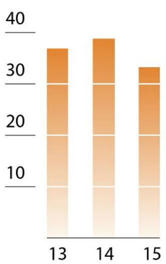
MANAGEMENT'S DISCUSSION AND ANALYSIS

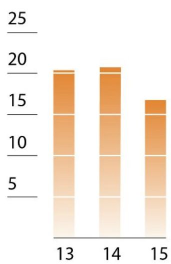
1.0 Financial Summary

1.1 Financial Position

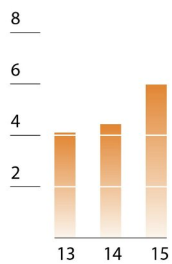
Total Assets
($ billions)



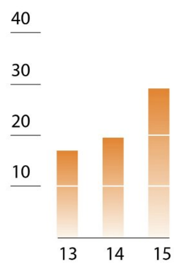
Total Equity
($ billions)



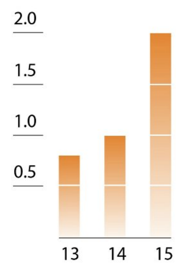
Total Long-term Debt *($ billions)*



Debt to Capital Employed[(1)] *(%)*

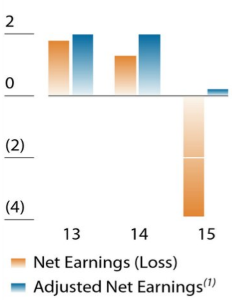


Debt to Cash Flow from Operations[(1)]
(times)

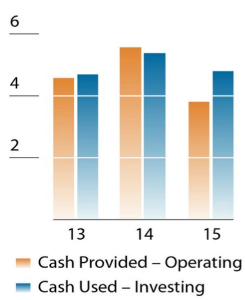


1.2 Financial Performance

Net Earnings (Loss)
($ billions)



Cash Flow
($ billions)

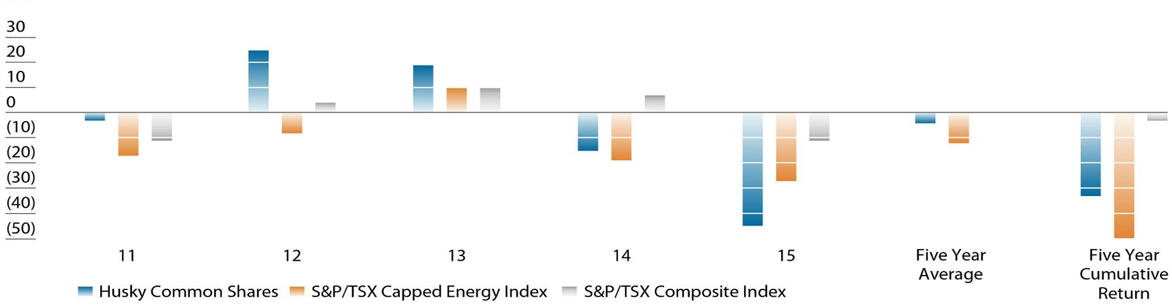


[(1)] *Debt to capital employed, debt to cash flow from operations and adjusted net earnings are non-GAAP measures. Adjusted net earnings was redefined in the third quarter of 2015 to equal net earnings before after-tax property, plant and equipment impairment, goodwill impairment, exploration and evaluation asset write-downs and inventory write-downs. Prior periods have been revised to conform with the current period presentation. Refer to Section 11.3.*

1.3 Total Shareholder Returns

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

Total Shareholder Returns
(%)



1.4 Selected Annual Information

($ millions, except where indicated)	2015	2014	2013
Gross revenues and Marketing and other	16,801	25,122	24,181
Net earnings (loss) by business segment			
Upstream	(4,254)	1,106	1,244
Downstream	660	363	830
Corporate	(256)	(211)	(245)
Net earnings (loss)	(3,850)	1,258	1,829
Net earnings (loss) per share – basic	(3.95)	1.26	1.85
Net earnings (loss) per share – diluted	(4.01)	1.20	1.85
Adjusted net earnings[(1)]	165	2,019	2,040
Cash flow from operations[(1)]	3,329	5,535	5,222
Ordinary dividends per common share[(2)]	0.90	1.20	1.20
Dividends per cumulative redeemable preferred share, series 1	1.11	1.11	1.11
Dividends per cumulative redeemable preferred share, series 3	1.19	–	–
Dividends per cumulative redeemable preferred share, series 5	0.90	–	–
Dividends per cumulative redeemable preferred share, series 7	0.62	–	–
Total assets	33,056	38,848	36,904
Short-term debt	720	895	–
Long-term debt including current portion	6,036	4,397	4,119
Total debt[(3)]	6,756	5,292	4,119
Cash and cash equivalents	70	1,267	1,097

(1) *Adjusted net earnings and cash flow from operations are non-GAAP measures. Adjusted net earnings was redefined in the third quarter of 2015 to equal net earnings before after-tax property, plant and equipment impairment, goodwill impairment, exploration and evaluation asset write-downs and inventory write-downs. Prior periods have been revised to conform with the current period presentation. Refer to Section 11.3 for a reconciliation to the GAAP measures.*
(2) *Dividends declared for the third quarter of 2015 were issued in the form of common shares. The quarterly common share dividend was suspended for the fourth quarter of 2015.*
(3) *Total debt includes short-term debt and long-term debt including current portion.*

2.0 Husky Business Overview

Husky Energy Inc. ("Husky" or the "Company") is one of Canada's largest integrated energy companies and is based in Calgary, Alberta. The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and the Cumulative Redeemable Preferred Shares Series 1, Series 3, Series 5 and Series 7 are listed under the symbols, "HSE.PR.A", "HSE.PR.C", "HSE.PR.E" and "HSE.PR.G", respectively. The Company operates in Western Canada, the United States, the Asia Pacific Region and the Atlantic Region within Upstream and Downstream business segments. Husky's balanced growth strategy focuses on consistent execution, disciplined financial management and safe and reliable operations.

2.1 Upstream

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

Profile and highlights of the Upstream segment include:

Heavy Oil

- Heavy oil thermal portfolio with production of approximately 48,400 bbls/day in 2015, compared to 43,800 bbls/day in 2014, and expected to increase to approximately 80,000 bbls/day by the end of 2016;
- First oil was achieved at the Rush Lake heavy oil thermal development in the third quarter of 2015. In addition, the Company announced the sanctioning of a second 10,000 bbls/day heavy oil thermal development, Rush Lake 2, in November 2015;
- Construction continued at the two 10,000 bbls/day Edam East and Vawn and the 4,500 bbls/day Edam West heavy oil thermal developments. First production is expected from Edam East in the second quarter of 2016 and from Vawn and Edam West in the third quarter of 2016;
- Development of the newly identified Colony formation commenced in 2015 at the Tucker thermal project in the Cold Lake region, which has similar characteristics to heavy oil thermal reservoirs in the Lloydminster region. First steam commenced in the first quarter of 2016 with first production expected in the second quarter; and
- Three additional 10,000 bbls/day heavy oil thermal developments have been identified in the Lloydminster region for development.

Asia Pacific Region

- The Liwan Gas Project, the first deepwater development offshore China, consists of three deepwater natural gas fields: Liwan 3-1, Liuhua 34-2 and Liuhua 29-1. Combined gross production from the Liwan 3-1 and Liuhua 34-2 gas fields increased during 2015 with natural gas production averaging 286 mmcf/day and NGL production averaging 14.6 mbbls/day. Negotiations for the sale of gas and liquids from Liuhua 29-1, the third deepwater field, are being pursued together with China National Offshore Oil Corporation ("CNOOC"). Husky holds a 49 percent working interest in the production sharing contract ("PSC") at the Liwan Gas Project and operates the deepwater infrastructure;
- Husky holds a 40 percent working interest in the Wenchang oil field, located in the Pearl River Mouth Basin approximately 400 kilometres southwest of the Hong Kong Special Administrative Region. The PSC is due to expire in the third quarter of 2017;
- Husky holds a 40 percent working interest in a joint venture company that holds the PSC for the Madura Strait Block covering approximately 622,000 acres, offshore East Java, south of Madura Island, Indonesia, and is focused on the development of the BD, MDA, MBH and MDK fields. The liquids-rich BD field is the first gas development Husky is advancing in the region and remains on target for first production in the 2017 timeframe. In November 2015, the Company sanctioned the development of the MDA, MBH and MDK gas fields having secured the Gas Sales Agreement for the first tranche of gas from the MDA and MBH fields development. Combined net sales volumes from the BD, MDA, MBH and MDK fields are expected to be about 100 mmcf/day of gas and 2,400 boe/day of associated NGL once fully ramped up. Production from the MDA, MBH and MDK gas fields is expected in the 2018 - 2019 timeframe;
- Longer term, the Company has four other discoveries in the Madura Straight Block that are under evaluation for development;
- Husky has a 100 percent interest in the rights to the Anugerah exploration block covering approximately two million acres. The Anugerah exploration block is located in the East Java Basin, Indonesia approximately 150 kilometres east of the Madura Strait Block;
- Husky and its joint venture partner CPC Corporation have rights to an exploration block in the South China Sea covering approximately 10,000 square kilometres located 100 kilometres southwest of the island of Taiwan. Husky holds a 75 percent working interest during exploration, while CPC Corporation has the right to participate in the development program up to a 50 percent interest; and
- During 2015, Husky signed a PSC for an exploration block offshore China. The 15/33 block covers approximately 155 square kilometres and is located in the Pearl River Mouth Basin in the South China Sea, approximately 140 kilometres southeast of the Hong Kong Special Administrative Region, in water depths of approximately 80 - 100 metres. Husky is the operator of the block during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, its partner CNOOC may assume a working interest of up to 51 percent during the development and production phase. Exploration cost recovery from production would be allocated to Husky.

Oil Sands

- The Sunrise Energy Project, a multiple stage in-situ oil sands project, achieved first oil on Phase 1 in March 2015. Gross production from the Sunrise Energy Project is continuing to ramp-up, averaging 14,200 bbls/day (7,100 bbls/day net Husky share) in the fourth quarter of 2015, and is expected to increase to 60,000 bbls/day (30,000 bbls/day net Husky share) around the end of 2016. The Sunrise Energy Project uses proven steam-assisted gravity drainage ("SAGD") technology, keeping site disturbance to a minimum. Regulatory approval is in place to expand the project to 200,000 bbls/day (100,000 bbls/day net Husky share); and
- In addition to the Sunrise Energy Project, Husky has an extensive portfolio of undeveloped oil sands leases, encompassing in excess of net 2,400 square kilometres in Alberta.

Atlantic Region

- Husky is the operator of the White Rose field with a 72.5 percent working interest in the core field and a 68.875 percent working interest in satellite tiebacks, including the North Amethyst, West White Rose and South White Rose extensions. Husky has a 13 percent non-operated interest in the Terra Nova oil field;
- Production commenced in the year from the first two development wells at the South White Rose extension and reached peak rates of 15,000 bbls/day net to Husky in September 2015;
- The Company has secured the drilling rig Henry Goodrich for a two-year drilling program focusing on development drilling at the White Rose field and satellite extensions. This includes activities at the South White Rose extension and North Amethyst field and near-field exploration. The rig is expected to arrive in mid-2016; and
- Husky has a 35 percent interest in three discoveries in the Flemish Pass Basin: Bay Du Nord, Mizzen and Harpoon. The offshore exploration and development program in the Atlantic Region is primarily focused on the Jeanne d'Arc Basin and the Flemish Pass Basin.

Western Canada Conventional and Resource Plays

- Large position in Western Canada oil and liquids-rich natural gas resource plays of approximately 1.8 million net acres;
- Expertise and experience exploring and developing the natural gas potential in the Alberta Deep Basin, Foothills and northwest plains of Alberta and British Columbia; and
- Crude oil producing properties in Western Canada that continue to produce with existing technology and have responded well to increasingly sophisticated techniques, such as horizontal drilling and enhanced oil recovery techniques.

Infrastructure and Marketing

- Extensive integrated heavy oil pipeline systems in the Lloydminster producing region;
- The Hardisty terminal expansion project which was completed in 2015 and included multiple initiatives to increase pipeline connectivity, blending capacity and product storage to support upstream production growth and provide additional flexibility in marketing the Company's products. In addition, construction is ongoing for the expansion of the Saskatchewan Gathering System which will accommodate production from the Company's heavy oil thermal developments; and
- The Infrastructure and Marketing business manages the sale and transportation of the Company's Upstream and Downstream production and third-party commodity trading volumes through access to capacity on third-party pipelines and storage facilities in both Canada and the United States.

2.2 Downstream

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

Profile and highlights of the Downstream segment include:

Upgrading

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

Canadian Refined Products

- Largest marketer of paving asphalt in Western Canada with a 29 mbbls/day capacity asphalt refinery located in Lloydminster, Alberta integrated with the local heavy oil production, transportation and upgrading infrastructure;
- Largest producer of ethanol in Western Canada with a combined 260 million litres per year of capacity at plants located in Lloydminster, Saskatchewan and Minnedosa, Manitoba;
- Refinery at Prince George, British Columbia with throughput capacity of 12 mbbls/day producing low sulphur gasoline and ultra low sulphur diesel; and
- Major regional motor fuel marketer with 485 retail marketing locations as at December 31, 2015, including bulk plants and travel centres with strategic land positions in Western Canada and Ontario. During 2015, the Company and Imperial Oil entered into a contractual agreement to create a single expanded truck transport network of approximately 160 sites. The agreement is subject to regulatory approval by Canada's Competition Bureau and other closing conditions.

U.S. Refining and Marketing

- Refinery in Lima, Ohio with a gross crude oil throughput capacity of 160,000 bbls/day and operating capacity of 135,000 – 155,000 bbls/day on its current crude slate. The Company is proceeding with the initial stages of a crude oil flexibility project designed to improve reliability at the facility and allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada. The crude oil flexibility project will allow the Refinery to swing between light and heavy crude oil feedstock; and
- A 50 percent interest in the BP-Husky Refinery in Toledo, Ohio with a nameplate capacity of 160,000 bbls/day and operating capacity of 135,000 – 145,000 bbls/day on its current crude slate. A feedstock optimization project was recently sanctioned by the joint arrangement partners which is designed to improve the Refinery's ability to process crude oils with a high content of naphthenic acids ("Hi-TAN"). Targeted completion of the required metallurgy changes will be performed during the Refinery's turnaround starting in the second quarter of 2016. Once the upgrades are complete, the Refinery will have the ability to process up to an additional 35,000 bbls/day of Hi-TAN crude. The Refinery's overall nameplate capacity will remain at 160,000 bbls/day.

3.0 The 2015 Business Environment

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

- The imbalance between global crude oil supply and demand, led primarily by the growth in U.S. unconventional and the Organization of the Petroleum Exporting Countries ("OPEC") production, lower economic growth forecasts from emerging markets and corresponding growth in global crude oil inventories, resulted in the continued weakness of key crude oil benchmarks in 2015;
- The substantial supply of natural gas in North America, resulting largely from technological advances in horizontal drilling and hydraulic fracturing which have unlocked significant reserves that were not economical under previously applied extraction methods, resulted in the continued weakness of North American natural gas benchmark prices in 2015;
- The weakening of the Canadian dollar in relation to the U.S. dollar;
- Reduced production growth from the Western Canadian oil sands resulting from lower benchmark crude oil prices;
- Industry advancement in alternative and improved extraction methods have rapidly evolved in North American and international onshore and offshore activity;
- A continuing emphasis on environmental, health and safety, enterprise risk management, resource sustainability and corporate social responsibility;
- Transportation constraints on crude oil produced in Western Canada. The oil and gas industry continues to work with stakeholders to develop a strong network of transportation infrastructure including pipelines, rail, marine and trucks. The development of a strong infrastructure network continues to be an important challenge for the industry in order to obtain market access for the growing supply of crude oil from the Western Canadian oil sands;
- A new climate change policy in Alberta that includes: an accelerated phase-out of coal, a new carbon pricing approach, a cap on total oil sands emissions and a methane gas emissions reduction plan. Details of the new policy are expected to be finalized in 2016;
- A new international climate change agreement, known as the Paris Agreement, was signed by Canada along with 195 other countries during 2015;
- In early 2016, the Alberta government adopted the recommendation of its Royalty Review Panel. The new royalty framework preserves the existing royalty structure and rates for oil sands. It also creates a harmonized royalty formula for crude oil, natural gas and NGL that emulates a revenue minus cost system. The new rates will be calibrated to match rates of returns that could be expected under the existing system. The royalty changes will take effect in 2017 and only apply to new wells. Royalties on existing wells will remain in place for 10 years;
- An increase in the Alberta provincial corporate tax rate during 2015 from 10 to 12 percent;
- Economic conditions remain uncertain as national indebtedness among countries and other factors continue to impact global GDP growth; and
- Continued global economic uncertainty has led to a tightening of investment from historical norms, creating greater competition among companies within capital markets and postponement of various capital projects.

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

The Company is exposed to a number of risks inherent to the exploration, development, production, marketing, transportation, storage and sale of crude oil, liquids-rich natural gas and related products. For a discussion on Risk and Risk Management, see Section 7.0 and the 2015 Annual Information Form.

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

Average Benchmarks

Average Benchmarks Summary		2015	2014
WTI crude oil[1]	(U.S. $/bbl)	**48.80**	93.00
Brent crude oil[2]	(U.S. $/bbl)	**52.46**	98.99
Light sweet at Edmonton	($/bbl)	**57.21**	94.57
Daqing[3]	(U.S. $/bbl)	**49.26**	98.18
Western Canada Select at Hardisty[4]	(U.S. $/bbl)	**35.28**	73.60
Lloyd heavy crude oil at Lloydminster	($/bbl)	**39.15**	73.28
WTI/Lloyd crude blend differential	(U.S. $/bbl)	**13.43**	19.41
Condensate at Edmonton	(U.S. $/bbl)	**47.36**	92.95
NYMEX natural gas[5]	(U.S. $/mmbtu)	**2.66**	4.42
NIT natural gas	($/GJ)	**2.62**	4.19
Chicago Regular Unleaded Gasoline	(U.S. $/bbl)	**67.11**	106.70
Chicago Ultra-low Sulphur Diesel	(U.S. $/bbl)	**68.02**	117.17
Chicago 3:2:1 crack spread	(U.S. $/bbl)	**18.62**	17.28
U.S./Canadian dollar exchange rate	(U.S. $)	**0.783**	0.906
Canadian Equivalents[6]			
WTI crude oil	($/bbl)	**62.32**	102.65
Brent crude oil	($/bbl)	**67.00**	109.26
Western Canada Select at Hardisty	($/bbl)	**45.06**	81.24
WTI/Lloyd crude blend differential	($/bbl)	**17.15**	21.42
NYMEX natural gas	($/mmbtu)	**3.40**	4.88

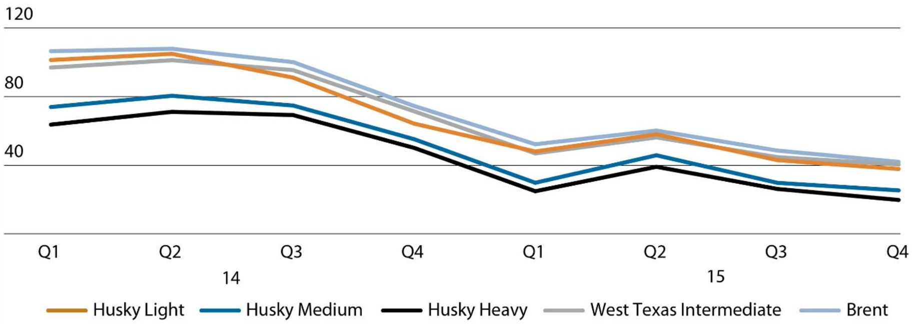
(1) *Calendar Month Average of settled prices for West Texas Intermediate at Cushing, Oklahoma.*
(2) *Calendar Month Average of settled prices for Dated Brent.*
(3) *Calendar Month Average of settled prices for Daqing.*
(4) *Western Canadian Select is a heavy blended crude oil, comprised of conventional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

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

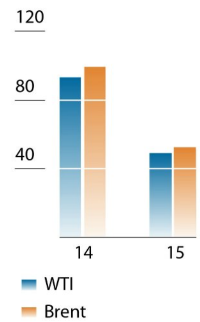
The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil. In the Upgrading business, heavy crude oil feedstock is processed into light synthetic crude oil. Husky's U.S. Refining and Marketing business processes a mix of different types of crude oil from various sources, but the mix is primarily light sweet crude oil at the Lima Refinery and approximately 50 percent heavy crude oil feedstock at the BP-Husky Toledo Refinery. The Company's Canadian Refined Products business relies primarily on purchased refined products for resale in the retail distribution network. Refined products are acquired, under supply contracts, from other Canadian refiners at rack prices or from production from the Husky Prince George Refinery.

Crude Oil Benchmarks

WTI, Brent and Husky Average Crude Oil Prices
(U.S. $/bbl)



Average WTI and Brent
(U.S. $/bbl)



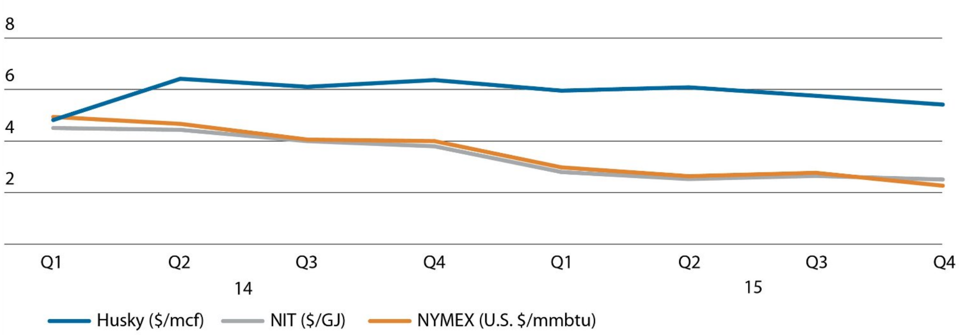
Key crude oil benchmarks declined significantly during 2015 as the global supply and demand imbalance persisted. Crude oil inventories in the U.S. surged higher during 2015 and ended the year at approximately 487 million barrels excluding strategic reserves. The increase in global crude oil supply was primarily attributable to growth from U.S. unconventional production and from OPEC.

The price received by the Company for crude oil production from Western Canada is primarily driven by the price of West Texas Intermediate ("WTI"), adjusted to Western Canada. The price received by the Company for crude oil production from the Atlantic Region is primarily driven by the price of Brent and the price received by the Company for crude oil and NGL production from the Asia Pacific Region is primarily driven by the price of Daqing. A portion of Husky's crude oil production from Western Canada is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2015, 57 percent of Husky's crude oil production was heavy crude oil or bitumen which was comparable to 56 percent in 2014.

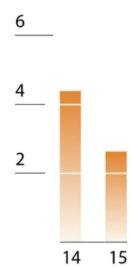
Husky's heavy crude oil and bitumen production is blended with diluent (condensate) in order to facilitate its transportation through pipelines. Therefore, the price received for a barrel of blended heavy crude oil or bitumen is impacted by the prevailing market price for condensate. The price of condensate at Edmonton decreased in 2015 primarily due to lower expected demand growth from oil sands and declining market benchmarks for energy commodities.

Natural Gas Benchmarks

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



Average NYMEX
(U.S. $/mmbtu)

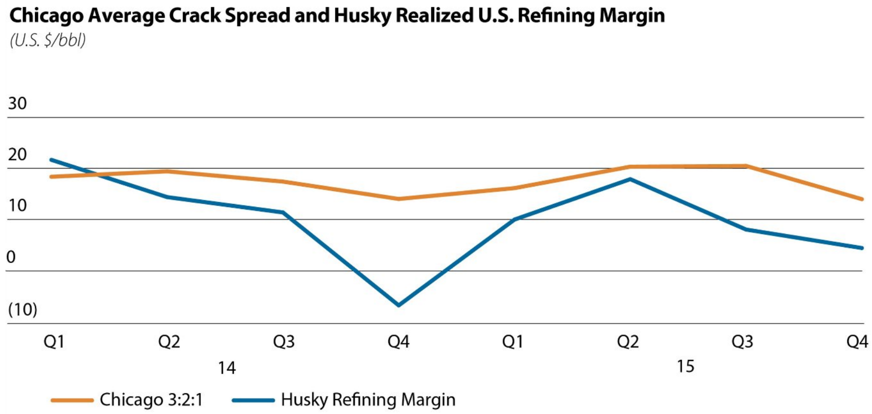


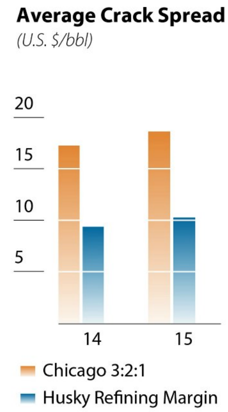
Average natural gas benchmark prices continued to weaken in 2015 primarily due to the substantial supply of natural gas in North America. The substantial natural gas supply has resulted largely from technological advances in horizontal drilling and hydraulic fracturing which have unlocked significant reserves that were not economical under previously applied extraction methods.

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

Natural gas is consumed internally by the Company's Upstream and Downstream operations which reduces the impact of weak natural gas benchmark prices on the Company's results.

Refining Benchmarks

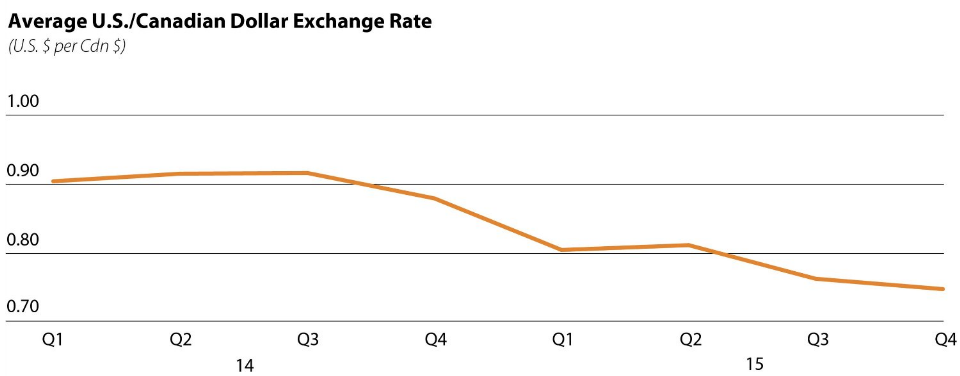


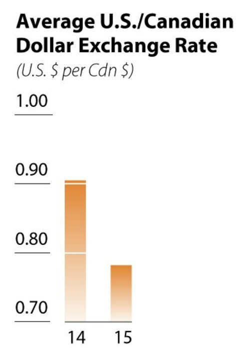


The 3:2:1 crack spread is the key indicator for refining margins as refinery gasoline output is approximately twice the distillate output. This crack spread is calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of distillate fuel less one barrel of crude oil. Market crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel and do not reflect the actual crude purchase costs nor the product configuration of a specific refinery. The Chicago Regular Unleaded Gasoline and the Chicago Ultra-low Sulphur Diesel average benchmark prices are the standard products included in the Chicago 3:2:1 market crack spread benchmark.

Husky'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. Husky'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. The Company benefited from the weakening of the Canadian dollar in 2015 which averaged U.S. $0.783 compared to U.S. $0.906 in 2014.

Sensitivity Analysis

The following table is indicative of the impact of changes in certain key variables in 2015 on earnings before income taxes and net earnings. The table below reflects what the effect would have been on the financial results during 2015 had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2015. 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	2015 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]	**48.80**	*U.S. $1.00/bbl*	**96**	**0.10**	**70**	**0.07**
NYMEX benchmark natural gas price[5]	**2.66**	*U.S. $0.20/mmbtu*	**24**	**0.02**	**17**	**0.02**
WTI/Lloyd crude blend differential[6]	**13.43**	*U.S. $1.00/bbl*	**(33)**	**(0.03)**	**(25)**	**(0.03)**
Canadian light oil margins	**0.048**	*Cdn $0.005/litre*	**14**	**0.01**	**10**	**0.01**
Asphalt margins	**23.57**	*Cdn $1.00/bbl*	**11**	**0.01**	**8**	**0.01**
Chicago 3:2:1 crack spread	**18.62**	*U.S. $1.00/bbl*	**49**	**0.05**	**30**	**0.03**
Exchange rate (U.S. $ per Cdn $)[3][7]	**0.783**	*U.S. $0.01*	**(53)**	**(0.05)**	**(39)**	**(0.04)**

[1] *Excludes mark to market accounting impacts.*
[2] *Based on 984.3 million common shares outstanding as of December 31, 2015.*
[3] *Does not include gains or losses on inventory.*
[4] *Includes impacts related to Brent based production.*
[5] *Includes impact of natural gas consumption.*
[6] *Excludes impact on asphalt operations.*
[7] *Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.*

4.0 Strategic Plan

Husky's strategy is to remain diverse, physically integrated and to continue its transition into a low sustaining capital business. Husky will enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward low sustaining capital thermal developments and resource plays, while advancing growth in the Asia Pacific Region, the Oil Sands and in the Atlantic Region. The Company's Downstream assets provide specialized support to its Upstream operations to enhance efficiency and extract additional value from production.

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

4.1 Upstream

The Company's heavy oil strategy is comprised of replacing natural declines in conventional production with growth in low sustaining capital thermal production. The Company advanced the development of its heavy oil thermal assets in 2015 with first oil achieved at the 10,000 bbls/day Rush Lake thermal development in July 2015 and substantial progress made on the two 10,000 bbls/day Edam East and Vawn thermal developments and the 4,500 bbls/day Edam West thermal development. In November 2015, the Company announced the sanctioning of a new 10,000 bbls/day heavy oil thermal development, Rush Lake 2. The Company has several other heavy oil thermal projects that are in the pre-development phase.

The Asia Pacific Region consists of the Wenchang oil field, the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields on Block 29/26 located offshore China, the Madura Strait block BD, MDA, MBH and MDK development fields, four discoveries offshore Indonesia and rights to additional exploration blocks in the South China Sea located at the Pearl River Mouth Basin and offshore Taiwan and in the East Java Basin, Indonesia. The Liwan Gas Project, located approximately 300 kilometres southeast of the Hong Kong Special Administrative Region, is an important component of the Company's near term production growth strategy and a key step in accessing the burgeoning energy markets in the Hong Kong Special Administrative Region and Mainland China. Husky, and its partner CNOOC, achieved first gas production from the Liwan 3-1 gas field in March 2014 and from the Liuhua 34-2 gas field in December 2014 with ramp up of production taking place in 2015.

During 2015, Husky advanced the development of the Sunrise Energy Project, a multiple stage in-situ oil sands development, achieving first oil at Plant 1A in March 2015 and first steam at Plant 1B in September 2015. The first phase is expected to reach production of approximately 60,000 bbls/day (30,000 bbls/day net Husky share) around the end of 2016. The Sunrise Energy Project uses proven SAGD technology, keeping site disturbance to a minimum. Regulatory approval is in place to expand the project to 200,000 bbls/day (100,000 bbls/day net Husky share). In addition to the Sunrise Energy Project, Husky has an extensive portfolio of undeveloped oil sands leases, encompassing in excess of net 2,400 square kilometres in Alberta.

In the Atlantic Region, the Company holds interests in eight Production Licences, 11 Exploration Licences (including two from Greenland) and 23 Significant Discovery Areas. Development activity at the White Rose core field and its satellites, including North Amethyst and the West and South White Rose Extensions, continues to advance. In 2015, the Company and its partner continued the appraisal drilling program around the Bay du Nord discovery in the Flemish Pass Basin with evaluation of initial results ongoing. The Company has a 35 percent working interest at Bay du Nord as well as the Mizzen and Harpoon discoveries. The Company has significant exploration acreage in this region and continues to explore innovative ways to further develop the significant resources in the region.

The Company's Western Canada conventional and resource play strategy is comprised of advancing the Ansell Multi-Zone, Wilrich and Strachan Cardium gas resource plays. The Company's decision to curtail oil resource drilling will continue during the current crude oil pricing environment.

The Infrastructure and Marketing business supports Upstream production while providing integration with the Company's Downstream assets through optimization of market access. The Company also plans to expand terminal pipeline access and product storage opportunities to enhance market access.

4.2 Downstream

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

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

The Company’s strategic plans emphasize safe, reliable, cost effective operations. To enhance crude oil processing optionality at the Lima Refinery, the Company continued to make progress on the implementation of the crude oil flexibility project targeted for completion in 2018. The crude oil flexibility project will enable the Lima Refinery to swing between light and heavy crude oil feedstock strengthening the Company’s integration model. In line with the heavy oil value chain integration model, during 2015 the Company started processing crude oil from the Sunrise Energy Project. One million barrels of crude oil from the Sunrise Energy Project were processed at the BP-Husky Toledo Refinery in 2015.

4.3 Financial

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

Husky intends to continue to maintain a healthy balance sheet to provide financial flexibility. The Company's target is to maintain a debt to cash flow from operations ratio of under 1.5 times and a debt to capital employed ratio of under 25 percent, which are both non-GAAP measures (refer to Section 8.4 and 11.3). Husky is committed to retaining its investment grade credit ratings to support access to debt capital markets. The Company has taken measures to strengthen its financial position in this commodity down cycle which include, but are not limited to, a reduction of 2016 budgeted capital spending, the suspension of the quarterly common share dividend, continued transition to low sustaining capital projects and planned dispositions of midstream and legacy Western Canada Upstream assets. Refer to Section 8.0 for additional information on the Company's liquidity and capital resources.

The Company expects that its portfolio of low sustaining capital Upstream assets in addition to its extensive Downstream assets and ability to capture incremental profits from the wellhead to the refinery rack will provide sufficient cash flow to fund future growth projects in the Atlantic Region, Heavy Oil, Oil Sands and Asia Pacific Region.

5.0 Key Growth Highlights

The 2015 Capital Program enabled Husky to advance its near-term profitable growth projects while maintaining prudent capital management in a weak commodity price environment.

5.1 Upstream

Heavy Oil

Heavy Oil Thermal Developments

The Company continued to advance its inventory of heavy oil thermal developments in 2015. These long-life developments are being built with modular, repeatable designs and will require low sustaining capital once brought online.

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

Heavy Oil Thermal Developments

Development	Design Capacity (bbls/day)	Percentage Completion	First Production Expected
Rush Lake	12,000(1)	100%	On production
Edam East	10,000	85%	Q2 2016
Vawn	10,000	78%	Q3 2016
Edam West	4,500(2)	80%	Q3 2016

(1) *Design capacity for Rush Lake has been revised to include 2,000 bbls/day from the Rush Lake Pilot Project.*
(2) *Capacity at the Edam West heavy oil thermal development was increased from 3,500 bbls/day to 4,500 bbls/day in 2015 reflecting design and efficiency improvements.*

Total heavy oil thermal production averaged 48,400 bbls/day in 2015 compared to 43,800 bbls/day in 2014, an 11 percent increase, primarily attributed to new production from the Rush Lake heavy oil thermal development combined with steady production from the balance of the Company's heavy oil thermal developments.

First oil was achieved at the Rush Lake heavy oil thermal development in July 2015 with production from the development reaching a year end exit rate of 13,900 bbls/day, exceeding its design capacity. In addition, the Company announced the sanctioning of a second 10,000 bbls/day heavy oil thermal development, Rush Lake 2, in November 2015.

At the 10,000 bbls/day Edam East and 10,000 bbls/day Vawn heavy oil thermal developments, construction is approximately 85 and 78 percent complete, respectively. First production at both heavy oil thermal developments is now expected ahead of schedule in the second quarter of 2016 at Edam East and in the third quarter of 2016 at Vawn.

At the 4,500 bbls/day Edam West heavy oil thermal development, construction is approximately 80 percent complete. First production is now expected ahead of schedule in the third quarter of 2016.

At the Tucker thermal project near Cold Lake, work is continuing to increase production and improve returns, with a new sustaining well pad drilled to help offset natural declines. Overall production at Tucker is now averaging 15,000 bbls/day. A steam generator has been added to the Tucker plant increasing steam capacity by about 15 percent. The increased steam capacity will be used to access the newly identified Colony formation which has similar characteristics to heavy oil reservoirs in the Lloydminster region and is suitable for development using thermal technology. First steam at the Colony formation commenced in the first quarter of 2016 with first production expected in the second quarter. Production volumes from the Tucker thermal project are expected to reach 20,000 bbls/day in the second half of 2016.

Three additional 10,000 bbls/day heavy oil thermal developments have been identified in the Lloydminster region for development.

Horizontal drilling and cold heavy oil production with sand drilling was substantially curtailed throughout 2015 primarily due to limited capital investment in a low commodity price environment.

Asia Pacific Region

China

Block 29/26

At the Liwan Gas Project, combined gross production from the Liwan 3-1 and Liuhua 34-2 gas fields increased during 2015. Natural gas production was 286 mmcf/day and NGL production was 14.6 mbbls/day. The Company's entitlement share of production from the Liwan Gas Project was reduced from approximately 76 percent up until late May 2015 to its equity interest of 49 percent, reflecting the completion of exploration cost recoveries from the Liwan 3-1 field which were originally funded solely by the Company. Negotiations for the sale of gas and liquids from Liuhua 29-1, the third deepwater field, are being pursued.

Block 15/33

In December 2015, Husky signed a PSC for an exploration block offshore China. The 15/33 block covers approximately 155 square kilometres and is located in the Pearl River Mouth Basin in the South China Sea, about 140 kilometres southeast of the Hong Kong Special Administrative Region, in water depths of approximately 80 - 100 metres. Husky is the operator of the block during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, its partner CNOOC may assume a working interest of up to 51 percent during the development and production phase. Exploration cost recovery from production would be allocated to Husky. Husky expects to drill two wells on the block in the 2017 timeframe.

Offshore Taiwan

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

Indonesia

Madura Strait

Progress continued on the shallow water gas developments in the Madura Strait Block during 2015. The amended BD field gas sales agreements were approved by SKK Migas, the Indonesian oil and gas regulator, in the second quarter of 2015. The platform jacket and topsides were successfully set in approximately 55 metres of water in October 2015 and development well drilling commenced in November 2015. Wellhead platform and pipeline infrastructure construction at the liquids-rich BD field is ongoing and approximately 68 percent complete. Construction of a floating production, storage and offloading ("FPSO") vessel to process gas and liquids production from the BD field is approximately 50 percent complete. Production from the project is expected to commence in the 2017 timeframe.

In November 2015, the Company sanctioned the development of the MDA, MBH and MDK gas fields having secured the gas sales agreement for the first tranche of gas from the combined MDA-MBH fields development in the second quarter. In December 2015, the Minister of Energy and Mineral Resources appointed the buyers for the remaining available tranches of gas sales from the three fields and negotiation of gas sales agreements are planned to commence in 2016. A tendering process is underway for an FPSO vessel and related engineering, procurement, construction and installation contracts for this development. Combined net sales volumes from the BD, MDA, MBH and MDK fields are expected to be about 100 mmcf/day of gas and 2,400 boe/day of associated NGL once fully ramped up.

Also in November 2015, SKK Migas approved the plan of development for the MAC gas field which was discovered in 2012.

Anugerah

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

Oil Sands

Sunrise Energy Project

First oil was achieved on Phase 1 at the Sunrise Energy Project in March 2015 with production from the project averaging 14,200 bbls/day (7,100 bbls/day net Husky share) in the fourth quarter of 2015. Steam operations commenced at the second of two processing plants in early September 2015 and commissioning is complete. All 55 well pairs are being steamed and producing bitumen. Production from the Sunrise Energy Project is expected to ramp up to 60,000 bbls/day (30,000 bbls/day net to Husky) around the end of 2016.

The Company is utilizing a custom drilling rig to improve drilling efficiencies and reduce costs. The rig provides for the closer spacing of wellheads, smaller drilling pads and fewer pad facilities. The Sunrise Energy Project uses proven SAGD technology, keeping site disturbance to a minimum.

Regulatory approval is in place to expand the project to 200,000 bbls/day (100,000 bbls/day net Husky share).

Atlantic Region

White Rose Field and Satellite Extensions

The Company drilled and completed two production wells at the South White Rose Extension during 2015 with peak production from the wells of 15,000 bbls/day net to Husky reached in early September.

The Company has secured the Henry Goodrich drilling rig for a two-year drilling program which will focus on development drilling at the White Rose field and satellite extensions. The rig is expected to arrive in mid-2016 and will be utilized for further development drilling at the South White Rose extension and the completion of North Amethyst's Hibernia formation production well.

The Company continues to assess potential development options for the West White Rose satellite extension. One of the two concepts being assessed, a fixed wellhead platform, received government and regulatory approvals in 2015. A subsea option to develop the field is also being evaluated.

Atlantic Exploration

An exploration and appraisal drilling program continued at the Bay du Nord discovery in the Flemish Pass Basin in 2015 including ongoing drilling of the Bay d'Espoir exploration well. Evaluation of results is ongoing.

Drilling of the Aster exploration well was completed in the first quarter of 2015, and the well did not encounter economic quantities of hydrocarbons.

Western Canada Resource Play Development

Natural Gas Resource Plays

During 2015, 34 wells (gross) were drilled and 38 wells (gross) were completed in key plays across the natural gas portfolio.

Natural Gas Resource Plays – Drilling and Completion Activity in Key Plays[(1)(2)]

		Year ended December 31, 2015	
Project	Location	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	**25**	**28**
Wilrich	Kakwa, Alberta	**4**	**5**
Strachan Cardium	Rocky Mountain House, Alberta	**5**	**5**
Total Gross		**34**	**38**
Total Net		**22**	**28**

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*
(2) *Drilling activity includes operated and non-operated wells.*

In the Ansell multi-zone natural gas resource play, 25 horizontal wells (gross) were drilled and 28 horizontal wells (gross) were completed in 2015. Average production from the play increased by 14 percent to approximately 20,000 boe/day in 2015 compared to 17,500 boe/day in 2014.

Oil Resource Plays and Conventional

Oil related drilling and completion activity in Western Canada was substantially curtailed throughout 2015 primarily due to limited capital investment in a low commodity price environment.

Infrastructure and Marketing

The Hardisty terminal expansion project was completed in the first quarter of 2015 and is operational. The project included multiple initiatives to increase pipeline connectivity, blending capacity and product storage to support upstream production growth and provide additional flexibility in marketing the Company's products.

In order to maintain market flexibility, the Company expanded its pumping capacity at the Hardisty terminal to comply with the new requirements of the Enbridge Clipper pipeline. The expansion was completed in the fourth quarter of 2015.

Construction is ongoing for the expansion of the Saskatchewan Gathering System which will accommodate production from the Company's heavy oil thermal developments. Production from the Rush Lake thermal development is now flowing in the newly expanded pipeline into Lloydminster.

5.2 Downstream

Canadian Refined Products

During 2015, Husky and Imperial Oil entered into a contractual agreement to create a single expanded truck transport network of approximately 160 sites. The agreement is subject to regulatory approval by Canada's Competition Bureau and other closing conditions.

Lima Refinery

The Company is proceeding with the initial stages of a crude oil flexibility project designed to improve reliability at the facility and allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada. The crude oil flexibility project will allow the Refinery to swing between light and heavy crude oil feedstock.

BP-Husky Toledo Refinery

A feedstock optimization project was recently sanctioned by the joint arrangement partners and is designed to improve the Refinery's ability to process Hi-TAN crude. Targeted completion of the required metallurgy changes will be performed during the Refinery's turnaround starting in the second quarter of 2016. Once the upgrades are complete, the Refinery will have the ability to process up to an additional 35,000 bbls/day of Hi-TAN crude. The Refinery's overall nameplate capacity will remain at 160,000 bbls/day.

The BP-Husky Toledo Refinery began processing bitumen from the Sunrise Energy Project in the second half of 2015.

6.0 Results of Operations

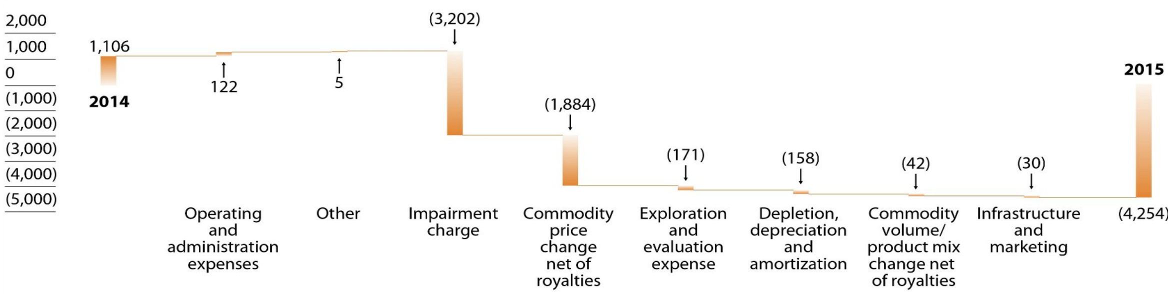
6.1 Segment Earnings

	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[1]	
($ millions)	**2015**	2014	**2015**	2014	**2015**	2014
Upstream						
Exploration and Production	**(5,945)**	1,337	**(4,338)**	992	**2,269**	4,189
Infrastructure and Marketing	**115**	153	**84**	114	**168**	211
Downstream						
Upgrading	**128**	227	**93**	168	**46**	50
Canadian Refined Products	**231**	287	**170**	214	**30**	86
U.S. Refining and Marketing	**306**	(30)	**397**	(19)	**425**	374
Corporate	**(206)**	(190)	**(256)**	(211)	**67**	113
Total	**(5,371)**	1,784	**(3,850)**	1,258	**3,005**	5,023

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

6.2 Upstream

After Tax Earnings (Loss) Variance Analysis
($ millions)



Exploration and Production

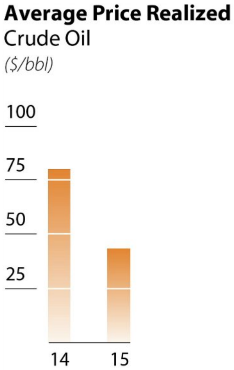
Exploration and Production Earnings Summary *($ millions)*	**2015**	2014
Gross revenues	**5,374**	8,634
Royalties	**(432)**	(1,030)
Net revenues	**4,942**	7,604
Purchases, operating, transportation and administrative expenses	**2,354**	2,521
Depletion, depreciation, amortization and impairment	**7,993**	3,434
Exploration and evaluation expenses	**447**	214
Other expenses	**93**	98
Provisions for (recovery of) income taxes	**(1,607)**	345
Net earnings (loss)	**(4,338)**	992

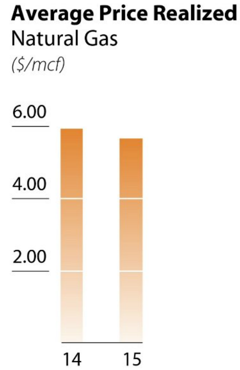
Exploration and Production net revenues decreased by $2,662 million in 2015 compared to 2014 primarily due to significant declines in global crude oil and North American natural gas benchmark prices partially offset by a weaker Canadian dollar. The decline in Exploration and Production net revenues was partially offset by a decline in royalties.

Depletion, depreciation, amortization and impairment expense in 2015 included a pre-tax impairment charge of $5,181 million recognized on certain legacy crude oil and natural gas assets, including associated goodwill, located in Western Canada compared to a pre-tax impairment charge of $838 million recognized in 2014.

Exploration and evaluation expense in 2015 included a pre-tax asset write-down of $242 million compared to a pre-tax write-down of $6 million in 2014. The write-down in 2015 was primarily recognized on certain Western Canada resource play assets.

Average Sales Prices Realized

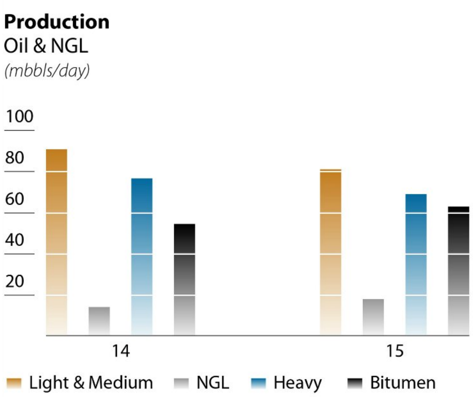


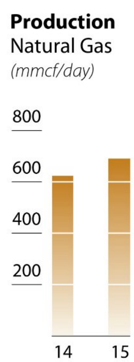


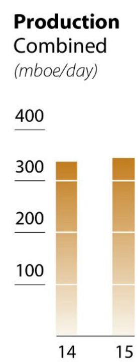
Average Sales Prices Realized	2015	2014
Crude oil and NGL *($/bbl)*		
Light & Medium crude oil	**57.55**	96.59
NGL	**45.88**	72.61
Heavy crude oil	**37.16**	71.91
Bitumen	**34.47**	70.57
Total crude oil and NGL average	**44.18**	81.10
Natural gas average *($/mcf)*	**5.80**	5.99
Total average *($/boe)*	**41.06**	67.38

The average sales prices realized by the Company declined by 46 percent for crude oil and NGL in 2015 reflecting significant declines in global crude oil benchmarks. The decline in crude oil benchmarks, resulting from an oversupplied market, was partially offset by a weaker Canadian dollar and narrower heavy crude oil and bitumen differentials. The average sales prices realized by the Company for natural gas declined by three percent in 2015 primarily due to significantly lower North American natural gas benchmark prices partially offset by a weaker Canadian dollar and a greater percentage of production coming from the Liwan Gas Project which receives higher fixed contract prices.

Daily Gross Production







Daily Gross Production	2015	2014
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light & Medium crude oil	**36.4**	41.8
NGL	**8.8**	9.8
Heavy crude oil	**69.1**	76.8
Bitumen[1]	**59.9**	54.6
	174.2	183.0
Oil Sands		
Sunrise – bitumen	**3.2**	–
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**32.1**	38.6
Terra Nova – light crude oil	**4.7**	6.0
	36.8	44.6
Asia Pacific Region		
Wenchang – light crude oil	**7.3**	4.8
Liwan and Wenchang – NGL[2]	**9.4**	4.2
	16.7	9.0
	230.9	236.6
Natural gas *(mmcf/day)*		
Western Canada	**513.9**	506.8
Asia Pacific Region[2]	**175.1**	114.2
	689.0	621.0
Total *(mboe/day)*	**345.7**	340.1

(1) *Bitumen consists of production from heavy oil thermal developments and the Tucker thermal development located near Cold Lake, Alberta. Heavy oil thermal average daily gross production was 48.4 mbbls/day and 43.8 mbbls/day for the years ended December 31, 2015 and 2014, respectively.*

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

Crude Oil and NGL Production

Crude oil and NGL production decreased by 5.7 mbbls/day compared to 2014 due to lower production in Western Canada and the Atlantic Region. In Western Canada, crude oil production decreased due to natural reservoir declines at mature properties combined with limited sustaining capital investment in a low commodity price environment. In the Atlantic Region, crude oil production decreased primarily due to natural reservoir declines at mature fields. The decreases were partially offset by higher NGL production from the Liwan Gas Project where production began at the end of the first quarter of 2014, new production from the Rush Lake heavy oil thermal development, the Sunrise Energy Project and the South White Rose extension and higher production from the Wenchang field where a planned turnaround on the FPSO vessel offstation reduced production in the second and third quarter of 2014.

Natural Gas Production

Natural gas production increased by 68 mmcf/day or 11 percent compared to 2014 primarily due to higher production from the Liwan Gas Project in the Asia Pacific Region where first gas was achieved at the Liwan 3-1 and Liuhua 34-2 gas fields at the end of the first and fourth quarters of 2014, respectively. The increase in gross production volumes was partially offset by a reversion of the Company's entitlement share of production at Liwan 3-1 to 49 percent, from approximately 76 percent, following the completion of Liwan 3-1 field exploration cost recoveries in May 2015.

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	2015	2014
Crude oil and NGL		
Light & Medium crude oil	**33%**	39%
NGL	**6%**	4%
Heavy crude oil	**18%**	24%
Bitumen	**15%**	17%
Crude oil and NGL	**72%**	84%
Natural gas	**28%**	16%
Total	**100%**	100%

2016 Production Guidance and 2015 Actual

Gross Production	Guidance[(1)] 2016	Year ended December 31 2015	Guidance 2015
Canada			
Light & Medium crude oil *(mbbls/day)*	66 - 68	**73**	79 - 83
NGL *(mboe/day)*	7 - 8	**9**	8 - 9
Heavy crude oil & bitumen *(mbbls/day)*	142 - 157	**132**	125 - 135
Natural gas *(mmcf/day)*	380 - 430	**514**	440 - 480
Canada total *(mboe/day)*	279 - 305	**300**	285 - 307
Asia Pacific			
Light crude oil *(mbbls/day)*	6 - 7	**8**	6 - 7
NGL *(mboe/day)*	7 - 8	**9**	7 - 8
Natural gas *(mmcf/day)*	140 - 150	**175**	160 - 195
Asia Pacific total *(mboe/day)*	36 - 40	**46**	40 - 48
Total *(mboe/day)*	315 - 345	**346**	325 - 355

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

Husky's total production for the year ended December 31, 2015 was within production guidance. Husky expects that total production volumes in 2016 will be comparable to 2015. The 2016 guidance reflects increasing heavy oil thermal production along with increasing bitumen production from the Sunrise Energy Project. The increases are anticipated to be offset by continued natural declines from mature properties reflecting the Company's decision to reduce the amount of sustaining capital in Western Canada. In addition, the Company expects a reduction in net production volumes from the Liwan Gas Project due to the completion of exploration cost recoveries from the Liwan 3-1 field in 2015.

Factors that could potentially impact Husky's production performance in 2016 include, but are not limited to:

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

Royalties

Royalty rates as a percentage of gross revenues averaged eight percent in 2015 compared to 12 percent in 2014. Royalty rates in Western Canada averaged nine percent in 2015 compared to 12 percent in 2014 primarily due to lower commodity prices with a sliding scale price sensitivity rate. Royalty rates in the Atlantic Region averaged 11 percent in 2015 compared to 17 percent in 2014 primarily due to lower crude oil prices. Royalty rates in the Asia Pacific Region averaged five percent in 2015 compared to eight percent in 2014 primarily due to lower crude oil prices which resulted in lower levies on production from Wenchang.

Operating Costs

($ millions)	**2015**	2014
Western Canada	**1,692**	1,819
Atlantic Region	**225**	218
Asia Pacific	**97**	82
Total	**2,014**	2,119
Unit operating costs *($/boe)*	**15.14**	16.12

Total Exploration and Production operating costs were $2,014 million in 2015 compared to $2,119 million in 2014. Total Upstream unit operating costs averaged $15.14/boe in 2015 compared to $16.12/boe in 2014.

Unit operating costs in Western Canada averaged $16.55/boe in 2015 compared to $17.39/boe in 2014. The decrease in unit operating costs was primarily attributable to lower energy costs, lower energy consumption and cost savings initiatives.

Unit operating costs in the Atlantic Region averaged $16.76/boe in 2015 compared to $13.38/boe in 2014. The increase in unit operating costs was primarily attributable to lower production volumes and higher maintenance activities in 2015 combined with insurance proceeds received in the second quarter of 2014.

Operating costs in the Asia Pacific Region averaged $5.78/boe in 2015 compared to $8.06/boe in 2014. The decrease in unit operating costs was primarily due to higher production volumes from the Liwan Gas Project and an increase in operating days at Wenchang in 2015.

Exploration and Evaluation Expenses

($ millions)	**2015**	2014
Seismic, geological and geophysical	**103**	111
Expensed drilling	**297**	45
Expensed land	**47**	58
Total	**447**	214

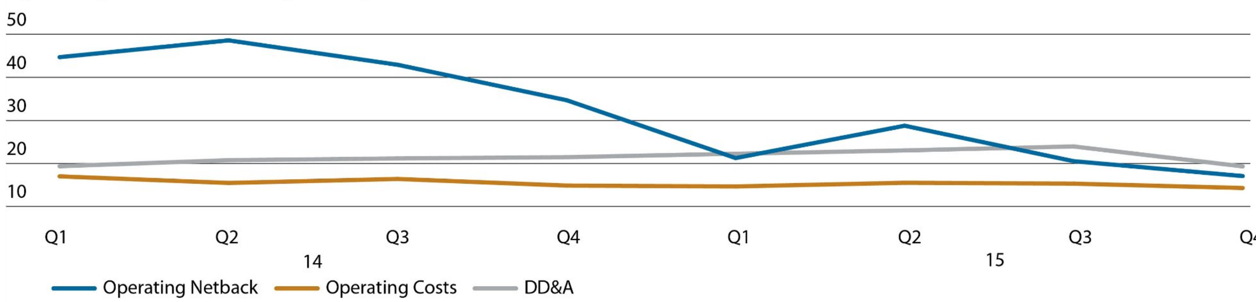
Exploration and evaluation expenses in 2015 were $447 million compared to $214 million in 2014. The increase in expensed drilling was primarily due to a $277 million write-off of certain Western Canada resource play assets including associated unfulfilled work commitment penalties recognized in the third quarter of 2015. The write-off was the result of management's plan to withdraw from further exploration and evaluation in these areas due to lower estimated short and long-term crude oil and natural gas prices. In addition, the Company expensed the Aster exploration well in the Atlantic Region during the first quarter of 2015.

Depletion, Depreciation, Amortization ("DD&A") and Impairment

During 2015, the Company recognized a pre-tax impairment charge of $5,181 million on certain crude oil and natural gas assets, including associated goodwill, located in Western Canada compared to a pre-tax impairment charge of $838 million recognized in 2014. The impairment charge in 2015 was the result of sustained declines in forecasted short and long-term crude oil and natural gas prices and management's plan to reduce capital investment in these areas.

During 2015, total DD&A excluding impairment averaged $22.28/boe compared to $20.92/boe in 2014. The increase was primarily due to higher depletion rates on production from the Liwan Gas Project which began producing at the end of the first quarter of 2014 and from the derecognition of approximately $46 million pre-tax of assets related to the cancellation of the West Mira drilling rig contract.

Operating Netback[(1)], Unit Operating Costs and DD&A *($/boe)*



[(1)] Operating netback is a non-GAAP measure and is equal to Husky's Upstream realized price less royalties, operating costs and transportation costs on a per unit basis. Refer to section 11.3.

Exploration and Production Capital Expenditures

Exploration and Production capital expenditures were lower in 2015 and reflected the Company's prudent capital management in a low commodity price environment. Other significant factors which impacted capital expenditures in 2015 include, but are not limited to, the completion of the Sunrise Energy Project and completion of the Liwan Gas Project. The Company's Exploration and Production capital expenditures were as follows:

Exploration and Production Capital Expenditures[1] *($ millions)*	2015	2014
Exploration		
Western Canada[2]	**24**	179
Heavy Oil[2]	**12**	30
Oil Sands[2]	–	5
Atlantic Region	**169**	96
Asia Pacific Region	–	16
	205	326
Development		
Western Canada[2]	**420**	927
Heavy Oil[2]	**899**	1,239
Oil Sands[2]	**264**	616
Atlantic Region	**379**	650
Asia Pacific Region	**46**	380
	2,008	3,812
Acquisitions		
Western Canada[2]	**2**	29
Heavy Oil[2]	**54**	22
	56	51
	2,269	4,189

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

(2) *During the second quarter of 2015, the Company reclassified certain capital expenditures to Heavy Oil, previously classified as part of Western Canada and Oil Sands. The prior period has been revised to conform to the current period presentation.*

Western Canada

During 2015, $446 million (20 percent) was invested in Western Canada conventional and resource plays, compared to $1,135 million (27 percent) in 2014, primarily on the development of the Company's natural gas resource plays including the Ansell multi-zone, Strachan Cardium and Wilrich projects.

Heavy Oil

During 2015, $965 million (42 percent) was invested in Heavy Oil, compared to $1,291 million (31 percent) in 2014, primarily on the development of the Company's heavy oil thermal developments, including: Rush Lake, Edam East, Edam West and Vawn.

Oil Sands

During 2015, $264 million (12 percent) was invested in Oil Sands, compared to $621 million (15 percent) in 2014, primarily on the completion of Phase 1 of the Sunrise Energy Project.

Atlantic Region

During 2015, $548 million (24 percent) was invested in the Atlantic Region, compared to $746 million (18 percent) in 2014, primarily on the development of the White Rose extension projects, including North Amethyst, West White Rose and South White Rose extension satellite fields and on further exploration and appraisal of the Bay du Nord discovery in the Flemish Pass Basin.

Asia Pacific Region

During 2015, $46 million (two percent) was invested in the Asia Pacific Region, compared to $396 million (nine percent) in 2014, primarily on the Liwan Gas Project.

Onshore drilling activity

The following table discloses the number of wells drilled in Heavy Oil, Oil Sands and Western Canada conventional and resource plays during 2015 and 2014:

	2015		2014	
Wells Drilled *(wells)*[1]	**Gross**	**Net**	Gross	Net
Heavy Oil	**87**	**86**	356	341
Oil Sands[2]	**28**	**14**	37	18
Western Canada conventional and resource plays				
Gas Resource	**39**	**29**	56	38
Oil Resource	**1**	**1**	40	36
Conventional Oil	**6**	**3**	123	92
Conventional Gas	**2**	–	1	–
Enhanced Oil Recovery	**2**	**2**	2	2
	165	**135**	615	527

(1) *Excludes Service/Stratigraphic test wells for evaluation purposes.*
(2) *Prior period net Oil Sands wells were revised to reflect Husky's 50 percent working interest in the Sunrise Energy Project.*

During 2015, the Company's onshore drilling was focused primarily on the development of Heavy Oil, Oil Sands, and natural gas resource plays. Oil related drilling and completion activity in Western Canada was substantially curtailed throughout 2015 primarily due to limited capital investment in a low commodity price environment.

Offshore drilling activity

The following table discloses Husky's offshore Atlantic and Asia Pacific Region drilling activity during 2015:

Region	Well	Working Interest	Well Type
Atlantic Region	Bay du Nord P-78	WI 35 percent	Exploration
Atlantic Region	Bay du Nord L-76	WI 35 percent	Exploration
Atlantic Region	Bay du Nord L-76Z	WI 35 percent	Exploration
Atlantic Region	Aster C-93A[1]	WI 40 percent	Exploration
Atlantic Region	Bay d'Espoir B-09	WI 35 percent	Exploration
Atlantic Region	White Rose J-05 3	WI 68.875 percent	Development
Atlantic Region	White Rose J-05 2	WI 72.5 percent	Development
Asia Pacific Region	Wenchang 13-1A4H2	WI 40 percent	Development

(1) *The Aster well was fully written off in the first quarter of 2015 as the well did not encounter economic quantities of hydrocarbons.*

2016 Upstream Capital Expenditures Program

($ millions)	
Western Canada	**150 - 200**
Heavy Oil	**300 - 350**
Oil Sands	**25 - 50**
Atlantic Region	**275 - 325**
Asia Pacific Region[1]	**330 - 350**
Total Upstream capital expenditures	**1,080 - 1,275**

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

The 2016 Upstream capital expenditures program reflects the Company's prudent capital management in a weak commodity price environment. The Company will continue its transition towards a low sustaining capital business while providing flexibility to quickly ramp up production and increase discretionary capital spending as commodity prices recover. The Company's 2016 Upstream capital expenditures program has been designed to remain in balance with cash flow from operations.

The Company has budgeted $300 - $350 million in Heavy Oil for 2016, primarily for the continued development of heavy oil thermal developments, including Edam East, Edam West, Vawn and Tucker. The Company is making progress in its strategy to transition a greater percentage of production to long-life heavy oil thermal production and the 2016 Upstream capital expenditures program will continue to build on this momentum.

The Company has budgeted $25 - $50 million in Oil Sands for 2016, primarily for the continued development of the Sunrise Energy Project.

The Company has budgeted $150 - $200 million in Western Canada conventional and resource plays for 2016, primarily for production sustainment and turnaround activity.

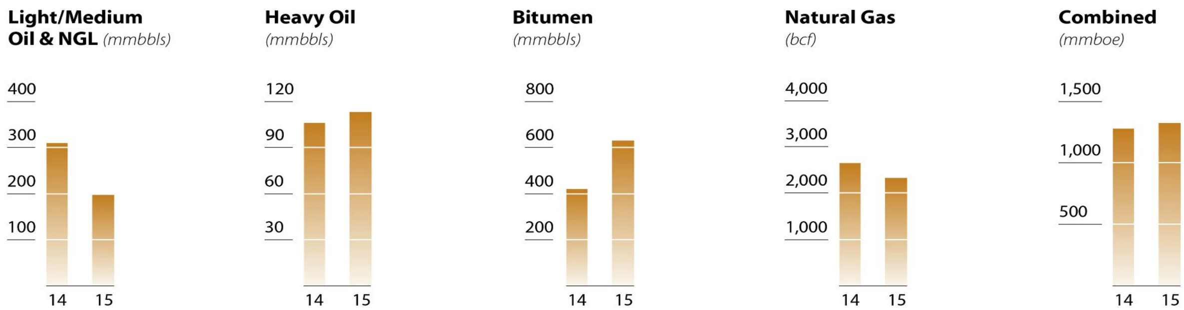
The Company has budgeted $275 - $325 million in the Atlantic Region for 2016, primarily for the continued development of the main White Rose field and extensions and the Bay du Nord appraisal drilling program in the Flemish Pass Basin.

The Company has budgeted $330 - $350 million for the Asia Pacific Region in 2016, primarily for the continued development of the Liwan Gas Project and the development of the Madura Strait Block in Indonesia.

Oil and Gas Reserves

The Company's reserves disclosure was prepared in accordance with Canadian Securities Administrators' National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") effective December 31, 2015 with a preparation date of January 29, 2016.

Proved Reserves at December 31:



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

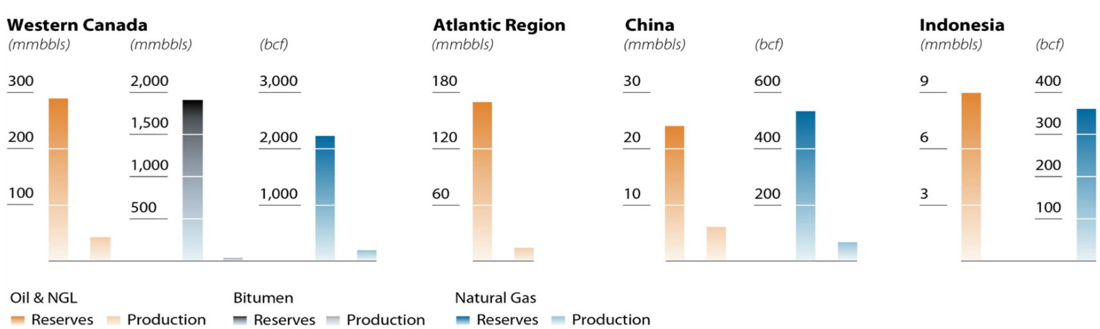
The Company's complete oil and gas reserves disclosure, prepared in accordance with NI 51-101 is contained in Husky's Annual Information Form, which is available at www.sedar.com, and certain supplementary oil and gas reserves disclosure prepared in accordance with U.S. disclosure requirements is contained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

Sproule Associates Ltd. ("Sproule"), an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and NGL reserves estimates. Sproule issued an audit opinion on January 15, 2016 stating that Husky's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions are, in aggregate, reasonable and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the Canadian Oil and Gas Evaluation Handbook.

At December 31, 2015, Husky's proved oil and gas reserves were 1,324 mmboe, up from 1,279 mmboe at the end of 2014. The Company's 2015 reserve replacement ratio, defined as net additions divided by total production during the period, was 166 percent excluding economic revisions (136 percent including economic revisions). Major additions to proved reserves in 2015 included:

- The extension through additional drilling locations and technical revisions at the Sunrise Energy Project that resulted in the booking of an additional 123 mmbbls of bitumen in proved undeveloped reserves;
- Extensions, improved recovery and strong performance in heavy oil thermal projects that resulted in the booking of an additional 105 mmbbls of bitumen in proved reserves;
- Strong performance from Liwan 3-1 that resulted in the booking of an additional 14 mmboe of natural gas and NGL in proved developed producing reserves; and
- The signing of a gas sales contract for the Madura MDA and MBH fields resulted in the booking of an additional 17 mmboe of natural gas in proved undeveloped reserves.

Proved Plus Probable Reserves and Production at December 31, 2015:



Reconciliation of Proved Reserves

	Canada					International		Total		
	Western Canada				Atlantic Region					
(forecast prices and costs before royalties)	Light/ Medium Crude Oil & NGL *(mmbbls)*	Heavy Crude Oil *(mmbbls)* [1]	Bitumen *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL (mmbbls)	Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Natural Gas (bcf)	Equivalent Units *(mmboe)*
Proved reserves										
December 31, 2014	222	106	420	2,154	63	24	508	835	2,662	1,279
Technical revisions	(81)	43	46	(220)	(1)	6	63	13	(157)	(14)
Acquisitions	–	–	–	9	–	–	–	–	9	2
Dispositions	(5)	–	–	(7)	–	–	–	(5)	(7)	(6)
Discoveries, extensions and improved recovery	2	2	182	111	6	–	101	192	212	227
Economic factors	(4)	(13)	–	(126)	–	–	–	(17)	(126)	(38)
Production	(17)	(25)	(23)	(188)	(13)	(6)	(64)	(84)	(252)	(126)
Proved reserves December 31, 2015	**117**	**113**	**625**	**1,733**	**55**	**24**	**608**	**934**	**2,341**	**1,324**
Proved and probable reserves December 31, 2015	**143**	**147**	**1,905**	**2,211**	**169**	**32**	**889**	**2,396**	**3,100**	**2,912**
December 31, 2014	283	162	1,917	2,637	177	31	836	2,570	3,473	3,149

[1] *Heavy oil thermal property reserves are classified as bitumen.*

Reconciliation of Proved Developed Reserves

	Canada					International		Total		
	Western Canada				Atlantic Region					
(forecast prices and costs before royalties)	Light/ Medium Crude Oil & NGL *(mmbbls)*	Heavy Crude Oil *(mmbbls)* [1]	Bitumen *(mmbbls)*	Natural Gas (bcf)	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL (mmbbls)	Natural Gas *(bcf)*	Crude Oil, Bitumen & NGL *(mmbbls)*	Natural Gas (bcf)	Equivalent Units *(mmboe)*
Proved developed reserves										
December 31, 2014	194	89	121	1,672	50	17	341	471	2,013	807
Technical revisions	(59)	53	15	(94)	1	6	62	16	(32)	9
Transfer from proved undeveloped	2	1	43	82	6	–	–	52	82	66
Acquisitions	–	–	–	9	–	–	–	–	9	2
Dispositions	(5)	–	–	(7)	–	–	–	(5)	(7)	(6)
Discoveries, extensions and improved recovery	2	2	1	40	1	–	–	6	40	12
Economic factors	(4)	(12)	–	(124)	–	–	–	(16)	(124)	(36)
Production	(17)	(25)	(23)	(188)	(13)	(6)	(64)	(84)	(252)	(126)
December 31, 2015	**113**	**108**	**157**	**1,390**	**45**	**17**	**339**	**440**	**1,729**	**728**

[1] *Heavy oil thermal property reserves are classified as bitumen.*

Infrastructure and Marketing

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

Infrastructure and Marketing Earnings Summary *($ millions, except where indicated)*	**2015**	2014
Gross revenues and Marketing and other	**1,302**	2,272
Gross margin		
Infrastructure gross margin	**141**	146
Marketing and other gross margin	**38**	70
	179	216
Operating and administrative expenses	**44**	40
Depletion, depreciation and amortization	**25**	25
Other income	**(5)**	(2)
Provisions for income taxes	**31**	39
Net earnings	**84**	114

Infrastructure and Marketing gross revenues decreased by $970 million in 2015 compared with 2014 primarily due to lower pipeline revenue in a weak commodity price environment.

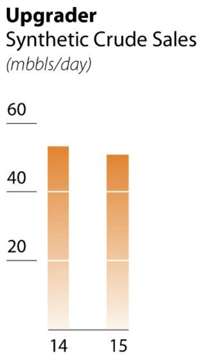
The Company's marketing and other gross margin decreased in 2015 primarily due to narrower product and location differentials between Canada and the U.S. which resulted in fewer arbitrage opportunities. In addition, the Company recorded a $6 million pre-tax provision to reduce inventories to net realizable value during 2015.

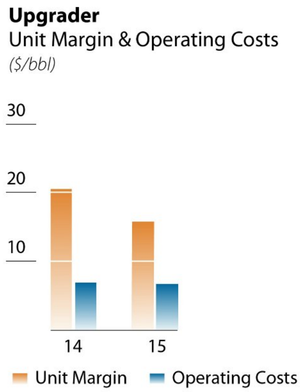
Infrastructure and Marketing Capital Expenditures

In 2015, Infrastructure and Marketing capital expenditures totalled $168 million which was comparable to $211 million in 2014. Capital expenditures in 2015 were primarily related to the expansion of the Saskatchewan Gathering System into Lloydminster.

6.3 Downstream

Upgrader





Upgrader Earnings Summary *($ millions, except where indicated)*	2015	2014
Gross revenues	**1,319**	2,212
Gross margin	**397**	536
Operating and administrative expenses	**173**	189
Depreciation and amortization	**106**	108
Other expense (income)	**(10)**	12
Provisions for income taxes	**35**	59
Net earnings	**93**	168
Upgrader throughput *(mbbls/day)*[(1)]	**69.8**	72.7
Total sales *(mbbls/day)*[(2)]	**69.3**	72.6
Synthetic crude oil sales *(mbbls/day)*	**51.1**	53.3
Upgrading differential *($/bbl)*	**18.66**	21.80
Unit margin *($/bbl)*[(2)]	**15.70**	20.23
Unit operating cost *($/bbl)*[(3)]	**6.63**	6.78

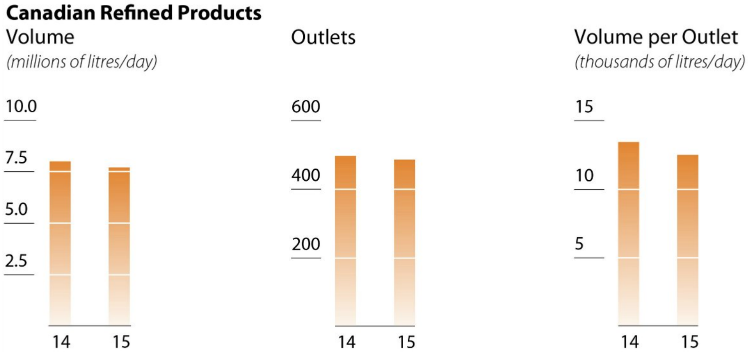
(1) *Throughput includes diluent returned to the field.*
(2) *Unit margin was revised in the first quarter of 2015 to reflect total sales volumes. The prior year has been revised to conform to current year presentation.*
(3) *Based on throughput.*

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

Upgrader gross revenues decreased by $893 million in 2015 compared to 2014 primarily due to lower realized prices for synthetic crude oil and low sulphur distillates combined with lower throughput and lower sales volumes resulting from unplanned maintenance to the facility's coke drums that suspended operations for eight weeks during the third quarter of 2015. Throughput declined by 2.9 mbbls/day, or four percent, and sales volumes declined by 3.3 mbbls/day, or five percent, compared to 2014.

Upgrader gross margin decreased by $139 million in 2015 compared to 2014 primarily due to a lower upgrading differential. During 2015, the upgrading differential averaged $18.66/bbl, a decrease of $3.14/bbl or 14 percent compared to 2014. The differential is equal to Husky Synthetic Blend less Lloyd Heavy Blend. The decrease in upgrading differential was attributable to lower realized prices for Husky Synthetic Blend partially offset by lower heavy crude oil feedstock costs. During 2015, the price of Husky Synthetic Blend averaged $61.32/bbl compared to $101.38/bbl in 2014.

Canadian Refined Products



Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	**2015**	2014
Gross revenues	**2,886**	4,020
Gross margin		
Fuel	**134**	147
Refining	**150**	251
Asphalt	**262**	246
Ancillary	**59**	57
	605	701
Operating and administrative expenses	**269**	307
Depreciation and amortization	**103**	102
Other expense	**2**	5
Provisions for income taxes	**61**	73
Net earnings	**170**	214
Number of fuel outlets(1)	**487**	497
Fuel sales volume, including wholesale		
Fuel sales *(millions of litres/day)*	**7.6**	8.0
Fuel sales per outlet *(thousands of litres/day)*	**12.5**	13.4
Refinery throughput		
Prince George Refinery *(mbbls/day)*	**10.7**	11.7
Lloydminster Refinery *(mbbls/day)*	**28.1**	28.8
Ethanol production *(thousands of litres/day)*	**794.9**	780.7

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

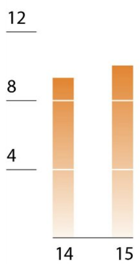
Canadian Refined Products gross revenues decreased by $1,134 million in 2015 compared to 2014 primarily due to lower refined product prices, lower throughput at the Prince George Refinery due to an unplanned outage in the second quarter and lower fuel sales volumes resulting from lower demand and select outlet closures. Throughput at the Prince George Refinery declined by 1.0 mbbls/day, or nine percent, and fuel sales per outlet declined by 900 litres per day, or seven percent, compared to 2014.

Refining gross margins decreased by $101 million in 2015 compared to 2014 primarily due to an unplanned outage at the Prince George Refinery in the second quarter of 2015 which resulted in lower throughput and the need to purchase finished products from third parties to deliver on committed sales volumes. In addition, refining gross margins were impacted by higher feedstock costs at the Lloydminster and Minnedosa Ethanol plants and lower federal grant revenue due to the program's expiry in 2015.

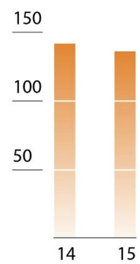
Asphalt gross margins increased by $16 million in 2015 compared to 2014 primarily due to strong contract pricing and lower feedstock costs.

U.S. Refining and Marketing

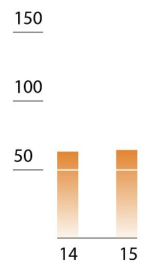
Refining Margin
U.S.
(U.S. $/bbl crude throughput)



Throughput
Lima Refinery
(mbbls/day)



Toledo Refinery
(mbbls/day)



U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	**2015**	2014
Gross revenues	**7,345**	10,663
Gross refining margin	**890**	722
Operating and administrative expenses	**484**	481
Depreciation and amortization	**333**	268
Other expense (income)	**(233)**	3
Recovery of income taxes	**(91)**	(11)
Net earnings (loss)	**397**	(19)
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**136.1**	141.6
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**63.7**	63.2
Refining margin *(U.S. $/bbl crude throughput)*	**10.09**	9.37
Refinery inventory *(mmbbls)*[(1)]	**9.8**	10.8

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

U.S. Refining and Marketing gross revenues decreased by $3,318 million in 2015 compared with 2014 primarily due to lower realized refined product prices consistent with significantly lower Chicago Regular Unleaded Gasoline and Chicago Ultra-low Sulphur Diesel benchmark prices partially offset by a weaker Canadian dollar. In addition, throughput at the Lima Refinery declined by 5.5 mbbls/day, or four percent, primarily due to unplanned outages in the isocracker unit and the coker unit.

U.S. Refining and Marketing gross margin increased by $168 million in 2015 compared with 2014 primarily due to higher market crack spreads combined with the impact of a weaker Canadian dollar. Gross refining margin was also impacted by a $16 million pre-tax charge to reduce inventories to net realizable value during 2015 compared to a $202 million pre-tax charge recognized during 2014.

Included in depreciation and amortization was a $46 million write-off of the carrying value of the isocracker unit at Lima which was damaged by a fire in January 2015. The Company recorded pre-tax business interruption loss and property damage insurance recoveries associated with the fire of $235 million which is reflected in other expense (income).

The Chicago 3:2:1 market crack spread benchmark is based on last in first out ("LIFO") accounting, which assumes that crude oil feedstock costs are based on the current month price of WTI, while crude oil feedstock costs included in realized margins are based on first in first out ("FIFO") accounting, which reflects purchases made in previous months when crude oil prices were higher. The estimated FIFO impact was a reduction in net earnings of approximately $130 million in 2015 compared to $108 million in 2014.

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

Downstream Capital Expenditures

In 2015, Downstream capital expenditures totalled $501 million compared to $510 million in 2014. In Canada, capital expenditures of $76 million were primarily related to upgrades at retail stations and projects at the Upgrader and Prince George Refinery. At the Lima Refinery, $318 million was spent primarily on repairs and upgrades to the isocracker unit in addition to various reliability and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $107 million (Husky's 50 percent share) and were primarily for facility upgrades and environmental protection initiatives.

6.4 Corporate

Corporate Summary *($ millions) income (expense)*	2015	2014
Administrative expenses	**(92)**	(156)
Stock-based compensation recovery	**39**	17
Depreciation and amortization	**(84)**	(73)
Other income	**2**	5
Net foreign exchange gain	**43**	81
Finance expense	**(114)**	(64)
Provisions for income taxes	**(50)**	(21)
Net loss	**(256)**	(211)

The Corporate segment reported a net loss of $256 million in 2015 compared to a net loss of $211 million in 2014. Administrative expenses decreased in 2015 primarily due to lower personnel costs. Stock-based compensation recovery was higher in 2015 primarily due to a decrease in the Company's share price. Net foreign exchange gains decreased in 2015 primarily due to a weakening of the Canadian dollar against the U.S. dollar which resulted in unrealized losses on the translation of a portion of the Company's U.S. dollar denominated long-term debt that was not designated as a hedge of the Company's net investment in its U.S. refining operations. Finance expense increased in 2015 primarily due to higher debt and a decrease in the amount of capitalized interest.

Foreign Exchange Summary *($ millions, except exchange rate amounts)*	2015	2014
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(34)**	7
Gains on contribution receivable	–	6
Gains on non-cash working capital	**35**	42
Other foreign exchange gains	**42**	26
Foreign exchange gains	**43**	81
U.S./Canadian dollar exchange rates:		
At beginning of year	**U.S $0.862**	U.S. $0.940
At end of year	**U.S $0.723**	U.S. $0.862

Consolidated Income Taxes

Consolidated income taxes were a recovery of $1,521 million in 2015 compared to income tax expense of $526 million in 2014. The decrease in consolidated income taxes was primarily due to a $1,357 million deferred income tax recovery associated with impairment charges recognized on crude oil and natural gas assets located in Western Canada. In addition, the Company recognized a deferred income tax recovery of $203 million from the distribution of U.S. $1.0 billion by BP-Husky Refining LLC to each member following the partial payment of the contribution payable by the Company in the first quarter of 2015. The decreases were partially offset by the recognition of a $157 million deferred income tax expense related to the increase in Alberta provincial tax rates.

($ millions)	2015	2014
Provisions for (recovery of) income taxes	**(1,521)**	526
Income taxes paid	**227**	661

7.0 Risk and Risk Management

7.1 Enterprise Risk Management

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

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

7.2 Significant Risk Factors

Operational, Environmental and Safety Incidents

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

Commodity Price Volatility

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

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

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

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

In certain instances, the Company uses derivative commodity instruments and futures contracts on commodity exchanges to manage exposure to price volatility on a portion of its refined product, oil and gas production, inventory or volumes in long distance transit.

The fluctuations in refined products, crude oil and natural gas prices are beyond the Company's control and could have a material adverse effect on the Company's business, financial condition and cash flow. For information on 2015 commodity price sensitivities, refer to Section 3.0.

Reservoir Performance Risk

Lower than projected reservoir performance on the Company's key growth projects could have a material impact on the Company's financial position, medium to long-term business strategy and cash flow. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and negatively affect the Company's reputation, investor confidence and the Company's ability to deliver on its growth strategy.

In order to maintain the Company's future production of crude oil, natural gas and NGL and maintain the value of the reserves portfolio, additional reserves must be added through discoveries, extensions, improved recovery, performance related revisions and acquisitions. The production rate of oil and gas properties tends to decline as reserves are depleted while the associated unit operating costs increase. In order to mitigate the effects of this, the Company must undertake successful exploration and development programs, increase the recovery factor from existing properties through applied technology and identify and execute strategic acquisitions of proved developed and undeveloped properties and unproved prospects. Maintaining an inventory of developable projects depends on, among other things, obtaining and renewing rights to explore, develop and produce oil and natural gas, drilling success, completing long-lead time capital intensive projects on budget and on schedule and the application of successful exploitation techniques on mature properties.

Restricted Market Access and Pipeline Interruptions

Husky's results depend upon the Company's ability to deliver products to the most attractive markets. The Company's results could be impacted by restricted market access resulting from a lack of pipeline or other transportation alternatives to attractive markets as well as regulatory and/or other marketplace barriers. The interruptions and restrictions may be caused by the inability of a pipeline to operate, or they can be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. With growing conventional, shale oil, and oil sands production across North America and limited availability of infrastructure to carry the Company's products to the marketplace, oil and natural gas transportation capacity is expected to be restricted in the next few years. Restricted market access may potentially have a material impact on the Company's financial condition, short-term to long-term business strategy, cash flow, earnings and corporate reputation. Unplanned shutdowns and closures of its refineries and or upgrader may limit Husky’s ability to deliver product with negative implications on sales and results from operating activities.

Security and Terrorist Threats

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

A cyber incident may impact the operational state and/or cause physical damage to the Company’s assets, along with potential health and safety risks or loss of intellectual property.

International Operations

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

Major Project Execution

The Company manages a variety of oil and gas projects ranging from Upstream to Downstream assets. The risks associated with project development and execution, as well as the risks involved in commissioning and integration of new assets with existing facilities, can impact the economic feasibility of the Company’s projects. These risks can result in, among other things, cost overruns, schedule delays and decreases in product markets. These risks can also impact the Company’s safety and environmental performance, which could negatively affect the Company’s reputation.

Partner Misalignment

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

Reserves Data and Future Net Revenue Estimates

The reserves data contained or referenced in this MD&A represent estimates only. The accurate assessment of oil and gas reserves is critical to the continuous and effective management of the Company's Upstream assets. Reserves estimates support various investment decisions about the development and management of oil and gas properties. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flow therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the assumed effects of regulation by government agencies, including with respect to royalty payments, all of which may vary considerably from actual results. All such estimates are to some degree uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, classification of such reserves and resources based on risk of recovery and estimates of future net revenues expected therefrom may differ substantially from actual results. The data may be prepared by different engineers or by the same engineers at different times. These factors may cause the estimates to vary substantially over time. All reserves estimates involve a degree of ambiguity and, at times, rely on indirect measurement techniques to estimate the size and recoverability of the resource. While new technologies have increased the accuracy of these techniques, there remains the potential for human or systemic error in recording and reporting the magnitude of the Company's oil and gas reserves. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and could negatively affect the Company's reputation, investor confidence and the Company's ability to deliver on its growth strategy.

Government Regulation

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

Environmental Regulation

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

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

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

Some of the topics that are or could in the future be subject to new or enhanced environmental regulation include:

- greenhouse gas ("GHG") emission regulations in jurisdictions where the Company has operations;
- increased restrictions on freshwater licensing;
- enhanced groundwater and surface water monitoring;
- enhanced water discharge criteria;
- provincial/state level calculation and regulation of carbon intensity for transportation fuels;
- fuel reformulation to support reduced transportation emissions;
- managing air pollutants at facility and equipment levels;
- potential for a moratorium on development in areas of particular value to species at risk; and
- the transportation of product by rail.

Transportation of Dangerous Goods Regulation

New regulations amending the Canadian Transportation of Dangerous Goods Regulations were published on May 20, 2015. The regulatory package was made in coordination with the United States Department of Transportation ("USDOT"), the USDOT package having been developed by the USDOT's affiliate regulators, the Federal Railroad Administration and the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). The new regulations unveiled a new, enhanced, class of tank car and were characterized by the USDOT as an aggressive, risk-based retrofitting schedule for older tank cars carrying, in particular, crude oil and ethanol. The new class of non-pressurized tank car (TC-117 in Canada and DOT-117 in the United States) adopts technical requirements for Class 3 flammable liquids service: jacketed and thermally insulated shells of 9/16-inch steel, full-height half-inch-thick head shields, re-closable pressure relief valves and rollover protection for top fittings.

The new regulations also provide a timeline for the retrofitting or retirement of existing DOT-111 cars and the newer industry-sponsored CPC-1232 cars that were constructed since 2011. Husky currently leases and operates a fleet of 1,534 tank cars, 314 or 20 percent of which are affected by the new regulations and will be replaced.

In December 2015, the U.S. congress passed the FAST Act, a federal transportation bill. Among other things, the FAST Act requires the phased implementation of new tank car standards previously finalized by PHMSA for all flammable liquids tank cars.

Husky loads, bills, and ships cars to destinations all over North America from five primary locations: Lloydminster Upgrader, Lloydminster Refinery, Prince George, Ram River and Lima. The new regulations may impact the Company's operations in North America.

Climate Change Regulation

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

Existing regulations in Alberta require facilities that emit more than 100,000 tonnes of carbon dioxide in a year to reduce their emissions intensity by up to 20 percent below an established baseline emissions intensity by January 1, 2017. These regulations currently affect the Company's Ram River Gas Plant and Tucker Thermal Facility. Husky's Sunrise Energy Project will not be impacted by the existing regulations before they expire in 2017. The Alberta Climate Leadership Plan will be implemented in 2017. The regulations under this plan are currently under development and will cover all of the Company's assets in Alberta. These regulations may materially impact the Company's current and future operations in the province.

The Saskatchewan government is currently in the process of developing regulations. These regulations may impact the Company's current and future operations in the province.

British Columbia currently has a $30 per tonne carbon tax that is in place on fuel the Company uses and purchases in that jurisdiction, which affects all of the Company's operations in British Columbia. Additionally, British Columbia has a Renewable and Low Carbon Fuel Requirements Regulation in place that requires a reduction in the allowable carbon intensities of all fuels, with penalties applied for intensities that do not meet targets. As a result of credits generated by the Company, it is anticipated that penalty payments will not begin to apply until the end of 2017. Beyond that, the cost of compliance with the regulation may become material.

At the Company's Prince George Refinery, certain biodiesel options are not feasible operationally or economically. With the current biodiesel option, it is not economically feasible to increase the blending percentages.

The B.C. government is currently conducting additional consultation on its Climate Leadership Plan. Future regulations may impact the Company's current and future operations in British Columbia.

Manitoba released its Climate Change and Green Economy Action Plan in December 2015 and pledged to start a carbon cap-and-trade system aiming to cut GHG emissions from 2005 levels by one-third by 2030 and by one-half by 2050. Manitoba has stated it will cap GHG emissions for certain sectors and link its cap-and-trade system with others in North America. Details on the plan will follow public consultations, and its implementation may impact Husky's operations in Manitoba.

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

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

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

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

Cost or Availability of Oil and Gas Field Equipment
The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including land and offshore drilling rigs, land and offshore geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at reasonable prices.

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

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

The Company's Atlantic Region business unit has a robust ice management program which uses a range of resources including a dedicated ice surveillance aircraft, as well as synergistic relationships with government agencies including Environment Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commence in February and continue until the threat has abated. In addition, Atlantic Region operators employ a series of supply and support vessels to actively manage ice and icebergs. These vessels are equipped with a variety of ice management tools including towing ropes, towing nets and water cannons. The Company also maintains a series of ad-hoc relationships with contractors, allowing the quick mobilization of additional resources as required.

7.3 Financial Risks

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

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

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollar denominated revenue to hedge against these potential fluctuations. The Company also designates a portion of its U.S debt as a hedge of the Company's net investment in the U.S. refining operations for which the U.S. dollar is the functional currency. At December 31, 2015, the amount that the Company designated was U.S. $3.2 billion (December 31, 2014 – U.S. $2.9 billion).

Interest Rate Risk

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.

Counterparty Credit Risk

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

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company's process for managing liquidity risk includes ensuring, to the extent possible, that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities and the availability to raise capital from various debt and equity capital markets under its shelf prospectuses. The availability of capital under its shelf prospectuses is dependent on market conditions at the time of sale.

Credit Rating Risk

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

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

	S&P Rating Services	Moody's Investor Service	DBRS Limited
Outlook/Trend	Negative - Issuer	Stable	Negative
Senior Unsecured Debt	BBB+	Baa2	A(low)
Series 1 Preferred Shares	P-2(low)		Pfd-2(low)
Series 3 Preferred Shares	P-2(low)		Pfd-2(low)
Series 5 Preferred Shares	P-2(low)		Pfd-2(low)
Series 7 Preferred Shares	P-2(low)		Pfd-2(low)
Commercial Paper			R-1(low)

Fair Value of Financial Instruments

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

The Company's financial instruments include cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, inventories measured at fair value, long-term income tax receivable, portions of other assets and other long-term liabilities.

For the year ended December 31, 2015, the Company recognized a \$15 million unrealized gain on its crude oil and natural gas risk management positions which were recorded in marketing and other. In addition, the Company recognized a \$27 million loss on foreign currency forwards, \$1 million unrealized gain recorded in other-net and \$28 million realized loss recorded in net foreign exchange gains. Refer to Note 24 to the 2015 Consolidated Financial Statements.

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

Cash Flow Summary *($ millions)*	**2015**	2014
Cash flow		
Operating activities	**3,760**	5,585
Financing activities	**(210)**	(6)
Investing activities	**(4,817)**	(5,423)

Cash Flow from Operating Activities
Cash flow generated from operating activities was $3,760 million in 2015 compared to $5,585 million in 2014. The decrease was primarily due to significantly lower realized crude oil and North American natural gas prices partially offset by lower cash taxes paid, higher production and cash flow from the Asia Pacific Region.

Cash Flow used for Financing Activities
Cash flow used for financing activities was $210 million in 2015 compared to $6 million in 2014. Cash flow used for financing activities was primarily used for the net repayment of $175 million of short-term debt in 2015 compared to the net issuance of $895 million of short-term debt in 2014. The increase in cash flow used for financing activities was partially offset by the net inflow of cash from the issuance and repayment of long-term debt.

Cash Flow used for Investing Activities
Cash flow used for investing activities was $4,817 million in 2015 compared to $5,423 million in 2014. The decrease was primarily due to a reduction in capital expenditures partially offset by the payment of $1.3 billion of the Company's BP-Husky Refining LLC contribution payable in 2015.

8.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2015, Husky's working capital deficiency was $922 million compared to a deficiency of $1,314 million at December 31, 2014. A reconciliation of Husky's working capital deficiency is as follows:

($ millions)	**December 31, 2015**	December 31, 2014	Change
Cash and cash equivalents	**70**	1,267	(1,197)
Accounts receivable	**1,014**	1,324	(310)
Income taxes receivable	**312**	353	(41)
Inventories	**1,247**	1,385	(138)
Prepaid expenses	**271**	166	105
Accounts payable and accrued liabilities	**(2,527)**	(2,989)	462
Asset retirement obligations	**(102)**	(97)	(5)
Short-term debt	**(720)**	(895)	175
Contribution payable	**(210)**	(1,528)	1,318
Long-term debt due within one year	**(277)**	(300)	23
Net working capital (deficiency)	**(922)**	(1,314)	392

The decrease in cash was primarily due to lower cash flow from operating activities in 2015 resulting primarily from significantly lower realized crude oil and North American natural gas prices. Fluctuations in accounts receivable and accounts payable were due to the timing of settlements compared to 2014. The decrease in contribution payable resulted from the U.S. $1 billion payment, equivalent to $1.3 billion at the time of payment, on a U.S. capital contribution obligation in February 2015. The Company has sufficient sources of liquidity to supplement the net working capital deficiency as at December 31, 2015. Refer to section 8.3 in this MD&A.

8.3 Sources of Liquidity

Liquidity describes a company's ability to access cash. Sources of liquidity include cash flow 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 continues to believe 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 and borrowings under committed and uncommitted credit facilities. The Company is continually examining its options with respect to sources of long and short-term capital resources to ensure it retains financial flexibility.

At December 31, 2015, Husky had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[(1)]	**645**	**429**
Syndicated credit facilities[(2)]	**4,000**	**2,781**
	4,645	**3,210**

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

At December 31, 2015, Husky had $3,210 million of unused credit facilities of which $2,781 million are long-term committed credit facilities and $429 million are short-term uncommitted credit facilities. A total of $216 million of the Company's short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $720 million of the Company's long-term committed borrowing credit facilities was used in support of commercial paper. At December 31, 2015 the Company had direct borrowings of $499 million against committed credit facilities. The Company's ability to renew existing bank credit facilities and raise new debt is dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. Credit ratings may be affected by the Company's level of debt, from time to time.

The Company's share capital is not subject to external restrictions; however, the syndicated credit facilities include leverage covenants used to assess the Company's financial strength. The covenant is calculated as long-term debt including current portion net of certain adjusting items specified in the agreement divided by earnings (loss) from operating activities before DD&A net of certain adjusting items specified in the agreement. The Company was in compliance with the syndicate credit facility covenants at December 31, 2015 and assesses the risk of non-compliance to be low. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. There were no amounts drawn on this demand credit facility at December 31, 2015.

On March 17, 2014, the Company issued U.S. $750 million of 4 percent notes due April 15, 2024 pursuant to a universal short form base shelf prospectus that expired on November 30, 2015. The notes are redeemable at the option of the Company at any time, subject to a make-whole premium if the notes are redeemed prior to the three month period prior to maturity. Interest is payable semi-annually. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On June 15, 2014, the Company repaid the maturing 5.9 percent notes issued under a trust indenture dated September 11, 2007. The amount paid to noteholders was U.S. $772 million, including U.S. $22 million of interest, equivalent to $839 million in Canadian dollars at the time of repayment, including interest of $25 million.

On September 15, 2014, the Company launched a commercial paper program in Canada. The program is supported by the Company's syndicated credit facilities and the Company is authorized to issue commercial paper up to a maximum of $1.0 billion having a term not to exceed 365 days. The weighted average interest rate for commercial paper outstanding as at December 31, 2015 was 0.81 percent (December 31, 2014 - 1.24 percent).

On December 9, 2014, the Company issued 10 million Series 3 Preferred Shares at a price of $25.00 per share for aggregate gross proceeds of $250 million. Holders of the Series 3 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.5 percent annually for the initial period ending December 31, 2019 as declared by the Company. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.13 percent. Holders of Series 3 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 4 (the "Series 4 Preferred Shares"), subject to certain conditions, on December 31, 2019 and on December 31 every five years thereafter. Holders of the Series 4 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.13 percent.

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

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

On March 12, 2015, the Company issued eight million Series 5 Preferred Shares at a price of $25.00 per share for aggregate gross proceeds of $200 million, by way of a prospectus supplement dated March 5, 2015 to the Canadian Shelf Prospectus. Net proceeds after share issue costs were $195 million. Holders of the Series 5 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending March 31, 2020 as declared by the board of directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.57 percent. Holders of Series 5 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 6 (the "Series 6 Preferred Shares"), subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Holders of the Series 6 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.57 percent. Net proceeds from the Series 5 Preferred Shares was used for general corporate purposes, which included, among other things, the partial repayment of bank debt incurred by Husky to fund early payment of U.S. $1 billion of the Company's net capital contribution payable with BP-Husky Refining LLC.

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

On March 12, 2015, the Company issued $750 million of 3.55 percent notes due March 12, 2025 by way of a prospectus supplement dated March 9, 2015 to the Canadian Shelf Prospectus. The notes are redeemable at the option of the Company at any time, subject to a make whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 12 and September 12 of each year, beginning September 12, 2015. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness. Net proceeds from the offering was used for general corporate purposes, which included, among other things, the partial repayment of bank debt incurred by Husky to fund early payment of U.S. $1 billion of the Company's net capital contribution payable with BP-Husky Refining LLC.

On June 17, 2015, the Company issued six million Series 7 Preferred Shares at a price of $25.00 per share for aggregate gross proceeds of $150 million, by way of a prospectus supplement dated June 10, 2015 to the Canadian Shelf Prospectus. Net proceeds after share issue costs were $145 million. Holders of the Series 7 Preferred Shares are entitled to receive a cumulative fixed dividend yielding 4.60 percent annually for the initial period ending June 30, 2020 as declared by the board of directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.52 percent. Holders of the Series 7 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 8 (the "Series 8 Preferred Shares"), subject to certain conditions, on June 30, 2020 and on June 30 every five years thereafter. Holders of the Series 8 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.52 percent. Net proceeds from the Series 7 Preferred Shares was used for general corporate purposes, which included, among other things, the partial repayment of bank debt incurred by Husky to fund capital expenditures for the advancement of near term heavy oil thermal projects.

On December 22, 2015, the Company filed a universal short form base shelf prospectus (the "U.S. Shelf Prospectus") with the Alberta Securities Commission and a related U.S. registration statement containing the U.S. Shelf Prospectus with the SEC that enables the Company to offer up to U.S. $3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the United States up to and including January 22, 2018. During the 25-month period that the U.S. Shelf Prospectus and the related U.S registration statement are effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement. This shelf prospectus and related U.S. registration statement replaces the universal short form base shelf prospectus filed with the Alberta Securities Commission and the related U.S registration statement filed with the SEC that expired on November 30, 2015 with $2.25 billion of unused capacity.

The Company has $1.9 billion in unused capacity under the Canadian Shelf Prospectus and U.S. $3.0 billion in unused capacity under the U.S. Shelf Prospectus and related U.S. registration statement as at December 31, 2015. The ability of the Company to utilize the capacity under its shelf prospectus and related U.S. registration statement is subject to market conditions at the time of sale.

Net debt

Net debt is calculated as total debt less cash and cash equivalents. At December 31, 2015, the Company had total debt of $6,756 million and cash and cash equivalents of $70 million compared to total debt of $5,292 million and cash and cash equivalents of $1,267 million at December 31, 2014. The Company's net debt increased by $2,661 million when compared to December 31, 2014:

Net debt *($ millions)*	December 31, 2015	December 31, 2014
Net debt at beginning of period	**(4,025)**	(3,022)
Change in net debt due to:		
Cash flow from operations[1]	**3,329**	5,535
Capital expenditures	**(3,005)**	(5,023)
Cash dividends paid on common and preferred shares	**(1,203)**	(1,182)
Change in non-cash working capital	**498**	571
Proceeds from asset sales	**122**	66
Net proceeds from issuance of preferred shares	**340**	243
Effect of exchange rates on cash and cash equivalents	**70**	14
Effect of exchange rates on long-term debt	**(692)**	(263)
Income taxes paid	**(227)**	(661)
Net interest paid	**(320)**	(277)
Contribution receivable	**–**	143
Contribution payable	**(1,363)**	(106)
Other	**(210)**	(63)
	(2,661)	(1,003)
Net debt at end of period	**(6,686)**	(4,025)

(1) *Cash flow from operations is a non-GAAP measure. Refer to Section 11.3 for a reconciliation to the GAAP measures.*

During the years ended December 31, 2015 and 2014, the Company's capital expenditures remained in balance with cash flow from operations. The Company's cash flow from operations is dependent on a number of factors, including commodity prices, production and sales volumes, refining and marketing margins, operating expenses, taxes, royalties and foreign exchange rates. Management prepares capital expenditure budgets annually which are regularly monitored and updated to adapt to changes in market factors. In addition, the Company requires authorizations for capital expenditures on projects, which assists with the management of capital.

To further support the Company's long-term business objectives, the Company's Board of Directors has suspended the quarterly common share dividend effective in the fourth quarter of 2015. This initiative supports long-term value maximization while providing further financial flexibility for the Company to achieve its business and financial objectives. The Board of Directors carefully considers numerous factors, including earnings, commodity price outlook, future capital requirements and the financial condition of the Company. The Board will continue to review the Company's common share dividend policy on a quarterly basis.

During the year ended December 31, 2015, the Company declared dividends of $1.20 per common share, which includes dividends declared for the fourth quarter of 2014, resulting in common share dividends of $1,181 million. During the year ended December 31, 2015, the Company paid $1,167 million in cash to common shareholders compared to $1,169 million during 2014. At December 31, 2015, $296 million in common shares was payable to shareholders on account of dividends declared on October 30, 2015.

The transition of the Western Canada portfolio is being accelerated through a planned disposition of select legacy assets. The Company is assessing a sale of select royalty assets and the potential partial sale of select midstream assets in the Lloydminster region, which includes pipelines and storage facilities. The Company intends to continue as the operator of these select midstream assets. The potential proceeds from these select asset dispositions would generate cash flow and allow the Company to pay down debt which would serve to strengthen the Company's balance sheet.

8.4 Capital Structure

Capital Structure	December 31, 2015	
($ millions)	Outstanding	Available[1]
Total debt	6,756	3,210
Common shares, preferred shares, retained earnings and other reserves	16,586	

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

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk, and to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes adjustments as economic conditions and the risk characteristics of its underlying assets change. The Company considers its capital structure to include shareholders' equity and debt which was $23.3 billion at December 31, 2015 (December 31, 2014 – $25.9 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to cash flow from operations which are non GAAP measures (refer to section 11.3). The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to cash flow from operations ratio of less than 1.5 times. At December 31, 2015, debt to capital employed was 28.9 percent (December 31, 2014 – 20.5 percent) and debt to cash flow from operations was 2.0 times (December 31, 2014 – 1.0 times) exceeding the Company's targets. The increase in the Company's debt to capital and debt to cash flow from operations ratios as at December 31, 2015 reflects the impact of sharp declines in global crude oil and North American natural gas benchmark pricing in the year which resulted in significantly lower cash flow from operations compared to 2014 and the weakening of the Canadian dollar which impacted the translation of the Company's U.S. denominated long-term debt. The Company has taken measures to strengthen its financial position and navigate through this commodity down cycle including but not limited to a reduction of 2016 budgeted capital spending, the suspension of the quarterly common share dividend, the continued transition to low sustaining capital projects and the planned disposition of select midstream assets in the Lloydminster region and select legacy Upstream assets in Western Canada. 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.

8.5 Contractual Obligations, Commitments and Off-Balance Sheet Arrangements

Contractual Obligations and Other Commercial Commitments

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

Contractual Obligations

Payments due by period ($ millions)	2016	2017-2018	2019-2020	Thereafter	Total
Long-term debt and interest on fixed rate debt	576	947	2,310	3,940	7,773
Operating leases	204	448	208	1,034	1,894
Firm transportation agreements	363	694	644	2,321	4,022
Unconditional purchase obligations[1]	2,337	2,703	2,234	1,346	8,620
Lease rentals and exploration work agreements	181	211	171	1,343	1,906
Obligations to fund equity investee[2]	6	114	114	417	651
Finance lease obligations[3]	35	69	70	800	974
Asset retirement obligations[4]	102	193	188	13,443	13,926
	3,804	5,379	5,939	24,644	39,766

(1) *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases.*
(2) *Equity investee refers to the Company's investment in Husky-CNOOC Madura Limited which is accounted for using the equity method.*
(3) *Refer to Note 15 to the 2015 Consolidated Financial Statements.*
(4) *Asset retirement obligation amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets.*

The Company renewed certain purchase, distribution and terminal commitments related to light oil and asphalt products in 2015.

The Company cancelled its contract for the West Mira semi-submersible rig in 2015 due to the supplier's inability to deliver West Mira in the timeframe required. Husky subsequently entered into a new agreement for the harsh environment Henry Goodrich rig for developmental drilling at the South White Rose Extension and North Amethyst field, and near field exploration. The rig is expected to arrive in mid-2016.

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

The Company updated its estimates for Asset Retirement Obligations ("ARO") as outlined in Note 16 to the 2015 Consolidated Financial Statements. On an undiscounted and inflated basis, the ARO decreased from $15.5 billion as at December 31, 2014 to $13.9 billion as at December 31, 2015, due to decreased estimated time to retirement in the Upstream and Downstream segments.

Other Obligations

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

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

Husky provides a defined contribution pension plan and a post-retirement health and dental plan for all qualified employees in Canada. The Company also provides a defined benefit pension plan for approximately 60 active employees, 83 participants with deferred benefits and 550 participants or joint survivors receiving benefits in Canada. This plan was closed to new entrants in 1991 after the majority of employees transferred to the defined contribution pension plan (Refer to Note 19 to the 2015 Consolidated Financial Statements).

The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery. During 2015, the Company amended the terms of payment of the Company's contribution payable with BP-Husky Refining LLC in the first quarter of 2015. In accordance with the amendment, U.S. $1 billion of the net contribution payable was paid on February 2, 2015. Subsequent to the payment, BP-Husky Refining LLC distributed U.S. $1 billion to each of the joint arrangement partners which resulted in the creation of a deferred tax asset and deferred tax recovery of $203 million. As a result of prepayment, the accretion rate was reduced from 6 percent to 2.5 percent for the future term of the agreement and the remaining maturity date was extended to December 31, 2017. The remaining net contribution payable amount of approximately U.S. $251 million (CDN $348 million) will be paid by way of funding all capital contributions of the BP-Husky Refining LLC joint operation with the current and long-term portions reflecting the timing of future expected capital expenditures as at December 31, 2015.

In accordance with the provisions of the regulations of the People's Republic of China, the Company is required to deposit funds in separate accounts restricted to future decommissioning and disposal obligations. The funds will be used for decommissioning and disposal expenses upon the expiry or termination of the contract for the Asia Pacific Region. At December 31, 2015, $121 million of the funds in decommissioning and disposal expense accounts have been classified as non-current and included in restricted cash.

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

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

Off-Balance Sheet Arrangements

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

Standby Letters of Credit

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

8.6 Transactions with Related Parties

The Company sells natural gas to and purchases steam from the Meridian Limited Partnership ("Meridian"), owner of the Meridian cogeneration facility, for use at the facility, Upgrader and Lloydminster ethanol plant. In addition, the Company provides facilities services and personnel for the operations of the Meridian cogeneration facility, which are primarily measured and reimbursed at cost. These transactions are related party transactions, as Meridian is an affiliate of one of the Company's principal shareholders, and have been measured at fair value. For the year ended December 31, 2015, the amount of natural gas sales to Meridian totalled $50 million. For the year ended December 31, 2015, the amount of steam purchased by the Company from Meridian totalled $16 million. For the year ended December 31, 2015, the total cost recovery by the Company for facilities services was $17 million. At December 31, 2015, the Company had $2 million due from Meridian with respect to these transactions.

At December 31, 2015, $38 million of the May 11, 2009 7.25 percent notes were held by related parties and are included in long-term debt in the Company's consolidated balance sheet. Mr. Canning Fok, co-chair and a director of the Company, indirectly subscribed for $3 million of the senior notes. Ace Dimension Limited subscribed for $35 million of the senior notes. These related party transactions were measured at fair market value at the date of the transactions and have been carried out on the same terms as applied to unrelated parties who purchased the senior notes pursuant to the public offering of the senior notes.

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.

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.

8.7 Outstanding Share Data

Authorized:

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

Issued and outstanding: February 23, 2016

• common shares	1,005,451,854
• cumulative redeemable preferred shares, series 1	12,000,000
• 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	26,956,351
• stock options exercisable	16,335,577

9.0 Critical Accounting Estimates and Key Judgments

Husky's consolidated financial statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Significant accounting policies are disclosed in Note 3 to the 2015 Consolidated Financial Statements. Certain of the Company's accounting policies require subjective judgment and estimation about uncertain circumstances.

9.1 Accounting Estimates

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

Depletion, Depreciation, Amortization and Impairment

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

Impairment of Non-Financial Assets

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

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

Asset Retirement Obligations

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

Fair Value of Financial Instruments

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

Employee Future Benefits

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

Income Taxes

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

Legal, Environmental Remediation and Other Contingent Matters

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

9.2 Key Judgments

Management makes judgments regarding the application of IFRS for each accounting policy. Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include successful efforts and impairment assessments, the determination of cash generating units ("CGUs"), the determination of a joint arrangement and the designation of the Company's functional currency.

Exploration and Evaluation Costs

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

Impairment of Financial Assets

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

Cash Generating Units

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

Joint Arrangements

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

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

Functional and Presentation Currency

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

10.0 Recent Accounting Standards and Changes in Accounting Policies

Recent Accounting Standards

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

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. Early adoption is permitted. The Company is currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

Leases

In January 2016, the IASB issued IFRS 16, Leases. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 Revenue from Contracts with Customers, has been applied, or is applied at the same date as IFRS 16. The Company is currently evaluating the impact of adopting IFRS 16 on the consolidated financial statements.

Financial Instruments

In July 2014, the IASB issued IFRS 9, "Financial Instruments", to replace IAS 39 which provides a logical model for classification and measurement, a single, forward-looking 'expected loss' impairment model and a substantially-reformed approach to hedge accounting. The standard is effective for the Company for annual periods beginning on January 1, 2018, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the standard on January 1, 2018. The Company is currently evaluating the impact of adopting IFRS 9 on the consolidated financial statements.

Change in Accounting Policy

The Company has applied the following standards and amendments for the first time for the annual reporting period commencing January 1, 2015:

- Annual Improvements to IFRS - 2010 - 2012 Cycle and 2011 - 2013 Cycle
- Defined Benefit Plans: Employee Contributions - Amendments to IAS 19

The adoption of these amendments did not have any impact on the annual Consolidated Financial Statements. The nature and the impact of each new standard or amendment is described below:

IFRS 8 Operating Segments

The amendments are applied retrospectively and clarify that an entity must disclose the judgments made by management in applying the aggregation criteria in paragraph 12 of IFRS 8, including a brief description of operating segments that have been aggregated and the economic characteristics used to assess whether the segments are 'similar'. The reconciliation of segment assets to total assets is only required to be disclosed if the reconciliation is reported to the chief operating decision maker, similar to the required disclosure for segment liabilities. The adoption of this amended standard has no material impact on the Company's Consolidated Financial Statements.

IFRS 2 Share-based Payment

This improvement is applied prospectively and clarifies various issues relating to the definitions of performance and service conditions which are vesting conditions, including:

- A performance condition must contain a service condition;
- A performance target may relate to the operations or activities of an entity, or to those of another entity in the same group;
- A performance target must be met while the counterparty is rendering service; and
- A performance condition may be a market or non-market condition.

The adoption of this amended standard has no impact on the Company's Consolidated Financial Statements.

IFRS 3 Business Combinations

The amendment is applied prospectively and clarifies that all contingent consideration arrangements classified as liabilities (or assets) arising from a business combination should be subsequently measured at fair value through profit or loss whether or not they fall within the scope of IFRS 9 (or International Accounting Standard ("IAS") 39, as applicable). The adoption of this amended standard has no impact on the Company's Consolidated Financial Statements.

11.0 Reader Advisories

11.1 Forward-Looking Statements

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

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result","are expected to","will continue","is anticipated","is targeting","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 2016 production guidance, including guidance for specified areas and product types; and the Company's 2016 Upstream capital expenditures program, including guidance for specified areas and product types;
- with respect to the Company's Asia Pacific Region: planned timing of first production from the Madura Strait BD, MDA, MBH and MDK fields, and forecasted combined net peak sales volumes for these fields; exploration and drilling plans at Block 15/33; and anticipated timeframe for acquiring seismic survey data for the offshore Taiwan block;
- with respect to the Company's Atlantic Region: anticipated timing of the arrival of the Henry Goodrich drilling rig and associated drilling plans for the White Rose field and satellite extensions, South White Rose extension and North Amethyst Hibernia formation;
- with respect to the Company's Oil Sands properties: forecast daily production from the Company's Sunrise Energy Project by the end of 2016;
- with respect to the Company's Heavy Oil properties: anticipated daily production from the Company's heavy oil thermal portfolio by the end of 2016; anticipated timing of first production from, and forecast net peak daily production from, the Company's Edam East, Edam West and Vawn heavy oil thermal projects; forecasted net peak daily production from the Company's Rush Lake 2 heavy oil thermal project; forecasted net peak daily production of three heavy oil thermal developments in the Lloydminster area; expected timing of first production at the Colony formation at the Tucker thermal project; and anticipated daily production from the Company's Tucker thermal project by the end of 2016;
- with respect to the Company's Western Canadian oil and gas resource plays: the Company's plan to pursue dispositions of select Upstream legacy assets, select royalty assets, and select midstream assets in the Lloydminster region, and the anticipated resulting balance sheet impact of such dispositions;
- with respect to the Company's Infrastructure and Marketing segment: plans to expand terminal pipeline access and product storage opportunities to enhance market access; and benefits of the expansion of the Saskatchewan Gathering System; and
- with respect to the Company's Downstream operating segment: anticipated timing and anticipated benefits of the crude oil flexibility project at the Lima Refinery; and anticipated timing and benefits of the feedstock optimization project at the BP-Husky Toledo Refinery.

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

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

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

The Company's Annual Information Form for the year ended December 31, 2015 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.

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. 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 its assessment of the future considering all information then available.

11.2 Oil and Gas Reserves Reporting

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

Unless otherwise stated, reserve estimates in this document, have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, have an effective date of December 31, 2015 and represent Husky's share. Unless otherwise noted, historical production numbers given represent Husky's share.

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

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

Note to U.S. Readers

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

11.3 Non-GAAP Measures

Disclosure of non-GAAP Measurements

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

Adjusted Net Earnings (Loss)

The term "Adjusted Net Earnings (Loss)" is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "net earnings (loss)" as determined in accordance with IFRS, as an indicator of financial performance. Adjusted net earnings (loss) is comprised of net earnings (loss) and excludes items such as after-tax property, plant and equipment impairment charges, goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs not considered to be indicative of the Company's ongoing financial performance. Adjusted net earnings (loss) is a complementary measure used in assessing Husky's financial performance through providing comparability between periods. Adjusted net earnings (loss) was redefined in the third quarter of 2015. Previously, adjusted net earnings (loss) was defined as net earnings (loss) plus after-tax property, plant and equipment impairment charges and inventory write-downs.

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

	Three months ended Dec. 31,		Year ended Dec. 31,		
($ millions)	**2015**	2014	**2015**	2014	2013
Net earnings (loss)	**(69)**	(603)	**(3,850)**	1,258	1,829
Impairment of property, plant and equipment, net of tax	**–**	622	**3,664**	622	204
Impairment of goodwill	**–**	–	**160**	–	–
Exploration and evaluation asset write-downs, net of tax	**6**	1	**177**	4	6
Inventory write-downs, net of tax	**14**	128	**14**	135	1
Adjusted net earnings (loss)	**(49)**	148	**165**	2,019	2,040

Cash Flow from Operations

The term "Cash Flow 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. Cash flow from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance by business in the stated period. Cash flow from operations equals net earnings (loss) plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, loss (gain) on sale of property, plant, and equipment and other non-cash items.

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

	Three months ended Dec. 31,		Year ended Dec. 31,		
($ millions)	**2015**	2014	**2015**	2014	2013
Net earnings (loss)	**(69)**	(603)	**(3,850)**	1,258	1,829
Items not affecting cash:					
Accretion	**30**	32	**121**	134	125
Depletion, depreciation, amortization and impairment	**801**	1,704	**8,644**	4,010	3,005
Inventory write-down to net realizable value	**22**	202	**22**	211	–
Exploration and evaluation expenses	**7**	1	**242**	6	10
Deferred income taxes (recoveries)	**(137)**	(282)	**(1,827)**	(191)	210
Foreign exchange (gain) loss	**(8)**	93	**27**	71	11
Stock-based compensation	**(15)**	(19)	**(39)**	(17)	105
Loss (gain) on sale of assets	**(6)**	(1)	**(16)**	(36)	(27)
Other	**15**	18	**5**	89	(46)
Cash flow from operations	**640**	1,145	**3,329**	5,535	5,222
Cash flow from operations – basic	**0.65**	1.16	**3.38**	5.63	5.31
Cash flow from operations – diluted	**0.65**	1.16	**3.38**	5.62	5.31

Operating Netback

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

Debt to Capital Employed

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

Earnings Coverage

Earnings coverage is a non-GAAP measure and is equal to net earnings (loss) before finance expense on long-term debt, capitalized interest and income taxes divided by finance expense on long-term debt, dividends on preferred shares and capitalized interest. Long-term debt includes the current portion of long-term debt. Earnings coverage has been included in this MD&A in accordance with the Canadian Shelf Prospectus disclosure requirements. The Company's earnings coverage on long-term debt was negative 14.7 times for the twelve month period ended December 31, 2015.

Debt to Cash Flow from Operations

Debt to cash flow from operations is a non-GAAP measure and is equal to total debt divided by cash flow from operations. Management believes this measurement assists management and investors in evaluating the Company's financial strength.

LIFO

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

11.4 Additional Reader Advisories

Intention of Management's Discussion and Analysis

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

Review by the Audit Committee

This Management's Discussion and Analysis was reviewed by the Audit Committee and approved by Husky's Board of Directors on February 25, 2016. Any events subsequent to that date could materially alter the veracity and usefulness of the information contained in this document.

Additional Husky Documents Filed with Securities Commissions

This Management's Discussion and Analysis dated February 25, 2016 should be read in conjunction with the 2015 Consolidated Financial Statements and related notes. The readers are also encouraged to refer to Husky's interim reports filed for 2015, which contain the Management's Discussion and Analysis and Consolidated Financial Statements, and Husky's 2015 Annual Information Form filed separately with Canadian regulatory agencies and Form 40-F filed with the SEC, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and www.huskyenergy.com. Husky's Management's Discussion and Analysis for the interim period ended December 31, 2015 is incorporated herein by reference.

Use of Pronouns and Other Terms

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

Standard Comparisons in this Document

Unless otherwise indicated, comparisons of results are for the years ended December 31, 2015 and 2014 and Husky's financial position at December 31, 2015 and 2014. All currency is expressed in Canadian dollars unless otherwise directed.

Reclassifications and Materiality for Disclosures

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

Additional Reader Guidance

Unless otherwise indicated:

- Financial information is presented in accordance with IFRS as issued by the IASB;
- Currency is presented in millions of Canadian dollars (*"$ millions"*);
- Gross production and reserves are Husky's working interest prior to deduction of royalty volume; and
- Prices are presented before the effect of hedging.

Terms

Adjusted Net Earnings (Loss)	*Net earnings (loss) before after-tax property, plant and equipment impairment charges, goodwill impairment charges, exploration and evaluation asset write-downs and inventory write-downs*
Bitumen	*Bitumen is a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons, with a viscosity greater than 10,000 millipascal-seconds or 10,000 centipoise measured at the hydrocarbon's original temperature in the reservoir and at atmospheric pressure on a gas-free basis, and that is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods*
Capital Employed	*Long-term debt, long-term debt due within one year, short-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Net earnings (loss) plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes, foreign exchange, stock-based compensation, gain or loss on sale of property, plant, and equipment and other non-cash items*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and short-term debt divided by capital employed*
Debt to Cash Flow from Operations	*Long-term debt, long-term debt due within one year and short-term debt divided by cash flow 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*
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*
Hi-TAN	*A measure of acidity. Crude oils with a high content of naphthenic acids are referred to as high total acid number (TAN) crude oils or high acid crude oil. The TAN value is defined as the milligrams of Potassium Hydroxide required to neutralize the acidic group of one gram of the oil sample. Crude oils in the industry with a TAN value greater than 1 are referred to as Hi-TAN crudes*
Earnings Coverage	*Net earnings (loss) before finance expense on long-term debt, capitalized interest and income taxes divided by finance expense on long-term debt, dividends on preferred shares and capitalized interest. Long-term debt includes the current portion of long-term debt*
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*
NOVA Inventory Transfer ("NIT")	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Oil sands	*Sands and other rock materials that contain crude bitumen and include all other mineral substances in association therewith*
Operating Netback	*Net revenues after deduction of operating costs, transportation and royalty payments*
Proved reserves	*Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves*
Proved developed reserves	*Reserves that are expected to be recovered from existing wells and installed facilities or , if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production*
Proved undeveloped reserves	*Reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status*
Probable reserves	*Additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves*
Seismic survey	*A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations*
Shareholders' Equity	*Common shares, preferred shares, retained earnings and other reserves*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Total Debt	*Long-term debt including long-term debt due within one year and short-term debt*
Turnaround	*Performance of plant or facility maintenance*

Abbreviations

ARO	*asset retirement obligations*	*mbbls/day*	*thousand barrels per day*
bbls	*barrels*	*mboe*	*thousand barrels of oil equivalent*
bbls/day	*barrels per day*	*mboe/day*	*thousand barrels of oil equivalent per day*
bcf	*billion cubic feet*	*mcf*	*thousand cubic feet*
boe	*barrels of oil equivalent*	*mcfge*	*thousand cubic feet of gas equivalent*
boe/day	*barrels of oil equivalent per day*	*MD&A*	*Management's Discussion and Analysis*
bps	*basis points*	*mmbbls*	*million barrels*
CGUs	*cash generating units*	*mmboe*	*million barrels of oil equivalent*
CHOPS	*cold heavy oil production with sand*	*mmbtu*	*million British Thermal Units*
CSA	*Canadian Securities Administrators*	*mmcf*	*million cubic feet*
DD&A	*depletion, depreciation and amortization*	*mmcf/day*	*million cubic feet per day*
EOR	*enhanced oil recovery*	*NGL*	*natural gas liquids*
EPA	*Environmental Protection Agency*	*NIT*	*NOVA Inventory Transfer*
FIFO	*first in first out*	*NYMEX*	*New York Mercantile Exchange*
FPSO	*floating production, storage and offloading vessel*	*OPEC*	*Organization of Petroleum Exporting Countries*
FVTPL	*fair value through profit or loss*	*PHMSA*	*Pipeline and Hazardous Materials Safety Administration*
GAAP	*Generally Accepted Accounting Principles*	*PSC*	*production sharing contract*
GHG	*greenhouse gas*	*S&P*	*Standard and Poor's*
GJ	*gigajoule*	*SAGD*	*Steam assisted gravity drainage*
IASB	*International Accounting Standards Board*	*SEC*	*U.S. Securities and Exchange Commission*
IFRIC	*International Financial Reporting Interpretations Committee Interpretation*	*SEDAR*	*System for Electronic Document Analysis and Retrieval*
IFRS	*International Financial Reporting Standards*	*TSX*	*Toronto Stock Exchange*
LIFO	*last in first out*	*WI*	*working interest*
mbbls	*thousand barrels*	*WTI*	*West Texas Intermediate*

11.5 Disclosure Controls and Procedures

Disclosure Controls and Procedures

Husky's management, under supervision of the Chief Executive Officer and the Chief Financial Officer, have evaluated the effectiveness of Husky's disclosure controls and procedures (as defined in the rules of the SEC and the Canadian Securities Administrators ("CSA")) as at December 31, 2015, and have concluded that such disclosure controls and procedures are effective.

Management's Annual Report on Internal Control over Financial Reporting

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

1) Husky's management, under the supervision of the Chief Executive Officer and Chief Financial Officer, is responsible for designing, establishing and maintaining adequate internal control over financial reporting for Husky. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.
2) Husky's management has used the Committee of Sponsoring Organizations of the Treadway Commission framework to evaluate the effectiveness of Husky's internal control over financial reporting.
3) As at December 31, 2015, management, under the supervision of the Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective.
4) KPMG LLP, who has audited the Consolidated Financial Statements of Husky for the year ended December 31, 2015, has also issued a report on internal controls over financial reporting under Auditing Standard No. 5 of the Public Company Accounting Oversight Board (United States) that attests to Husky's internal controls over financial reporting.

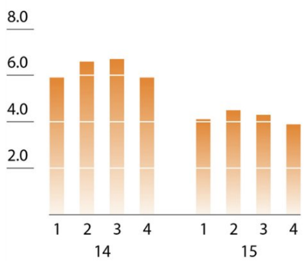
Changes in Internal Control over Financial Reporting

There have been no changes in Husky's internal control over financial reporting during the year ended December 31, 2015, that have materially affected or are reasonably likely to materially affect its internal control over financial reporting.

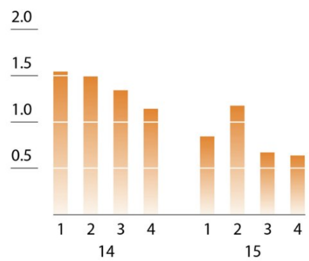
12.0 Selected Quarterly Financial & Operating Information

12.1 Summary of Quarterly Results

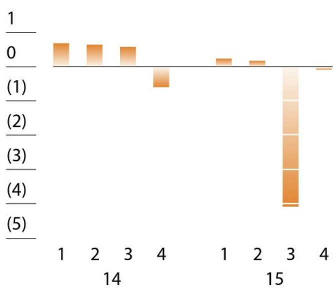
Gross Revenues and Marketing and Other
($ billions)



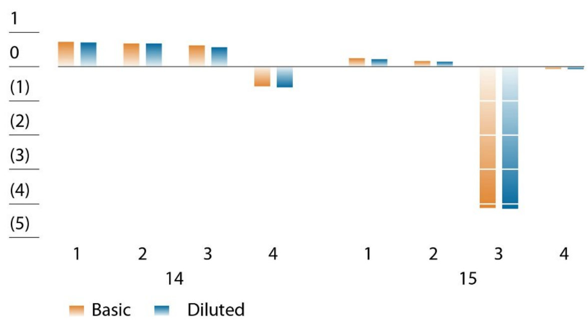
Cash Flow from Operations[1]
($ billions)



Net Earnings (Loss)
($ billions)



Net Earning (Loss) Per Share
($ per share)



[1] *Cash flow from operations is a non-GAAP measure. Refer to Section 11.3.*

Fourth Quarter Results Summary *($ millions, except where indicated)*	Three months ended **Dec. 31 2015**	 Dec. 31 2014
Gross revenues and marketing and other		
Upstream		
Exploration and Production	**1,189**	1,890
Infrastructure and Marketing	**301**	660
Downstream		
Upgrader	**364**	475
Canadian Refined Products	**699**	945
U.S. Refining and Marketing	**1,692**	2,504
Corporate and Eliminations	**(342)**	(599)
Total gross revenues and marketing and other	**3,903**	5,875
Net earnings (loss)		
Upstream		
Exploration and Production	**(134)**	(374)
Infrastructure and Marketing	**10**	28
Downstream		
Upgrader	**57**	9
Canadian Refined Products	**49**	41
U.S. Refining and Marketing	**(5)**	(216)
Corporate and Eliminations	**(46)**	(91)
Net earnings (loss)	**(69)**	(603)
Per share – Basic	**(0.08)**	(0.62)
Per share – Diluted	**(0.09)**	(0.65)
Adjusted net earnings (loss)[(1)]	**(49)**	148
Cash flow from operations[(1)]	**640**	1,145
Per share – Basic	**0.65**	1.16
Per share – Diluted	**0.65**	1.16
Upstream		
Daily gross production		
Crude oil and NGL production *(mbbls/day)*	**246.9**	242.7
Natural gas production *(mmcf/day)*	**660.7**	701.5
Total production *(mboe/day)*	**357.0**	359.6
Average sales prices realized *($/boe)*		
Crude oil and NGL *($/bbl)*	**35.71**	63.96
Natural gas *($/mcf)*	**5.51**	6.37
Total average sales prices realized *($/boe)*	**34.89**	55.53
Downstream		
Refinery throughput		
Lloydminster Upgrader *(mbbls/day)*	**81.2**	76.3
Lloydminster Refinery *(mbbls/day)*	**28.2**	29.0
Prince George Refinery *(mbbls/day)*	**11.3**	11.7
Lima Refinery *(mbbls/day)*	**144.8**	162.8
Toledo Refinery *(mbbls/day)*	**66.6**	63.8
Total throughput *(mbbls/day)*	**332.1**	343.6
Upgrader unit margin *($/bbl)*	**20.47**	13.60
Upgrader synthetic crude oil sales *(mbbls/day)*	**59.4**	54.8
Upgrader total sales *(mbbls/day)*	**80.7**	75.9
Retail fuel sales *(million of litres/day)*	**7.3**	8.1
Canadian light oil margins *($/litre)*	**0.048**	0.049
Lloydminster Refinery asphalt margin *($/bbl)*	**23.57**	22.92
U.S. Refining Margin *(U.S. $/bbl crude throughput)*	**4.51**	(6.62)
U.S./Canadian dollar exchange rate *(U.S. $)*	**0.749**	0.881

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

Gross Revenue and Marketing and other

The Company's consolidated gross revenues and marketing and other decreased by $1,972 million in the fourth quarter of 2015 compared to the fourth quarter of 2014.

In the Upstream business segment, Exploration and Production gross revenues decreased primarily due to significant declines in global crude oil and North American natural gas benchmark prices during 2015. The declines resulted in lower average sales prices realized by the Company partially offset by a weaker Canadian dollar. After factoring in the impact of a weaker Canadian dollar, the total average sales price realized by the Company decreased by 37 percent in the fourth quarter of 2015 compared to the same period in 2014. Infrastructure and Marketing gross revenues and marketing and other decreased primarily due to lower pipeline revenue in a weak commodity environment and narrowing product price and location differentials between Canada and the United States.

In the Downstream business segment, Upgrader gross revenues decreased primarily due to lower realized prices for synthetic crude oil and low sulphur distillates partially offset by higher throughput and sales volumes. Canadian Refined Products gross revenues decreased primarily due to lower realized prices for refined products and lower fuel sales resulting from falling demand and select retail outlet closures partially offset by strong contract prices for asphalt. U.S. Refining and Marketing gross revenues decreased primarily due to lower realized refined product prices consistent with lower Chicago Regular Unleaded Gasoline and Chicago Ultra-low Sulphur Diesel benchmark prices partially offset by a weaker Canadian dollar. In addition, throughput was lower at the Lima Refinery which continues to be negatively impacted by an unplanned outage in the isocracker unit where a fire occurred in January 2015.

Net Earnings (Loss)

The Company's consolidated net loss decreased by $534 million in the fourth quarter of 2015 compared to the fourth quarter of 2014.

In the Upstream business segment, Exploration and Production net loss decreased primarily due to an after-tax impairment charge of $622 million recognized in the fourth quarter of 2014 on certain conventional crude oil and natural gas assets located in Western Canada, higher exploration and evaluation expenses in the fourth quarter of 2014 associated with the Aster exploration well write-off and lower royalties in the fourth quarter of 2015 associated with lower commodity prices. The decreases to net loss were partially offset by the factors above that negatively impacted gross revenues.

In the Downstream business segment, Upgrader net earnings increased primarily due to higher average upgrading differentials. The increase in upgrading differentials was attributable to significantly lower heavy crude oil feedstock costs partially offset by lower realized prices for Husky Synthetic Blend. During the fourth quarter of 2015, the price of Husky Synthetic Blend averaged $56.50/bbl compared to $79.88/bbl in the fourth quarter of 2014. U.S. Refining and Marketing net loss decreased primarily due to lower after-tax inventory write-downs and FIFO losses. The Company recorded inventory write-downs and FIFO losses of $10 million and $72 million, respectively, during the fourth quarter of 2015 compared to $128 million and $130 million, respectively, during the fourth quarter of 2014. During the fourth quarter of 2015, the Company recorded pre-tax business interruption loss and property damage insurance recoveries associated with the unplanned outage in the isocracker unit of $79 million. The decreases to net loss were partially offset by the factors above that negatively impacted gross revenues.

Adjusted Net Earnings (Loss)

Adjusted net earnings (loss) which excludes after-tax property, plant and equipment impairment, goodwill impairment, exploration and evaluation asset write-downs and inventory write-downs, decreased by $197 million in the fourth quarter of 2015 compared to the fourth quarter of 2014. The decrease was primarily attributable to lower adjusted net earnings from Exploration and Production where significant declines in global crude oil and North American natural gas benchmark prices resulted in lower average realized crude oil and natural gas prices partially offset by a weaker Canadian dollar. The decrease was partially offset by higher adjusted net earnings from the Upgrader primarily due to higher average upgrading differentials and from U.S. Refining and Marketing primarily due to lower after-tax FIFO losses and a weaker Canadian dollar. Adjusted net earnings (loss) is a non-GAAP measure; refer to section 11.3.

Cash Flow from Operations

Cash flow from operations decreased by $505 million in the fourth quarter of 2015 compared to the fourth quarter of 2014 primarily due to the same factors which impacted adjusted net earnings (loss). Cash flow from operations is a non-GAAP measure; refer to section 11.3.

Daily Gross Production

Production decreased by 2.6 mboe/day during the fourth quarter of 2015 compared to the fourth quarter of 2014 as a result of:

- Lower crude oil and natural gas production in Western Canada due to natural reservoir declines at mature crude oil properties and limited capital reinvestment in a low commodity price environment;
- Lower entitlement share of natural gas production from the Liwan Gas Project in the Asia Pacific Region. Higher gross production volumes from the Liwan Gas Project, resulting from production ramp-up during 2015, was offset by a reversion of the Company's entitlement share of production volumes to 49 percent, from approximately 76 percent, following the completion of exploration cost recoveries from the Liwan 3-1 field in May 2015; and
- Natural reservoir declines at mature fields in the Atlantic Region;
- Partially offset by strong production performance from heavy oil thermal developments including new production from Rush Lake which began producing crude oil in July 2015;
- Production ramp up from the Sunrise Energy Project which began producing bitumen in late March 2015; and
- New production from the South White Rose extension in the Atlantic Region which began producing crude oil in 2015.

Segmented Operational Information

Segmented Operational Information	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1
Gross revenues and marketing and other								
Upstream								
Exploration and Production	**1,189**	**1,253**	**1,577**	**1,355**	1,890	2,210	2,352	2,182
Infrastructure and Marketing	**301**	**273**	**293**	**435**	660	658	461	493
Downstream								
Upgrader	**364**	**190**	**418**	**347**	475	604	560	573
Canadian Refined Products	**699**	**839**	**747**	**601**	945	1,145	991	939
U.S. Refining and Marketing	**1,692**	**1,973**	**1,955**	**1,725**	2,504	2,811	2,928	2,420
Corporate and Eliminations	**(342)**	**(242)**	**(464)**	**(377)**	(599)	(738)	(678)	(664)
Total gross revenues and marketing and other	**3,903**	**4,286**	**4,526**	**4,086**	5,875	6,690	6,614	5,943
Net earnings (loss)								
Upstream								
Exploration and Production	**(134)**	**(4,103)**	**18**	**(119)**	(374)	436	554	376
Infrastructure and Marketing	**10**	**32**	**(21)**	**63**	28	24	16	46
Downstream								
Upgrader	**57**	**(29)**	**28**	**37**	9	31	49	79
Canadian Refined Products	**49**	**69**	**39**	**13**	41	57	48	68
U.S. Refining and Marketing	**(5)**	**36**	**172**	**194**	(216)	29	56	112
Corporate and Eliminations	**(46)**	**(97)**	**(116)**	**3**	(91)	(6)	(95)	(19)
Net earnings (loss)	**(69)**	**(4,092)**	**120**	**191**	(603)	571	628	662
Per share – Basic	**(0.08)**	**(4.17)**	**0.11**	**0.19**	(0.62)	0.58	0.63	0.67
Per share – Diluted	**(0.09)**	**(4.19)**	**0.10**	**0.17**	(0.65)	0.52	0.63	0.66
Adjusted net earnings (loss)(1)	**(49)**	**(101)**	**124**	**191**	148	572	629	670
Cash flow from operations(1)	**640**	**674**	**1,177**	**838**	1,145	1,341	1,504	1,545
Per share – Basic	**0.65**	**0.68**	**1.20**	**0.85**	1.16	1.36	1.53	1.57
Per share – Diluted	**0.65**	**0.68**	**1.20**	**0.85**	1.16	1.36	1.52	1.57
U.S./Canadian dollar exchange rate (U.S. $)	**0.749**	**0.764**	**0.813**	**0.806**	0.881	0.918	0.917	0.906
Exploration and Production								
Daily production, before royalties								
Crude oil & NGL production *(mbbls/day)*								
Light & Medium crude oil	**84.3**	**72.1**	**77.3**	**88.5**	91.5	81.4	88.4	103.8
NGL	**16.9**	**16.7**	**19.0**	**20.4**	18.0	15.7	11.9	10.3
Heavy crude oil	**66.7**	**67.9**	**70.0**	**71.9**	77.5	76.1	78.1	75.5
Bitumen	**79.0**	**66.7**	**50.3**	**55.7**	55.7	56.2	54.6	52.0
Total crude oil & NGL production *(mbbls/day)*	**246.9**	**223.4**	**216.6**	**236.5**	242.7	229.4	233.0	241.6
Natural gas *(mmcf/day)*	**660.7**	**657.7**	**721.6**	**717.0**	701.5	670.3	603.6	505.9
Total production *(mboe/day)*	**357.0**	**333.0**	**336.9**	**356.0**	359.6	341.1	333.6	325.9
Average sales prices								
Light & Medium crude oil *($/bbl)*	**49.31**	**54.23**	**69.99**	**56.91**	72.69	96.64	109.61	106.81
NGL *($/bbl)*	**42.46**	**43.18**	**51.97**	**45.29**	59.42	77.85	76.26	85.16
Heavy crude oil *($/bbl)*	**28.71**	**36.51**	**50.21**	**32.97**	58.86	77.29	79.45	72.18
Bitumen *($/bbl)*	**25.67**	**33.86**	**48.45**	**34.97**	58.21	75.50	77.97	70.78
Natural gas *($/mcf)*	**5.51**	**5.76**	**6.09**	**5.96**	6.37	6.11	6.42	4.82
Operating costs *($/boe)*	**14.51**	**15.52**	**15.72**	**14.87**	15.07	16.61	15.68	17.21
Operating netbacks(2)								
Lloydminster – Thermal Oil *($/bbl)*(3)	**18.77**	**22.06**	**33.52**	**22.68**	43.73	58.92	61.67	53.32
Lloydminster – Non-Thermal Oil *($/boe)*(3)	**7.53**	**13.51**	**26.88**	**9.12**	30.54	45.50	48.81	40.29
Cold Lake – Bitumen *($/bbl)*(3)	**13.91**	**17.75**	**5.89**	**10.18**	27.75	43.68	45.29	35.99
Oil Sands – Bitumen *($/bbl)*(3)	**(56.39)**	**(103.92)**	**(119.67)**	–	–	–	–	–
Western Canada – Crude Oil *($/bbl)*(3)	**8.96**	**14.97**	**26.06**	**8.81**	31.84	44.04	49.15	45.39
Western Canada – NGL & natural gas *($/mcf)*(4)	**0.64**	**1.08**	**1.00**	**0.88**	2.16	2.29	2.90	3.40
Atlantic – Light Oil *($/bbl)*(3)	**31.36**	**36.51**	**46.81**	**43.21**	55.50	65.78	84.47	83.74
Asia Pacific – Light Oil, NGL & natural gas *($/boe)*(3)	**68.15**	**67.70**	**69.60**	**68.19**	64.05	67.21	71.56	78.41
Total *($/boe)*(2)	**17.28**	**20.72**	**28.93**	**21.45**	34.84	43.05	48.70	44.81

Segmented Operational Information (continued)	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1
Upgrader								
Synthetic crude oil sales *(mbbls/day)*	**59.4**	**31.6**	**55.0**	**58.5**	54.8	56.1	48.2	53.9
Total sales *(mbbls/day)*	**80.7**	**42.5**	**73.2**	**81.0**	75.9	76.3	67.2	71.1
Upgrading differential *($/bbl)*	**22.19**	**17.58**	**18.93**	**15.72**	14.96	19.98	25.27	27.40
Canadian Refined Products								
Fuel sales *(million litres/day)*	**7.3**	**7.7**	**7.6**	**7.6**	8.1	8.5	7.5	7.7
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	**28.2**	**26.4**	**28.4**	**29.2**	29.0	28.3	29.0	29.0
Prince George refinery *(mbbls/day)*	**11.3**	**11.0**	**8.5**	**11.4**	11.7	11.7	11.3	12.0
U.S. Refining and Marketing								
Refinery throughput								
Lima refinery *(mbbls/day)*	**144.8**	**142.9**	**136.1**	**119.2**	162.8	156.0	135.9	110.5
BP-Husky Toledo refinery *(mbbls/day)*	**66.6**	**66.4**	**69.7**	**52.1**	63.8	64.2	59.4	65.5

(1) *Adjusted net earnings (loss) and cash flow from operations are non-GAAP measures. Refer to Section 11.3 for a reconciliation to the GAAP measures.*
(2) *Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis. Refer to Section 11.3.*
(3) *Includes associated co-products converted to boe.*
(4) *Includes associated co-products converted to mcfge.*

Significant Items Impacting Gross Revenues, Net Earnings and Cash flow from Operations

Variations in the Company's gross revenues, net earnings and cash flow from operations are primarily driven by changes in production volumes, commodity prices, commodity price differentials, refining crack spreads, foreign exchange rates and planned turnarounds. Falling crude oil and North American natural gas prices starting in the second half of 2014, and continuing through 2015, resulted in significant declines in the Company's gross revenues, net earnings and cash flow from operations. Other significant items which impacted gross revenues, net earnings and cash flow from operations over the last eight quarters include:

- In the fourth quarter of 2015, the Company accrued business interruption and property damage insurance recoveries of $79 million associated with a fire that damaged the Company's isocracker unit at Lima during the first quarter of 2015, bringing year to date insurance recoveries to $235 million at the end of the fourth quarter of 2015.
- In the fourth quarter of 2015, the Company recorded a pre-tax provision of $16 million in the U.S. Refining and Marketing business segment and a pre-tax provision of $6 million in the Infrastructure and Marketing business segment to bring inventory to net realizable value.
- In the third quarter of 2015, the Company recorded after-tax property, plant and equipment and goodwill impairment charges of $3,824 million related to crude oil and natural gas assets located in Western Canada. The after-tax impairment charge was the result of sustained declines in forecasted short and long-term crude oil and natural gas prices and management's decision to reduce capital expenditures in these areas. In addition, the Company recorded an after-tax exploration and evaluation asset write-down of $167 million during the third quarter on certain Western Canada resource play assets and an associated $35 million after-tax work commitment penalty. The write-down was the result of management's plan to withdraw from further exploration and evaluation due to lower estimated short and long-term crude oil and natural gas prices.
- In the third quarter of 2015, the Company accrued business interruption and property damage insurance recoveries of $64 million associated with a fire that damaged the Company's isocracker unit at Lima during the first quarter of 2015, bringing year to date insurance recoveries to $156 million at the end of the third quarter of 2015.
- In the third quarter of 2015, the Company derecognized approximately $46 million pre-tax of assets related to the cancellation of the West Mira drilling rig contract.
- In the third quarter of 2015, operations at the Company's Upgrader were suspended for approximately eight weeks for unplanned maintenance to address repairs to the facility's coke drums.
- In the second quarter of 2015, the Company recognized a deferred income tax expense of $157 million related to an increase in Alberta provincial tax rates.
- In the second quarter of 2015, the Company wrote-off approximately $46 million pre-tax of the carrying value of the isocracker unit at the Lima Refinery which was damaged by a fire in the first quarter of 2015. During the second quarter of 2015, the Company accrued business interruption and property damage insurance recoveries associated with the fire of $92 million.
- In the first quarter of 2015, the Company recognized a deferred income tax recovery of $203 million in its U.S. Refining and Marketing business segment related to the partial payment of the contribution payable to BP-Husky Refining LLC.
- In the first quarter of 2015, the Company was negatively impacted by unplanned outage at the Lima and BP-Husky Toledo refineries. The Lima Refinery was negatively impacted by an unplanned outage where a fire occurred in the isocracker unit in January 2015 and the BP-Husky Toledo Refinery was negatively impacted by unplanned maintenance to repair a damaged fluid catalytic cracking unit.
- In the fourth quarter of 2014, the Company recognized an after-tax impairment charge of $622 million related to Western Canada crude oil and natural gas properties resulting from lower estimated short and long-term crude oil and natural gas prices. In addition, the Company recorded an after-tax provision of $128 million, in the U.S. Refining and Marketing business segment, to bring inventory to net realizable value.

Segmented Financial Information

	Upstream								Downstream			
	Exploration and Production[1]				Infrastructure and Marketing				Upgrading			
2015 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	1,189	1,253	1,577	1,355	311	250	337	366	364	190	418	347
Royalties	(85)	(83)	(134)	(130)	–	–	–	–	–	–	–	–
Marketing and other	–	–	–	–	(10)	23	(44)	69	–	–	–	–
Revenues, net of royalties	1,104	1,170	1,443	1,225	301	273	293	435	364	190	418	347
Expenses												
Purchases of crude oil and products	7	8	17	9	269	217	302	335	212	162	310	238
Production, operating and transportation expenses	524	519	521	512	12	7	9	9	44	40	42	43
Selling, general and administrative expenses	57	51	60	69	2	2	1	2	1	1	1	1
Depletion, depreciation, amortization and impairment	641	5,920	713	719	8	6	6	5	28	26	26	26
Exploration and evaluation expenses	39	308	43	57	–	–	–	–	–	–	–	–
Other – net	(21)	(48)	33	(15)	(3)	(4)	3	(1)	–	–	–	(11)
Earnings from operating activities	(143)	(5,588)	56	(126)	13	45	(28)	85	79	(39)	39	50
Share of equity investment	(4)	(1)	–	–	–	–	–	–	–	–	–	–
Net foreign exchange gains (losses)	–	–	–	–	–	–	–	–	–	–	–	–
Finance income	–	1	1	1	–	–	–	–	–	–	–	–
Finance expenses	(36)	(35)	(35)	(36)	–	–	–	–	(1)	–	–	–
	(36)	(34)	(34)	(35)	–	–	–	–	(1)	–	–	–
Earnings (loss) before income tax	(183)	(5,623)	22	(161)	13	45	(28)	85	78	(39)	39	50
Provisions for (recovery of) income taxes												
Current	111	27	(14)	(165)	(5)	5	40	182	7	(2)	(6)	(16)
Deferred	(160)	(1,547)	18	123	8	8	(47)	(160)	14	(8)	17	29
	(49)	(1,520)	4	(42)	3	13	(7)	22	21	(10)	11	13
Net earnings (loss)	(134)	(4,103)	18	(119)	10	32	(21)	63	57	(29)	28	37
Capital expenditures[3][4]	378	597	571	723	42	77	30	19	12	19	7	8
Total assets	21,103	21,296	26,550	26,488	1,699	1,814	1,857	1,830	1,141	1,098	1,107	1,209

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

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

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

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

Downstream (continued)								Corporate and Eliminations[2]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
699	839	747	601	1,692	1,973	1,955	1,725	(342)	(242)	(464)	(377)	3,913	4,263	4,570	4,017
–	–	–	–	–	–	–	–	–	–	–	–	(85)	(83)	(134)	(130)
–	–	–	–	–	–	–	–	–	–	–	–	(10)	23	(44)	69
699	839	747	601	1,692	1,973	1,955	1,725	(342)	(242)	(464)	(377)	3,818	4,203	4,392	3,956
544	655	599	483	1,583	1,784	1,549	1,539	(342)	(242)	(464)	(377)	2,273	2,584	2,313	2,227
55	57	63	63	120	119	107	128	–	–	–	–	755	742	742	755
8	7	6	10	2	3	2	3	32	(15)	16	20	102	49	86	105
26	26	26	25	76	74	114	69	22	22	20	20	801	6,074	905	864
–	–	–	–	–	–	–	–	–	–	–	–	39	308	43	57
(2)	(1)	(2)	1	(80)	(65)	(91)	–	1	(3)	–	–	(105)	(121)	(57)	(26)
68	95	55	19	(9)	58	274	(14)	(55)	(4)	(36)	(40)	(47)	(5,433)	360	(26)
–	–	–	–	–	–	–	–	–	–	–	–	(4)	(1)	–	–
–	–	–	–	–	–	–	–	(11)	(14)	6	62	(11)	(14)	6	62
–	–	–	–	–	–	–	–	27	3	1	1	27	4	2	2
(2)	(1)	(2)	(1)	(1)	–	(1)	(1)	(48)	(48)	(36)	(14)	(88)	(84)	(74)	(52)
(2)	(1)	(2)	(1)	(1)	–	(1)	(1)	(32)	(59)	(29)	49	(72)	(94)	(66)	12
66	94	53	18	(10)	58	273	(15)	(87)	(63)	(65)	9	(123)	(5,528)	294	(14)
(67)	32	24	17	(3)	(16)	24	10	40	28	27	26	83	74	95	54
84	(7)	(10)	(12)	(2)	38	77	(219)	(81)	6	24	(20)	(137)	(1,510)	79	(259)
17	25	14	5	(5)	22	101	(209)	(41)	34	51	6	(54)	(1,436)	174	(205)
49	69	39	13	(5)	36	172	194	(46)	(97)	(116)	3	(69)	(4,092)	120	191
14	6	5	5	182	100	95	48	13	18	19	17	641	817	727	820
1,448	1,568	1,634	1,622	6,784	6,776	6,316	6,226	881	993	1,018	968	33,056	33,545	38,482	38,343

	Upstream								Downstream			
	Exploration and Production[(1)]				Infrastructure and Marketing				Upgrading			
2014 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	1,890	2,210	2,352	2,182	638	647	458	459	475	604	560	573
Royalties	(178)	(260)	(302)	(290)	–	–	–	–	–	–	–	–
Marketing and other	–	–	–	–	22	11	3	34	–	–	–	–
Revenues, net of royalties	1,712	1,950	2,050	1,892	660	658	461	493	475	604	560	573
Expenses												
Purchases of crude oil and products	20	23	31	22	604	611	426	415	380	491	421	384
Production, operating and transportation expenses	540	562	525	545	10	9	5	8	48	42	43	47
Selling, general and administrative expenses	22	78	74	79	3	1	2	2	2	3	2	2
Depletion, depreciation, amortization and impairment	1,553	671	637	573	6	6	6	7	29	27	28	24
Exploration and evaluation expenses	113	42	19	40	–	–	–	–	–	–	–	–
Other – net	(71)	(60)	(22)	93	(1)	(1)	–	–	3	–	–	8
Earnings from operating activities	(465)	634	786	540	38	32	22	61	13	41	66	108
Share of equity investment	8	(10)	(2)	(2)	–	–	–	–	–	–	–	–
Net foreign exchange gains (losses)	–	–	–	–	–	–	–	–	–	–	–	–
Finance income	(2)	(1)	1	1	–	–	–	–	–	–	–	–
Finance expenses	(40)	(41)	(38)	(32)	–	–	–	–	–	–	–	(1)
	(42)	(42)	(37)	(31)	–	–	–	–	–	–	–	(1)
Earnings (loss) before income taxes	(499)	582	747	507	38	32	22	61	13	41	66	107
Provisions for (recovery of) income taxes												
Current	52	156	112	66	36	1	(13)	75	1	19	17	10
Deferred	(177)	(10)	81	65	(26)	7	19	(60)	3	(9)	–	18
	(125)	146	193	131	10	8	6	15	4	10	17	28
Net earnings (loss)	(374)	436	554	376	28	24	16	46	9	31	49	79
Capital expenditures[(3)]	1,136	1,070	859	1,124	98	59	30	24	14	23	9	4
Total assets	26,035	26,283	25,667	25,525	1,969	1,907	2,001	1,978	1,243	1,244	1,372	1,330

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*
(2) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*
(3) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

Downstream (continued)								Corporate and Eliminations(2)				Total			
Canadian Refined Products				U.S. Refining and Marketing											
Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
945	1,145	991	939	2,504	2,811	2,928	2,420	(599)	(738)	(678)	(664)	5,853	6,679	6,611	5,909
–	–	–	–	–	–	–	–	–	–	–	–	(178)	(260)	(302)	(290)
–	–	–	–	–	–	–	–	–	–	–	–	22	11	3	34
945	1,145	991	939	2,504	2,811	2,928	2,420	(599)	(738)	(678)	(664)	5,697	6,430	6,312	5,653
782	964	822	751	2,655	2,571	2,659	2,056	(599)	(738)	(678)	(664)	3,842	3,922	3,681	2,964
67	65	68	63	121	113	116	122	–	–	–	–	786	791	757	785
14	11	9	10	2	3	2	2	91	(35)	59	24	134	61	148	119
27	26	25	24	68	77	62	61	21	18	18	16	1,704	825	776	705
–	–	–	–	–	–	–	–	–	–	–	–	113	42	19	40
–	1	–	(1)	–	–	–	–	–	4	(9)	–	(69)	(56)	(31)	100
55	78	67	92	(342)	47	89	179	(112)	13	(68)	(40)	(813)	845	962	940
–	–	–	–	–	–	–	–	–	–	–	–	8	(10)	(2)	(2)
–	–	–	–	–	–	–	–	35	31	(3)	18	35	31	(3)	18
–	–	–	–	–	–	–	–	1	1	3	4	(1)	–	4	5
(1)	(1)	(2)	(1)	(1)	(1)	–	(1)	(17)	(22)	(37)	3	(59)	(65)	(77)	(32)
(1)	(1)	(2)	(1)	(1)	(1)	–	(1)	19	10	(37)	25	(25)	(34)	(76)	(9)
54	77	65	91	(343)	46	89	178	(93)	23	(105)	(15)	(830)	801	884	929
18	18	17	27	(77)	2	15	61	25	27	30	22	55	223	178	261
(5)	2	–	(4)	(50)	15	18	5	(27)	2	(40)	(18)	(282)	7	78	6
13	20	17	23	(127)	17	33	66	(2)	29	(10)	4	(227)	230	256	267
41	57	48	68	(216)	29	56	112	(91)	(6)	(95)	(19)	(603)	571	628	662
31	25	19	11	118	89	92	75	22	13	47	31	1,419	1,279	1,056	1,269
1,676	1,746	1,839	1,842	5,788	6,133	5,891	5,980	2,137	1,737	883	2,022	38,848	39,050	37,653	38,677