MANAGEMENT'S DISCUSSION AND ANALYSIS

May 5, 2017

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1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Mar. 31**	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30
($ millions, except where indicated)	**2017**	2016	2016	2016	2016	2015	2015	2015
Production *(mboe/day)*	**334.0**	327.0	301.0	315.8	341.3	357.0	333.0	336.9
Gross revenues and marketing and other	**4,615**	3,865	3,520	3,261	2,578	3,903	4,286	4,526
Net earnings (loss)	**71**	186	1,390	(196)	(458)	(69)	(4,092)	120
Per share – Basic	**0.06**	0.19	1.37	(0.20)	(0.47)	(0.08)	(4.17)	0.11
Per share – Diluted	**0.06**	0.19	1.37	(0.20)	(0.47)	(0.09)	(4.19)	0.10
Adjusted net earnings (loss)(1)	**71**	(6)	(100)	(91)	(458)	(53)	(101)	124
Funds from operations(1)	**709**	670	484	488	434	640	674	1,177
Per share – Basic	**0.71**	0.67	0.48	0.49	0.43	0.65	0.68	1.20
Per share – Diluted	**0.71**	0.67	0.48	0.49	0.43	0.65	0.68	1.20

(1) *Adjusted net earnings (loss) and funds from operations are non-GAAP measures. Refer to Section 11 for a reconciliation to the GAAP measures.*

Performance

- Net earnings of $71 million in the first quarter of 2017 compared to a net loss of $458 million in the first quarter of 2016 with the increase primarily due to:
  - Higher Upstream North American commodity prices;
  - Increased production from the Company's thermal developments;
  - Increased natural gas and natural gas liquids ("NGLs") production from the Liwan Gas Project in Asia Pacific;
  - Higher realized refining margins; and
  - Increased throughput in U.S. Refining operations.

  Partially offset by:
  - Lower production from Western Canada mainly due to the disposition of select legacy assets in 2016.
- Funds from operations of $709 million in the first quarter of 2017 compared to $434 million in the first quarter of 2016 with the increase attributed to the same factors noted above for net earnings.
- Production decreased by 7.3 mboe/day or two percent to 334.0 mboe/day in the first quarter of 2017 compared to the first quarter of 2016 as a result of:
  - Decreased production from Western Canada mainly due to the disposition of select legacy assets in 2016.

  Partially offset by:
  - Increased production from thermal developments due to production ramp up at the Sunrise Energy Project, new production from Edam West, Vawn and Edam East thermal developments and strong production performance from the Tucker Thermal Project; and
  - Increased natural gas and NGLs production from the Liwan Gas Project in Asia Pacific.

Key Projects

- At the Tucker Thermal Project, first oil was achieved at a new eight-well pad. Production from the Tucker Thermal Project is anticipated to ramp up throughout 2017 and 2018 towards 30,000 bbls/day.
- Production from the Sunrise Energy Project continued to ramp up during the first quarter of 2017 with production averaging 35,800 bbls/day (17,900 bbls/day Husky working interest). Average annual production in 2017 is expected to be in the range of 40,000 to 44,000 bbls/day (20,000 to 22,000 bbls/day Husky working interest).
- At the liquids-rich BD Project offshore Indonesia, preparations are being finalized for first production, including plans to commission the floating production, storage and offloading (“FPSO“) vessel. The project is expected to ramp up to its full sales gas rate in the second half of 2017, with a production target of 100 mmcf/day of natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGLs (2,400 bbls/day Husky working interest).
- At the MDA-MBH fields, platform construction is more than 40 percent complete. A contract for the floating production unit is awaiting final government approval. First gas is expected in the 2018-2019 timeframe, with an additional shallow water field at MDK expected to be tied in during the same period.
- Total sales gas volumes from BD, MDA-MBH and MDK are expected to be approximately 250 mmcf/day of natural gas (100 mmcf/day Husky working interest) and 6,000 bbls/day (2,400 bbls/day Husky working interest) of associated NGLs once production is fully ramped up.
- On the Block 15/33 located offshore China, the Company expects to drill two exploration wells in the 2017-2018 timeframe.
- On April 10, 2017, the Company signed a new production sharing contract ("PSC") for a new exploration block offshore China, Block 16/25, with China National Offshore Oil Corporation ("CNOOC"). Block 16/25 is located in the Pearl River Mouth Basin, about 150 kilometres southeast of the Hong Kong Special Administrative Region. The Company expects to drill two exploration wells on the shallow water block during the 2018 timeframe, which are planned to be drilled in conjunction with the two planned exploration wells at the nearby exploration Block 15/33. The Company is the operator of both blocks during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, CNOOC may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases.
- In Atlantic, first oil was achieved from a North Amethyst infill well in February 2017 with peak production of approximately 8,600 bbls/day Husky working interest.
- The Company and its partner continued to assess the commercial potential of the discoveries at Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen.
- Progress continues to be made on the implementation of the single expanded truck transport network with Imperial Oil; the consolidation of the two networks is expected in the second half of 2017.
- The Company continued work on the crude oil flexibility project at the Lima Refinery. The project is designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada. The project will provide 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 feedstock. The full scope of the project is expected to be completed around the end of 2018.
- The Company continued front-end engineering and design (“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 crude oil and bitumen production.

Divestitures

- During the first quarter of 2017, the Company signed purchase and sale agreements with third parties for the sale of select legacy assets in Western Canada representing approximately 2,200 boe/day for gross proceeds of approximately $73 million. As at March 31, 2017, the assets and related liabilities have been classified as held for sale.
- In April 2017, the Company also signed purchase and sale agreement with a third party for the sale of select legacy assets in Western Canada representing approximately 1,100 boe/day for gross proceeds of approximately $15 million, which are expected to close in the second quarter of 2017.

Financial

- During the first quarter of 2017, the Company issued $750 million in notes maturing March 10, 2027, with a coupon of 3.60 percent.
- Dividends on preferred shares of $17 million were paid in the first quarter of 2017, of which $9 million were declared in 2017 and $8 million were declared in the fourth quarter of 2016.
- On March 30, 2017, the Company filed a universal short form base shelf prospectus (the "2017 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including April 30, 2019.

2. Business Environment

Average Benchmarks

Average Benchmarks Summary		Three months ended Mar. 31, 2017	Dec. 31, 2016	Sept. 30, 2016	Jun. 30, 2016	Mar. 31, 2016
West Texas Intermediate ("WTI") crude oil[(1)]	*(U.S. $/bbl)*	**51.91**	49.29	44.94	45.59	33.45
Brent crude oil[(2)]	*(U.S. $/bbl)*	**53.78**	49.47	45.85	45.57	33.89
Light sweet at Edmonton	*($/bbl)*	**63.97**	61.60	54.80	54.78	40.81
Daqing[(3)]	*(U.S. $/bbl)*	**51.71**	47.90	42.19	43.18	30.15
Western Canadian Select at Hardisty[(4)]	*(U.S. $/bbl)*	**37.34**	34.97	31.44	32.29	19.21
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**41.62**	40.05	36.10	35.81	18.49
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**14.32**	14.19	13.42	13.17	14.04
Condensate at Edmonton	*(U.S. $/bbl)*	**52.27**	48.33	43.07	44.07	34.40
NYMEX natural gas[(5)]	*(U.S. $/mmbtu)*	**3.32**	2.98	2.81	1.95	2.09
NOVA Inventory Transfer ("NIT") natural gas	*($/GJ)*	**2.79**	2.67	2.09	1.18	2.00
Chicago Regular Unleaded Gasoline	*(U.S. $/bbl)*	**62.53**	59.07	58.90	63.80	41.88
Chicago Ultra-low Sulphur Diesel	*(U.S. $/bbl)*	**63.96**	61.49	59.88	59.34	44.81
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**11.22**	10.59	14.29	16.67	9.23
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.756**	0.750	0.766	0.776	0.728
Canadian $ Equivalents[(6)]						
WTI crude oil	*($/bbl)*	**68.66**	65.72	58.67	58.75	45.95
Brent crude oil	*($/bbl)*	**71.14**	65.96	59.86	58.72	46.55
Daqing	*($/bbl)*	**68.40**	63.87	55.08	55.64	41.41
Western Canadian Select at Hardisty	*($/bbl)*	**49.39**	46.63	41.04	41.61	26.39
WTI/Lloyd crude blend differential	*($/bbl)*	**18.94**	18.92	17.52	16.97	19.29
NYMEX natural gas	*($/mmbtu)*	**4.39**	3.97	3.67	2.51	2.87

(1) *Calendar Month Average of settled prices for WTI 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, 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. benchmark commodity prices and monthly average U.S./Canadian dollar exchange rates.*

Crude Oil Benchmarks

Global crude oil benchmarks continued to show signs of recovery during the first quarter of 2017 as members of the Organization of Petroleum Exporting Countries ("OPEC") and non-members voluntarily reduced oil supply late in 2016. WTI averaged U.S. $51.91/bbl during the first quarter of 2017, compared to U.S. $33.45/bbl during the first quarter of 2016. Brent averaged U.S. $53.78/bbl during the first quarter of 2017 compared to U.S. $33.89/bbl during the first quarter of 2016.

The price received by the Company for crude oil production from Western Canada is primarily driven by the price of WTI, adjusted to Western Canada. The price received by the Company for crude oil production from Atlantic is primarily driven by the price of Brent, and the price received by the Company for crude oil and NGLs production from Asia Pacific 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 the first quarter of 2017, 69 percent of the Company's crude oil and NGLs production was heavy crude oil and bitumen compared to 60 percent in the first quarter of 2016.

The Company's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate. The price of condensate at Edmonton increased in the first quarter of 2017 compared to the first quarter of 2016 primarily due to the increase in crude oil benchmark pricing.

Natural Gas Benchmarks

North American natural gas benchmarks increased compared to the first quarter of 2016 due to higher levels of U.S. exports and lower natural gas production, which was partially offset by unseasonably mild weather conditions resulting in lower demand.

The price received by the Company for natural gas production from Western Canada is primarily driven by the NIT near-month contract price of natural gas, while the price received by the Company for production from Asia Pacific is determined 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

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

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

The majority of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities and refined products whose prices are determined by reference to U.S. benchmark prices. The majority of the Company's non-hydrocarbon related expenditures are denominated in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. In addition, changes in foreign exchange rates impact the translation of U.S. Downstream and Asia Pacific operations and U.S. dollar denominated debt. In the first quarter of 2017, the Canadian dollar averaged U.S. $0.756 compared to U.S. $0.728 in the first quarter of 2016.

The Company’s fixed long-term sales contracts in Asia Pacific are priced in Chinese Yuan (“RMB”). 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 5.20 in the first quarter of 2017 compared to RMB 4.76 in the first quarter of 2016.

Sensitivity Analysis

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

Sensitivity Analysis	2017 First Quarter Average	Increase	Effect on Earnings before Income Taxes[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	51.91	*U.S. $1.00/bbl*	105	0.10	76	0.08
NYMEX benchmark natural gas price[5]	3.32	*U.S. $0.20/mmbtu*	10	0.01	7	0.01
WTI/Lloyd crude blend differential[6]	14.32	*U.S. $1.00/bbl*	(48)	(0.05)	(36)	(0.04)
Canadian light oil margins	0.048	*Cdn $0.005/litre*	12	0.01	8	0.01
Asphalt margins	21.50	*Cdn $1.00/bbl*	8	0.01	5	0.01
Chicago 3:2:1 crack spread	11.22	*U.S. $1.00/bbl*	84	0.08	53	0.05
Exchange rate (U.S. $ per Cdn $)[3][7]	0.756	*U.S. $0.01*	(60)	(0.06)	(44)	(0.04)

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.5 million common shares outstanding as at March 31, 2017.*
(3) *Does not include gains or losses on inventory.*
(4) *Includes impacts related to Brent and Daqing 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.*

3. Strategic Plan

The Company's strategy is to continue lowering its cost structure and drive free cash flow growth.

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

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

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 are grouped together as the Downstream business segment due to the similar nature of their products and services.

4. Key Growth Highlights

The 2017 capital program is designed to enable the Company to advance its near-term profitable growth projects while maintaining prudent capital management.

4.1 Upstream

Thermal Developments

The Company continued to advance its inventory of thermal developments in the first quarter of 2017. These long-life developments are being built with modular, repeatable designs and will require low sustaining capital once brought online. Total bitumen production, including the Tucker Thermal Project and Sunrise Energy Project, averaged 120,600 bbls/day in the first quarter of 2017 and is expected to average approximately 130,000 bbls/day by the fourth quarter of 2017.

Lloydminster Thermal Projects

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

In late 2016, the Company sanctioned three new Lloyd thermal projects with total design capacity of 30,000 bbls/day at Dee Valley, Spruce Lake North and Spruce Lake Central. Progress is being made towards regulatory approval, and first production for all three is expected in 2020.

Tucker Thermal

At the Tucker Thermal Project, first oil was achieved at a new eight-well pad in the first quarter of 2017. Drilling has also commenced at a 15-well pad, with first oil planned in the first half of 2018. Production from the Tucker Thermal Project is anticipated to ramp up in 2017 and 2018 towards 30,000 bbls/day.

Sunrise Energy Project

In the first quarter of 2017, average well rates continued to increase at the Sunrise Energy Project with total production averaging 35,800 bbls/day (17,900 bbls/day Husky working interest). The Company has introduced higher operating pressures, as approved by the Alberta Energy Regulator ("AER"), contributing to a 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. Work is progressing to tie in 14 new well pairs, and steaming is expected to commence later this year.

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

Asia Pacific

China

Block 29/26

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

Block 15/33

On the Block 15/33 located offshore China, the Company expects to drill two exploration wells in the 2017-2018 timeframe.

Block 16/25

On April 10, 2017, the Company signed a PSC for a new exploration block offshore China, Block 16/25, with CNOOC. Block 16/25 is located in the Pearl River Mouth Basin, about 150 kilometres southeast of the Hong Kong Special Administrative Region. The Company expects to drill two exploration wells on the shallow water block during the 2018 timeframe, which are planned to be drilled in conjunction with the two planned exploration wells at the nearby exploration Block 15/33. The Company is the operator of both blocks during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, CNOOC may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases.

Offshore Taiwan

The Company has contracted to acquire a three-dimensional seismic survey on the most attractive identified structures on the block. Data acquisition is planned to commence in the second quarter of 2017.

Indonesia

Madura Strait

Progress continued on the natural gas developments in the Madura Strait Block in the first quarter of 2017.

At the liquids-rich BD Project offshore Indonesia, preparations are being finalized for first production, including plans to commission the FPSO vessel. The project is expected to ramp up to its full sales gas rate in the second half of 2017, with a production target of 100 mmcf/day of natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGLs (2,400 bbls/day Husky working interest).

At the MDA-MBH fields, platform construction is more than 40 percent complete. A contract for the floating production unit is awaiting final government approval. First gas is expected in the 2018-2019 timeframe, with an additional shallow water field at MDK expected to be tied in during the same period.

Total sales gas volumes from BD, MDA-MBH and MDK are expected to be approximately 250 mmcf/day of natural gas (100 mmcf/day Husky working interest) and 6,000 bbls/day (2,400 bbls/day Husky working interest) of associated 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 this and other data are being evaluated to determine the potential for future drilling opportunities.

Atlantic

White Rose Field and Satellite Extensions

The Company continues to offset natural reservoir declines through infill and development well drilling at the White Rose field and satellite extensions. An infill well was brought into production at North Amethyst in February 2017 with peak production of approximately 8,600 bbls/day Husky working interest. An additional infill well is planned at White Rose later this year. All wells are tied back to the SeaRose FPSO, providing for improved capital efficiencies.

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

Atlantic Exploration

A near-field delineation well was spud in February and completed in April on an existing significant discovery licence northwest of the main White Rose field. Evaluation of results is ongoing. Husky has a 93.23% working interest in the well.

The Company and its partner plan to drill two additional exploration wells in the Flemish Pass beginning in mid-2017. The wells are near-field prospects to the Bay du Nord discovery. The Company holds a 35 percent non-working interest in existing discoveries at Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen. The Company and its partner continue to assess the commercial potential of these discoveries.

Western Canada Resource Play Development

Natural Gas Resource Plays

The Company is primarily pursuing a 16-well development drilling program in the Spirit River formation in the Ansell and Kakwa areas.

4.2 Downstream

Canadian Refined Products

In 2016, the Company and Imperial Oil received regulatory approval from the Canadian Competition Bureau to create a single expanded truck transport network of approximately 160 sites. Contract closing conditions were met late in the fourth quarter of 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 the first quarter of 2017. 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 with the Refinery currently able to process up to 10,000 bbls/day of heavy crude oil feedstock. The full scope of the project is expected to be completed around the end of 2018.

Lloydminster Asphalt Expansion

FEED work continued on a potential 30,000 bbls/day expansion of the Company's asphalt processing capacity in Lloydminster with a sanction decision expected around the end of 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 crude oil and bitumen production.

5. Results of Operations

5.1 Upstream

Exploration and Production

Exploration and Production Earnings (Loss) Summary	Three months ended March 31,	
($ millions)	**2017**	2016
Gross revenues	**1,251**	836
Royalties	**(104)**	(54)
Net revenues	**1,147**	782
Purchases of crude oil and products	**—**	12
Production, operating and transportation expenses	**417**	451
Selling, general and administrative expenses	**57**	42
Depletion, depreciation and amortization ("DD&A")	**547**	562
Exploration and evaluation expenses	**21**	17
Other – net	**16**	—
Share of equity investment loss (gain)	**(1)**	1
Financial items	**31**	40
Provisions for (recovery of) income taxes	**16**	(93)
Net earnings (loss)	**43**	(250)

Exploration and Production net revenues increased by $365 million in the first quarter of 2017 compared to the first quarter of 2016, primarily due to higher realized North American commodity prices combined with increased production from the Company's thermal developments, and increased natural gas and NGLs production in Asia Pacific. This was partially offset by lower oil and natural gas production in Western Canada due to the disposition of select legacy assets in Western Canada in 2016.

Production, operating and transportation expenses decreased by $34 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to cost savings initiatives and lower production from Western Canada. This was partially offset by higher energy costs from thermal developments.

Average Sales Prices Realized

	Three months ended March 31,	
Average Sales Prices Realized	**2017**	2016
Crude oil and NGLs *($/bbl)*		
Light and Medium crude oil	**66.70**	39.65
NGLs	**49.64**	31.89
Heavy crude oil	**41.28**	18.12
Bitumen	**35.20**	12.83
Total crude oil and NGLs average	**45.10**	24.41
Natural gas average *($/mcf)*	**5.35**	4.41
Total average *($/boe)*	**41.58**	25.02

The average sales prices realized by the Company for crude oil and NGLs production increased by 85 percent in the first quarter of 2017 compared to the same period in 2016, reflecting a recovery in commodity benchmark prices.

The average sales prices realized by the Company for natural gas production increased by 21 percent in the first quarter of 2017 compared to the same period in 2016. The increase in realized natural gas pricing was primarily due to a higher percentage of fixed priced natural gas production from the Liwan Gas Project relative to total natural gas production and higher North American benchmark pricing.

Daily Gross Production

Daily Gross Production	Three months ended March 31, 2017	2016
Crude Oil and NGLs *(mbbls/day)*		
Western Canada		
Light and Medium crude oil	**14.5**	33.0
NGLs	**8.0**	8.8
Heavy crude oil	**48.0**	61.5
Bitumen[(1)]	**120.6**	81.8
	191.1	185.1
Atlantic		
White Rose and Satellite Fields – light crude oil	**34.5**	36.1
Terra Nova – light crude oil	**5.1**	4.4
	39.6	40.5
Asia Pacific		
Wenchang – light crude oil	**6.6**	7.4
Liwan and Wenchang – NGLs[(2)]	**6.2**	5.2
	12.8	12.6
	243.5	238.2
Natural gas *(mmcf/day)*		
Western Canada	**409.8**	508.7
Asia Pacific[(2)]	**133.3**	109.9
	543.1	618.6
Total *(mboe/day)*	**334.0**	341.3

(1) *Bitumen consists of production from thermal developments in Lloydminster, the Tucker Thermal Project located near Cold Lake, Alberta and the Sunrise Energy Project.*
(2) *Reported production volumes include Husky's net working interest production from the Liwan Gas Project (49 percent).*

Crude Oil and NGLs Production

Crude oil and NGLs production increased by 5.3 mbbls/day in the first quarter of 2017 compared to the first quarter of 2016 primarily due to the continued production ramp-up at the Sunrise Energy Project, new production from the Edam West, Vawn and Edam East thermal developments and strong performance from the Tucker Thermal Project. This was partially offset by lower production from Western Canada due to the disposition of select legacy assets in Western Canada in 2016.

Natural Gas Production

Natural gas production decreased in the first quarter of 2017 compared to the first quarter of 2016. In Western Canada, natural gas production decreased by 98.9 mmcf/day primarily due to divestitures of select legacy assets during 2016, natural reservoir declines from mature properties and strategic shut-ins due to unfavourable economics. In Asia Pacific, natural gas production increased by 23.4 mmcf/day due to the resolution of issues with the gas buyer's onshore gas pipeline infrastructure that hindered production in the first quarter of 2016.

2017 Production Guidance

The following table shows actual daily production for the three months ended March 31, 2017, and the year ended December 31, 2016, as well as the previously issued production guidance for 2017.

	Guidance 2017	Actual Production: Three months ended March 31, 2017	Actual Production: Year ended December 31, 2016
Canada			
Light & medium crude oil *(mbbls/day)*	46 - 48	54	56
NGLs *(mbbls/day)*	8 - 9	8	8
Heavy crude oil & bitumen *(mbbls/day)*	167 - 173	169	151
Natural gas *(mmcf/day)*	345 - 353	410	442
Canada total *(mboe/day)*	278 - 288	299	289
Asia Pacific			
Light crude oil *(mbbls/day)*	5 - 6	7	7
NGLs *(mbbls/day)*	8 - 10	6	6
Natural gas *(mmcf/day)*	171 - 182	133	114
Asia Pacific total *(mboe/day)*	42 - 46	35	32
Total *(mboe/day)*	320 - 335	334	321

Royalties

Royalty rates as a percentage of gross revenues averaged eight percent in the first quarter of 2017 compared to seven percent in the same period in 2016. Royalty rates in Western Canada averaged eight percent in the first quarter of 2017 compared to six percent in the same period in 2016 due to higher prices. Royalty rates for Atlantic averaged 14 percent in the first quarter of 2017 compared to 11 percent in the same period in 2016 primarily due to higher revenue. Royalty rates in Asia Pacific averaged six percent in the first quarter of 2017 compared to five percent in the same period in 2016.

Operating Costs

($ millions)	Three months ended March 31, 2017	2016
Western Canada	340	366
Atlantic	52	52
Asia Pacific	19	24
Total	411	442
Per unit operating costs ($/boe)	13.75	13.31

Total Exploration and Production operating costs were $411 million in the first quarter of 2017 compared to $442 million in the same period in 2016. Total unit operating costs averaged $13.75/boe in the first quarter of 2017 compared to $13.31/boe in the same period in 2016 with the increase primarily due to higher unit operating costs in Western Canada.

Per unit operating costs in Western Canada averaged $14.64/boe in the first quarter of 2017 compared to $13.74/boe in the same period in 2016. The increase in unit operating costs per boe was primarily due to higher energy costs from thermal developments, which was partially offset by cost savings initiatives realized in the first quarter of 2017.

Per unit operating costs in Atlantic averaged $14.64/bbl in the first quarter of 2017 compared to $14.20/bbl in the same period in 2016. The increase in unit operating costs per boe was primarily due to lower production.

Unit operating costs in Asia Pacific averaged $5.96/boe in the first quarter of 2017 compared to $8.38/boe in the same period in 2016. The decrease in unit operating costs per boe was primarily due to higher production at the Liwan Gas Project and cost saving initiatives.

Exploration and Evaluation Expenses

($ millions)	Three months ended March 31, 2017	2016
Seismic, geological and geophysical	19	16
Expensed land	2	1
Total	21	17

Exploration and evaluation expenses in the first quarter of 2017 were $21 million compared to $17 million in the first quarter of 2016. The increase is primarily due to increased seismic activity in Western Canada related to thermal developments.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were higher in the first quarter of 2017 compared to the first quarter of 2016 reflecting increased investment in Western Canada Resource Plays, Thermal Developments and Atlantic drilling. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[1]

($ millions)	Three months ended March 31, 2017	2016
Exploration		
Western Canada	9	2
Thermal Developments	—	3
Atlantic	62	11
Asia Pacific[2]	2	—
	73	16
Development		
Western Canada	30	45
Thermal Developments	118	86
Non-Thermal Developments	11	—
Atlantic	43	17
Asia Pacific[2]	4	11
	206	159
Acquisitions		
Western Canada	10	—
	289	175

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

Western Canada

During the first three months of 2017, $49 million (17 percent) was invested in Western Canada, compared to $47 million (27 percent) in the same period in 2016. Capital expenditures in 2017 relate primarily to sustainment activities and resource play development drilling in the Spirit River formation in the Ansell and Kakwa areas compared to 2016 where capital expenditures related primarily to the development of the Rainbow Lake NGL project.

Thermal Developments

During the first three months of 2017, $118 million (41 percent) was invested in Thermal Developments, compared to $89 million (51 percent) in the same period in 2016. Capital expenditures in 2017 relate primarily to the development of the Rush Lake 2 thermal development,a new pad at the Tucker Thermal Project and continued investment in the Sunrise Energy Project.

Non-Thermal Developments

During the first three months of 2017, $11 million (4 percent) was invested in Non-Thermal Developments, compared to nil in the same period in 2016. Capital expenditures in 2017 relate primarily to sustainment activities.

Atlantic

During the first three months of 2017, $105 million (36 percent) was invested in Atlantic, compared to $28 million (16 percent) in the same period in 2016. Capital expenditures in 2017 relate primarily to satellite field developments at North Amethyst, the South White Rose Extension and the White Rose Extension Project as well as delineation drilling northwest of the main White Rose field and further exploration and appraisal drilling in the Flemish Pass Basin. The increase in capital expenditures in the first three months of 2017 compared to the same period in 2016 reflects the arrival of the Henry Goodrich rig in mid-2016 and the rig being fully operational for the first quarter of 2017.

Asia Pacific

During the first three months of 2017, $6 million (two percent) was invested in Asia Pacific, compared to $11 million (six percent) in the same period in 2016.

Exploration and Production Wells Drilled

Onshore drilling activity

The following table discloses the number of wells drilled in Thermal and Western Canada Resource Play Developments during the three months ended March 31, 2017 and 2016:

	Three months ended March 31,			
	2017		2016	
Wells Drilled [(1)]	**Gross**	**Net**	Gross	Net
Thermal Developments	**9**	**9**	36	36
Western Canada Resource Play Development	**10**	**9**	2	1
	19	**18**	38	37

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

During the first quarter of 2017, the Company's onshore drilling was focused primarily on Thermal Developments and Western Canada Resource Play Development.

Offshore drilling activity

The following table discloses the Company's offshore Atlantic drilling activity during the three months ended March 31, 2017:

Region	***Well***	***Working Interest***	***Well Type***
Atlantic	North Amethyst G-25 10	WI 68.875 percent	Development

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 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.

Infrastructure and Marketing Earnings Summary	Three months ended March 31,	
($ millions)	**2017**	2016
Gross revenues	**333**	215
Purchases of crude oil and products	**295**	171
Infrastructure gross margin	**38**	44
Marketing and other	**36**	(102)
Total Infrastructure and Marketing gross margin	**74**	(58)
Production, operating and transportation expenses	**3**	8
Selling, general and administrative expenses	**1**	1
Depletion, depreciation and amortization	**—**	6
Other – net	**(2)**	(3)
Share of equity investment gain	**(24)**	—
Provisions for (recovery of) income taxes	**26**	(19)
Net earnings (loss)	**70**	(51)

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $118 million and $124 million, respectively, in the first quarter of 2017 compared to the first quarter of 2016 primarily due to higher commodity prices and increased volumes.

Marketing and other increased by $138 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to crude oil marketing gains from widening price differentials between Canada and the U.S. in the first quarter of 2017.

Share of equity investment increased by $24 million in the first quarter of 2017 compared to the first quarter of 2016 due to the formation of HMLP in mid-2016.

5.2 Downstream

Upgrader

Upgrader Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2017**	2016
Gross revenues	**384**	281
Purchases of crude oil and products	**248**	137
Gross margin	**136**	144
Production, operating and transportation expenses	**49**	36
Selling, general and administrative expenses	**2**	1
Depletion, depreciation and amortization	**19**	28
Provisions for income taxes	**18**	21
Net earnings	**48**	58
Upgrader throughput *(mbbls/day)*[(1)]	**77.9**	77.6
Total sales *(mbbls/day)*	**76.2**	78.3
Synthetic crude oil sales *(mbbls/day)*	**54.1**	57.7
Upgrading differential *($/bbl)*	**20.88**	22.23
Unit margin *($/bbl)*	**19.83**	20.21
Unit operating cost *($/bbl)*[(2)]	**6.99**	5.10

(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 $103 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to higher realized prices for synthetic crude oil and ultra low sulphur distillates, partially offset by lower sales volume which decreased by 2.1 mbbls/day, or three percent, compared to the first quarter of 2016.

Upgrader gross margin decreased by $8 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to lower average upgrading differentials and lower sales volumes. During the first quarter of 2017, the upgrading differential averaged $20.88/bbl, a decrease of $1.35/bbl, or six percent compared to the first quarter of 2016. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The decrease in the upgrading differential was due to higher heavy crude oil feedstock costs partially offset by higher realized prices for Husky Synthetic Blend. During the first quarter of 2017, the price of Husky Synthetic Blend averaged $67.53/bbl compared to $45.99/bbl in the first quarter of 2016.

Production, operating and transportation expenses increased by $13 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to higher maintenance and energy costs.

DD&A expense decreased by $9 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to fully depreciating a capitalized turnaround asset in late 2016.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2017**	2016
Gross revenues	**568**	435
Purchases of crude oil and products	**445**	339
Gross margin		
Fuel	**28**	26
Refining	**42**	17
Asphalt	**40**	39
Ancillary	**13**	14
	123	96
Production, operating and transportation expenses	**60**	49
Selling, general and administrative expenses	**11**	7
Depletion, depreciation and amortization	**29**	24
Other – net	**—**	(1)
Financial items	**3**	2
Provisions for income taxes	**5**	4
Net earnings	**15**	11
Number of fuel outlets[(1)]	**480**	481
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**6.4**	6.2
Fuel sales per retail outlet *(thousands of litres/day)*	**11.5**	11.1
Refinery throughput		
Prince George Refinery *(mbbls/day)*	**11.8**	11.0
Lloydminster Refinery *(mbbls/day)*	**28.0**	28.0
Ethanol production *(thousands of litres/day)*	**839.6**	810.7

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

Canadian Refined Products gross revenues increased by $133 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to higher refined product prices and higher sales volume.

Canadian Refined Products purchases of crude oil and products increased by $106 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to higher commodity pricing and higher sales volume.

Throughput at the Prince George Refinery increased by 0.8 mbbls/day, or seven percent, and fuel sales per retail outlet increased by 0.4 mbbls/day, or four percent, compared to the first quarter of 2016. Ethanol production increased by 28.9 thousands of litres/day, or four percent, compared to the first quarter of 2016.

Refining gross margins increased by $25 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to higher sales volume combined with higher ethanol pricing and refining margins.

Production, operating and transportation expenses increased by $11 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to higher energy costs.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended March 31,	
($ millions, except where indicated)	**2017**	2016
Gross revenues	**2,440**	1,126
Purchases of crude oil and products	**2,240**	1,040
Gross margin	**200**	86
Production, operating and transportation expenses	**140**	137
Selling, general and administrative expenses	**4**	3
Depletion, depreciation and amortization	**89**	81
Other – net	**(3)**	(125)
Financial items	**3**	1
Recovery of income taxes	**(12)**	(4)
Net loss	**(21)**	(7)
Select operating data:		
Lima Refinery throughput *(mbbls/day)*	**172.0**	127.5
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**77.0**	69.4
Refining margin *(U.S. $/bbl crude throughput)*	**8.33**	3.76
Refinery inventory *(mmbbls)* [1]	**8.6**	10.1

[1] *Feedstock and refined products are included in refinery inventory.*

U.S. Refining and Marketing gross revenues increased by $1,314 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to higher refined product prices and higher sales volume.

U.S. Refining and Marketing purchases of crude oil and products increased by $1,200 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to higher crude oil feedstock costs, and increased throughput at both the Lima and BP-Husky Toledo Refineries. Throughput at the Lima Refinery increased by 44.5 mbbls/day when compared to the first quarter of 2016 primarily due to the isocracker being fully in service in the first quarter of 2017 and lower throughput in the first quarter of 2016 as the Lima Refinery was preparing for the turnaround in 2016. Throughput at the BP-Husky Toledo Refinery increased by 7.6 mbbls/day compared to the first quarter of 2016 primarily due to the increased utilization of the assets.

U.S. Refining and Marketing gross margin increased by $114 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to higher benchmark refining margins and higher throughputs.

Other – net income decreased by $122 million in the first quarter of 2017 compared to the first quarter of 2016 primarily due to the insurance recoveries in 2016 related to the isocracker unit fire.

The Chicago 3:2:1 crack spread is based on LIFO accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while crude oil feedstock costs included in realized margins are based on FIFO accounting, which reflects purchases made in previous months. The estimated FIFO impact was a reduction in net earnings of approximately $9 million in the first quarter of 2017 compared to a reduction in net earnings of $21 million in the first quarter of 2016.

Downstream Capital Expenditures

In the first three months of 2017, Downstream capital expenditures totalled $83 million compared to $196 million in the same period in 2016. In Canada, capital expenditures of $32 million were primarily related to preparation work for the scheduled turnaround at the Lloydminster Refinery in the second quarter of 2017 and various projects at the Prince George Refinery and ethanol plants. At the Lima Refinery, capital expenditures of $23 million were primarily related to various reliability and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures of $28 million (Husky's 50 percent share) were primarily related to environmental protection initiatives. The decrease in downstream capital expenditures was primarily due to the completion of turnarounds and the feedstock optimization project in U.S. Refining and Marketing in 2016.

5.3 Corporate

Corporate Summary	Three months ended March 31,	
($ millions) income (expense)	**2017**	2016
Selling, general and administrative expenses	**(59)**	(63)
Depletion, depreciation and amortization	**(16)**	(21)
Other – net	**—**	(66)
Net foreign exchange gain (loss)	**(2)**	13
Finance income	**5**	5
Finance expense	**(55)**	(64)
Recovery of (provisions for) income taxes	**43**	(23)
Net loss	**(84)**	(219)

The Corporate segment reported a net loss of $84 million in the first quarter of 2017 compared to a net loss of $219 million in the first quarter of 2016. Other – net expense of $66 million in the first quarter of 2016 related to unrealized losses on the Company's short-term hedging program, which concluded in June 2016. The net foreign exchange loss was $2 million in the first quarter of 2017 compared to a gain of $13 million in the first quarter of 2016.

Foreign Exchange Summary	Three months ended March 31,	
($ millions, except where indicated)	**2017**	2016
Loss on non-cash working capital	**(19)**	(13)
Other foreign exchange gain	**17**	26
Net foreign exchange gain (loss)	**(2)**	13
U.S./Canadian dollar exchange rates:		
At beginning of period	**U.S. $0.745**	U.S. $0.723
At end of period	**U.S. $0.751**	U.S. $0.771

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 condensed interim consolidated financial statements.

Consolidated Income Taxes

	Three months ended March 31,	
($ millions)	**2017**	2016
Provision for (recovery of) income taxes	**10**	(68)
Cash income taxes paid (recovered)	**21**	(35)

Consolidated income taxes were a provision of $10 million in the first quarter of 2017 compared to a recovery of $68 million in the first quarter of 2016. The increase in consolidated income tax provision was primarily due to the increase in earnings before tax in the first quarter of 2017.

6. Risk Management and Financial Risks

6.1 Risk Management

The Company is exposed to market risks and various operational risks. For a detailed discussion of these risks, see the Company's Annual Information Form dated February 24, 2017. The Company has processes in place designed to identify the principal risks of the business and put in place appropriate mitigation to manage such risks where possible. The Company's exposure to operational, political, environmental, financial, liquidity and contract and credit risk has not materially changed since December 31, 2016, which was discussed in the Company's MD&A for the year ended December 31, 2016.

6.2 Financial Risks

The following provides an update on the Company's commodity price, interest rate and foreign currency risk management.

Commodity Price Risk Management

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

At March 31, 2017, the Company was party to crude oil purchase and sale derivative contracts to mitigate its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. The Company was also party to third party physical natural gas purchase and sale derivative contracts in order to mitigate commodity price fluctuations. Refer to Note 14 of the condensed interim consolidated financial statements.

Interest Rate Risk Management

Interest rate risk is the impact of fluctuating interest rates on earnings, cash flows and valuations. 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. At March 31, 2017, the balance in long-term debt related to deferred gains resulting from unwound interest rate swaps that were previously designated as a fair value hedge was $2 million (December 31, 2016 – $2 million). The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of less than $1 million for the three months ended March 31, 2017 (three months ended March 31, 2016 – less than $1 million).

During 2014, the Company discontinued its cash flow hedge with respect to forward starting interest rate swaps. These forward starting interest rate swaps were settled and derecognized. Accordingly, the accrued gain in other reserves is being amortized into net earnings over the remaining life of the underlying long-term debt to which the hedging relationship was originally designated. The amortization period is 10 years. At March 31, 2017, the balance in other reserves related to the accrued gain was $17 million (December 31, 2016 – $18 million), net of tax of $6 million (December 31, 2016 – net of tax of $6 million). The amortization of the accrued gain resulted in an offset to finance expenses of less than $1 million for the three months ended March 31, 2017. Refer to the Interest Rate Risk Management disclosure within Note 14 of the condensed interim consolidated financial statements.

Foreign Currency Risk Management

At March 31, 2017, 68 percent or CDN $4.0 billion of the Company's outstanding long-term debt was denominated in U.S. dollars. No long-term debt, including amounts due within one year, is exposed to changes in the Canadian/U.S. exchange rate, as all U.S. denominated debt has been designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.

At March 31, 2017, the Company had designated all of its U.S. $3.0 billion denominated debt as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency. For the three months ended March 31, 2017, the Company incurred an unrealized gain of $27 million, arising from the translation of the debt, net of tax of $4 million, which was recorded in hedge of net investment within other comprehensive income ("OCI").

The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery, and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a U.S. dollar functional currency foreign operation. At March 31, 2017, the Company's share of this obligation was U.S. $93 million including accrued interest. At March 31, 2017, the cost of a Canadian dollar in U.S. currency was $0.751.

7. Liquidity and Capital Resources

7.1 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 March 31, 2017, the Company had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities [1]	**750**	**339**
Syndicated credit facilities [2]	**4,000**	**3,800**
	4,750	**4,139**

[1] *Consists of demand credit facilities.*
[2] *Commercial paper outstanding is supported by the Company's syndicated credit facilities.*

At March 31, 2017, the Company had $4,139 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $339 million are short-term uncommitted credit facilities. A total of $411 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 March 31, 2017, the Company had no direct borrowing against committed credit facilities. The Company's ability to renew existing bank credit facilities and raise new debt is dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. Credit ratings may be affected by the Company's level of debt, from time to time.

Working capital is the amount by which current assets exceed current liabilities. At March 31, 2017, working capital was $2,113 million compared to $1,125 million at December 31, 2016.

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 March 31, 2017.

On February 23, 2015, the Company filed a universal short form base shelf prospectus (the "2015 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enabled 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.

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 December, 31, 2016 to, but excluding, March 31, 2017, is equal to the sum of the Government of Canada 90-day treasury bill rate on December 1, 2016 plus 1.73 percent, being 2.239 percent. The floating rate quarterly dividend applicable to the Series 2 Preferred Shares will be reset every quarter. The dividend rate applicable to the Series 1 Preferred Shares for the five-year period commencing March 31, 2016, to, but excluding, March 31, 2021 is equal to the sum of the Government of Canada five-year bond yield on March 1, 2016 plus 1.73 percent, being 2.404 percent. Both rates were calculated in accordance with the articles of amendment of the Company creating the Series 1 Preferred Shares and Series 2 Preferred Shares dated March 11, 2011.

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

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

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

As at March 31, 2017, the Company has $3.0 billion in unused capacity under the 2017 Canadian Shelf Prospectus and U.S. $3.0 billion in unused capacity under the U.S. Shelf Prospectus and related U.S. registration statement. 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.

7.2 Capital Structure

Capital Structure		March 31, 2017
($ millions)	Outstanding	Available [1]
Total debt [2]	6,053	4,139
Common shares, preferred shares, retained earnings and accumulated OCI	17,634	

[1] *Total debt available includes committed and uncommitted credit facilities.*
[2] *Total debt is defined as long-term debt including long-term debt due within one year and short-term debt.*

The Company considers its capital structure to include shareholders' equity (excluding non-controlling interest) and debt which totalled $23.7 billion as at March 31, 2017 (December 31, 2016 – $23.0 billion). To maintain or adjust the capital structure, the Company may, from time to time, sell assets, 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). 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 March 31, 2017, debt to capital employed was 25.5 percent (December 31, 2016 – 23.2 percent) and debt to funds from operations was 2.6 times (December 31, 2016 – 2.6 times).

The increase in the Company's debt to capital employed as at March 31, 2017 is due to the issuance of $750 million in notes during the quarter. The debt to funds from operations ratio remains unchanged as at March 31, 2017, reflecting the issuance of those notes above and is partially offset by the recovery of global commodity prices. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company has taken measures to strengthen its financial position and navigate through this commodity down cycle, which measures include, but are not limited to, a reduction of budgeted capital spending, the suspension of the quarterly common share dividend, the sale of non-core assets in Western Canada and the continued transition to lower sustaining and higher return Lloyd thermal projects.

7.3 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. These obligations represent contracts and other commitments that are known and non-cancellable. Refer to the Company's MD&A for the year ended December 31, 2016 under the caption "Liquidity and Capital Resources" which summarizes contractual obligations and commercial commitments as at December 31, 2016. During the first quarter of 2017, there were no material changes to the Company's contractual obligations or non-cancellable commitments.

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.

7.4 Transactions with Related Parties

The Company performs management services as the operator of the assets held by HMLP for which it earns a management fee. The Company is also the contractor for HMLP and constructs its assets on a cost recovery basis with certain restrictions. HMLP charges an access fee to the Company for the use of its pipeline systems in performing the Company's blending business, and the Company also pays for transportation and storage services. For the three months ended March 31, 2017, the Company charged HMLP $96 million related to construction and management services, and the Company had purchases from HMLP of $8 million related to the use of the pipeline for the Company's blending activities and $41 million related to transportation and storage. As at March 31, 2017, the Company had $35 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 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 three months ended March 31, 2017, the amount of natural gas sales to Meridian totalled $13 million, the amount of steam purchased by the Company from Meridian totalled $5 million, and the total cost recovery by the Company for facilities services was $2 million. At March 31, 2017, the Company had less than $1 million due from Meridian with respect to these transactions.

At March 31, 2017, $33 million of the Company's May 11, 2009, 7.25 percent senior notes, maturing December 2019, were held by a related party, Ace Dimension Limited, and are included in long-term debt in the Company's condensed interim consolidated financial statements. 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 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 in Canada.

8. Critical Accounting Estimates and Key Judgments

The application of some of the Company's accounting policies requires subjective judgment about uncertain circumstances. The potential effects of these estimates, as described in the Company's MD&A for the year ended December 31, 2016, as well as critical areas of judgments have not changed during the current period. The emergence of new information and changed circumstances may result in changes to actual results or changes to estimated amounts that differ materially from current estimates.

9. Recent Accounting Standards and Changes in Accounting Policies

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

Recent Accounting Standards

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 other comprehensive income rather than net earnings, unless this creates an accounting mismatch. IFRS 9 includes a new, forward-looking 'expected loss' impairment model that will result in 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.

Changes in Accounting Policies

Effective January 1, 2017, the Company adopted the following new accounting standards issued by the IASB:

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 2017 annual consolidated financial statements.

10. Outstanding Share Data

Authorized:
- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: May 1, 2017:

• common shares	1,005,451,854
• 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	24,093,218
• stock options exercisable	12,386,292

11. Reader Advisories

This MD&A should be read in conjunction with the condensed interim consolidated financial statements and related Notes.

Readers are encouraged to refer to the Company's MD&A for the year ended December 31, 2016, the 2016 consolidated financial statements and the Annual Information Form dated February 24,2017 filed with Canadian securities regulatory authorities and the 2016 Form 40-F filed with the U.S. Securities and Exchange Commission for additional information relating to the Company. These documents are available at *www.sedar.com*, at *www.sec.gov* and at *www.huskyenergy.com*.

Use of Pronouns and Other Terms Denoting Husky

In this MD&A, the terms "Husky" and the "Company" denote the corporate entity Husky Energy Inc. and its subsidiaries on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended March 31, 2017, are compared to the results for the three months ended March 31, 2016. Discussions with respect to the Company's financial position as at March 31, 2017 are compared to its financial position as at December 31, 2016. Amounts presented within this MD&A are unaudited.

Additional Reader Guidance

- The condensed interim consolidated financial statements and comparative financial information included in this MD&A have been prepared in accordance with IAS 34, "Interim Financial Reporting" as issued by the IASB.
- All dollar amounts are in Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices are presented before the effect of hedging.
- There have been no changes to the Company's internal controls over financial reporting ("ICFR") for the three months ended March 31, 2017 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

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, 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 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 used in this MD&A and related disclosures 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.

For the three months ended March 31, 2017 and 2016, there were no reconciling items between net earnings (loss) and adjusted net earnings (loss).

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 plus the settlement of asset retirement obligations, income taxes paid (received), interest received 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 March 31, 2017, and December 31, 2016:

($ millions)	**March 31, 2017**	December 31, 2016
Total debt	**6,053**	5,339
Funds from operations[(1)]	**2,349**	2,076
Debt to Funds from operations	**2.6**	2.6

(1) *Annualized using twelve month rolling figures.*

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 plus the settlement of asset retirement obligations, income taxes paid (received), interest received 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 ended March 31, 2017, and 2016:

	Three months ended March 31,	
($ millions)	**2017**	2016
Cash flow – operating activities	**621**	122
Settlement of asset retirement obligations	**48**	22
Income taxes paid (received)	**21**	(35)
Interest received	**(2)**	(3)
Change in non-cash working capital	**21**	328
Funds from operations	**709**	434
Capital expenditures	**(384)**	(410)
Free cash flow	**325**	24
Funds from operations – basic	**0.71**	0.43
Funds from operations – diluted	**0.71**	0.43

LIFO

The Chicago 3:2:1 crack spread 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 crack spread.

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 March 31, 2017, and December 31, 2016:

($ millions)	**March 31, 2017**	December 31, 2016
Short-term debt	**200**	200
Long-term debt due within one year	**400**	403
Long-term debt	**5,453**	4,736
Total debt	**6,053**	5,339
Cash and cash equivalents	**(2,245)**	(1,319)
Net Debt	**3,808**	4,020

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

Cautionary Note Required by National Instrument 51-101

Unless otherwise noted, historical production numbers given represent the Company'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.

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.

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	*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	*Including capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and short-term debt divided by capital employed*
Debt to Funds from Operations	*Long-term debt, long-term debt due within one year and short-term debt divided by funds from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil and bitumen to facilitate transmissibility of the oil through a pipeline*
Feedstock	*Raw materials which are processed into petroleum products*
Free Cash Flow	*Funds from operations less capital expenditures*
Funds from Operations	*Cash flow – operating activities plus the settlement of asset retirement obligations, deferred revenue, income taxes paid (received), interest received 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 high-TAN crudes*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
Light crude oil	*Crude oil with a relative density greater than 31.1 degrees API gravity*
Medium crude oil	*Crude oil with a relative density that is greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity*
Net Debt	*Total debt less cash and cash equivalents*
Net Revenue	*Gross revenue 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, production and operating costs and transportation costs on a per unit basis*
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	*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

AER	*Alberta Energy Regulator*	*mboe/day*	*thousand barrels of oil equivalent per day*
bbls	*barrels*	*mcf*	*thousand cubic feet*
bbls/day	*barrels per day*	*MD&A*	*Management's Discussion and Analysis*
boe	*barrels of oil equivalent*	*mmbbls*	*million barrels*
boe/day	*barrels of oil equivalent per day*	*mmboe*	*million barrels of oil equivalent*
DD&A	*depletion, depreciation and amortization*	*mmbtu*	*million British Thermal Units*
EDGAR	*Electronic Data Gathering, Analysis, and Retrieval system (U.S.A.)*	*mmcf*	*million cubic feet*
FEED	*front end engineering and design*	*mmcf/day*	*million cubic feet per day*
FIFO	*first in first out*	*m3*	*cubic meter*
FPSO	*Floating production, storage and offloading vessel*	*NGLs*	*natural gas liquids*
GAAP	*Generally Accepted Accounting Principles*	*NIT*	*NOVA Inventory Transfer*
GJ	*gigajoule*	*NYMEX*	*New York Mercantile Exchange*
IAS	*International Accounting Standard*	*OCI*	*other comprehensive income*
IASB	*International Accounting Standards Board*	*OPEC*	*Organization of the Petroleum Exporting Countries*
ICFR	*Internal Controls over Financial Reporting*	*RIN*	*Renewable Identification Number*
IFRS	*International Financial Reporting Standards*	*RMB*	*Chinese Yuan*
LIFO	*Last in first out*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
mbbls	*thousand barrels*	*SOR*	*steam-oil ratio*
mbbls/day	*thousand barrels per day*	*WTI*	*West Texas Intermediate*
mboe	*thousand barrels of oil equivalent*		

12. Forward-Looking Statements and Information

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 designed", “is targeting”, “is estimated”, “intend”, “plan”, “projection”, “could”, “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 objective of maintaining stated debt to capital employed and debt to cash flow from operations ratio targets; and the Company’s 2017 Upstream capital expenditure program;

- with respect to the Company's Thermal Development properties: the Company’s forecasted daily total bitumen production for the fourth quarter of 2017; production expectations for the Tucker Thermal Project for 2017 and 2018; and anticipated timing of first production from and design capacities for the Company’s Rush Lake 2 thermal development and its three new Lloyd thermal projects at Dee Valley, Spruce Lake North and Spruce Lake Central; the Company’s expectation of improved well conformance and production rates over the next two years for the Sunrise Energy Project; and the Company’s forecasted 2017 average annual production from the Sunrise Energy Project;

- with respect to the Company's Asia Pacific region: planned timing of first production and anticipated combined daily net sales volumes from the Madura Strait MDA-MBH, MDK and BD Gas Project once production is fully ramped up; timing of ramp-up to full gas sales rate at the BD Gas Project; the Company’s drilling plans at Block 15/33 and Block 16/25 located offshore China; and anticipated timing for the acquisition by the Company of three-dimensional seismic survey data for offshore Taiwan;

- with respect to the Company's Atlantic region: the drilling plans of the Company at White Rose for 2017; and the drilling plans of the Company and its partner in the Flemish Pass for 2017;

- with respect to the Company's Western Canada Resource Play Development: the Company's strategic plans for its Western Canada portfolio and drilling plans; and

- with respect to the Company's Downstream operating segment: anticipated timing of the consolidation of the Company's and Imperial Oil's truck networks; anticipated timing for completion of the crude oil flexibility project at the Lima Refinery; and the potential expansion of the Company's Lloydminster asphalt refinery.

There are numerous uncertainties inherent in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from 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 and regulators, among others.

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

The Company's Annual Information Form for the year ended December 31, 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.

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