MANAGEMENT'S DISCUSSION AND ANALYSIS

October 26, 2017

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1. Summary of Quarterly Results

	Three months ended							
Quarterly Summary	**Sept. 30**	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31
($ millions, except where indicated)	**2017**	2017	2017	2016	2016	2016	2016	2015
Production *(mboe/day)*	**317.7**	319.5	334.0	327.0	301.0	315.8	341.3	357.0
Gross revenues and marketing and other[(1)]	**4,713**	4,351	4,348	3,865	3,520	3,261	2,578	3,903
Net earnings (loss)	**136**	(93)	71	186	1,390	(196)	(458)	(69)
Per share – Basic	**0.13**	(0.10)	0.06	0.19	1.37	(0.20)	(0.47)	(0.08)
Per share – Diluted	**0.13**	(0.10)	0.06	0.19	1.37	(0.20)	(0.47)	(0.09)
Adjusted net earnings (loss)[(2)]	**136**	10	71	(6)	(100)	(91)	(458)	(53)
Funds from operations[(2)]	**891**	715	661	662	619	505	412	635
Per share – Basic	**0.89**	0.71	0.66	0.66	0.62	0.50	0.41	0.65
Per share – Diluted	**0.89**	0.71	0.66	0.66	0.62	0.50	0.41	0.65

(1) *During the third quarter of 2017, the Company corrected certain intrasegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for the first two quarters of 2017. There was no impact on net earnings. Refer to Note 3 of the condensed interim consolidated financial statements.*

(2) *Adjusted net earnings (loss) and funds from operations are non-GAAP measures. The calculation of funds from operations has changed from prior periods. Prior periods have been restated to conform to current presentation. Refer to Section 11 for a reconciliation to the GAAP measures and an explanation of the changes.*

Performance

- Net earnings of $136 million in the third quarter of 2017 compared to net earnings of $1,390 million in the third quarter of 2016, with the decrease primarily due to an after-tax gain of $1,490 million in 2016 related to asset dispositions. The other changes in net earnings were 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; and
  - Increased U.S refining margins and throughput.

  Partially offset by:
  - Lower upgrading differentials; and
  - Strengthening of the Canadian dollar.
- Funds from operations of $891 million in the third quarter of 2017 compared to $619 million in the third quarter of 2016 with the increase attributed to the same factors noted above for net earnings.
- Production increased by 16.7 mboe/day or six percent to 317.7 mboe/day in the third quarter of 2017 compared to the third quarter of 2016 as a result of:
  - Increased production from thermal developments;
  - Increased natural gas and NGLs production from the Liwan Gas Project; and
  - Increased natural gas production due to new production from the Madura-BD Gas Project.

Partially offset by:

- Decreased production from Western Canada mainly due to the disposition of select legacy assets in 2016 and 2017.

Key Projects

- Development continues at the 10,000 bbls/day Rush Lake 2 thermal project. Construction of the central processing facility is progressing to schedule and drilling of the Steam Assisted Gravity Drainage ("SAGD") injector-producer well pairs has commenced. First production is expected in the first quarter of 2019.
- Regulatory approval was received for the Dee Valley project, where site clearing has commenced, and the Spruce Lake Central project. The regulatory application was submitted for the Spruce Lake North project. First production for all three projects is expected in 2020.
- At the Tucker Thermal Project, completions and tie-ins for the new 15-well pad are in progress with first steam expected by the end of 2017. Production from this new pad is expected to ramp up through the first half of 2018, with total production expected to grow towards its 30,000 bbls/day design capacity by the end of 2018.
- At the Liwan Gas Project, a gas sales agreement was reached for future gas production from Liuhua 29-1, the third deepwater gas field at the project. Project sanction is expected to be considered by the Company's Board of Directors later this year.
- The liquids-rich Madura-BD Gas Project in the Madura Strait commenced production. Third quarter production averaged 38.3 mmcf/day (15.3 mmcf/day Husky working interest) and is being sold from the onshore gas distribution facility in East Java under a fixed price gas contract. NGLs have been produced and stored in the purpose built floating production, storage and offloading ("FPSO") vessel. The first lifting of the NGLs occurred mid-October. The project is expected to ramp up throughout 2017 towards full sales gas rates, with a gross daily sales target of 100 mmcf/day of natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGLs (2,400 bbls/day Husky working interest).
- Construction and installation of the shallow water jackets and subsea pipelines for the MDA-MBH fields has been completed. The contract for a leased floating production unit has been signed and planning for the build has commenced. Drilling of five MDA field production wells and two MBH field production wells is planned for the first half of 2018. First gas is expected in the 2019 timeframe, with the additional MDK shallow water field expected to be tied in during the same period.
- The contracts have been awarded and early development work has started for the West White Rose Project offshore Newfoundland and Labrador. The project was sanctioned in May 2017 and will be developed using a fixed drilling platform, which has received regulatory approval. Preparations for construction of the concrete gravity structure to support the topsides will begin in the fourth quarter of 2017 at the purpose-built graving dock in Argentia, Newfoundland and Labrador.
- An oil production well and a supporting water injection well were completed at South White Rose during the quarter. The production well is expected to have gross peak production of approximately 6,500 bbls/day (4,500 bbls/day Husky working interest).
- A 16-well program targeting the Wilrich formation in the Ansell and Kakwa areas is under way, with nine Wilrich wells drilled to date in 2017. Due to improved operating efficiencies, drilling times have been reduced by 30 percent since the start of 2017, contributing to a 22 percent reduction in per-well drilling costs.
- A drilling program targeting the oil and liquids-rich Montney formation in the Wembley and Karr areas is continuing. At Wembley, where one well is already on production, two additional wells have been drilled to date in 2017. Two wells have been drilled at Karr, with first production scheduled to commence in the fourth quarter.
- The consolidation of a single expanded truck transport network of approximately 160 sites was completed during the quarter.
- The Company continued work on a crude oil flexibility project at the Lima Refinery. The timing of the project completion has been updated and will occur in phases over a two-year period of 2018 and 2019. This revised schedule optimizes project work and times the execution with normal maintenance thereby allowing the refinery to maintain higher levels of sustained production. There have been no changes to the scope of the project.

Acquisitions and Divestitures

- During the third quarter of 2017, the Company entered into a purchase and sale agreement to acquire the Superior Refinery, a 50,000 barrel per day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet Specialty Products Partners, L.P. for approximately $544 million (US$435 million) in cash. The transaction is subject to regulatory approval and closing adjustments and is expected to close in the fourth quarter of 2017.
- During the third quarter of 2017, the Company signed a purchase and sale agreement with third parties to sell its Ram River and Foothills Deep Gas assets for gross cash proceeds of $65 million. The transaction is effective July 1, 2017 and is expected to close in the fourth quarter of 2017.

Financial

- Dividends on preferred shares of $9 million were declared and payable in the third quarter of 2017.
- On September 15, 2017, the Company repaid the maturing 6.20 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to note holders was $365 million, including $11 million of interest.
- During the third quarter of 2017, the Company completed a series of transactions related to the Canadian defined benefit pension plan, which is closed to new entrants. The Company recognized an $8 million loss on settlement related to the inactive plan members and a $3 million (net of tax of $1 million) loss in other comprehensive income for an annuity that was purchased to offset the defined benefit obligation for the active plan members.

2. Business Environment

Average Benchmarks

		Three months ended					Nine months ended	
Average Benchmarks Summary		**Sept. 30, 2017**	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sept. 30, 2016	**Sept. 30, 2017**	Sept. 30, 2016
West Texas Intermediate ("WTI") crude oil[(1)]	*(US$/bbl)*	**48.21**	48.29	51.91	49.29	44.94	**49.47**	41.33
Brent crude oil[(2)]	*(US$/bbl)*	**52.08**	49.87	53.78	49.47	45.85	**51.91**	41.77
Light sweet at Edmonton	*($/bbl)*	**56.74**	61.92	63.97	61.60	54.80	**60.88**	50.13
Daqing[(3)]	*(US$/bbl)*	**49.51**	47.35	51.71	47.90	42.19	**49.52**	38.51
Western Canadian Select at Hardisty[(4)]	*(US$/bbl)*	**38.27**	37.16	37.34	34.97	31.44	**37.59**	27.65
Lloyd heavy crude oil at Lloydminster	*($/bbl)*	**44.05**	43.80	41.62	40.05	36.10	**43.16**	30.13
WTI/Lloyd crude blend differential	*(US$/bbl)*	**9.59**	11.05	14.32	14.19	13.42	**11.66**	13.54
Condensate at Edmonton	*(US$/bbl)*	**47.60**	48.43	52.27	48.33	43.07	**49.43**	40.51
NYMEX natural gas[(5)]	*(US$/mmbtu)*	**3.00**	3.18	3.32	2.98	2.81	**3.17**	2.29
NOVA Inventory Transfer ("NIT") natural gas	*($/GJ)*	**1.93**	2.63	2.79	2.67	2.09	**2.45**	1.76
Chicago Regular Unleaded Gasoline	*(US$/bbl)*	**66.40**	62.72	62.53	59.07	58.90	**63.89**	55.06
Chicago Ultra-low Sulphur Diesel	*(US$/bbl)*	**69.69**	62.08	63.96	61.49	59.88	**65.25**	54.81
Chicago 3:2:1 crack spread	*(US$/bbl)*	**19.30**	14.36	11.22	10.59	14.29	**14.98**	13.46
U.S./Canadian dollar exchange rate	*(US$)*	**0.799**	0.744	0.756	0.750	0.766	**0.766**	0.757
Canadian $ Equivalents[(6)]								
WTI crude oil	*($/bbl)*	**60.34**	64.91	68.66	65.72	58.67	**64.58**	54.60
Brent crude oil	*($/bbl)*	**65.18**	67.03	71.14	65.96	59.86	**67.77**	55.18
Daqing	*($/bbl)*	**61.96**	63.64	68.40	63.87	55.08	**64.65**	50.87
Western Canadian Select at Hardisty	*($/bbl)*	**47.90**	49.95	49.39	46.63	41.04	**49.07**	36.53
WTI/Lloyd crude blend differential	*($/bbl)*	**12.00**	14.85	18.94	18.92	17.52	**15.22**	17.89
NYMEX natural gas	*($/mmbtu)*	**3.75**	4.27	4.39	3.97	3.67	**4.14**	3.03

(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 in the third quarter of 2017 remained relatively consistent with the second quarter of 2017, but have strengthened compared to the third quarter of 2016. WTI averaged US$48.21/bbl during the third quarter of 2017, compared to US$44.94/bbl during the third quarter of 2016. Brent averaged US$52.08/bbl during the third quarter of 2017 compared to US $45.85/bbl during the third 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. The Company's crude oil and NGLs production was 72 percent heavy crude oil and bitumen in both the third quarter of 2017 and 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 third quarter of 2017 compared to the third quarter of 2016 primarily due to the increase in crude oil benchmark pricing.

Natural Gas Benchmarks

The NIT natural gas price benchmark declined in the third quarter of 2017 compared to the third quarter of 2016 due to an oversupply of natural gas in North America, which is largely the result of pipeline outages.

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, helping to mitigate the impact of weak natural gas benchmark prices on results.

Refining Benchmarks

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

The cost of the 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 physically blending biofuel 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 margins net of RINs purchases.

The Company's realized refining margins are affected by the product configuration of its refineries, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil. The product slates produced at the Lima 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 third quarter of 2017, the Canadian dollar averaged US$0.799 compared to US$0.766 in the third quarter of 2016.

The Company’s 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 5.325 in the third quarter of 2017 compared to RMB 5.108 in the third quarter of 2016.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in the third quarter of 2017 on earnings before income taxes and net earnings on an annualized basis. The table below reflects what the effect would have been on the financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during the third 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 Third 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]	**48.21**	*US $1.00/bbl*	**95**	**0.09**	**72**	**0.07**
NYMEX benchmark natural gas price[5]	**3.00**	*US $0.20/mmbtu*	**12**	**0.01**	**9**	**0.01**
WTI/Lloyd crude blend differential[6]	**9.59**	*US $1.00/bbl*	**(41)**	**(0.04)**	**(34)**	**(0.03)**
Canadian light oil margins	**0.049**	*Cdn $0.005/litre*	**15**	**0.02**	**11**	**0.01**
Asphalt margins	**21.77**	*Cdn $1.00/bbl*	**13**	**0.01**	**10**	**0.01**
Chicago 3:2:1 crack spread	**19.30**	*US $1.00/bbl*	**119**	**0.12**	**75**	**0.07**
Exchange rate (US $ per Cdn $)[3][7]	**0.799**	*US $0.01*	**(67)**	**(0.07)**	**(53)**	**(0.05)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 1,005.1 million common shares outstanding as at September 30, 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 business strategy is to focus on returns from investment in a deep portfolio of opportunities that can generate increased funds from operations and free cash flow.

The Company has two main areas of focus:

- The Integrated Corridor includes natural gas, non-thermal oil, NGLs and thermal bitumen production from Western Canada, the Lloydminster upgrading and asphalt refining complex, the Husky Midstream Limited Partnership (35 percent working interest and operatorship), and the Lima and Toledo refineries in the U.S. Midwest. Gas production from the repositioned Western Canada portfolio is closely aligned with the Company's gas requirements for thermal bitumen and refining requirements and acts as a natural hedge.

- The Offshore business includes operations and exploration in the Asia Pacific region, primarily offshore China, Indonesia and Taiwan, and in the Atlantic, offshore Newfoundland and Labrador. Each area generates high-netback production, with near and long-term investment potential.

In the Integrated Corridor, the Company has a large and growing inventory of thermal bitumen projects in the Lloydminster region of Saskatchewan and Alberta, as well as the Tucker Thermal Project near Cold Lake, Alberta and the Sunrise Energy Project north of Fort McMurray, Alberta. These projects are physically integrated with the Downstream assets, which increases flexibility, provides for secure U.S. market access and increases margin capture.

Offshore in the Asia Pacific region, the Liwan Gas Project offshore China and a series of natural gas fields in the Madura Strait offshore Indonesia are being developed through fixed-price contracts, providing insulation from commodity price instability. In the Atlantic, the Company continues to develop satellite tiebacks from the main White Rose field and is moving forward with the West White Rose development. Both Offshore regions leverage existing infrastructure to drive greater cost efficiencies, with products sold into regional and global markets.

4. Key Growth Highlights

The 2017 capital program reflects the Company's focus on returns from investment in a deep portfolio of opportunities that can generate increased funds from operations and free cash flow.

4.1 Upstream

Upstream operations in the Integrated Corridor and Offshore include 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).

Thermal Developments

The Company continued to advance its inventory of thermal bitumen developments in the third quarter of 2017. These long-life developments are being built with modular, repeatable designs and require low sustaining capital once brought online. Total bitumen production, including Lloyd thermal projects, the Tucker Thermal Project and the Sunrise Energy Project, averaged 117,700 bbls/day in the third quarter of 2017 and is expected to average approximately 120,000 bbls/day by the fourth quarter of 2017.

Lloyd Thermal Projects
Development continues at the 10,000 bbls/day Rush Lake 2 thermal project. Construction of the central processing facility is progressing to schedule and drilling of the SAGD injector-producer well pairs has commenced. First production is expected in the first quarter of of 2019.

In late 2016, the Company sanctioned three Lloyd thermal projects with total design capacity of 30,000 bbls/day at Dee Valley, Spruce Lake North and Spruce Lake Central. Regulatory approval was received during the quarter for the Dee Valley project, where site clearing has commenced, and the Spruce Lake Central project. The regulatory application was submitted for the Spruce Lake North project. First production for all three projects is expected in 2020.

Tucker Thermal Project
Completions and tie-ins for the new 15-well pad are in progress with first steam expected in the fourth quarter of 2017. Production from this new pad is expected to ramp up through the first half of 2018, with total production at the Tucker Thermal Project expected to grow towards its 30,000 bbls/day design capacity by the end of 2018.

Sunrise Energy Project
Average well rates continued to increase at the Sunrise Energy Project with total production averaging 40,500 bbls/day (20,250 bbls/day Husky working interest) during the third quarter of 2017. The tie-in of 14 previously drilled well pairs has been completed, with steaming now under way and production being phased in sequence.

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

Asia Pacific

China
Block 29/26
A gas sales agreement was reached for future gas production from Liuhua 29-1, the third deepwater gas field at the Liwan Gas Project. Project sanction is expected to be considered by the Company's Board of Directors later this year.

Block 15/33 and 16/25
The Company expects to drill two exploration wells on both Block 15/33 and 16/25 offshore China in the 2018 timeframe.

Offshore Taiwan
Block DW-1
The Company has completed the three-dimensional seismic survey data acquisition and data analysis has commenced.

Indonesia

Madura Strait

Progress continued on the natural gas developments in the Madura Strait Block.

Gas production from the Madura-BD Gas Project averaged 38.3 mmcf/day (15.3 mmcf/day Husky working interest) during the third quarter and is being sold from the onshore gas distribution facility in East Java under a fixed price gas contract. NGLs have been produced and stored in the purpose built FPSO vessel. The first lifting of the NGLs occurred in mid-October. The project is expected to ramp up throughout 2017 towards full sales gas rates, with a gross daily sales target of 100 mmcf/day of natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGLs (2,400 bbls/day Husky working interest).

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

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

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

Anugerah

The Company continues to evaluate seismic survey data to determine the potential for future drilling opportunities.

Atlantic

White Rose Field and Satellite Extensions

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

The Company continues to offset natural reservoir declines through infill and development well drilling at the White Rose field and satellite extensions. An oil production well and a supporting water injection well were completed at South White Rose during the quarter. The production well is expected to have gross peak production of approximately 6,500 bbls/day (4,500 bbls/day Husky working interest). Work has commenced on an additional infill well at White Rose with first oil expected in late 2017. All wells are tied back to the SeaRose FPSO, providing for improved capital efficiencies.

Atlantic Exploration

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

The Company and its partner continue to assess a discovery at Northwest White Rose. A potential development could leverage the SeaRose FPSO vessel, existing subsea infrastructure and the West White Rose wellhead platform. The Company has a 93.232 percent ownership interest in the discovery.

Western Canada Resource Play Development

Oil and Natural Gas Resource Plays

A 16-well program targeting the Wilrich formation in the Ansell and Kakwa areas is under way, with nine Wilrich wells drilled to date in 2017. Due to improved operating efficiencies, drilling times have been reduced by 30 percent since the start of 2017, contributing to a 22 percent reduction in per-well drilling costs.

A drilling program targeting the oil and liquids-rich Montney formation in the Wembley and Karr areas is continuing. At Wembley, where one well is already on production, two additional wells have been drilled to date in 2017. Two wells have been drilled at Karr, with first production scheduled to commence in the fourth quarter.

4.2 Downstream

Downstream operations in the Integrated Corridor include upgrading of heavy crude oil feedstock into synthetic crude oil in Canada (Upgrading), refining crude oil in Canada, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol (Canadian Refined Products). It also includes refining in the U.S. of primarily crude oil to produce and market 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.

Canadian Refined Products

The consolidation of a single expanded truck transport network of approximately 160 sites was completed during the quarter.

A final investment decision for the Lloydminster Asphalt Expansion, previously to be decided in 2018, has been deferred to post 2020, in light of the Superior Refinery acquisition noted below.

U.S. Refining and Marketing

The Company continued work on a 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, providing the ability to swing between light and heavy crude oil feedstock. The first stage of the project was completed in 2016 and the refinery is now able to process up to 10,000 bbls/day of heavy crude oil feedstock. The timing of the project completion has been updated and will occur in phases over a two-year period of 2018 and 2019. This revised schedule optimizes project work and times the execution with normal maintenance thereby allowing the refinery to maintain higher levels of sustained production. There have been no changes to the scope of the project.

During the third quarter of 2017, the Company entered into a purchase and sale agreement to acquire the Superior Refinery, a 50,000 barrel per day permitted capacity facility located in Superior, Wisconsin, U.S., from Calumet Specialty Products Partners, L.P. for approximately $544 million (US$435 million) in cash. The transaction is subject to regulatory approval and closing adjustments and is expected to close in the fourth quarter of 2017.

5. Results of Operations

5.1 Upstream

Exploration and Production

Exploration and Production Earnings (Loss) Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Gross revenues	**1,157**	941	**3,623**	2,821
Royalties	**(71)**	(56)	**(266)**	(200)
Net revenues	**1,086**	885	**3,357**	2,621
Purchases of crude oil and products	**—**	6	**1**	32
Production, operating and transportation expenses	**413**	429	**1,260**	1,322
Selling, general and administrative expenses	**63**	57	**181**	151
Depletion, depreciation, amortization and impairment ("DD&A")	**514**	474	**1,766**	1,578
Exploration and evaluation expenses	**31**	17	**108**	110
Loss (gain) on sale of assets	**3**	(236)	**(29)**	(137)
Other – net	**(7)**	18	**(31)**	24
Share of equity investment loss	**1**	1	**1**	3
Financial items	**29**	32	**94**	108
Provisions for (recovery of) income taxes	**11**	24	**2**	(155)
Net earnings (loss)	**28**	63	**4**	(415)

Third Quarter

Exploration and Production net revenues increased by $201 million in the third quarter of 2017 compared to the third quarter of 2016, primarily due to higher realized North American commodity prices combined with increased production from the Company's thermal development projects and increased 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 2016 and 2017.

Production, operating and transportation expenses decreased by $16 million in the third quarter of 2017 compared to the third quarter of 2016 primarily due to cost savings initiatives and lower production from Western Canada.

Gain on sale of assets decreased by $239 million in the third quarter of 2017 compared to the third quarter of 2016 primarily due to the sale of select assets in Western Canada during the third quarter in 2016.

Nine Months

In the first nine months of 2017, Exploration and Production net revenues increased by $736 million and production, operating and transportation expenses decreased by $62 million, compared to the same period in 2016, primarily due to the same factors which impacted the third quarter.

Royalty costs increased by $66 million in the first nine months of 2017 compared to the same period in 2016 primarily due to the increase in Exploration and Production net revenues noted above.

DD&A expense increased by $188 million in the first nine months of 2017 compared to the same period in 2016, primarily due to the recognition of a pre-tax impairment charge of $168 million on crude oil and natural gas assets in Western Canada during the second quarter of 2017.

Gain on sale of assets decreased by $108 million in the first nine months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the third quarter.

Provisions for income taxes increased by $157 million in the first nine months of 2017 compared to the same period in 2016 primarily due to higher earnings before income taxes in 2017 compared to 2016.

Average Sales Prices Realized

Average Sales Prices Realized	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
Crude oil and NGLs *($/bbl)*				
Light and Medium crude oil	**63.13**	54.91	**64.50**	49.11
NGLs	**37.83**	35.62	**41.18**	34.66
Heavy crude oil	**41.89**	35.04	**41.73**	28.80
Bitumen	**38.14**	29.53	**36.93**	25.02
Total crude oil and NGLs average	**43.62**	36.83	**44.43**	33.53
Natural gas average *($/mcf)*[(1)]	**5.25**	3.99	**5.39**	3.98
Total average *($/boe)*	**40.05**	33.11	**41.07**	30.73

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

Third Quarter

The average sales prices realized by the Company for crude oil and NGLs production increased by 18 percent in the third quarter of 2017 compared to the same period in 2016, reflecting an increase in commodity benchmark prices.

The average sales prices realized by the Company for natural gas production increased by 32 percent in the third 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 and new gas production from the Madura-BD Gas Project relative to total natural gas production.

Nine Months

In the first nine months of 2017, the average sales prices realized by the Company for crude oil and NGLs production increased by 33 percent compared to the same period in 2016, primarily due to the same factors which impacted the third quarter.

Average sales prices realized by the Company for natural gas production in the first nine months of 2017 increased by 35 percent compared to the same period in 2016, primarily due to the same factors which impacted the third quarter.

Daily Gross Production

Daily Gross Production	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
Crude Oil and NGLs *(mbbls/day)*				
Western Canada				
Light and Medium crude oil	**11.1**	16.5	**12.5**	26.4
NGLs	**11.4**	7.9	**10.1**	8.2
Heavy crude oil	**44.1**	49.5	**45.1**	56.1
Bitumen[(1)]	**117.7**	103.6	**118.5**	91.2
	184.3	177.5	**186.2**	181.9
Atlantic				
White Rose and Satellite Fields – light crude oil	**23.6**	19.7	**30.7**	28.9
Terra Nova – light crude oil	**2.1**	5.1	**3.7**	3.7
	25.7	24.8	**34.4**	32.6
Asia Pacific				
Wenchang – light crude oil	**5.9**	6.3	**6.2**	6.9
Liwan and Wenchang – NGLs[(2)]	**7.9**	5.5	**6.8**	5.2
	13.8	11.8	**13.0**	12.1
	223.8	214.1	**233.6**	226.6
Natural gas *(mmcf/day)*				
Western Canada	**379.5**	414.2	**390.4**	454.7
Asia Pacific[(2)]				
Liwan	**168.6**	107.1	**145.0**	101.4
Madura[(3)]	**15.3**	—	**5.1**	—
	183.9	107.1	**150.1**	101.4
	563.4	521.3	**540.5**	556.1
Total *(mboe/day)*	**317.7**	301.0	**323.7**	319.3

(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).*
(3) *Reported production volumes include Husky's net working interest from the Madura-BD Gas Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for interim financial statement purposes.*

Crude Oil and NGLs Production

Third Quarter

Crude oil and NGLs production increased by 9.7 mbbls/day in the third quarter of 2017 compared to the third 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 increased NGLs production in Asia Pacific and Western Canada. This was partially offset by lower crude oil production from Western Canada due to the disposition of select legacy assets in 2016 and 2017.

Nine Months

Crude oil and NGLs production increased by 7.0 mbbls/day in the first nine months of 2017 compared to the same period in 2016, primarily due to the same factors which impacted the third quarter.

Natural Gas Production

Third Quarter

Natural gas production increased by 42.1 mmcf/day in the third quarter of 2017 compared to the third quarter of 2016. In Western Canada, natural gas production decreased by 34.7 mmcf/day primarily due to the disposition of select legacy assets during 2016 and 2017, natural reservoir declines from mature properties and strategic shut-ins due to unfavourable economics. In Asia Pacific, natural gas production increased by 76.8 mmcf/day due to increased gas demand in 2017 and new production from the Madura-BD Gas Project.

Nine Months

Natural gas production decreased by 15.6 mmcf/day in the first nine months of 2017 compared to the same period in 2016. In Western Canada, natural gas production decreased by 64.3 mmcf/day, primarily due to the same factors which impacted the third quarter. In Asia Pacific, natural gas production increased by 48.7 mmcf/day, primarily due to the same factors which impacted the third quarter and 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 nine months ended September 30, 2017, and the year ended December 31, 2016, as well as the previously issued production guidance for 2017.

		Actual Production	
	Guidance 2017	**Nine months ended September 30, 2017**	Year ended December 31, 2016
Canada			
Light & medium crude oil *(mbbls/day)*	46 - 48	**47**	56
NGLs *(mbbls/day)*	8 - 9	**10**	8
Heavy crude oil & bitumen *(mbbls/day)*	167 - 173	**164**	151
Natural gas *(mmcf/day)*	345 - 353	**390**	442
Canada total *(mboe/day)*	278 - 288	**286**	289
Asia Pacific			
Light crude oil *(mbbls/day)*	5 - 6	**6**	7
NGLs *(mbbls/day)*	8 - 10	**7**	6
Natural gas *(mmcf/day)*[(1)]	171 - 182	**150**	114
Asia Pacific total *(mboe/day)*	42 - 46	**38**	32
Total *(mboe/day)*	320 - 335	**324**	321

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

Royalties

Third Quarter

Royalty rates as a percentage of gross revenues averaged six percent in both the third quarter of 2017 and of 2016. Royalty rates in Western Canada averaged six percent in the third quarter of 2017 compared to five percent in the same period of 2016 primarily due to higher commodity prices. Royalty rates for Atlantic averaged six percent in the third quarter of 2017 compared to 12 percent in the same period in 2016, primarily due to production shifting to lower rate fields in 2017 combined with higher eligible costs. Royalty rates in Asia Pacific averaged six percent in both the third quarter of 2017 and of 2016.

Nine Months

Royalty rates as a percentage of gross revenues averaged seven percent in both the first nine months of 2017 and of 2016. Royalty rates in Western Canada averaged seven percent in the first nine months of 2017 compared to six percent in the same period of 2016, primarily due to the same factors which impacted the third quarter. Royalty rates for the Atlantic region averaged 10 percent in the first nine months of 2017 compared to 13 percent in the same period of 2016 primarily due to the same factors which impacted the third quarter. Royalty rates in the Asia Pacific region averaged six percent in both the first nine months of 2017 and of 2016.

Operating Costs

($ millions)	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
Western Canada	**336**	336	**1,020**	1,052
Atlantic	**59**	64	**166**	177
Asia Pacific(1)	**23**	22	**66**	69
Total	**418**	422	**1,252**	1,298
Per unit operating costs ($/boe)	**14.12**	15.15	**14.17**	14.09

(1) *Reported operating costs include Husky's net working interest from the Madura-BD Gas Project (40 percent). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for interim financial statement purposes.*

Third Quarter

Total Exploration and Production operating costs were $418 million in the third quarter of 2017 compared to $422 million in the same period in 2016. Total unit operating costs averaged $14.12/boe in the third quarter of 2017 compared to $15.15/boe in the same period in 2016 with the decrease primarily due to lower unit operating costs across the portfolio.

Per unit operating costs in Western Canada averaged $14.48/boe in the third quarter of 2017 compared to $14.72/boe in the same period in 2016. The decrease in unit operating costs per boe was primarily due to cost savings initiatives realized in 2017.

Per unit operating costs in Atlantic averaged $24.98/bbl in the third quarter of 2017 compared to $28.07/bbl in the same period in 2016. The decrease in unit operating costs per bbl was primarily due to higher production and lower subsea maintenance costs in 2017.

Unit operating costs in Asia Pacific averaged $5.83/boe in the third quarter of 2017 compared to $7.89/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.

Nine Months

Total Exploration and Production operating costs were $1,252 million in the first nine months of 2017 compared to $1,298 million in the same period in 2016. Total unit operating costs averaged $14.17/boe in the first nine months of 2017 compared to $14.09/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 $14.87/boe in the first nine months of 2017 compared to $13.97/boe in the same period in 2016. The increase in unit operating costs per boe was primarily due to higher energy costs, partially offset by cost savings initiatives realized in 2017.

Per unit operating costs in Atlantic averaged $17.68/bbl in the first nine months of 2017 compared to $19.76/bbl in the same period in 2016. The decrease in unit operating costs per bbl was primarily due to the same factors which impacted the third quarter.

Unit operating costs in Asia Pacific averaged $6.40/boe in the first nine months of 2017 compared to $8.67/boe in the same period in 2016. The decrease in unit operating costs per boe was primarily due to the same factors which impacted the third quarter.

Exploration and Evaluation Expenses

($ millions)	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
Seismic, geological and geophysical	26	15	76	46
Expensed drilling	3	—	22	59
Expensed land	2	2	10	5
Total	31	17	108	110

Third Quarter

Exploration and evaluation expenses in the third quarter of 2017 were $31 million compared to $17 million in the third quarter of 2016. The increase in seismic, geological and geophysical expense of $11 million is primarily due to increased seismic operations in both Western Canada, related to thermal developments, and Asia Pacific, related to the exploration block in offshore Taiwan.

Nine Months

Exploration and evaluation expenses in the first nine months of 2017 were $108 million compared to $110 million in the same period in 2016. The decrease in exploration and evaluation expenses was primarily due to lower daily drilling rates for the two unsuccessful exploration wells in the Flemish Pass in 2017, partially offset by the same factors which impacted the third quarter.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were higher in the third quarter of 2017 compared to the third quarter of 2016 reflecting increased investment in thermal developments, Atlantic drilling and Western Canada resource plays. Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[1] ($ millions)	Three months ended September 30, 2017	2016	Nine months ended September 30, 2017	2016
Exploration				
Western Canada	27	6	47	10
Thermal developments	—	1	1	5
Atlantic	1	(3)	66	16
Asia Pacific[2]	3	1	6	1
	31	5	120	32
Development				
Western Canada	39	10	91	92
Thermal developments	131	59	357	199
Non-thermal developments	20	6	52	14
Atlantic	134	52	264	156
Asia Pacific[2]	—	36	—	98
	324	163	764	559
Acquisitions				
Western Canada	—	—	25	—
Thermal developments	—	5	42	7
	355	173	951	598

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

Western Canada

During the first nine months of 2017, $163 million (17 percent) was invested in Western Canada, compared to $102 million (17 percent) in the same period in 2016. Capital expenditures in 2017 related primarily to resource play development drilling in the Wilrich formation in the Ansell and Kakwa areas and the Montney formation in the Karr and Wembley areas.

Thermal Developments

During the first nine months of 2017, $400 million (42 percent) was invested in thermal developments compared to $211 million (35 percent) in the same period in 2016. Capital expenditures in 2017 related primarily to the development of the Rush Lake 2 thermal development, a new 15-well pad at the Tucker Thermal Project and continued investment in the Sunrise Energy Project.

Non-Thermal Developments

During the first nine months of 2017, $52 million (five percent) was invested in non-thermal developments compared to $14 million (two percent) in the same period in 2016. Capital expenditures in 2017 related primarily to sustainment activities.

Atlantic

During the first nine months of 2017, $330 million (35 percent) was invested in Atlantic compared to $172 million (29 percent) in the same period in 2016. Capital expenditures in 2017 related primarily to satellite field developments at North Amethyst, the South White Rose Extension and the West White Rose Project as well as delineation drilling northwest of the main White Rose field. The increase in capital expenditures in the first nine 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 2017.

Asia Pacific

During the first nine months of 2017, $6 million (one percent) was invested in Asia Pacific compared to $99 million (17 percent) in the same period in 2016. The decrease in capital expenditures in the first nine months of 2017 compared to the same period in 2016 reflects the installation of a second deepwater production pipeline at Liwan Gas Project in 2016.

Exploration and Production Wells Drilled

Onshore drilling activity

The following table discloses the number of wells drilled in thermal and Western Canada resource play developments during the three and nine months ended September 30, 2017 and 2016:

	Three months ended September 30,				Nine months ended September 30,			
	2017		2016		**2017**		2016	
Wells Drilled [(1)]	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Thermal developments	**12**	**9**	27	27	**54**	**51**	70	70
Western Canada resource play development	**5**	**5**	—	—	**18**	**16**	2	1
	17	**14**	27	27	**72**	**67**	72	71

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*

Offshore drilling activity

The following table discloses the Company's drilling activity during the nine months ended September 30, 2017:

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

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 value 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 September 30,		Nine months ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Gross revenues	**513**	275	**1,272**	760
Purchases of crude oil and products	**495**	273	**1,198**	671
Infrastructure gross margin	**18**	2	**74**	89
Marketing and other	**(4)**	5	**31**	(79)
Total Infrastructure and Marketing gross margin	**14**	7	**105**	10
Production, operating and transportation expenses	**1**	2	**6**	17
Selling, general and administrative expenses	**1**	1	**3**	3
Depletion, depreciation, amortization and impairment	**1**	1	**2**	13
Loss (gain) on sale of assets	**—**	(1,442)	**1**	(1,442)
Other – net	**10**	(3)	**(2)**	(7)
Share of equity investment loss (gain)	**(13)**	20	**(61)**	20
Provisions for income taxes	**4**	122	**43**	116
Net earnings	**10**	1,306	**113**	1,290

Third Quarter

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $238 million and $222 million, respectively, in the third quarter of 2017 compared to the third quarter of 2016 primarily due to increased volumes and prices.

Gain on sale of assets decreased by $1,442 million in the third quarter of 2017 compared to the third quarter of 2016 due to the sale of ownership interest in select midstream assets in the third quarter of 2016.

Share of equity investment gain increased by $33 million in the third quarter of 2017 compared to the third quarter of 2016 due to the pipeline spill costs incurred in 2016.

Provisions for income taxes decreased by $118 million in the third quarter of 2017 compared to the third quarter of 2016 due to the tax associated with the sale of ownership interest in select midstream assets in the third quarter of 2016.

Nine Months

Infrastructure and Marketing gross revenues and purchases of crude oil and products increased by $512 million and $527 million, respectively, in the first nine months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the third quarter.

Marketing and other increased by $110 million in the first nine months of 2017 compared to the same period in 2016 primarily due to crude oil marketing gains from widening price differentials between Canada and the U.S. in 2017 and mark-to-market losses recognized on the Company's risk management positions in 2016.

Gain on sale of assets decreased by $1,443 million in the first nine months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the third quarter.

Share of equity investment gain increased by $81 million in the first nine months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the third quarter and the formation of HMLP in mid-2016.

Provisions for income taxes decreased by $73 million in the first nine months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the third quarter.

5.2 Downstream

Upgrader

Upgrader Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2017**	2016	**2017**	2016
Gross revenues	**377**	334	**988**	984
Purchases of crude oil and products	**287**	225	**679**	584
Gross margin	**90**	109	**309**	400
Production, operating and transportation expenses	**45**	43	**148**	119
Selling, general and administrative expenses	**1**	—	**6**	2
Depletion, depreciation, amortization and impairment	**31**	27	**69**	82
Other – net	**—**	—	**—**	(1)
Financial items	**1**	1	**1**	1
Provisions for income taxes	**3**	11	**23**	54
Net earnings	**9**	27	**62**	143
Upgrader throughput *(mbbls/day)* [(1)]	**76.7**	69.2	**65.2**	74.6
Total sales *(mbbls/day)*	**79.4**	69.7	**65.3**	74.9
Synthetic crude oil sales *(mbbls/day)*	**58.2**	53.3	**47.6**	57.0
Upgrading differential *($/bbl)*	**13.60**	19.45	**17.73**	20.82
Unit margin *($/bbl)*	**12.32**	17.00	**17.33**	19.49
Unit operating cost *($/bbl)* [(2)]	**6.38**	6.75	**8.31**	5.82

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

Third Quarter

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 $43 million in the third quarter of 2017 compared to the third quarter of 2016 primarily due to higher sales volumes and higher realized prices for synthetic crude oil. Sales volumes increased by 9.7 mbbls/day, or 14 percent, and throughput increased by 7.5 mbbls/day, or 11 percent, compared to the third quarter of 2016. The price of Husky Synthetic Blend in the the third quarter of 2017 averaged $60.43/bbl compared to $58.97/bbl in the third quarter of 2016.

Upgrader feedstock purchases increased by $62 million in the third quarter of 2017 compared to the third quarter of 2016 primarily due to higher throughput volumes and higher Lloyd Heavy Blend pricing which averaged $46.84/bbl in the third quarter of 2017 compared to $39.53/bbl in the third quarter of 2016.

Upgrader gross margin decreased by $19 million in the third quarter of 2017 compared to the third quarter of 2016 primarily due to lower average upgrading differentials. During the third quarter of 2017, the upgrading differential averaged $13.60/bbl, a decrease of $5.85/bbl, or 30 percent compared to the third quarter of 2016. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The decrease in the upgrading differential was due to the tightening of the light/heavy differentials.

Nine Months

Upgrader gross revenues increased by $4 million in the first nine months of 2017 compared to the same period in 2016. Upgrader feedstock purchases increased by $95 million in the first nine months of 2017 compared to the same period in 2016 primarily due to higher Lloyd Heavy Blend pricing which averaged $47.04/bbl compared to $34.38/bbl in the same period in 2016, partially offset by lower crude throughput resulting from the planned turnaround in the second quarter of 2017. Upgrader gross margin decreased by $91 million in the first nine months of 2017 compared to the same period in 2016. The upgrading differential averaged $17.73/bbl, a decrease of $3.09/bbl, or 15 percent compared to the same period in 2016.

Production, operating and transportation expenses increased by $29 million in the first nine months of 2017 compared to the same period in 2016 primarily due to higher maintenance, labour and energy costs.

Provisions for income taxes decreased by $31 million in the first nine months of 2017 compared to the same period in 2016 primarily due to lower earnings before income taxes in 2017.

Canadian Refined Products

Canadian Refined Products Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2017**	2016	**2017**	2016
Gross revenues	**802**	678	**1,972**	1,698
Purchases of crude oil and products	**650**	516	**1,572**	1,295
Gross margin				
Fuel	**35**	35	**95**	98
Refining	**28**	33	**107**	82
Asphalt	**72**	79	**155**	179
Ancillary	**17**	15	**43**	44
	152	162	**400**	403
Production, operating and transportation expenses	**63**	62	**190**	175
Selling, general and administrative expenses	**12**	6	**34**	20
Depletion, depreciation, amortization and impairment	**27**	26	**83**	75
Gain on sale of assets	**(5)**	(2)	**(5)**	(3)
Other – net	**—**	(8)	**—**	(9)
Financial items	**3**	2	**9**	5
Provisions for income taxes	**14**	21	**24**	38
Net earnings	**38**	55	**65**	102
Number of fuel outlets [1]	**557**	481	**504**	481
Fuel sales volume, including wholesale				
Fuel sales *(millions of litres/day)*	**8.1**	6.8	**7.0**	6.6
Fuel sales per retail outlet *(thousands of litres/day)*	**12.4**	12.4	**11.9**	11.8
Refinery throughput				
Prince George Refinery *(mbbls/day)*	**11.9**	9.7	**11.1**	8.6
Lloydminster Refinery *(mbbls/day)*	**30.0**	26.7	**25.7**	27.6
Ethanol production *(thousands of litres/day)*	**845.9**	796.3	**798.5**	805.4

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

Third Quarter

Canadian Refined Products gross revenues increased by $124 million in the third quarter of 2017 compared to the third quarter of 2016 primarily due to higher sales volume at the Prince George Refinery, where a planned turnaround was completed in the third quarter of 2016 and higher refined product prices at the Lloydminister Refinery.

Canadian Refined Products purchases of crude oil and products increased by $134 million in the third quarter of 2017 compared to the third quarter of 2016 primarily due to higher commodity pricing.

Throughput at the Prince George Refinery increased by 2.2 mbbls/day, or 23 percent, due to a planned turnaround completed in the third quarter of 2016.

Nine Months

Canadian Refined Products gross revenues increased by $274 million in the first nine months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the third quarter as well as higher commodity pricing, offset by the lower volumes at the Lloydminster Refinery due to a planned turnaround in the second quarter of 2017.

Canadian Refined Products purchases of crude oil and products increased by $277 million in the first nine months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the third quarter, offset by the lower volumes at the Lloydminster Refinery due to a planned turnaround in the second quarter of 2017.

Refining gross margins increased by $25 million in the first nine months of 2017 compared to the same period in 2016 primarily due to higher sales volumes combined with higher ethanol pricing and refining margins.

Asphalt gross margins decreased by $24 million in the first nine months of 2017 compared to the same period in 2016 primarily due to market oversupply related to weather delays resulting in lower prices in 2017.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2017**	2016	**2017**	2016
Gross revenues	**2,292**	1,642	**6,600**	4,105
Purchases of crude oil and products	**1,876**	1,448	**5,743**	3,571
Gross margin	**416**	194	**857**	534
Production, operating and transportation expenses	**135**	127	**412**	391
Selling, general and administrative expenses	**4**	3	**11**	9
Depletion, depreciation, amortization and impairment	**82**	88	**264**	246
Other – net	**10**	—	**(7)**	(175)
Financial items	**4**	—	**10**	2
Provisions for (recovery of) income taxes	**67**	(8)	**62**	23
Net earnings (loss)	**114**	(16)	**105**	38
Select operating data:				
Lima Refinery throughput *(mbbls/day)*	**178.3**	155.6	**174.8**	129.1
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**77.3**	58.4	**75.1**	56.3
Refining margin *(US$/bbl crude throughput)*	**13.38**	7.34	**9.77**	9.60
Refinery inventory *(mmbbls)* [(1)]	**8.4**	11.2	**8.4**	11.2

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

Third Quarter

U.S. Refining and Marketing gross revenues increased by $650 million in the third quarter of 2017 compared to the third quarter of 2016 primarily due to the higher Chicago 3:2:1 crack spreads and higher sales volume as a result of stronger operations in 2017 and a scheduled major planned turnaround at the BP-Husky Toledo Refinery completed in the third quarter of 2016.

U.S. Refining and Marketing purchases of crude oil and products increased by $428 million in the third quarter of 2017 compared to the third 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 22.7 mbbls/day when compared to the third quarter of 2016 due to the isocracker being fully in service in 2017. Throughput at the BP-Husky Toledo Refinery increased by 18.9 mbbls/day compared to the third quarter of 2016 primarily due to a scheduled major turnaround completed in the third quarter of 2016.

U.S. Refining and Marketing gross margin increased by $222 million in the third quarter of 2017 compared to the third quarter of 2016 primarily due to higher Chicago 3:2:1 crack spreads and higher sales volumes.

Provision of income taxes increased by $75 million in the third quarter of 2017 compared to the third quarter of 2016 primarily due to higher earnings before income taxes in the third quarter of 2017.

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 an increase in net earnings of approximately $31 million in the third quarter of 2017 compared to a reduction in net earnings of $40 million in the third quarter of 2016.

Nine Months

U.S. Refining and Marketing gross revenues increased by $2,495 million and purchases of crude oil and products increased by $2,172 million in the first nine months of 2017 compared to the same period in 2016, primarily due to the same factors which impacted the third quarter as well as the major planned turnaround at the Lima Refinery in the second quarter of 2016.

U.S. Refining and Marketing gross margin increased by $323 million in the first nine months of 2017 compared to the same period in 2016 primarily due to the same factors which impacted the third quarter.

Other – net income decreased by $168 million in the first nine months of 2017 compared to the same period in 2016 primarily due to reduced insurance recoveries associated with the isocracker unit fire in 2016.

Provisions for income taxes increased by $39 million million in the first nine months of 2017 compared to the same period in 2016 primarily due to higher earnings before income taxes in the first nine months of 2017.

Downstream Capital Expenditures

In the first nine months of 2017, Downstream capital expenditures totalled $469 million compared to $628 million in the same period in 2016. The decrease in Downstream capital expenditures was primarily due to the completion of major planned turnarounds at the Lima Refinery and BP-Husky Toledo Refinery and the feedstock optimization project in U.S. Refining and Marketing in 2016. In Canada, capital expenditures of $278 million were primarily related to the scheduled turnarounds at the Lloydminster Upgrader and Lloydminster Refinery in the second quarter of 2017. At the Lima Refinery, capital expenditures of $125 million were primarily related to the crude oil flexibility project and various reliability, safety and environmental protection initiatives. At the BP-Husky Toledo Refinery, capital expenditures of $66 million (Husky working interest) were primarily related to reliability, safety and environmental protection initiatives.

5.3 Corporate

Corporate Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions) income (expense)	**2017**	2016	**2017**	2016
Selling, general and administrative expenses	**(61)**	(39)	**(183)**	(184)
Depletion, depreciation and amortization	**(18)**	(22)	**(51)**	(63)
Other – net	**(12)**	17	**(9)**	(114)
Net foreign exchange gain (loss)	**2**	1	**(11)**	5
Finance income	**9**	2	**22**	7
Finance expense	**(58)**	(60)	**(175)**	(182)
Recovery of income taxes	**75**	56	**172**	109
Net loss	**(63)**	(45)	**(235)**	(422)

Third Quarter

The Corporate segment reported a net loss of $63 million in the third quarter of 2017 compared to a net loss of $45 million in the third quarter of 2016. Selling, general and administrative expenses increased by $22 million in the third quarter of 2016 primarily due to an increase in employee costs and stock-based compensation.

Nine Months

The Corporate segment reported a net loss of $235 million in the first nine months of 2017 compared to a net loss of $422 million in the same period in 2016. Other – net expense of $114 million in the first nine months of 2016 related primarily to losses on the Company's short term hedging program which concluded in June 2016.

Foreign Exchange Summary	Three months ended September 30,		Nine months ended September 30,	
($ millions, except where indicated)	**2017**	2016	**2017**	2016
Non-cash working capital gain (loss)	**(8)**	—	**(13)**	(20)
Other foreign exchange gain	**10**	1	**2**	25
Net foreign exchange gain (loss)	**2**	1	**(11)**	5
U.S./Canadian dollar exchange rates:				
At beginning of period	**US$0.770**	US$0.769	**US$0.745**	US$0.723
At end of period	**US$0.799**	US$0.762	**US$0.799**	US$0.762

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 September 30,		Nine months ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Provisions for (recovery of) income taxes	**24**	114	**(18)**	(33)
Cash income taxes paid (recovered)	**(122)**	47	**(35)**	(9)

Third Quarter

Consolidated income taxes provision was $24 million in the third quarter of 2017 compared to a provision of $114 million in the third quarter of 2016. The decrease in consolidated income tax provision was primarily due to the recognition of gains on the sale of the Company's ownership interest in select midstream assets and the sale of select Western Canada legacy oil and natural gas assets in the third quarter of 2016.

Nine Months

Consolidated income taxes recovery was $18 million in the first nine months of 2017 compared to a recovery of $33 million in the same period in 2016.

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 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 September 30, 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 15 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 September 30, 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 less than $1 million. The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $1 million for both the three and nine months ended September 30, 2017.

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 September 30, 2017, the balance in other reserves related to the accrued gain was $16 million, net of tax of $6 million. The amortization of the accrued gain resulted in an offset to finance expenses of nil and $2 million for the three and nine months ended September 30, 2017. Refer to the Interest Rate Risk Management disclosure within Note 15 of the condensed interim consolidated financial statements.

Foreign Currency Risk Management

At September 30, 2017, 64 percent or Cdn $3.4 billion (US$2.7 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.

For the three and nine months ended September 30, 2017, the Company incurred an unrealized gain of $130 million and unrealized gain of $245 million, respectively, arising from the translation of the debt, net of tax of $21 million and $39 million, respectively, 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 September 30, 2017, the Company's share of this obligation was US$58 million including accrued interest. At September 30, 2017, the cost of a Canadian dollar in U.S. currency was $0.799.

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 September 30, 2017, the Company had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities [(1)]	**750**	**325**
Syndicated credit facilities [(2)]	**4,000**	**3,800**
	4,750	**4,125**

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

At September 30, 2017, the Company had $4,125 million of unused credit facilities of which $3,800 million are long-term committed credit facilities and $325 million are short-term uncommitted credit facilities. A total of $425 million short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $200 million of long-term committed borrowing credit facilities was used in support of commercial paper. At September 30, 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 credit 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 September 30, 2017, working capital was $2,461 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 September 30, 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 US$3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the United States up to and including January 22, 2018. During the 25-month period that the 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.

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 September 30, 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 a universal short form base shelf prospectus (the "2017 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including April 30, 2019. The 2017 Canadian Shelf Prospectus replaced the 2015 Canadian Shelf Prospectus, which expired on March 23, 2017. During the 25-month period that the 2017 Canadian Shelf Prospectus is in effect, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

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

As at September 30, 2017, the Company has $3.0 billion in unused capacity under the 2017 Canadian Shelf Prospectus and US$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 2017 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 *($ millions)*	**September 30, 2017** **Outstanding**
Total debt [(1)]	**5,436**
Common shares, preferred shares, retained earnings and accumulated OCI	**17,317**

[(1)] *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 $22.8 billion as at September 30, 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 September 30, 2017, debt to capital employed was 23.9 percent (December 31, 2016 – 23.2 percent) and debt to funds from operations was 1.9 times (December 31, 2016 – 2.4 times), within the Company's targets.

The increase in the Company's debt to capital employed as at September 30, 2017 is due to the issuance of $750 million in notes during the first six months of 2017, partially offset by debt repayment of $365 million during the third quarter of 2017. The decrease in debt to funds from operations ratio as at September 30, 2017 is due to higher net earnings from higher global commodity prices offset by the issuance and the repayment of those notes described above. 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 commodity cycles. 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 three months ended September 30, 2017, Husky-CNOOC Madura Limited, of which the Company is a joint venturer, entered into an arrangement to lease a floating production unit for the purposes of producing the MDA-MBH field gas reserves. The Company's 40 percent proportionate share of the additional obligations to fund the equity investee is $193 million for a term of 10 years subsequent to the date of commencement.

During the three months ended September 30, 2017, the Company entered into new agreements totaling an incremental $230 million for a term of 15 years to purchase refined products for the expanded Canadian truck transportation network.

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. These transactions are related party transactions, as the Company has a 35 percent ownership interest in HMLP and the remaining ownership interests in HMLP belong to PAH and CKI, which are affiliates of one of the Company's principal shareholders. For the three and nine months ended September 30, 2017, the Company charged HMLP $113 million and $266 million, respectively, related to construction and management services, and the Company had purchases from HMLP of $52 million and $156 million, respectively, related to the use of the pipeline for the Company's blending, transportation and storage activities. As at September 30, 2017, the Company had $73 million due from HMLP and $20 million 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, as well as the Company's 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 and nine months ended September 30, 2017, the amount of natural gas sales to Meridian totalled $8 million and $34 million, respectively, the amount of steam purchased by the Company from Meridian totalled $3 million and $12 million, respectively, and the total cost recovery by the Company for facilities services was $2 million and $9 million, respectively. At September 30, 2017, the Company had $2 million due from Meridian with respect to these transactions.

At September 30, 2017, $31 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 judgment 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 implementation of IFRS 16 consists of four phases:

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

The Company is currently in the scoping phase of implementing IFRS 16. The impact on the Company's consolidated financial statements upon adoption of IFRS 16 is currently being assessed.

Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Early adoption is permitted.

The implementation of IFRS 15 consists of four phases:

- Project awareness and engagement - This phase includes identifying and engaging the appropriate members of the finance and operations teams, as well as communicating the key requirements of IFRS 15 to stakeholders.
- Scoping - This phase focuses on identifying the Company's major revenue streams, determining how and when revenue is currently recognized and determination of whether any changes are expected upon adoption.

- Detailed analysis and solution development - Steps in this phase include addressing any potential differences in revenue recognition identified in the scoping phase, according to the priority assigned. This involves detailed analysis of the IFRS 15 revenue recognition criteria, review of contracts with customers to ensure revenue recognition practices are in accordance with IFRS 15 and evaluating potential changes to revenue processes and systems.
- Implementation - This phase includes implementing the changes required for compliance with IFRS 15. The focus of this phase is the approval and implementation of any new accounting and tax policies, processes, systems and controls, as required, as well as the execution of customized training programs and preparation of disclosures under IFRS 15.

The Company is currently in the detailed analysis and solution development phase of implementing IFRS 15. The adoption of 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 implementation of IFRS 9 consists of four phases:

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

The Company is currently in the implementation phase of implementing IFRS 9. 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 Statements 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: October 23, 2017:

• common shares	1,005,120,012
• cumulative redeemable preferred shares, series 1	10,435,932
• cumulative redeemable preferred shares, series 2	1,564,068
• cumulative redeemable preferred shares, series 3	10,000,000
• cumulative redeemable preferred shares, series 5	8,000,000
• cumulative redeemable preferred shares, series 7	6,000,000
• stock options	23,000,416
• stock options exercisable	13,261,323

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 September 30, 2017 and the nine months ended September 30, 2017 are compared to the results for the three months ended September 30, 2016 and the nine months ended September 30, 2016. Discussions with respect to the Company's financial position as at September 30, 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 September 30, 2017 that have materially affected, or are reasonably likely to affect, the Company's ICFR.

Cautionary Note Required by National Instrument 51-101

Unless otherwise noted, historical production volumes provided represent the Company's working interest share before royalties.

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

Non-GAAP Measures

Disclosure of non-GAAP Measures

The Company uses measures primarily based on IFRS and also on secondary non-GAAP measures. The non-GAAP measures included in this MD&A and related disclosures are: adjusted net earnings (loss), funds from operations, free cash flow, debt to capital employed, debt to funds from operations and LIFO. None of these measures are used to enhance the Company's reported financial performance or position. There are no comparable measures in accordance with IFRS for debt to capital employed or debt to funds from operations. These are useful complementary measures in assessing the Company's financial performance, efficiency and liquidity. The non-GAAP measures do not have 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)

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

The following table shows the reconciliation of net earnings (loss) to adjusted net earnings (loss) for the three and nine months ended September 30, 2017 and 2016:

		Three months ended September 30,		Nine months ended September 30,	
($ millions)		**2017**	2016	**2017**	2016
GAAP	Net earnings	**136**	1,390	**114**	736
	Impairment of property, plant and equipment, net of tax	**—**	—	**123**	12
	Exploration and evaluation asset write-downs, net of tax	**1**	—	**4**	22
	Gain on sale of assets, net of tax	**(1)**	(1,490)	**(24)**	(1,419)
Non-GAAP	Adjusted net earnings (loss)	**136**	(100)	**217**	(649)

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 measure assists management and investors in evaluating the Company's financial strength.

Debt to Funds from Operations

Debt to funds from operations is a non-GAAP measure and is equal to long-term debt, long-term debt due within one year and short-term debt divided by funds from operations. Funds from operations is equal to cash flow – operating activities plus change in non-cash working capital. Management believes this measure 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 September 30, 2017, and December 31, 2016:

($ millions)	**September 30, 2017**	December 31, 2016
Total debt	**5,436**	5,339
Funds from operations[1]	**2,929**	2,198
Debt to funds from operations	**1.9**	2.4

[1] *Annualized using 12 - month rolling figures.*

Funds from Operations and Free Cash Flow

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

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

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

The following table shows the reconciliation of net earnings to funds from operations and free cash flow, and related per share amounts for the three and nine months ended September 30, 2017, and 2016:

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Net earnings	**136**	1,390	**114**	736
Items not affecting cash:				
Accretion	**27**	29	**84**	96
Depletion, depreciation, amortization and impairment	**673**	638	**2,235**	2,057
Exploration and evaluation expenses	**1**	—	**6**	30
Deferred income taxes	**52**	99	**1**	(16)
Foreign exchange loss (gain)	**(3)**	12	**(5)**	25
Stock-based compensation	**11**	5	**20**	30
Gain on sale of assets	**(2)**	(1,680)	**(33)**	(1,582)
Unrealized mark to market loss (gain)	**31**	(28)	**(1)**	12
Share of equity investment loss (gain)	**(12)**	21	**(60)**	23
Other	**9**	(2)	**8**	(5)
Settlement of asset retirement obligations	**(23)**	(11)	**(91)**	(56)
Deferred revenue	**(9)**	146	**(11)**	186
Change in non-cash working capital	**3**	124	**61**	(209)
Cash flow – operating activities	**894**	743	**2,328**	1,327
Change in non-cash working capital	**(3)**	(124)	**(61)**	209
Funds from operations	**891**	619	**2,267**	1,536
Capital expenditures	**(511)**	(309)	**(1,475)**	(1,314)
Free cash flow	**380**	310	**792**	222
Funds from operations – basic	**0.89**	0.62	**2.25**	1.53
Funds from operations – diluted	**0.89**	0.62	**2.25**	1.53

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.

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	*Funds from operations equals cash flow – operating activities plus change in non-cash working capital*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Heavy crude oil	*Crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity*
High-TAN	*A measure of acidity. Crude oils with a high content of naphthenic acids are referred to as high total acid number (TAN) crude oils or high acid crude oil. The TAN value is defined as the milligrams of Potassium Hydroxide required to neutralize the acidic group of one gram of the oil sample. Crude oils in the industry with a TAN value greater than 1 are referred to as high-TAN crudes*
Last in first out ("LIFO")	*Last in first out accounting assumes that crude oil feedstock costs are based on the current month price of WTI*
Light crude oil	*Crude oil with a relative density greater than 31.1 degrees API gravity*
Medium crude oil	*Crude oil with a relative density that is greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity*
Net 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 associated mineral substances*
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*	*SAGD*	*Steam-assisted Gravity Drainage*
mbbls	*thousand barrels*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
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 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 adjusted funds from operations ratio targets; and the Company’s 2017 Upstream capital expenditure program;

- with respect to the Company's thermal developments: the Company’s forecasted daily total bitumen production for the fourth quarter of 2017; anticipated timing of first production from and design capacity of the Company’s Rush Lake 2 thermal development and its three Lloyd thermal projects at Dee Valley, Spruce Lake North and Spruce Lake Central; anticipated timing of first steam and 2018 production expectations for the Tucker Thermal Project; and the Company’s forecasted 2017 average annual production from the Sunrise Energy Project;

- with respect to the Company's Offshore business in Asia Pacific: the anticipated timing of project sanctioning for Liuhua 29-1; the Company’s drilling plans at Block 15/33 and Block 16/25 offshore China; the expected timing of ramp-up to full gas sales rate, and gross daily sales targets of natural gas and NGLs, at the Madura-BD Gas Project; the expected timing of drilling of five MDA field production wells and two MBH field production wells, and the expected timing of first gas therefrom; the expected timing of tie-in of the additional MDK shallow water field; and anticipated combined daily gross sales volumes from the Madura-BD Gas Project and the MDA-MBH and MDK fields once production is fully ramped up;

- with respect to the Company's Offshore business in the Atlantic: the expected timing of construction of the concrete gravity structure at the West White Rose Project; the expected timing of first oil and the expected timing and volume of gross peak production at the West White Rose Project; the expected peak production from the oil production well at South White Rose; and the timing of first oil from an additional infill well at White Rose;

- with respect to the Company's Western Canada resource play development: the Company's strategic and drilling plans for its Western Canada portfolio; expected timing of the closing of the sale of the Company's Ram River and Foothills Deep Gas assets; and the expected timing of first production from the two wells at Karr; and

- with respect to the Company's Downstream operating segment: the expected timing for completion of the crude oil flexibility project at the Lima Refinery; the expected timing of a final investment decision on the potential expansion of the Company's Lloydminster asphalt refinery; and the expected timing of closing of the acquisition of the Superior 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, including the timing of regulatory approvals, that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third party consultants, suppliers and regulators, among others.

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

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