects the completion of the Bay du Nord delineation program in 2016.

Asia Pacific Region

During 2016, \$118 million (14 percent) was invested in the Asia Pacific Region, compared to \$46 million (two percent) in 2015. Capital expenditures in 2016 relate primarily to the Liwan Gas Project. The increase in capital expenditures in 2016 compared to 2015 relates primarily to the planned completion of a second subsea pipeline at Liwan.

Onshore drilling activity

The following table discloses the number of wells drilled in Heavy Oil, Oil Sands and Western Canada conventional and resource plays during 2016 and 2015:

Wells Drilled (wells) ⁽¹⁾	2016		2015	
	Gross	Net	Gross	Net
Heavy Oil	75	75	87	86
Oil Sands ⁽²⁾	—	—	28	14
Western Canada conventional and resource plays				
Gas Resource	3	2	39	29
Oil Resource	—	—	1	1
Conventional Oil	—	—	6	3
Conventional Gas	—	—	2	—
Enhanced Oil Recovery	—	—	2	2
	78	77	165	135

⁽¹⁾ Excludes Service/Stratigraphic test wells for evaluation purposes.

⁽²⁾ Reflects Husky's 50 percent working interest in the Sunrise Energy Project.

During 2016, the Company's onshore drilling was focused primarily on Heavy Oil thermal developments. The decrease of Heavy Oil and Oil Sands drilling and completion activity is due to the completion of three new heavy oil thermal developments in 2016 and first oil at Sunrise Energy Project in 2015. Western Canada resource play drilling and completion activity has been curtailed due to limited capital investment in a low commodity price environment.

Offshore drilling activity

The following table discloses the Company's offshore Atlantic Region and Asia Pacific Region drilling activity during 2016:

Region	Well	Working Interest	Well Type
Atlantic Region	Bay d'Espoir B-09 ⁽¹⁾	WI 35 percent	Exploration
Atlantic Region	Bay du Loup M-62 ⁽¹⁾	WI 35 percent	Exploration
Atlantic Region	Baccalieu F-89	WI 35 percent	Exploration
Atlantic Region	North Amethyst E-18 12Y	WI 68.875 percent	Development
Atlantic Region	South White Rose Extension J-05 4	WI 68.875 percent	Development
Asia Pacific Region	Madura BD A-1	WI 40 percent	Development
Asia Pacific Region	Madura BD A-2	WI 40 percent	Development
Asia Pacific Region	Madura BD A-3	WI 40 percent	Development
Asia Pacific Region	Madura BD A-4	WI 40 percent	Development

⁽¹⁾ The Bay d'Espoir B-09 and Bay du Loup M-62 exploration wells were fully written off in the second quarter of 2016 as the wells did not encounter economic quantities of hydrocarbons.

2017 Upstream Capital Expenditures Program

(\$ millions)

Western Canada	210 - 225
Heavy Oil	685 - 720
Oil Sands	90 - 100
Atlantic Region	320 - 335
Asia Pacific Region ⁽¹⁾	230 - 240
Total Upstream capital expenditures	1,535 - 1,620

⁽¹⁾ Includes capital expenditures expected to be incurred by the Husky-CNOOC Madura Ltd. joint venture which are classified as contribution to joint ventures in the investing activities on the Company's Consolidated Statements of Cash Flows.

The 2017 Upstream capital expenditures program reflects the Company's prudent capital management in a weak commodity price environment. The Company will continue its transition towards a low sustaining capital business. The Company's 2017 Upstream capital expenditures program has been designed to remain in balance with funds from operations.

The Company has budgeted \$685 - \$720 million in Heavy Oil for 2017, primarily for the development of Rush Lake 2 and three newly sanctioned Lloyd thermal projects with total design capacity of about 30,000 bbls/day at Dee Valley, Spruce Lake North and Spruce Lake Central. The three newly sanctioned Lloyd thermal projects are subject to regulatory approval, first production for all three is expected in 2020. The Company is making progress in its strategy to transition a greater percentage of production to long-life heavy oil thermal production and the 2017 Upstream capital expenditures program will continue to build on this momentum.

The Company has budgeted \$90 - \$100 million in Oil Sands for 2017, primarily for the continued development of the Sunrise Energy Project.

The Company has budgeted \$210 - \$225 million in Western Canada resource play development for 2017, primarily for development drilling at the Spirit River formation in the Ansell and Kakwa areas.

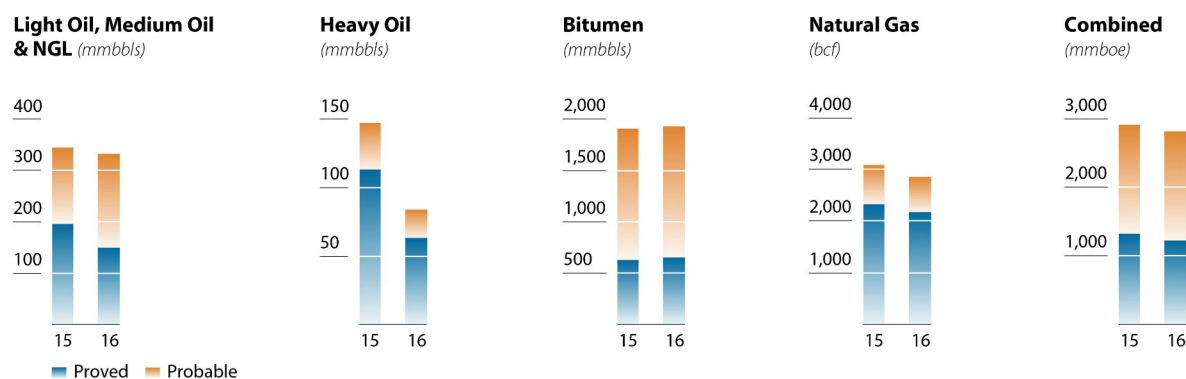
The Company has budgeted \$320 - \$335 million in the Atlantic Region for 2017, primarily for the continued development of the main White Rose field and satellite extensions.

The Company has budgeted \$230 - \$240 million for the Asia Pacific Region in 2017, primarily for the continued development of the Liwan Gas Project and the development of the Madura Strait Block in Indonesia.

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, 2016 with a preparation date of January 31, 2017.

Proved and Probable Reserves at December 31:



Note: All heavy oil thermal reserves are classified as bitumen.

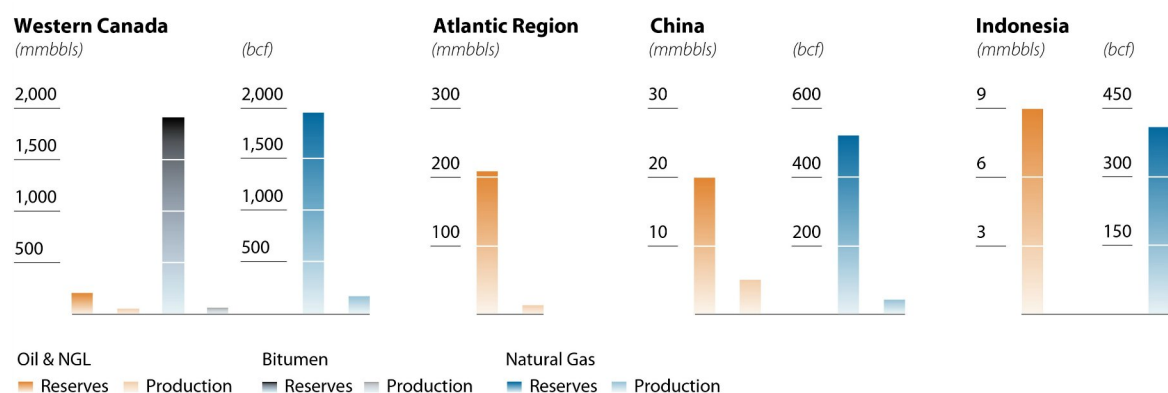
The Company's complete oil and gas reserves disclosure, prepared in accordance with NI 51-101 is contained in the Company's Annual Information Form, which is available at www.sedar.com and certain supplementary oil and gas reserves disclosure prepared in accordance with U.S. disclosure requirements is 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, 2017 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, 2016, the Company's proved oil and gas reserves were 1,224 mmboe, down from 1,324 mmboe at the end of 2015. The Company's 2016 reserve replacement ratio, defined as net additions divided by total production during the period, was 19 percent excluding economic revisions (15 percent including economic revisions). The 2016 reserves replacement ratio, excluding disposition/acquisition and economic factors was 92 percent (88 percent including economic factors). Major changes to proved reserves in 2016 included:

- The disposition of a significant portion of the Western Canada assets resulted in a total divestiture of 90 mmboe. Total acquisitions were 5 mmboe, mainly in the Heavy Oil and Gas thermal bitumen area and Western Canada gas plays;
- Technical revisions in Heavy Oil and Gas thermal bitumen projects that resulted in the booking of an additional 47 mmbbls of bitumen in proved reserves;
- An additional 102 bcf of conventional natural gas in proved developed producing reserves was booked from Liwan 3-1; and
- The extension through additional drilling locations and technical revisions at the Tucker Thermal Project that resulted in the booking of an additional 9 mmbbls of bitumen in proved undeveloped reserves.

Proved Plus Probable Reserves and Production at December 31, 2016:



Reconciliation of Proved Reserves

	Canada				International			Total		
	Western Canada				Atlantic Region			Crude Oil, Bitumen & NGL (mmbbls)	Natural Gas (bcf)	Equivalent Units (mmboe)
	Light/Medium Crude Oil & NGL (mmbbls)	Heavy Crude Oil (mmbbls)	Bitumen (mmbbls) ⁽¹⁾	Natural Gas (bcf)	Light Crude Oil (mmbbls)	Light Crude Oil & NGL (mmbbls)	Natural Gas (bcf)			
<i>(forecast prices and costs before royalties)</i>										
Proved reserves										
December 31, 2015	117	113	625	1,733	55	24	608	934	2,341	1,324
Technical revisions	3	14	45	40	4	4	102	70	142	94
Acquisitions	—	—	3	8	—	—	—	3	8	5
Dispositions	(29)	(44)	—	(105)	—	—	—	(73)	(105)	(90)
Discoveries, extensions and improved recovery	—	2	11	13	—	—	—	13	13	14
Economic factors	(1)	(2)	—	(10)	—	—	—	(3)	(10)	(5)
Production	(11)	(20)	(36)	(162)	(12)	(5)	(42)	(84)	(204)	(118)
Proved reserves December 31, 2016	79	63	648	1,517	47	23	668	860	2,185	1,224
Proved and probable reserves December 31, 2016	95	83	1,923	1,940	207	29	926	2,337	2,866	2,815
December 31, 2015	143	147	1,905	2,211	169	32	889	2,396	3,100	2,912

⁽¹⁾ Heavy oil thermal property reserves are classified as bitumen.

Reconciliation of Proved Developed Reserves

	Canada				Atlantic Region	International		Total			
	Western Canada					Light Crude Oil (mmbbls)	Light Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	Crude Oil, Bitumen & NGL (mmbbls)	Natural Gas (bcf)	Equivalent Units (mmboe)
	Light/ Medium Crude Oil & NGL (mmbbls)	Heavy Crude Oil (mmbbls)	Bitumen (mmbbls) ⁽¹⁾	Natural Gas (bcf)							
<i>(forecast prices and costs before royalties)</i>											
Proved developed reserves											
December 31, 2015	113	108	157	1,390	45	17	339	440	1,729	728	
Technical revisions	3	19	19	41	7	4	103	52	144	74	
Transfer from proved undeveloped	—	—	19	9	2	7	167	28	176	58	
Acquisitions	—	—	—	8	—	—	—	—	8	2	
Dispositions	(29)	(44)	—	(105)	—	—	—	(73)	(105)	(90)	
Discoveries, extensions and improved recovery	—	2	1	12	—	—	—	3	12	5	
Economic factors	(1)	(2)	—	(10)	—	—	—	(3)	(10)	(5)	
Production	(11)	(20)	(36)	(162)	(12)	(5)	(42)	(84)	(204)	(118)	
December 31, 2016	75	63	160	1,183	42	23	567	363	1,750	654	

⁽¹⁾ Heavy oil thermal property reserves are classified as bitumen.

Infrastructure and Marketing

The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGLs, sulphur and petroleum coke production. The Company owns infrastructure in Western Canada, including pipeline and storage facilities, and has access to capacity on third party pipelines and storage facilities in both Canada and the U.S. The Company is able to capture differences between the two markets by utilizing infrastructure capacity to deliver feedstock acquired in Canada to the U.S. market.

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 include 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 HMLP, of which the Company owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent. The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets.

Infrastructure and Marketing Earnings Summary (\$ millions, except where indicated)	2016	2015
Gross revenues	955	1,264
Purchases of crude oil and products	857	1,123
Infrastructure gross margin	98	141
Marketing and other	(88)	38
Total Infrastructure and Marketing gross margin	10	179
Production, operating and transportation expenses	20	37
Selling, general and administrative expenses	5	7
Depletion, depreciation, amortization and impairment	13	25
Gain on sale of assets	(1,439)	—
Other – net	(3)	(5)
Share of equity investment gain	(16)	—
Provisions for income taxes	122	31
Net earnings	1,308	84

Infrastructure and Marketing gross revenues and purchases of crude oil products decreased by \$309 million and \$266 million respectively in 2016 compared to 2015, primarily due to lower commodity prices in the first half of 2016 and the sale of 65 percent of the Company's ownership interest in select midstream assets.

Marketing and other decreased by \$126 million in 2016 compared with 2015 primarily due to crude oil marketing losses from narrowing price differentials between Canada and the United States during 2016. This was partially offset by unrealized gas storage mark-to-market gains as a result of rising forward North American natural gas prices towards the end of 2016.

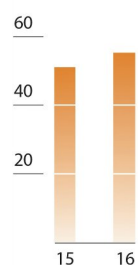
Gain on sale of assets increased by \$1,439 million in 2016 compared with 2015 due to the sale of 65 percent of the Company's ownership interest in select midstream assets.

Share of equity investment gain increased by \$16 million in 2016 compared with 2015 due to the formation of HMLP. Refer to Note 11 of the Consolidated Financial Statements.

6.3 Downstream

Upgrader

Upgrader
Synthetic Crude Sales
(mbbls/day)



Upgrader
Unit Margin & Operating Costs
(\$/bbl)



Upgrader Earnings Summary (\$ millions, except where indicated)

	2016	2015
Gross revenues	1,324	1,319
Purchases of crude oil and products	808	922
Gross margin	516	397
Production, operating and transportation expenses	168	169
Selling, general and administrative expenses	4	4
Depletion, depreciation, amortization and impairment	103	106
Other – net	(1)	(11)
Financial items	1	1
Provisions for income taxes	66	35
Net earnings	175	93
Upgrader throughput (mbbls/day) ⁽¹⁾	72.5	69.8
Total sales (mbbls/day)	72.8	69.3
Synthetic crude oil sales (mbbls/day)	55.2	51.1
Upgrading differential (\$/bbl)	20.74	18.66
Unit margin (\$/bbl)	19.37	15.70
Unit operating cost (\$/bbl) ⁽²⁾	6.33	6.63

⁽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 Upgrader profitability is primarily dependent on the differential between the cost of heavy crude oil feedstock and the sales price of synthetic crude oil.

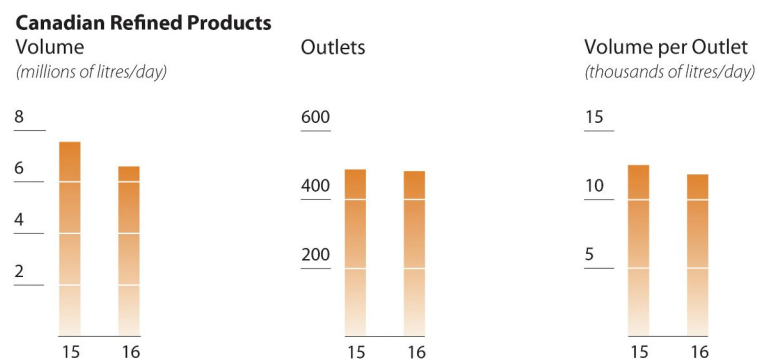
Upgrader gross revenues increased by \$5 million in 2016 compared to 2015 primarily due to higher throughput and sales volumes offset by lower realized prices for synthetic crude oil and low sulphur distillates. The increase in throughput volumes is mainly due to unplanned maintenance to the facility's coke drums that suspended operations for approximately six weeks in the third quarter of 2015.

Upgrader purchases of crude oil and products decreased by \$114 million compared to 2015 primarily due to lower heavy crude oil feedstock costs.

Upgrader gross margin increased by \$119 million in 2016 compared to 2015 primarily due to higher average upgrading differentials and the same factors impacting gross revenues and purchases of crude oil and products as discussed above.

During 2016, the upgrading differential averaged \$20.74/bbl, an increase of \$2.08/bbl or 11 percent compared to 2015. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The increase in the upgrading differential was attributable to significantly lower heavy crude oil feedstock costs partially offset by lower realized prices for Husky Synthetic Blend. During 2016, the price of Husky Synthetic Blend averaged \$57.54/bbl compared to \$61.32/bbl in 2015.

Canadian Refined Products



Canadian Refined Products Earnings Summary (\$ millions, except where indicated)	2016	2015
Gross revenues	2,301	2,886
Purchases of crude oil and products	1,770	2,281
Gross margin	531	605
Fuel	136	134
Refining	123	150
Asphalt	217	262
Ancillary	55	59
	531	605
Production, operating and transportation expenses	241	238
Selling, general and administrative expenses	43	31
Depletion, depreciation, amortization and impairment	102	103
Gain on sale of assets	(3)	(5)
Other – net	(10)	1
Financial items	7	6
Provisions for income taxes	41	61
Net earnings	110	170
Number of fuel outlets ⁽¹⁾	481	487
Fuel sales volume, including wholesale		
Fuel sales (millions of litres/day)	6.6	7.6
Fuel sales per outlet (thousands of litres/day)	11.8	12.5
Refinery throughput		
Prince George Refinery (mbbls/day)	9.4	10.7
Lloydminster Refinery (mbbls/day)	27.8	28.1
Ethanol production (thousands of litres/day)	820.6	794.9

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

Canadian Refined Products gross revenues decreased by \$585 million in 2016 compared to 2015 primarily due to lower demand driven by a weaker economic environment, resulting in lower refined product prices and lower fuel sales volumes.

Fuel gross margins increased by \$2 million in 2016 compared to 2015 primarily due to widening rack to retail differentials partially offset by lower sales volumes.

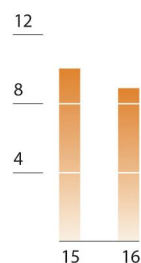
Refining gross margins decreased by \$27 million in 2016 compared to 2015 primarily due to a planned turnaround at the Prince George Refinery in 2016, which resulted in lower throughput and the need to purchase finished products from third parties to deliver on committed sales volumes. Gross margins also decreased at the Lloydminster and Minnedosa Ethanol plants primarily due to higher grain feedstock costs.

Asphalt gross margins decreased by \$45 million in 2016 compared to 2015 primarily due to weather related impacts, which reduced demand and the prevailing price of asphalt.

U.S. Refining and Marketing

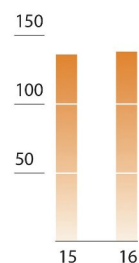
Refining Margin

U.S.
(U.S. \$/bbl crude throughput)



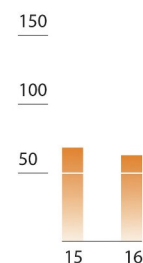
Throughput

Lima Refinery
(mbbls/day)



Toledo Refinery

(mbbls/day)



U.S. Refining and Marketing Earnings Summary (\$ millions, except where indicated)

	2016	2015
Gross revenues	5,995	7,345
Purchases of crude oil and products	5,188	6,455
Gross margin	807	890
Production, operating and transportation expenses	535	474
Selling, general and administrative expenses	13	10
Depletion, depreciation, amortization and impairment	342	333
Other – net	(176)	(236)
Financial items	3	3
Provisions for (recovery of) income taxes	33	(91)
Net earnings	57	397
Selected operating data:		
Lima Refinery throughput (mbbls/day)	138.2	136.1
BP-Husky Toledo Refinery throughput (mbbls/day) ⁽¹⁾	62.2	68.2
Refining margin (U.S. \$/bbl crude throughput)	8.94	10.09
Refinery inventory (mmbbls) ⁽²⁾	10.8	9.8

⁽¹⁾ BP-Husky Toledo Refinery throughput was revised in the first quarter of 2016 to reflect total throughput. Prior periods reflected crude throughput only and have been restated to conform with current presentation.

⁽²⁾ Included in refinery inventory is feedstock and refined products.

U.S. Refining and Marketing gross revenues and purchases of crude oil and products decreased by \$1,350 million and \$1,267 million, respectively in 2016 compared to 2015, primarily due to lower product and crude pricing, higher cost of RINs, as well as lower sales volumes and throughput at the BP-Husky Toledo Refinery resulting from the scheduled major turnaround earlier in the year. Throughput increased at the Lima Refinery due to unplanned outages in the isocracker and coker units in 2015, partially offset by the scheduled major turnaround in the second quarter of 2016. The isocracker unit was repaired and returned to service in the third quarter of 2016.

Production and operating costs increased by \$61 million in 2016 compared to 2015 primarily due to the completion of the scheduled major turnarounds at both the BP-Husky Toledo Refinery and Lima Refinery in 2016.

The Company accrued business interruption and property damage insurance recoveries of \$176 million in 2016 associated with the isocracker unit fire at the Lima Refinery, compared to \$235 million in 2015, which is reflected in other-net expense. To date, the Company has recorded \$411 million in insurance recoveries.

The Chicago 3:2:1 market crack spread benchmark is based on last in first out ("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 first in first out ("FIFO") accounting, which reflects purchases made in previous months. The estimated FIFO impact was an increase in net earnings of approximately \$50 million in 2016 compared to a reduction of \$130 million in 2015.

In addition, the product slates produced at the Lima and BP-Husky Toledo Refineries contain approximately 10 percent to 15 percent of other products that are sold at discounted market prices compared to gasoline and distillate, which are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

The 2015 recovery of income taxes mainly relates to a deferred income tax recovery of \$203 million on the partial payment of the contribution payable to BP-Husky Refining LLC.

Downstream Capital Expenditures

In 2016, Downstream capital expenditures totalled \$726 million compared to \$501 million in 2015. In Canada, capital expenditures of \$103 million were primarily related to the scheduled major turnaround at the Prince George Refinery and projects at the Upgrader.

At the Lima Refinery, \$340 million was primarily related to the scheduled major turnaround, a crude oil flexibility project, upgrades to the isocracker unit and various reliability and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled \$283 million (Husky's 50 percent share) and were primarily related to the scheduled major turnaround, the feedstock optimization project, facility upgrades and environmental protection initiatives.

6.4 Corporate

Corporate Summary (\$ millions) income (expense)	2016	2015
Selling, general and administrative expenses	(247)	(53)
Depletion, depreciation, amortization and impairment	(87)	(84)
Other – net	(110)	2
Net foreign exchange gain	13	43
Finance income	12	32
Finance expense	(245)	(146)
Recovery of (provisions for) income taxes	153	(50)
Net loss	(511)	(256)

The Corporate segment reported a net loss of \$511 million in 2016 compared to a net loss of \$256 million in 2015. Selling, general and administrative expenses increased in 2016 primarily due to an increase in stock-based compensation expense which was \$33 million in 2016 compared to a recovery of \$39 million in 2015 due to declines in the Company's share price in 2015, as well as higher re-organization costs recognized in 2016 and lower overhead recoveries as a result of lower activity in Western Canada. Other-net expense of \$110 million in 2016 relates primarily to losses on the Company's short term hedging program, which concluded in June 2016. Finance expense increased in 2016 primarily due to a decrease in the amount of capitalized interest compared to 2015 as the Sunrise Energy Project commenced production in 2015. Foreign exchange gain decreased by \$30 million due to the items noted below.

Foreign Exchange Summary (\$ millions, except exchange rate amounts)	2016	2015
Gains (losses) on translation of U.S. dollar denominated long-term debt	–	(34)
Gains on non-cash working capital	4	35
Other foreign exchange gains	9	42
Foreign exchange gains	13	43
U.S./Canadian dollar exchange rates:		
At beginning of year	U.S. \$0.723	U.S. \$0.862
At end of year	U.S. \$0.745	U.S. \$0.723

Included in other foreign exchange gains are realized and unrealized foreign exchange gains 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

(\$ millions)	2016	2015
Provisions for (recovery of) income taxes	28	(1,521)
Income taxes paid (received)	(3)	227

Consolidated income taxes were an expense of \$28 million in 2016 compared to an income tax recovery of \$1,521 million in 2015. The increase in consolidated income taxes was primarily due to the recognition of gains on the sale of 65 percent of the Company's ownership interest in select midstream assets and the sale of select Western Canada legacy oil and natural gas assets in 2016. The income tax recovery in 2015 was primarily due to a \$1,357 million deferred income tax recovery associated with impairment charges recognized on crude oil and natural gas assets located in Western Canada.

7.0 Risk and Risk Management

7.1 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.

7.2 Significant Risk Factors

Operational, Environmental and Safety Incidents

The Company's businesses are subject to inherent operational risks in 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 ("HOIMS"), 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

Husky'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, NGLs and natural gas could adversely affect the value and quantity of Husky's oil and gas reserves. Husky'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 is limited and planned increases of North American heavy crude oil production may create the need for additional heavy oil refining and transportation capacity. Wider price differentials between heavier and lighter grades of crude oil could have a material adverse effect on Husky's results of operations and financial condition, reduce the value and quantities of Husky'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 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 and the availability of alternate sources of energy.

Husky's natural gas production is currently located in Western Canada and the Asia Pacific Region. Western Canada 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.

The natural gas Husky produces in the Asia Pacific Region is sold to specific buyers with long-term contracts. For the Liwan 3-1 gas field, a price profile has been fixed for five years and then will be linked to local benchmark pricing for the years following subject to a floor and ceiling. For the Liuhua 34-2 field, the price is fixed with a single escalation step during the contract delivery period. Natural gas price in North America is affected primarily by supply and demand, as well as by prices for alternative energy sources.

In certain instances, the Company uses derivative commodity instruments and futures contracts on commodity exchanges, including commodity put and call options under a short-term hedging program, 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 and business strategy. 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 NGLs 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

Husky'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 effected 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 Husky'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 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 and exchange rate fluctuations, unreasonable taxation and corrupt behaviour of public officials, joint venture partners or third-party representatives that could result in lost business opportunities for Husky. 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, which include the Company's ability to obtain the necessary environmental and regulatory approvals, changing government regulation and public expectation in relation to the impact on the environment, as well as the risks involved in commissioning and integration of new assets with existing facilities, can impact the economic feasibility of the Company's projects. Obtaining regulatory approvals can involve significant stakeholder consultation, environmental impact assessments and public hearings. These risks can result in, among other things, cost overruns, schedule delays and decreases in product markets. These risks can also impact the Company's safety and environmental performance, which could negatively affect 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, breach of contract, tax, bribery and employment matters, which could result in an unfavourable decision, including fines, sanctions, monetary damages 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 Husky's assets in which the Company has an ownership interest. This can reduce Husky's control and ability to manage risks. Husky 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 and Future Net Revenue 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. All such estimates are to some degree uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. 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. For those reasons, the Company's estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom may differ substantially from actual results. 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 results of operations, financial condition, and ability to deliver on its growth business strategy.

Government Regulation

Given the scope and complexity of Husky'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 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 Husky's financial condition and results of operations 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 scope and complexity of changes in environmental regulation make it challenging to forecast the potential impact to Husky. Husky has made projections of the impact of scenarios involving certain potential laws and regulations relating to climate change. Husky engages in dialogue on proposed changes, both directly and through industry associations, with the goal of ensuring the Company's interests are recognized and Husky is sufficiently prepared to fully comply when new regulations come into force.

Husky 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 Husky's financial condition and results of operations through increased capital and operating costs.

Climate Change Regulation

The Company continues to monitor international and domestic efforts to address climate change, including international low carbon fuel standards and regulations and emerging regulations in the jurisdictions in which the Company operates.

The Alberta Climate Leadership Plan is expected to be implemented starting in 2017. This plan includes an economy wide carbon levy, rising to \$30/ton in 2018 as well as a Carbon Competitiveness Regulation that will manage emissions at large final emitting facilities ("LFEs") including the Ram River Gas Plant, Tucker Thermal Facility and Sunrise Energy Project. The regulations under this plan are currently under development and will cover all of the Company's assets in Alberta. These regulations may materially adversely affect the Company's results of operations in the province.

Climate change regulations to be developed in Saskatchewan will have to meet equivalency standards with the Canadian federal government and may materially adversely affect the Company's results of operations in the province.

The cost of compliance with British Columbia's \$30 per ton carbon tax and the Renewable and Low Carbon Fuel Requirements Regulation may become material. Additionally, future regulations in support of British Columbia's commitment under its Climate Leadership Plan may materially adversely affect the Company's results of operations in British Columbia.

The Manitoba Climate Change and Green Economy Action Plan implementation may materially adversely affect Husky's results of operations in Manitoba.

The Federal Government of Canada has announced its intention to commence developing a new federal climate change plan in consultation with the provinces. It is not clear how this new plan will be structured and what impacts it will have on Husky's results of operations. Climate change regulations may become more onerous over time as governments implement policies to further reduce GHG emissions. Although the impact of emerging regulations is uncertain, they could have a material adverse effect on the Company's financial condition and results of operations through increased capital and operating costs and change in demand for refined products.

The Company's U.S. refining business may be materially adversely affected by the implementation of the EPA's climate change rules or by future U.S. GHG legislation that applies to the oil and gas industry or the consumption of petroleum products. Such legislation or regulation could require the Company's U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may have a material adverse effect on the Company's financial condition and results of operations through increased capital and operating costs and change in demand for refined products.

The U.S. 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% limit prescribed by most automobile warranties), the price and availability of RINs has been volatile.

The Company complies with the RFS program in the US 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 gain 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 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 land and offshore drilling rigs, land and offshore geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at reasonable prices.

Climatic Conditions

Extreme climatic conditions may have material adverse effects on 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, or disruptions to the operations of major customers or 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. All of these could potentially cause material adverse effects on the Company's results of operations and financial condition.

The Company operates in some of the harshest environments in the world, including offshore in the Atlantic Region. Climate change may increase 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 Newfoundland and Labrador may threaten offshore oil production facilities, causing 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 Region business unit 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 Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commence in February and continue until the threat has abated. In addition, Atlantic Region 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.

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 by third parties. 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 Husky's strategy is dependent on ensuring our 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 results of operations.

7.3 Financial Risks

The Company's financial risks are largely related to commodity price risk, foreign currency risk, interest rate risk, counterparty credit risk, liquidity risk and credit rating 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 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, inventories measured at fair value, long-term income tax receivable, portions of other assets and other long-term liabilities.

For the year ended December 31, 2016, the Company recognized a \$39 million unrealized loss on its crude oil and natural gas risk management positions which were recorded in marketing and other. In addition, the Company recognized a \$10 million realized gain recorded in net foreign exchange and a \$121 million realized loss on a short-term corporate hedging program recorded in other-net. Refer to Note 24 to the 2016 Consolidated Financial Statements.

Commodity Price Risk

In certain instances, the Company uses derivative commodity instruments and futures contracts on commodity exchanges, including commodity put and call options under a short-term hedging program, to manage exposure to price volatility on a portion of its refined product, oil and gas production, and 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. For the year ended December 31, 2016, the Company incurred a realized loss of \$121 million on a short-term corporate hedging program, which is recorded in other-net in the Consolidated Statements of Income (Loss). The hedging program concluded in June 2016.

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 on a monthly basis.

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 the majority 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 the availability 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 Husky's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of Husky to engage in ordinary course derivative or hedging transactions and maintain ordinary course contracts with customers and suppliers on acceptable terms depends on Husky's credit ratings. A reduction in the current rating on Husky's debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in Husky's ratings outlook could adversely affect Husky'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 Husky'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 include 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.

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

Cash Flow Summary (\$ millions)	2016	2015
Cash flow		
Operating activities	1,971	3,760
Financing activities	(1,362)	(210)
Investing activities	632	(4,817)

Cash Flow from Operating Activities

Cash flow generated from operating activities was \$1,971 million in 2016 compared to \$3,760 million in 2015. The decrease was primarily due to lower realized crude oil and North American natural gas prices, a reduction to the fixed priced natural gas from Asia Pacific and lower U.S. market crack spreads, partially offset by lower operating costs due to cost savings initiatives and increased production from new and existing heavy oil thermal developments.

Cash Flow used for Financing Activities

Cash flow used for financing activities was \$1,362 million in 2016 compared to \$210 million in 2015. In 2016, cash flow used for financing activities was primarily used for the net repayment of \$520 million of short-term debt and \$768 million of long term debt, compared to to the net repayment of \$175 million of short-term debt and net issuance of \$949 million of long term debt in 2015. In 2015, the Company paid \$1,167 million on dividends on common shares, the common share dividends were subsequently suspended in late 2015 and the Company did not pay cash dividends on common shares in 2016.

Cash Flow from (used for) Investing Activities

Cash flow generated from investing activities was \$632 million in 2016 compared to cash flow used for investing activities of \$4,817 million in 2015. The increase was primarily due to total cash proceeds from asset sales of \$2,935 million in 2016 from the sale of 65 percent of the Company's ownership interest in select midstream assets, the sale of royalty interests representing approximately 1,700 boe/day of Western Canada Production and the sale of approximately 30,200 boe/day of select legacy Western Canada crude oil and natural gas assets combined with the decrease of capital expenditures in 2016. The cash flow used for investing activities in 2015 also included \$1,363 million of a partial payment of the contribution payable to BP-Husky Refining LLC, compared to \$193 million in 2016.

8.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2016, Husky's working capital was \$1,125 million compared to a deficiency of \$922 million at December 31, 2015. A reconciliation of Husky's working capital (deficiency) is as follows:

(\$ millions)	December 31, 2016	December 31, 2015	Change
Cash and cash equivalents	1,319	70	1,249
Accounts receivable	1,036	1,014	22
Income taxes receivable	186	312	(126)
Inventories	1,558	1,247	311
Prepaid expenses	135	271	(136)
Restricted cash	84	—	84
Accounts payable and accrued liabilities	(2,226)	(2,527)	301
Short-term debt	(200)	(720)	520
Long-term debt due within one year	(403)	(277)	(126)
Contribution payable	(146)	(210)	64
Asset retirement obligations	(218)	(102)	(116)
Net working capital (deficiency)	1,125	(922)	2,047

The increase in cash was primarily due to proceeds from the sale of royalty interests representing approximately 1,700 boe/day of Western Canada production, the sale of 65 percent of the Company's ownership interest in select midstream assets and the sale of approximately 30,200 boe/day of legacy Western Canada crude oil and natural gas assets in 2016. Fluctuations in accounts receivable and accounts payable are due to the timing of settlements in 2016 compared to 2015. The decrease in income taxes receivable is due to timing of expected tax refunds. The increase in inventories is primarily due to higher U.S. refining throughputs in the fourth quarter of 2016 compared to 2015.

The decrease in short-term debt is due to the net repayment of \$520 million of short-term debt in 2016 compared to the net repayment of \$175 million of short-term debt in 2015.

8.3 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, 2016, the Company had the following available credit facilities:

Credit Facilities

<i>(\$ millions)</i>	Available	Unused
Operating facilities ⁽¹⁾	670	292
Syndicated credit facilities ⁽²⁾	4,000	3,800
	4,670	4,092

⁽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, 2016, the Company had \$4,092 million of unused credit facilities of which \$3,800 million are long-term committed credit facilities and \$292 million are short-term uncommitted credit facilities. A total of \$378 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, 2016, 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; however, the Company's leverage covenant under both of its revolving syndicated credit facilities was modified to 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, 2016 and assesses 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, 2016.

On February 23, 2015, the Company filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada (the "Canadian Shelf Prospectus") 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 March 23, 2017. During the 25-month period that the Canadian Shelf Prospectus is effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On March 6, 2015, the Company's \$1.63 billion and \$1.60 billion revolving syndicated credit facilities were each increased to \$2.0 billion. The terms of the revolving syndicated credit facilities remain unchanged.

On March 12, 2015, the Company issued eight million Cumulative Redeemable Preferred Shares, Series 5 (the "Series 5 Preferred Shares") at a price of \$25.00 per share for aggregate gross proceeds of \$200 million, by way of a prospectus supplement dated March 5, 2015, to the Canadian Shelf Prospectus. Net proceeds after share issue costs were \$195 million. Holders of 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 five 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. Net proceeds from the Series 5 Preferred Shares was used for general corporate purposes, which included, among other things, the partial repayment of bank debt incurred by the Company to fund early payment of U.S. \$1 billion of the Company's net capital contribution payable with BP-Husky Refining LLC.

On March 12, 2015, the Company repaid the maturing 3.75 percent notes issued under a trust indenture dated December 21, 2009. The amount paid to noteholders was \$306 million, including \$6 million of interest.

On March 12, 2015, the Company issued \$750 million of 3.55 percent notes due March 12, 2025 by way of a prospectus supplement dated March 9, 2015 to the 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 12 and September 12 of each year, beginning September 12, 2015. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness. Net proceeds from the offering was used for general corporate purposes, which included, among other things, the partial repayment of bank debt incurred by the Company to fund early payment of U.S. \$1 billion of the Company's net capital contribution payable with BP-Husky Refining LLC.

On June 17, 2015, the Company issued six million Cumulative Redeemable Preferred Shares, Series 7 (the "Series 7 Preferred Shares") at a price of \$25.00 per share for aggregate gross proceeds of \$150 million, by way of a prospectus supplement dated June 10, 2015, to the Canadian Shelf Prospectus. Net proceeds after share issue costs were \$145 million. Holders of 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 five 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 five 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. Net proceeds from the Series 7 Preferred Shares was used for general corporate purposes, which included, among other things, the partial repayment of bank debt incurred by the Company to fund capital expenditures for the advancement of near term heavy oil thermal projects.

On December 22, 2015, the Company filed a universal short form base shelf prospectus (the "U.S. Shelf Prospectus") with the Alberta Securities Commission and a related U.S. registration statement containing the U.S. Shelf Prospectus with the SEC that enables the Company to offer up to U.S. \$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 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.

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, 2016 to, but excluding, December 31, 2016, is equal to the sum of the Government of Canada 90 day treasury bill rate on August 31, 2016 plus 1.73 percent, being 2.242 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 the 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, 2016 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.

The Company has \$1.9 billion in unused capacity under the Canadian Shelf Prospectus and U.S. \$3.0 billion in unused capacity under the U.S. Shelf Prospectus and related U.S. registration statement as at December 31, 2016. The ability of the Company to utilize the capacity under its Canadian Shelf Prospectus and U.S. Shelf Prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

Net debt

Net debt is calculated as total debt less cash and cash equivalents. At December 31, 2016, the Company had total debt of \$5,339 million and cash and cash equivalents of \$1,319 million compared to total debt of \$6,756 million and cash and cash equivalents of \$70 million at December 31, 2015. The Company's net debt decreased by \$2,666 million when compared to December 31, 2015:

Net debt (\$ millions)	December 31, 2016	December 31, 2015
Net debt at beginning of period	(6,686)	(4,025)
Change in net debt due to:		
Funds from operations ⁽¹⁾	2,076	3,329
Capital expenditures	(1,705)	(3,005)
Cash dividends paid on common and preferred shares	(27)	(1,203)
Change in non-cash working capital	(227)	498
Proceeds from asset sales	2,935	122
Net proceeds from issuance of preferred shares	—	340
Effect of exchange rates on cash and cash equivalents	8	70
Effect of exchange rates on long-term debt	130	(692)
Income taxes received (paid)	3	(227)
Net interest paid	(344)	(320)
Contribution payable	(193)	(1,363)
Other	10	(210)
	2,666	(2,661)
Net debt at end of period	(4,020)	(6,686)

⁽¹⁾ Funds from operations is a non-GAAP measure. Refer to Section 11.3 for a reconciliation to the GAAP measure.

During the years ended December 31, 2016 and 2015, the Company's capital expenditures were funded by funds from operations. The Company's funds from operations is 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.

During the year ended December 31, 2016, the Company issued common stock dividends of \$296 million on January 11, 2016, on account of common share dividends declared for the third quarter of 2015. The common share dividend was suspended by the Board of Directors in the fourth quarter of 2015. This initiative supports long-term value maximization while providing further financial flexibility for the Company 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. The Board will continue to review the Company's common share dividend policy on a quarterly basis. During the year ended December 31, 2016, there were no common share dividends declared compared to \$1,181 million during 2015.

8.4 Capital Structure

<i>Capital Structure</i> (\$ millions)	December 31, 2016	
	Outstanding	Available ⁽¹⁾
Total debt	5,339	4,092
Common shares, preferred shares, retained earnings and other reserves	17,616	

⁽¹⁾ Total debt available includes committed and uncommitted credit facilities.

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 \$23.0 billion at December 31, 2016 (December 31, 2015 – \$23.3 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 11.3). 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, 2016, debt to capital employed was 23.2 percent (December 31, 2015 – 28.9 percent) and debt to funds from operations was 2.6 times (December 31, 2015 – 2.0 times).

The decrease in the Company's debt to capital employed as at December 31, 2016 is due to proceeds received from the sale of 65 percent of the Company's ownership interest in select midstream assets in the third quarter of 2016 and the sale of royalty interests representing approximately 1,700 boe/day of Western Canada production and the sale of approximately 30,200 boe/day of legacy Western Canada crude oil and natural gas assets in 2016, which were partially used for the repayment of debt. The higher debt to funds from operations ratio as at December 31, 2016 reflects the impact of lower global crude oil and North American natural gas benchmark pricing, which resulted in significantly lower funds from operations. 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 has taken measures to strengthen its financial position and navigate through this commodity down cycle which include, but are not limited to, a reduction of budgeted capital spending, the suspension of the quarterly common share dividend, the sale of royalty interests in Western Canada production, the sale of non-core assets in Western Canada, a strategic disposition of select midstream assets and the continued transition to lower sustaining and higher return Lloyd thermal projects.

Divestitures

Pipeline and Terminals

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 include 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 HMLP, of which the Company owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent. The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets.

Upstream Exploration and Production - Western Canada

In 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 and the sale of approximately 30,200 boe/day of legacy crude oil and natural gas assets in Western Canada for gross proceeds of \$1.12 billion.

Use of Proceeds

Cash proceeds from the dispositions allowed the Company to pay down debt, which served to strengthen the Company's balance sheet. This also enables the Company to focus on fewer, more material plays while providing for a more capital efficient business with reduced sustaining capital requirements.

8.5 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

<i>Payments due by period (\$ millions)</i>	2017	2018-2019	2020-2021	Thereafter	Total
Long-term debt and interest on fixed rate debt	674	1,891	668	3,720	6,953
Operating leases ⁽¹⁾	252	306	229	1,650	2,437
Firm transportation agreements ⁽¹⁾	458	908	943	4,822	7,131
Unconditional purchase obligations ⁽²⁾	2,749	2,680	2,161	1,549	9,139
Lease rentals and exploration work agreements	49	142	102	850	1,143
Obligations to fund equity investee ⁽³⁾	52	110	110	379	651
Finance lease obligations ⁽⁴⁾	35	70	70	764	939
Asset retirement obligations ⁽⁵⁾	218	376	337	10,503	11,434
	4,487	6,483	4,620	24,237	39,827

⁽¹⁾ Included in operating leases and firm transportation agreements are blending and storage agreements and transportation commitments of \$0.6 billion and \$2.1 billion respectively with HMLP.

⁽²⁾ Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases.

⁽³⁾ Equity investee refers to the Company's investment in Husky-CNOOC Madura Limited and HMLP which is accounted for using the equity method.

⁽⁴⁾ Refer to Note 17 in the 2016 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 \$156 million of cash deposited into restricted accounts for funding of future asset retirement obligations in the Asia Pacific Region.

The Company renewed certain purchase, distribution and terminal commitments related to light oil and asphalt products in 2016. Certain transportation, storage and operating lease commitments were signed with HMLP in conjunction with the divestiture of certain midstream assets.

Due to the harsh environment, the Henry Goodrich rig arrived in mid-2016 for development drilling at White Rose.

Husky-CNOOC Madura Limited, of which the Company is a joint venturer, has entered into an arrangement to lease an FPSO vessel for the purposes of developing the Madura BD field gas reserves. The Company is obligated to pay 40 percent of the lease payment which is included in obligations to fund equity investee. The FPSO was delivered and testing began in December 2016.

The Company updated its estimates for Asset Retirement Obligations ("ARO") as outlined in Note 16 to the 2016 Consolidated Financial Statements. On an undiscounted and inflated basis, the ARO decreased from \$13.9 billion as at December 31, 2015 to \$11.4 billion as at December 31, 2016, 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 the outcome of adverse 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.

The Company provides a defined contribution pension plan and a post-retirement health and dental plan for all qualified employees in Canada. The Company also provides a defined benefit pension plan for approximately 53 active employees, 74 participants with deferred benefits and 546 participants or joint survivors receiving benefits in Canada. This plan was closed to new entrants in 1991 after the majority of employees transferred to the defined contribution pension plan (Refer to Note 22 in the 2016 Consolidated Financial Statements).

The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery. The remaining net contribution payable amount of approximately U.S. \$110 million (CDN \$146 million) will be paid by way of funding all capital contributions of the BP-Husky Refining LLC joint operation and the remaining balance will be fully repaid by the end of 2017.

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 contract for the Asia Pacific Region. As at December 31, 2016, Husky has deposited funds of \$156 million into the restricted cash accounts, of which \$84 million relates to the Wenchang field and has been classified as current.

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.

8.6 Transactions with Related Parties

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 include 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 HMLP, of which the Company owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent. This transaction is a related party transaction, as PAH and CKI are affiliates of one of the Company's principal shareholders, and has been measured at fair value. The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets. Subsequent to the sale of its ownership interest, the Company performs management services as the operator of the pipeline for which it earns a management fee from HMLP. 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 its blending business and the Company also pays for transportation and storage services. For the year ended December 31, 2016, the Company charged HMLP \$133 million related to construction and management services, and the Company had purchases from HMLP of \$15 million related to the use of the pipeline for the Company's blending activities and \$64 million related to transportation and storage. As at December 31, 2016, the Company had \$26 million due from HMLP and nil due to HMLP related to these transactions. All transactions with HMLP have been measured at fair value.

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. 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, 2016, the amount of natural gas sales to Meridian totalled \$41 million. For the year ended December 31, 2016, the amount of steam purchased by the Company from Meridian totalled \$13 million. For the year ended December 31, 2016, the total cost recovery by the Company for facilities services was \$12 million. At December 31, 2016, the Company had under \$1 million due from Meridian with respect to these transactions.

At December 31, 2016, \$34 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.

On June 29, 2011, the Company issued 7.4 million common shares at a price of \$27.05 per share for total gross proceeds of \$200 million in a private placement to its then principal shareholders, L.F. Management and Investment S.à r.l (formerly L.F. Investments (Barbados) Limited) and Hutchison Whampoa Luxembourg Holdings S.à r.l, which was completed in conjunction with a public offering by the Company of common shares.

On December 7, 2010, the Company issued 28.9 million common shares at a price of \$24.50 per share for total gross proceeds of \$707 million in a private placement to its principal shareholders, L.F. Management and Investment S.à r.l (formerly L.F. Investments (Barbados) Limited) and Hutchison Whampoa Luxembourg Holdings S.à r.l, which was completed in conjunction with a public offering by the Company of common shares in Canada.

8.7 Outstanding Share Data

Authorized:

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

Issued and outstanding: February 20, 2017

• common shares	1,005,451,845
• 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	25,300,870
• stock options exercisable	15,596,918

9.0 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 2016 Consolidated Financial Statements. Certain of the Company's accounting policies require subjective judgment and estimation about uncertain circumstances.

9.1 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 estimates 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. Determining whether there are any indications of impairment requires significant judgment of external factors, such as an extended decrease in prices or margins for oil and gas commodities or products, a significant decline in an asset's market value, a significant downward revision of estimated volumes, an upward revision of future development costs, a decline 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 is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to net earnings.

The determination of the recoverable amount for impairment purposes involves the use of numerous assumptions and estimates. 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, 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.

9.2 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, unless otherwise noted. 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.

10.0 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 (Loss) 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. The Company is currently evaluating the dollar impact of adopting IFRS 16 on the Company's consolidated financial statements.

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. The Company is currently in the scoping phase of implementation. Adopting IFRS 15 is not expected to have a material impact on the Company's consolidated financial statements.

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 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. The Company intends to retrospectively adopt the standard on January 1, 2018. The adoption of IFRS 9 is not expected to have a material impact on the Company's consolidated financial statements.

Amendments to IAS 7 Statement of Cash Flows

In January 2016, the IASB issued amendments to IAS 7 to be applied prospectively for annual periods beginning on or after January 1, 2017 with early adoption permitted. The amendments require disclosure of information enabling users of financial statements to evaluate changes in liabilities arising from financing activities. The adoption of the IAS 7 amendments will require additional disclosure in the Company's 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 transactions. The adoption of the amendments is not expected to 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, 2016:

Amendments to IAS 1 Presentation of Financial Statements

The amendments clarify guidance on materiality and aggregation, use of subtotals, aggregation and disaggregation of financial statement line items, the order of the notes to the financial statements and disclosure of significant accounting policies. The adoption of this amended standard had no material impact on the Company's consolidated financial statements.

Amendments to IFRS 7 Financial Instrument: Disclosures

The amendments clarify:

- Whether a servicing contract is continuing involvement in a transferred asset for the purpose of determining the disclosures required; and
- The applicability of the amendments to IFRS 7 on offsetting disclosures to condensed interim financial statements.

The adoption of this amended standard had no material impact on the Company's consolidated financial statements.

11.0 Reader Advisories

11.1 Forward-Looking Statements

Special Note Regarding 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", "estimated", "intend", "plan", "projection", "forecast", "guidance", "could", "may", "would", "aim", "vision", "goals", "objective", "target", "schedules" 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 2017 production guidance, including guidance for specified areas and product types; the Company's 2017 Upstream capital expenditures program, including guidance for specified areas and product types; and the Company's objective to maintain debt to capital employed and debt to funds from operations below certain levels;
- with respect to the Company's Asia Pacific Region: anticipated volumes of peak combined net sales volumes of gas and NGL from the BD, MDA, MBH and MDK fields; anticipated timing of signing the floating production vessel lease contract for, and first production at, the MDA, MBH, and MDK gas fields; anticipated timing of exploration and drilling plans at Block 15/33; anticipated timing of acquisition of seismic surveying data at the Taiwan exploration block; and anticipated timing of first production from and achieving full gas sales rates at the BD field;
- with respect to the Company's Atlantic Region: anticipated exploration and growth potential in the region; and timing to consider sanction of the West White Rose extension project;
- with respect to the Company's Oil Sands properties: anticipated range of daily production volumes from the Company's Sunrise Energy Project for 2017; and expected improved well conformance and production rates at the Company's Sunrise Energy Project over the next two years;
- with respect to the Company's Heavy Oil properties: the Company's strategic plans for its Heavy Oil Thermal production; anticipated timing of first production from, and combined nameplate capacities of, the Dee Valley, Spruce Lake North and Spruce Lake Central thermal projects; nameplate capacity for the Company's Edam West thermal development; and nameplate capacity and expected timing for first production of the Rush Lake 2 thermal development;
- with respect to the Company's Western Canadian oil and gas resource plays: the Company's strategic plans for its Western Canada resource plays;
- with respect to the Company's Infrastructure and Marketing business: the Company's plans to expand export pipeline access and product storage opportunities to enhance market access; and
- with respect to the Company's Downstream operating segment: potential expansion of the Company's asphalt processing capacity in Lloydminster and the benefits and timing of such expansion; anticipated timing of completion, outcome, and benefits of the crude oil flexibility project at the Company's Lima Refinery; and the timing of the implementation of the agreement with Imperial Oil and consolidation of the two networks to create a single expedited truck transport network.

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 document 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, regulators and other sources.

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, 2016 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.

11.2 Oil and Gas Reserves Reporting

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

Unless otherwise stated, reserve estimates in this document, 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, 2016 and represent Husky's share. Unless otherwise noted, historical production numbers given represent Husky's share.

The Company uses the terms 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 reserve replacement ratio, which is consistent with other oil and gas companies' disclosures. Reserve 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 reserve 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 reserve replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserve replacement ratio only measures the amount of reserves added to a company's reserve base during a given period.

Steam-oil ratio measures the average volume of steam required to produce a barrel of oil. This measure does not have any standardized meaning and should not be used to make comparisons to similar measures presented by other issuers.

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.

11.3 Non-GAAP Measures

Disclosure of non-GAAP Measurements

The Company uses measurements primarily based on IFRS and also on secondary non-GAAP measurements. The non-GAAP measurements 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, earnings coverage, debt to funds from operations and LIFO. None of these measurements are 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, earnings coverage or debt to funds from operations. These are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity. The non-GAAP measurements do not have a standardized meaning 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)

The term "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:

(\$ millions)	Three months ended Dec. 31,		Year ended Dec. 31,		
	2016	2015	2016	2015	2014
Net earnings (loss)	186	(69)	922	(3,850)	1,258
Impairment (impairment reversal) of property, plant and equipment, net of tax	(202)	—	(190)	3,664	622
Impairment of goodwill	—	—	—	160	—
Exploration and evaluation asset write-downs, net of tax	41	6	63	177	4
Inventory write-downs, net of tax	6	14	6	14	135
Loss (gain) on sale of assets, net of tax	(37)	(4)	(1,456)	(16)	(27)
Adjusted net earnings (loss)	(6)	(53)	(655)	149	1,992

Funds from Operations and Free Cash Flow

The term "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 less the settlement of asset retirement obligations, deferred revenue, income taxes received (paid) and change in non-cash working capital.

The term "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:

(\$ millions)	Three months ended Dec. 31,		Year ended Dec. 31,		
	2016	2015	2016	2015	2014
Cash flow – operating activities	644	1,291	1,971	3,760	5,585
Settlement of asset retirement obligations	31	31	87	98	167
Deferred revenue	(23)	(26)	(209)	(102)	—
Income taxes received (paid)	6	31	(3)	227	661
Interest received	(1)	(3)	(5)	(3)	(7)
Change in non-cash working capital	13	(684)	235	(651)	(871)
Funds from operations	670	640	2,076	3,329	5,535
Capital expenditures	(391)	(641)	(1,705)	(3,005)	(5,023)
Free cash flow	279	(1)	371	324	512
Funds from operations – basic	0.67	0.65	2.07	3.38	5.63
Funds from operations – diluted	0.67	0.65	2.07	3.38	5.62

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, 2016, 2015 and 2014:

(\$ millions)	December 31, 2016	December 31, 2015	December 31, 2014
Short-term debt	200	720	895
Long-term debt due within one year	403	277	300
Long-term debt	4,736	5,759	4,097
Total Debt	5,339	6,756	5,292
Cash and cash equivalents	(1,319)	(70)	(1,267)
Net Debt	4,020	6,686	4,025

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. The operating netback was determined as gross revenue less royalties, production and operating and transportation costs on a per unit basis.

Debt to Capital Employed

Debt to capital employed percentage 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 less the settlement of asset retirement obligations, deferred revenue, income taxes received (paid) and 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 reconciliation of debt to funds from operations for the periods ended December 31, 2016, 2015 and 2014:

(\$ millions)	December 31, 2016	December 31, 2015	December 31, 2014
Total Debt	5,339	6,756	5,292
Funds from operations	2,076	3,329	5,535
Debt to Funds from Operations	2.6	2.0	1.0

Earnings Coverage

Earnings coverage is a non-GAAP measure and is equal to net earnings (loss) before finance expense on long-term debt, capitalized interest and income taxes divided by finance expense on long-term debt, dividends on preferred shares and capitalized interest. Long-term debt includes the current portion of long-term debt. The Company's earnings coverage on long-term debt was 3.2 times for the twelve month period ended December 31, 2016.

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.

11.4 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 Audit Committee and approved by the Company's Board of Directors on February 23, 2017. 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 23, 2017 should be read in conjunction with the 2016 Consolidated Financial Statements and related notes. The readers are also encouraged to refer to the Company's interim reports filed for 2016, which contain the Management's Discussion and Analysis and Consolidated Financial Statements, and the Company's 2016 Annual Information Form filed separately with Canadian regulatory agencies and Form 40-F filed with the SEC, the U.S. 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, 2016 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, 2016 and 2015 and the Company's financial position at December 31, 2016 and 2015. All currency is expressed in Canadian dollars unless otherwise directed.

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 their 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;
- Currency is presented in millions of Canadian dollars ("*\$ millions*");
- Gross production and reserves are the Company's working interest prior to deduction of royalty volume; and
- 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
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
Earnings Coverage	Net earnings (loss) before finance expense on long-term debt, capitalized interest and income taxes divided by finance expense on long-term debt, dividends on preferred shares and capitalized interest. Long-term debt includes the current portion of long-term debt
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 items affecting cash which includes settlement of asset retirement obligations, deferred revenue, income taxes received (paid) and 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 Hi-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
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 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 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
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

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, retained earnings and other reserves
Steam-oil ratio	The steam-oil ratio measures the volume of steam used to produce one unit volume of oil
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
Total Debt	Long-term debt including long-term debt due within one year and short-term debt
Turnaround	Performance of plant or facility maintenance

Abbreviations

ARO	asset retirement obligations	mbbls/day	thousand barrels per day
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	thousand cubic feet of gas equivalent
boe/day	barrels of oil equivalent per day	MD&A	Management's Discussion and Analysis
bps	basis points	mmbbls	million barrels
CGUs	cash generating units	mmbboe	million barrels of oil equivalent
CHOPS	cold heavy oil production with sand	mmbtu	million British Thermal Units
CO ₂ e	carbon dioxide equivalent	mmcf	million cubic feet
CSA	Canadian Securities Administrators	mmcf/day	million cubic feet per day
DD&A	depletion, depreciation and amortization	m ³	cubic meter
ELs	exploration licenses	NGL	natural gas liquids
EOR	enhanced oil recovery	NIT	NOVA Inventory Transfer
EPA	U.S. Environmental Protection Agency	NYMEX	New York Mercantile Exchange
FEED	front end engineering and design	OPEC	Organization of Petroleum Exporting Countries
FIFO	first in first out	PHMSA	Pipeline and Hazardous Materials Safety Administration
FPSO	floating production, storage and offloading vessel	PSC	production sharing contract
FVTPL	fair value through profit or loss	RFS	Renewable Fuel Standard
GAAP	Generally Accepted Accounting Principles	RIN	Renewable Identification Number
GHG	greenhouse gas	RVO	renewable volume obligation
GJ	gigajoule	S&P	Standard and Poor's
HOIMS	Husky Operational Integrity Management System	SAGD	steam assisted gravity drainage
IASB	International Accounting Standards Board	SEC	U.S. Securities and Exchange Commission
IFRIC	International Financial Reporting Interpretations Committee Interpretation	SEDAR	System for Electronic Document Analysis and Retrieval
IFRS	International Financial Reporting Standards	tCO ₂ e	tons of carbon dioxide equivalent
LFES	Large Final Emitting Facilities	TSX	Toronto Stock Exchange
LIFO	last in first out	WI	working interest
mbbls	thousand barrels	WTI	West Texas Intermediate

11.5 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, 2016, 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, 2016, 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, 2016, 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

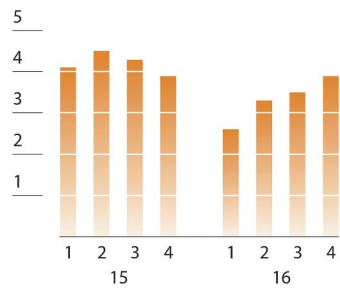
There have been no changes in Husky's internal control over financial reporting during the year ended December 31, 2016, that have materially affected or are reasonably likely to materially affect its internal control over financial reporting.

12.0 Selected Quarterly Financial and Operating Information

12.1 Summary of Quarterly Results

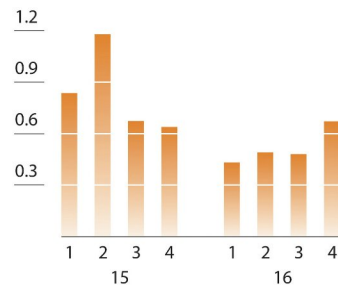
Gross Revenues and Marketing and Other

(\$ billions)



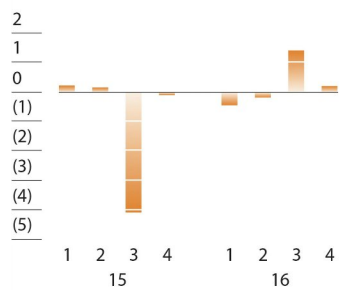
Funds from Operations⁽¹⁾

(\$ billions)



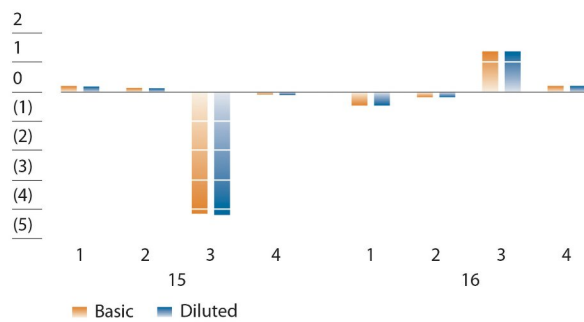
Net Earnings (Loss)

(\$ billions)



Net Earning (Loss) Per Share

(\$ per share)



⁽¹⁾ Funds from operations is a non-GAAP measure. Refer to Section 11.3.

Fourth Quarter Results Summary (\$ millions, except where indicated)	Three months ended	
	Dec. 31 2016	Dec. 31 2015
Gross revenues and marketing and other		
Upstream		
Exploration and Production	1,215	1,189
Infrastructure and Marketing	186	301
Downstream		
Upgrader	340	364
Canadian Refined Products	603	699
U.S. Refining and Marketing	1,890	1,692
Corporate and Eliminations	(369)	(342)
Total gross revenues and marketing and other	3,865	3,903
Net earnings (loss)		
Upstream		
Exploration and Production	198	(134)
Infrastructure and Marketing	18	10
Downstream		
Upgrader	32	57
Canadian Refined Products	8	49
U.S. Refining and Marketing	19	(5)
Corporate and Eliminations	(89)	(46)
Net earnings (loss)	186	(69)
Per share – Basic	0.19	(0.08)
Per share – Diluted	0.19	(0.09)
Adjusted net earnings (loss) ⁽¹⁾	(6)	(53)
Funds from operations ⁽¹⁾	670	640
Per share – Basic	0.67	0.65
Per share – Diluted	0.67	0.65
Upstream		
Daily gross production		
Crude oil and NGL production (mbbls/day)	234.5	246.9
Natural gas production (mmcf/day)	555.4	660.7
Total production (mboe/day)	327.0	357.0
Average sales prices realized (\$/boe)		
Crude oil and NGL (\$/bbl)	42.27	35.71
Natural gas (\$/mcf)	5.65	5.51
Total average sales prices realized (\$/boe)	39.90	34.89
Downstream		
Refinery throughput		
Lloydminster Upgrader (mbbls/day)	66.5	81.2
Lloydminster Refinery (mbbls/day)	28.4	28.2
Prince George Refinery (mbbls/day)	11.8	11.3
Lima Refinery (mbbls/day)	165.1	144.8
Toledo Refinery (mbbls/day) ⁽²⁾	78.8	72.8
Total throughput (mbbls/day)	350.6	338.3
Upgrader unit margin (\$/bbl)	18.85	20.47
Upgrader synthetic crude oil sales (mbbls/day)	50.0	59.4
Upgrader total sales (mbbls/day)	66.9	80.7
Retail fuel sales (million of litres/day)	6.6	7.3
Canadian light oil margins (\$/litre)	0.057	0.048
Lloydminster Refinery asphalt margin (\$/bbl)	20.80	23.57
U.S. Refining Margin (U.S. \$/bbl crude throughput)	9.86	4.51
U.S./Canadian dollar exchange rate (U.S. \$)	0.750	0.749

⁽¹⁾ Adjusted net earnings (loss) and funds from operations are non-GAAP measures. Refer to Section 11.3 for a reconciliation to the GAAP measures.

⁽²⁾ BP-Husky Toledo Refinery throughput was revised in the first quarter of 2016 to reflect total throughput. Prior periods reflected crude throughput only and have been restated to conform with current presentation.

Gross Revenue and Marketing and other

The Company's consolidated gross revenues and marketing and other decreased by \$38 million in the fourth quarter of 2016 compared to the fourth quarter of 2015.

In the Upstream business segment, Exploration and Production gross revenues increased primarily due to higher crude and North American natural gas pricing in the fourth quarter of 2016, which was partially offset by a higher Canadian dollar and lower Liwan natural gas pricing. Infrastructure and Marketing gross revenues and marketing and other decreased primarily due to the sale of select midstream assets.

In the Downstream business segment, Upgrader gross revenues decreased primarily due to reduced sales volumes resulting from plant maintenance in the fourth quarter of 2016. Canadian Refined Products gross revenues decreased primarily due to lower refined product prices and lower fuel sales volumes and demand resulting from a weak economic environment. U.S. Refining and Marketing gross revenues increased primarily due to higher sales price and volume at both the BP-Husky Toledo Refinery and Lima Refinery.

Net Earnings (Loss)

The Company's consolidated net earnings increased by \$255 million in the fourth quarter of 2016 compared to the same period in 2015.

In the Upstream business segment, Exploration and Production net earnings increased primarily due to higher commodity prices, lower operating costs due to cost saving initiatives and a net impairment reversal in the fourth quarter of 2016. The increase to net earnings was partially offset by a higher Canadian dollar and lower Liwan natural gas pricing.

In the Downstream business segment, Upgrader net earnings decreased primarily due to lower average upgrading differentials and lower sales volumes due to plant maintenance. The decline in upgrading differentials was attributable to significantly higher heavy crude oil feedstock costs partially offset by higher realized prices for Husky Synthetic Blend. During the fourth quarter of 2016, the price of Husky Synthetic Blend averaged \$64.39/bbl compared to \$56.50/bbl in the fourth quarter of 2015. Canadian Refined Products net earnings decreased primarily due to a lower asphalt gross margin due to lower asphalt prices and rising crude feedstock costs in the fourth quarter of 2016. U.S. Refining and Marketing net earnings increased primarily due to the factors noted above that positively impacted gross revenue. The Company recorded FIFO gains of \$25 million during the fourth quarter of 2016 compared to FIFO losses of \$72 million during the fourth quarter of 2015. During the fourth quarter of 2016, the Company recorded pre-tax business interruption loss and property damage insurance recoveries associated with the unplanned outage in the isocracker unit of \$1 million compared to \$79 million in the fourth quarter of 2015.

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 \$47 million in the fourth quarter of 2016 compared to the fourth quarter of 2015. The increase was primarily attributable to higher adjusted net earnings from Exploration and Production due to an increase in average realized crude oil and North American natural gas prices and higher U.S. Refining and Marketing adjusted net earnings due to a higher volume and margins. The increase was partially offset by lower adjusted net earnings from the Upgrader primarily due to lower average upgrading differentials and sales volume and from Canadian Refined Products primarily due to lower asphalt prices and rising crude feedstock prices. Adjusted net earnings (loss) is a non-GAAP measure; refer to section 11.3.

Funds from Operations

Funds from operations increased by \$30 million in the fourth quarter of 2016 compared to the fourth quarter of 2015 primarily due to the same factors which impacted adjusted net earnings (loss). Funds from operations is a non-GAAP measure; refer to section 11.3.

Daily Gross Production

Production decreased by 30 mbbbls/day during the fourth quarter of 2016 compared to the fourth quarter of 2015 as a result of:

- Disposition of select legacy Western Canada crude oil and natural gas assets; and
- Natural reservoir declines at mature properties in Western Canada and the Atlantic Region with limited sustaining capital investment in a low commodity price environment.

Partially offset by:

- Increased thermal production driven by the Rush Lake ramp up, strong production performance from Tucker, and new production from Edam East, Vawn and Edam West; and
- The production ramp up at the Sunrise Energy Project.

Segmented Operational Information

Segmented Operational Information	2016				2015			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues and marketing and other								
Upstream								
Exploration and Production	1,215	941	1,044	836	1,189	1,253	1,577	1,355
Infrastructure and Marketing	186	280	288	113	301	273	293	435
Downstream								
Upgrader	340	334	369	281	364	190	418	347
Canadian Refined Products	603	678	585	435	699	839	747	601
U.S. Refining and Marketing	1,890	1,642	1,337	1,126	1,692	1,973	1,955	1,725
Corporate and Eliminations	(369)	(355)	(362)	(213)	(342)	(242)	(464)	(377)
Total gross revenues and marketing and other	3,865	3,520	3,261	2,578	3,903	4,286	4,526	4,086
Net earnings (loss)								
Upstream								
Exploration and Production	198	63	(228)	(250)	(134)	(4,103)	18	(119)
Infrastructure and Marketing	18	1,306	35	(51)	10	32	(21)	63
Downstream								
Upgrader	32	27	58	58	57	(29)	28	37
Canadian Refined Products	8	55	36	11	49	69	39	13
U.S. Refining and Marketing	19	(16)	61	(7)	(5)	36	172	194
Corporate and Eliminations	(89)	(45)	(158)	(219)	(46)	(97)	(116)	3
Net earnings (loss)	186	1,390	(196)	(458)	(69)	(4,092)	120	191
Per share – Basic	0.19	1.37	(0.20)	(0.47)	(0.08)	(4.17)	0.11	0.19
Per share – Diluted	0.19	1.37	(0.20)	(0.47)	(0.09)	(4.19)	0.10	0.17
Adjusted net earnings (loss) ⁽¹⁾	(6)	(100)	(91)	(458)	(53)	(101)	124	191
Funds from operations ⁽¹⁾	670	484	488	434	640	674	1,177	838
Per share – Basic	0.67	0.48	0.49	0.43	0.65	0.68	1.20	0.85
Per share – Diluted	0.67	0.48	0.49	0.43	0.65	0.68	1.20	0.85
U.S./Canadian dollar exchange rate (U.S. \$)	0.750	0.766	0.776	0.728	0.749	0.764	0.813	0.806
Exploration and Production								
Daily production, before royalties								
Crude oil & NGL production (mmbbls/day)								
Light & Medium crude oil	54.9	47.6	69.4	80.9	84.3	72.1	77.3	88.5
NGL	15.9	13.4	12.8	14.0	16.9	16.7	19.0	20.4
Heavy crude oil	48.4	49.5	57.5	61.5	66.7	67.9	70.0	71.9
Bitumen	115.3	103.6	88.0	81.8	79.0	66.7	50.3	55.7
Total crude oil & NGL production (mmbbls/day)	234.5	214.1	227.7	238.2	246.9	223.4	216.6	236.5
Natural gas (mmcf/day)	555.4	521.3	528.8	618.6	660.7	657.7	721.6	717.0
Total production (mboe/day)	327.0	301.0	315.8	341.3	357.0	333.0	336.9	356.0
Average sales prices								
Light & Medium crude oil (\$/bbl)	64.12	54.91	56.11	39.65	49.31	54.23	69.99	56.91
NGL (\$/bbl)	46.47	35.62	36.68	31.89	42.46	43.18	51.97	45.29
Heavy crude oil (\$/bbl)	36.30	35.04	34.88	18.12	28.71	36.51	50.21	32.97
Bitumen (\$/bbl)	33.80	29.53	30.95	12.83	25.67	33.86	48.45	34.97
Natural gas (\$/mcf)	5.65	3.99	3.46	4.41	5.51	5.76	6.09	5.96
Operating costs (\$/boe)	13.92	15.15	13.90	13.31	14.51	15.52	15.72	14.87
Operating netbacks ⁽²⁾								
Lloydminster – Thermal Oil (\$/bbl) ⁽³⁾	22.02	19.72	24.61	10.02	18.77	22.06	33.52	22.68
Lloydminster – Non-Thermal Oil (\$/boe) ⁽³⁾	11.58	11.28	15.05	0.50	7.53	13.51	26.88	9.12
Cold Lake – Bitumen (\$/bbl) ⁽³⁾	21.34	20.04	26.55	5.28	13.91	17.75	5.89	10.18
Oil Sands – Bitumen (\$/bbl) ⁽³⁾	5.42	0.90	(26.52)	(53.29)	(56.39)	(103.92)	(119.67)	–
Western Canada – Crude Oil (\$/bbl) ⁽³⁾	5.06	11.37	18.95	(1.94)	8.96	14.97	26.06	8.81
Western Canada – NGL & natural gas (\$/mcf) ⁽⁴⁾	1.36	0.45	(0.56)	0.36	0.64	1.08	1.00	0.88
Atlantic – Light Oil (\$/bbl) ⁽³⁾	40.49	22.83	28.55	27.82	31.36	36.51	46.81	43.21
Asia Pacific – Light Oil, NGL & natural gas (\$/boe) ⁽³⁾	61.09	47.77	59.21	61.11	68.15	67.70	69.60	68.19
Total (\$/boe) ⁽²⁾	22.32	15.70	17.30	9.68	17.28	20.72	28.93	21.45

Segmented Operational Information (continued)	2016				2015			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upgrader								
Synthetic crude oil sales (mbbls/day)	50.0	53.3	59.8	57.7	59.4	31.6	55.0	58.5
Total sales (mbbls/day)	66.9	69.7	76.5	78.3	80.7	42.5	73.2	81.0
Upgrading differential (\$/bbl)	20.36	19.45	20.85	22.23	22.19	17.58	18.93	15.72
Canadian Refined Products								
Fuel sales (million litres/day)	6.6	6.8	6.8	6.2	7.3	7.7	7.6	7.6
Refinery throughput								
Lloydminster refinery (mbbls/day)	28.4	26.7	28.2	28.0	28.2	26.4	28.4	29.2
Prince George refinery (mbbls/day)	11.8	9.7	5.1	11.0	11.3	11.0	8.5	11.4
U.S. Refining and Marketing								
Refinery throughput								
Lima refinery (mbbls/day)	165.1	155.6	103.9	127.5	144.8	142.9	136.1	119.2
BP-Husky Toledo refinery (mbbls/day) ⁽⁵⁾	78.8	58.4	41.2	69.4	72.8	68.0	75.5	56.3

⁽¹⁾ Adjusted net earnings (loss) and funds from operations are non-GAAP measures. Refer to Section 11.3 for a reconciliation to the GAAP measures.

⁽²⁾ Operating netback is a non-GAAP measure and is equal to gross revenue less royalties, production and operating costs and transportation costs on a per unit basis. Refer to Section 11.3.

⁽³⁾ Includes associated co-products converted to boe.

⁽⁴⁾ Includes associated co-products converted to mcfge.

⁽⁵⁾ BP-Husky Toledo Refinery throughput was revised in the first quarter of 2016 to reflect total throughput. Prior periods reflected crude throughput only and have been restated to conform with current presentation.

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. Weak crude oil and North American natural gas prices throughout 2016, resulted in significant declines in the 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:

- In 2016, the Company accrued business interruption and property damage insurance recoveries of \$176 million associated with a fire that damaged the Company's isocracker unit at Lima during the first quarter of 2015. To date, the Company has recorded \$411 million in insurance recoveries.
- In the fourth quarter of 2016, the Company recognized after-tax property, plant and equipment net impairment reversal charges of \$202 million 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.
- In the fourth quarter of 2016, the Company completed the sale of select assets in southern Alberta representing approximately 4,700 boe/day for gross proceeds of \$24 million and after-tax gains of \$37 million.
- In the fourth quarter of 2016, an additional well was brought into production at the South White Rose drill centre.
- In the third quarter of 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 and an after-tax gain of \$1.32 billion. The assets include 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.
- In the third quarter of 2016, the Company completed the sale of several packages of 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.
- In the third quarter of 2016, the Company's China subsidiary signed a Heads of Agreement ("HOA") with China National Offshore Oil Corporation ("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 thousand cubic feet (mcf) at the current exchange rates. Gross take-or-pay volumes from the fields remain unchanged in the range of 300-330 million cubic feet per day (mmcf/day). Liquids production, net to Husky, is 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.
- In the third quarter of 2016, the Company achieved first production at the North Amethyst Hibernia formation well.
- In the third quarter of 2016, the Company achieved first oil at the 4,500 bbls/day Edam West heavy oil thermal development.
- In the second quarter of 2016, 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.
- In the second quarter of 2016, Prince George Refinery gross margins were lower due to a planned turnaround.
- In the second quarter of 2016, the 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.

- In the second quarter of 2016, 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.
- In the second quarter of 2016, the Company completed the sale of several packages of select legacy Western Canada crude oil and natural gas assets in Saskatchewan and Alberta 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.
- In the second quarter of 2016, the Company completed the sale of royalty interests representing approximately 1,700 boe/day of Western Canada production. The sale proceeds include \$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.
- In the second quarter of 2016, first oil was achieved at the 10,000 bbls/day Vawn heavy oil thermal development.
- In the second quarter of 2016, the Company achieved first oil at the 10,000 bbls/day Edam East heavy oil thermal development.
- In the second quarter of 2016, the Company achieved first oil at the development of the Colony formation at the Tucker Thermal Project. This formation has similar characteristics to heavy oil thermal reservoirs in the Lloydminster region.
- In the first quarter of 2016, throughput decreased at the Upgrader primarily due to unscheduled maintenance.
- In 2015, the Company accrued business interruption and property damage insurance recoveries of \$235 million associated with a fire that damaged the Company's isocracker unit at Lima during the first quarter of 2015.
- In the fourth quarter of 2015, the Company recorded a pre-tax provision of \$16 million in the U.S. Refining and Marketing business segment and a pre-tax provision of \$6 million in the Infrastructure and Marketing business segment to bring inventory to net realizable value.
- In the third quarter of 2015, the Company recorded after-tax property, plant and equipment and goodwill impairment charges of \$3,824 million related to crude oil and natural gas assets located in Western Canada. The after-tax impairment charge was the result of sustained declines in forecasted short and long-term crude oil and natural gas prices and management's decision to reduce capital expenditures in these areas. In addition, the Company recorded an after-tax exploration and evaluation asset write-down of \$167 million during the third quarter on certain Western Canada resource play assets and an associated \$35 million after-tax work commitment penalty. The write-down was the result of management's plan to withdraw from further exploration and evaluation due to lower estimated short and long-term crude oil and natural gas prices.
- In the third quarter of 2015, the Company derecognized approximately \$46 million pre-tax of assets related to the cancellation of the West Mira drilling rig contract.
- In the third quarter of 2015, operations at the Company's Upgrader were suspended for approximately eight weeks for unplanned maintenance to address repairs to the facility's coke drums.
- In the second quarter of 2015, the Company recognized a deferred income tax expense of \$157 million related to an increase in Alberta provincial tax rates.
- In the second quarter of 2015, the Company wrote-off approximately \$46 million pre-tax of the carrying value of the isocracker unit at the Lima Refinery which was damaged by a fire in the first quarter of 2015.
- In the first quarter of 2015, the Company recognized a deferred income tax recovery of \$203 million in its U.S. Refining and Marketing business segment related to the partial payment of the contribution payable to BP-Husky Refining LLC.
- In the first quarter of 2015, the Company was negatively impacted by unplanned outages at the Lima and BP-Husky Toledo refineries. The Lima Refinery was negatively impacted by an unplanned outage when a fire occurred in the isocracker unit in January 2015 and the BP-Husky Toledo Refinery was negatively impacted by unplanned maintenance to repair a damaged fluid catalytic cracking unit.

Segmented Financial Information

2016 (\$ 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	1,215	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 tax	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⁾	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

2015 (\$ 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	1,189	1,253	1,577	1,355	311	250	337	366	364	190	418	347
Royalties	(85)	(83)	(134)	(130)	—	—	—	—	—	—	—	—
Marketing and other	—	—	—	—	(10)	23	(44)	69	—	—	—	—
Revenues, net of royalties	1,104	1,170	1,443	1,225	301	273	293	435	364	190	418	347
Expenses												
Purchases of crude oil and products	7	8	17	9	269	217	302	335	212	162	310	238
Production, operating and transportation expenses	524	519	521	512	12	7	9	9	44	40	42	43
Selling, general and administrative expenses	57	51	60	69	2	2	1	2	1	1	1	1
Depletion, depreciation, amortization and impairment	641	5,920	713	719	8	6	6	5	28	26	26	26
Exploration and evaluation expenses	39	308	43	57	—	—	—	—	—	—	—	—
Loss (gain) on sale of assets	(4)	(15)	—	2	—	—	—	—	—	—	—	—
Other – net	(17)	(33)	33	(17)	(3)	(4)	3	(1)	—	—	—	(11)
	1,247	6,758	1,387	1,351	288	228	321	350	285	229	379	297
Earnings from operating activities	(143)	(5,588)	56	(126)	13	45	(28)	85	79	(39)	39	50
Share of equity investment gain (loss)	(4)	(1)	—	—	—	—	—	—	—	—	—	—
Net foreign exchange gains (losses)	—	—	—	—	—	—	—	—	—	—	—	—
Finance income	—	1	1	1	—	—	—	—	—	—	—	—
Finance expenses	(36)	(35)	(35)	(36)	—	—	—	—	(1)	—	—	—
	(36)	(34)	(34)	(35)	—	—	—	—	(1)	—	—	—
Earnings (loss) before income taxes	(183)	(5,623)	22	(161)	13	45	(28)	85	78	(39)	39	50
Provisions for (recovery of) income taxes												
Current	111	27	(14)	(165)	(5)	5	40	182	7	(2)	(6)	(16)
Deferred	(160)	(1,547)	18	123	8	8	(47)	(160)	14	(8)	17	29
	(49)	(1,520)	4	(42)	3	13	(7)	22	21	(10)	11	13
Net earnings (loss)	(134)	(4,103)	18	(119)	10	32	(21)	63	57	(29)	28	37
Capital expenditures ⁽³⁾⁽⁴⁾	378	597	571	723	42	77	30	19	12	19	7	8
Total assets	21,103	21,296	26,550	26,488	1,699	1,814	1,857	1,830	1,141	1,098	1,107	1,209

⁽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.

⁽⁴⁾ 2015 Exploration and Production capital expenditures were revised during the fourth quarter of 2015 to exclude capital expenditures incurred by the Husky-CNOOC Madura Ltd joint venture, which are classified as contribution to joint venture investing activities on the Company's Consolidated Statements of Cash Flows.

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
699	839	747	601	1,692	1,973	1,955	1,725	(342)	(242)	(464)	(377)	3,913	4,263	4,570	4,017
—	—	—	—	—	—	—	—	—	—	—	—	(85)	(83)	(134)	(130)
—	—	—	—	—	—	—	—	—	—	—	—	(10)	23	(44)	69
699	839	747	601	1,692	1,973	1,955	1,725	(342)	(242)	(464)	(377)	3,818	4,203	4,392	3,956
544	655	599	483	1,583	1,784	1,549	1,539	(342)	(242)	(464)	(377)	2,273	2,584	2,313	2,227
55	57	63	63	120	119	107	128	—	—	—	—	755	742	742	755
8	7	6	10	2	3	2	3	32	(15)	16	20	102	49	86	105
26	26	26	25	76	74	114	69	22	22	20	20	801	6,074	905	864
—	—	—	—	—	—	—	—	—	—	—	—	39	308	43	57
(2)	(1)	(2)	—	—	—	—	—	—	—	—	—	(6)	(16)	(2)	2
—	—	—	1	(80)	(65)	(91)	—	1	(3)	—	—	(99)	(105)	(55)	(28)
631	744	692	582	1,701	1,915	1,681	1,739	(287)	(238)	(428)	(337)	3,865	9,636	4,032	3,982
68	95	55	19	(9)	58	274	(14)	(55)	(4)	(36)	(40)	(47)	(5,433)	360	(26)
—	—	—	—	—	—	—	—	—	—	—	—	(4)	(1)	—	—
—	—	—	—	—	—	—	—	(11)	(14)	6	62	(11)	(14)	6	62
—	—	—	—	—	—	—	—	27	3	1	1	27	4	2	2
(2)	(1)	(2)	(1)	(1)	—	(1)	(1)	(48)	(48)	(36)	(14)	(88)	(84)	(74)	(52)
(2)	(1)	(2)	(1)	(1)	—	(1)	(1)	(32)	(59)	(29)	49	(72)	(94)	(66)	12
66	94	53	18	(10)	58	273	(15)	(87)	(63)	(65)	9	(123)	(5,528)	294	(14)
(67)	32	24	17	(3)	(16)	24	10	40	28	27	26	83	74	95	54
84	(7)	(10)	(12)	(2)	38	77	(219)	(81)	6	24	(20)	(137)	(1,510)	79	(259)
17	25	14	5	(5)	22	101	(209)	(41)	34	51	6	(54)	(1,436)	174	(205)
49	69	39	13	(5)	36	172	194	(46)	(97)	(116)	3	(69)	(4,092)	120	191
14	6	5	5	182	100	95	48	13	18	19	17	641	817	727	820
1,448	1,568	1,634	1,622	6,784	6,776	6,316	6,226	881	993	1,018	968	33,056	33,545	38,482	38,343