Husky Energy

Portfolio Strength

Annual Report **2014**

Corporate Profile

Husky Energy is one of Canada's largest integrated energy companies. It is based in Calgary, Alberta and publicly traded on the Toronto Stock Exchange under the symbol HSE. The Company operates in Canada, the United States and the Asia Pacific Region with Upstream and Downstream business segments.

Highlights

Financial Highlights[1]

Year ended December 31		**2014**	2013
(millions of dollars except where indicated)			
Gross revenue		**25,122**	24,181
Revenues, net of royalties		**24,092**	23,317
Cash flow from operations[2]		**5,535**	5,222
Per share *(dollars)*	Basic	**5.63**	5.31
	Diluted	**5.62**	5.31
Net operating earnings[2][3]		**2,015**	2,034
Net earnings		**1,258**	1,829
Per share *(dollars)*	Basic	**1.26**	1.85
	Diluted	**1.20**	1.85
Dividends			
Per Common Share *(dollars)*	Ordinary	**1.20**	1.20
Capital investment[4]		**5,023**	5,028
Return on capital in use *(%)*[2]		**10.7**	12.6
Return on capital employed *(%)*[2]		**7.7**	8.7
Return on equity *(%)*[2]		**6.2**	9.3
Debt to capital employed *(%)*[2]		**20.5**	17.0
Debt to cash flow *(times)*[2]		**1.0**	0.8

(1) Results are reported in accordance with IFRS, as issued by the IASB, except where indicated.
(2) Non-GAAP measures. Please refer to Section 11.3 of the MD&A on Page 53.
(3) Excludes charges for impairments and net realizable value provisions.
(4) Excludes capitalized costs related to asset retirement obligations incurred during the period.

Operational Highlights

Year ended December 31	**2014**	2013
Daily production, before royalties		
Light crude oil & NGL *(mbbls/day)*	**83.7**	81.1
Medium crude oil *(mbbls/day)*	**21.5**	23.2
Heavy crude oil and bitumen *(mbbls/day)*	**131.4**	122.2
Total crude oil & NGL *(mbbls/day)*	**236.6**	226.5
Natural gas *(mmcf/day)*	**621**	513
Total *(mboe/day)*	**340.1**	312.0
Total proved reserves,		
before royalties *(mmboe)*[1]	**1,279**	1,265
Upgrader throughput *(mbbls/day)*	**72.7**	66.1
Fuel sales *(million litres/day)*	**8.0**	8.1
Lima Refinery throughput *(mbbls/day)*	**141.6**	149.4
Toledo Refinery throughput *(mbbls/day, 50% w.i.)*	**63.2**	65.0
Lloydminster Refinery throughput *(mbbls/day)*	**28.8**	26.4
Prince George Refinery throughput *(mbbls/day)*	**11.7**	10.3
Ethanol production *(thousand litres/day)*	**780.7**	742.4

(1) Proved reserves based on forecasted prices in accordance to N1 51-101.

Statement from the Co-Chairs

In a year marked by a precipitous decline in oil prices, Husky Energy's balanced growth strategy and strong financial position helped weatherproof our business.

The Liwan Gas Project began natural gas production early in the year. The Sunrise Energy Project, which is now in production, commenced steaming near the end of 2014, and several heavy oil thermal projects were advanced as Husky continued its transformation into a low sustaining capital business.

Our strong portfolio of near, mid and long term projects provides both the resiliency and flexibility to shift our capital and resources towards higher return developments.

In 2014, production rose nine percent from the previous year, with growth supported by strong performance from heavy oil thermal operations and rising sales gas volumes from Liwan.

We continued to add to our proved reserves. In addition, an independent assessment significantly increased our best estimate contingent heavy oil resources in the Lloydminster region, providing a comprehensive roadmap to identify and develop additional thermal projects.

With a business plan tailored to market conditions and an expansive portfolio of low sustaining capital projects, we are maintaining great flexibility to calibrate our course to achieve our objectives.

As we move forward into 2015, we remain focused on safe and reliable operations, a healthy balance sheet and a clear line of sight to steady production and reserves growth.

On behalf of the Board of Directors of Husky Energy, we thank our shareholders for their ongoing support.

Victor T.K. Li
Co-Chairman

Canning K.N. Fok
Co-Chairman

CEO Report to Shareholders

Business results in 2014 were marked by several highlights as Husky advanced a series of high quality return projects.

Steps taken by the Company over the past four years have provided firm footing in the current pricing environment. These include:

- Rejuvenating the heavy oil business to focus on long life, high return thermal projects with strong full cycle returns.
- Successful execution of the Liwan Gas Project, now providing significant cash flow through fixed price sales contracts.
- Delivery of the Sunrise Energy Project, which is now in production.
- Targeted Downstream investments to improve the flexibility of feedstocks, product range and market access to further enhance margins and support Upstream crude oil and bitumen production.

Husky's strong portfolio is a key element of its balanced growth strategy, providing the flexibility to adjust the timing and scope of its projects in line with market conditions. The tight integration between the Upstream and Downstream businesses supports the capture of value.

2014 Performance Highlights

Heavy Oil

Husky's legacy heavy oil business in Western Canada has been transformed into a growth engine with a focus on long life, high netback thermal developments.

The thermal advantage includes low sustaining capital requirements, strong full cycle rates of return, modular designs and greater cost certainty. High quality reservoirs provide for quick production ramp up to full operation.

Thermal production continued to exceed expectations in 2014, reaching 44,000 bbls/day compared to 18,000 bbls/day in 2010.

The 3,500 bbls/day Sandall thermal project achieved first oil ahead of schedule in early 2014 and continued to perform above its nameplate capacity throughout the year. Construction was further advanced at the 10,000 bbls/day Rush Lake thermal project, with first oil scheduled in the third quarter of 2015.

Site work and module fabrication began at Edam East and Vawn, both 10,000 bbls/day projects, as well as a 3,500 bbls/day thermal development at Edam West. All three projects are on track for startup in 2016, starting with Edam East in the third quarter.

An updated resource assessment in 2014 provided a comprehensive roadmap to further identify and develop additional thermal projects. The independent evaluation conducted by Sproule Unconventional Limited significantly increased the overall best estimate contingent resources in the region from 107 million barrels to 1.9 billion barrels, of which 54 percent has the potential to be recovered using thermal technology.

Total heavy oil initially in place is estimated to be 17 billion barrels, of which 16 billion barrels are discovered heavy oil initially in place.

This assessment work is guiding ongoing development in locating new thermal projects.

The Company has recovered about 950 million barrels over the past 70 years of operations in the area. The assessment supports Husky's expectation of extracting even greater value from this resource base in the future.

Western Canada

The Company continued to shape its resource play portfolio in Western Canada by advancing projects at a measured pace.

Total resource play production reached approximately 34,000 boe/day, led by solid performance from the Ansell resource project. Average annual volumes from Ansell are anticipated to rise to more than 20,000 boe/day by the end of 2016 with solid full cycle rates of return.

Drilling and development activities on oil resource plays in 2014 were focused on the Bakken, Viking, Cardium and Lower Shaunavon projects.

Downstream Integration

Husky's Downstream business is integrated with its Western Canada production activities. It includes upgrading, refining, transportation, storage and marketing in Canada and the United States. Low cost investments made by the Company in 2014 improved the flexibility of its feedstocks, product range and market access.

Throughputs at the Lloydminster Upgrader and refineries averaged 318,000 bbls/day in 2014.

Two new 300,000-barrel storage tanks and pipe interconnections were built at Hardisty, Alberta, to improve storage capability. Husky's South Saskatchewan gathering system was further expanded to accommodate the growing heavy oil thermal production in the Lloydminster area.

Asia Pacific Region

The Company advanced its Asia Pacific business in 2014 with the startup of the Liwan Gas Project in the South China Sea.

Liwan began natural gas production at the end of the first quarter and is delivering significant cash flow through fixed price contracts, which are not exposed to commodity price volatility.

Located approximately 300 kilometres southeast of the Hong Kong Special Administrative Region, the deepwater project consists of three fields: Liwan 3-1, Liuhua 34-2 and Liuhua 29-1, which share a subsea production system, subsea pipeline transportation and onshore gas processing infrastructure.

Liwan produces natural gas, natural gas liquids and condensates. Average gross sales gas volumes rose to approximately 265 million cubic feet per day (mmcf/day) at the end of the year, including sales gas from the Liuhua 34-2 field that was tied into the main Liwan infrastructure in late 2014.

Husky holds a 49 percent interest in the Production Sharing Contract (PSC) for the Liwan Project and operates the deepwater infrastructure. CNOOC Limited holds a 51 percent interest in the PSC and operates the shallow water facilities and onshore gas terminal.

Offshore Indonesia, four shallow water natural gas developments are under way in the Madura Strait. At the liquids-rich BD field, the Company awarded a contract for an FPSO (floating production, storage and offloading) vessel and construction moved forward on a wellhead platform and pipeline infrastructure in preparation for planned first production in 2017.

Tender plans for the MDA and MBH fields received regulatory approval and a sales gas agreement was negotiated, while a Plan of Development for the MDK field received government approval. The three fields are located near the East Java pipeline system and are expected to come online in the 2017-2019 timeframe.

Husky owns a 40 percent interest in the Madura Strait developments.

Oil Sands

Steam injection commenced at the in-situ Sunrise Energy Project in northern Alberta, with first oil achieved in the first quarter of 2015.

Sunrise is a long life, low decline project with low sustaining capital requirements and is a key component of the Company's oil sands portfolio.

With an estimated lifespan of 40-plus years, the reservoir is expected to provide for steady, long-term production.

Production from the steam-assisted gravity drainage project is expected to ramp up to 60,000 barrels per day (30,000 barrels per day net to Husky) around the end of 2016.

Husky is the operator and has a 50 percent working interest in the project. The partner operates the jointly-owned BP-Husky Toledo refinery, which has been positioned to process Sunrise bitumen into various transportation fuels and other energy products.

Atlantic Region

The Company further advanced its satellite extension projects in the White Rose field in the Jeanne d'Arc Basin offshore Newfoundland and Labrador.

Gas injection and oil production equipment was installed at South White Rose, with first oil scheduled for the mid-2015 timeframe. South White Rose is Husky's second major subsea tieback project, building on the Company's safe and successful operations at the North Amethyst field.

Production from South White Rose will be tied back to the *SeaRose* FPSO through a series of flexible underwater flowlines. Forecast net peak production is approximately 15,000 bbls/day.

The *SeaRose* continues to maintain a strong track record for reliability, with uptime of approximately 95 percent in 2014.

A production well was drilled at the Hibernia-level formation beneath the North Amethyst field, with first oil scheduled for the third quarter of 2015 and forecast net peak production of about 5,000 bbls/day.

An 18-month exploration and appraisal program began in the Flemish Pass in the area of the Bay du Nord discovery. Best estimate contingent resources at Bay du Nord are estimated at 400 million barrels (on a 100 percent working interest basis) as of December 31, 2014. The staged development of Bay du Nord is expected to produce first oil early in the next decade. Husky owns a 35 percent working interest in these resources.

Delivering Higher Quality Returns

Over the past four years, the Company has undertaken a deliberate program to transition into a low sustaining capital business.

It has rejuvenated its heavy oil business, delivered the Liwan project and Sunrise is now in production.

In addition, Husky has several other near-term projects in flight that will further support this transition. As a result, a significant portion of the Company's total production is expected to come from low sustaining capital projects by the end of 2016.

Husky Energy continues to focus on efficiencies, manage its investment flows and maintain its strong balance sheet to deliver value.

Asim Ghosh
CEO

Business Results

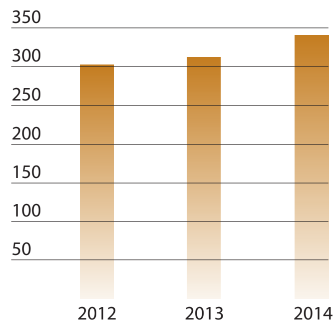
Production

Total Upstream production was within guidance at 340,000 boe/day in 2014, an increase of approximately nine percent over 2013.

New production was added from the Liwan Gas Project and heavy oil thermals.

The Ansell resource play in Western Canada also continued to produce good results.

Production
(mboe/day)

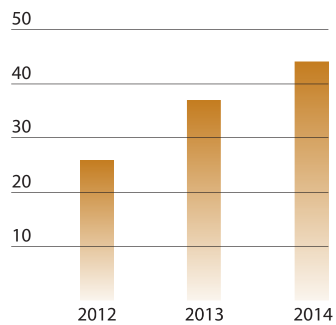


Heavy Oil Thermal Production

Production from heavy oil thermal developments contributed 44,000 bbls/day in 2014, compared to 18,000 bbls/day in 2010.

As long life, high netback developments with low sustaining capital requirements, thermals can be brought online quickly with about two years between sanction and first oil.

Heavy Oil Thermal Production
(mbbls/day)

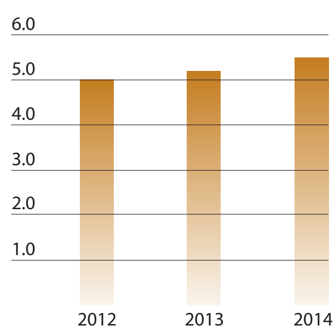


Cash Flow

Cash flow from operations was $5.5 billion, compared to $5.2 billion in 2013.

Cash flow was positively influenced by startup of production at the Liwan Gas Project and solid returns from heavy oil thermal developments.

Cash Flow
($ billions)



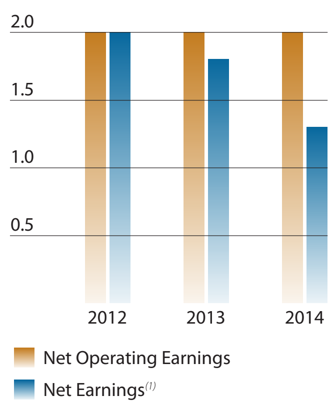
Net Earnings

Net earnings in 2014 before one-time charges were $2.0 billion, comparable to 2013.

A non-cash impairment charge of $622 million after tax was recorded in the fourth quarter on mature assets in Western Canada related to reductions in the price forecast.

Including one-time charges, net earnings in 2014 were $1.3 billion. This also included a FIFO loss of $108 million after tax in the U.S. refining business as a result of falling commodity prices.

Net Earnings
($ billions)



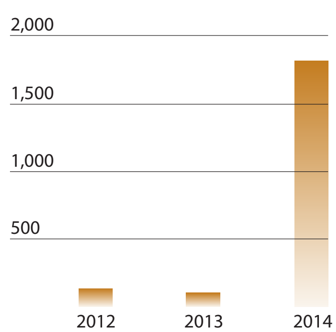
(1) Excludes charges for impairments and net realizable value provisions.

Heavy Oil Contingent Resource Estimate

An independent evaluation conducted by Sproule Unconventional Limited has significantly increased the overall best estimate contingent resources in the Lloydminster region from 107 million barrels to 1.9 billion barrels, of which 54 percent has the potential to be recovered using thermal technology.

Total heavy oil initially in place is estimated to be 17 billion barrels, of which 16 billion barrels are discovered heavy oil initially in place.

Heavy Oil Contingent Resource Estimate *(mmbbls)*

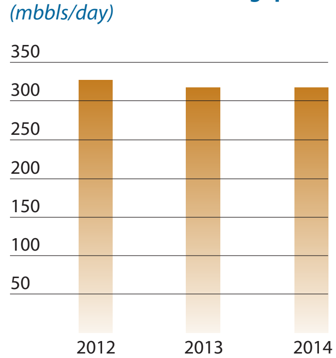


Downstream Throughputs

The Company's integrated U.S. refining capability, pipeline strategy and infrastructure supports its crude oil and bitumen production.

Throughputs at the Lloydminster Upgrader and refineries averaged 318,000 bbls/day in 2014, comparable to 2013 volumes.

Total Downstream Throughputs
(mbbls/day)



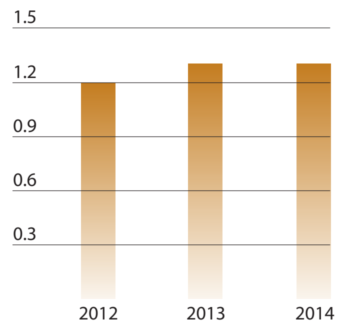
Strategic Reserves Replacement

Husky continued to build its proved reserves in 2014. The average proved reserves replacement ratio was 115 percent, excluding economic factors (111 percent including economic factors).

The average proved reserve replacement ratio (excluding economic factors) over the past four years was 157 percent. Including economic factors, the average proved four-year reserves replacement ratio was 143 percent.

Total proved reserves before royalties in 2014 were 1.3 billion boe. Total probable reserves were 1.9 billion boe and best estimate contingent resources were 14.8 billion boe.

Total Proved Reserves before Royalties *(mmboe)*

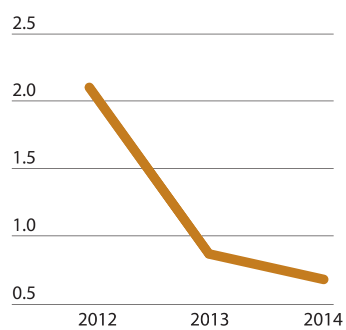


Critical and Serious Incidents

The Company's strong safety culture is supported by the Husky Operations Integrity Management System (HOIMS). HOIMS is an enterprise-wide approach to consistently manage operations, identify hazards and mitigate risk.

The rate of critical and serious incidents per hours worked at Husky has declined over the past four years in tandem with an increased focus on identifying, addressing and preventing incidents that pose the most serious potential.

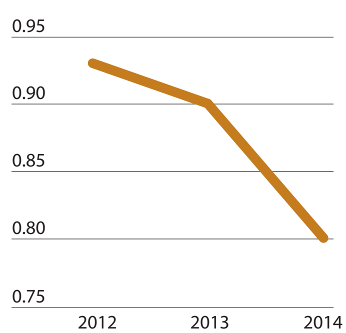
Critical and Serious Incidents
(per 200,000 exposure hours)



Total Recordable Injury Rate

Husky recorded a 0.8 total recordable injury rate (TRIR) in 2014, compared to 0.9 in 2013. TRIR measures fatalities, lost time, restricted work and medical aid incidents. The rate has declined 32 percent since 2011.

Total Recordable Injury Rate
(per 200,000 exposure hours)



Management's Discussion and Analysis

February 23, 2015

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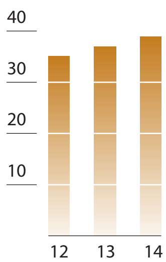
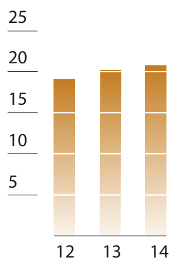
1.0 Financial Summary

1.1 Financial Position

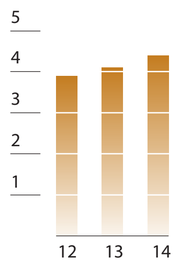
Total Assets
($ billions)



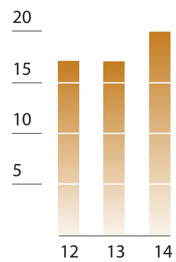
Total Equity
($ billions)



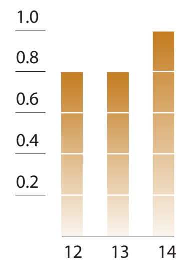
Total Long-term Debt *($ billions)*



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

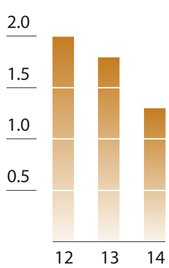


Debt to Cash Flow from Operations[(1)]
(times)

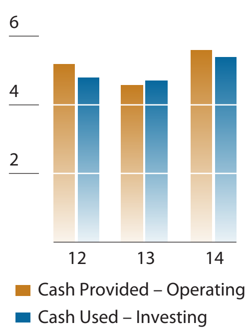


1.2 Financial Performance

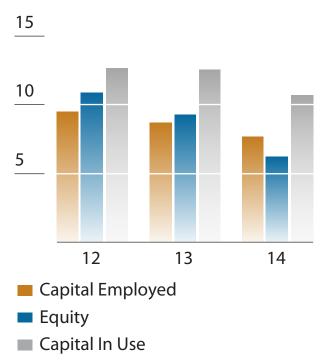
Net Earnings
($ billions)



Cash Flow
($ billions)



Return[(1)]
(%)

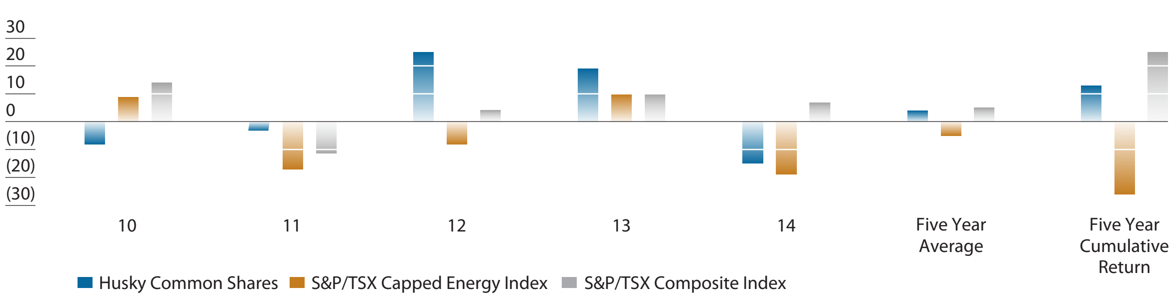


[(1)] *Debt to capital employed, debt to cash flow, return on capital employed, return on equity and return on capital in use constitute non-GAAP measures. (Refer to Section 11.3)*

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)	2014	2013	2012
Gross revenues	25,122	24,181	22,948
Net earnings (loss) by segment			
Upstream	1,106	1,244	1,322
Downstream	363	830	893
Corporate	(211)	(245)	(193)
Net earnings	1,258	1,829	2,022
Net earnings per share – basic	1.26	1.85	2.06
Net earnings per share – diluted	1.20	1.85	2.06
Ordinary dividends per common share	1.20	1.20	1.20
Dividends per cumulative redeemable preferred share, series 1	1.11	1.11	1.11
Cash flow from operations[(1)]	5,535	5,222	5,010
Total assets	38,848	36,904	35,161
Other long-term liabilities[(2)]	585	271	328
Long-term debt including current portion	4,397	4,119	3,918
Total non-current liabilities	12,464	12,663	12,908
Commercial paper	895	–	–
Cash and cash equivalents	1,267	1,097	2,025
Return on equity *(percent)*[(1)(3)]	6.2	9.3	10.9
Return on capital in use (percent)[(1)(4)]	10.7	12.6	12.7
Return on capital employed *(percent)*[(1)(5)]	7.7	8.7	9.5

(1) *Cash flow from operations and financial ratios constitute non-GAAP measures. (Refer to Section 11.3)*
(2) *As at December 31, 2014, 2013 or 2012, the Company did not have long-term financial liabilities.*
(3) *Return on equity equals net earnings divided by the two-year average shareholder's equity. (Refer to Section 11.3)*
(4) *Return on capital in use for the years ended December 31, 2014 and 2013 was adjusted for after-tax impairment charges on property, plant and equipment of $622 million and $204 million, respectively. Return on capital in use, including impairment charges, for the years ended December 31, 2014 and 2013 was 7.5 percent and 11.3 percent, respectively. (Refer to Section 11.3)*
(5) *Return on capital employed for the years ended December 31, 2014 and 2013 was adjusted for after-tax impairment charges on property, plant and equipment of $622 million and $204 million, respectively. Return on capital employed, including impairment charges, for the years ended December 31, 2014 and 2013 was 5.3 percent and 7.9 percent respectively. (Refer to Section 11.3)*

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 and Cumulative Redeemable Preferred Shares, Series 3 are listed under the symbols, "HSE.PR.A" and "HSE.PR.C", respectively. The Company operates in Western Canada, the United States, the Asia Pacific Region and the Atlantic Region with 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 and blending of crude oil and natural gas and storage of crude oil, diluent and natural gas (Infrastructure and Marketing). 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:

- Large base of crude oil producing properties in Western Canada that continue to produce with existing technology and have responded well to the application of increasingly sophisticated techniques, such as horizontal drilling. Enhanced oil recovery ("EOR") techniques, including thermal in-situ recovery methods, have been extensively used in the mature Western Canada Sedimentary Basin to increase recovery rates and to stabilize decline rates of light and heavy crude oil. EOR techniques, such as Alkaline Surfactant Polymer, are being field tested and advanced, while techniques that have been in practice for several decades continue to be optimized;
- Large position in Western Canada oil and liquids-rich natural gas resource plays of approximately 1,800,000 net acres;

- Heavy oil thermal portfolio with production of approximately 44,000 bbls/day in 2014 increasing to approximately 80,000 bbls/day by the end of 2016 with planned first production in the third quarter of 2015 from the 10,000 bbls/day Rush Lake thermal project and planned first production in the second half of 2016 from the two 10,000 bbls/day Edam East and Vawn thermal development projects and the 3,500 bbls/day Edam West thermal development project;
- Expertise and experience exploring and developing the natural gas potential in the Alberta Deep Basin, Foothills and northwest plains of Alberta and British Columbia;
- Sunrise Energy Project, a multiple stage in-situ oil sands development, with Phase 1 expected to commence production towards the end of the first quarter of 2015 ramping up to approximately 60,000 bbls/day (30,000 bbls/day net Husky share) around the end of 2016. Sunrise will use 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);
- In addition to Sunrise, Husky has an extensive portfolio of undeveloped oil sands leases, encompassing in excess of 550,000 acres in northern Alberta;
- Offshore China includes a production interest in the Wenchang oil field and the significant natural gas discoveries at the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields within Block 29/26 (the "Liwan Gas Project"). First production was achieved from the Liwan 3-1 gas field in March 2014 and from the Liuhua 34-2 gas field in December 2014;
- Husky has a 40 percent interest in 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 and MBH fields and five discovered natural gas fields;
- Husky has a 100 percent interest in the rights to the Anugerah exploration block covering approximately 2,030,000 acres, which is located in the East Java Basin, Indonesia approximately 150 kilometres east of the Madura Straight 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;
- 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. Development continued at White Rose and its three satellite extensions in 2014. Husky has a 13 percent non-operated interest in the Terra Nova oil field. The offshore exploration and development program in the Atlantic Region is focused on the Jeanne d'Arc Basin and the Flemish Pass Basin;
- Husky has a 35 percent interest in each of the three Flemish Pass Basin discoveries: Bay Du Nord, Mizzen and Harpoon;
- Extensive integrated heavy oil pipeline systems in the Lloydminster producing region; 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 and natural gas storage of 29 bcf, owned and leased.

2.2 Downstream

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading), refining in Canada of crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products and production of ethanol (Canadian Refined Products) and refining in the U.S. of primarily crude oil to produce and market gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards (U.S. Refining and Marketing).

Profile and highlights of the Downstream segment include:

- Heavy oil upgrading facility located in the Lloydminster, Saskatchewan heavy oil producing region with a throughput capacity of 82 mbbls/day;
- A refinery at Lima, Ohio with a gross crude oil throughput capacity of 160 mbbls/day and a 50 percent interest in the BP-Husky Refinery in Toledo, Ohio with a name plate capacity of 160 mbbls/day and operating capacity of 135 – 145 mbbls/day on its current crude slate;
- Refinery at Prince George, British Columbia with throughput capacity of 12 mbbls/day producing low sulphur gasoline and ultra low sulphur diesel;
- Largest marketer of paving asphalt in Western Canada, with a 29 mbbls/day capacity asphalt refinery located at 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 litre per year of capacity at plants located in Lloydminster, Saskatchewan and Minnedosa, Manitoba; and
- Major regional motor fuel marketer with 490 retail marketing locations as at December 31, 2014, including bulk plants and travel centres with strategic land positions in Western Canada and Ontario.

3.0 The 2014 Business Environment

Husky's operations are significantly influenced by domestic and international business environment factors. The global crude oil and liquid fuel industry is impacted by various factors, including those encountered during 2014, that are anticipated to continue to impact the industry to varying degrees into 2015 and beyond. Business factors impacting Husky's industry during 2014 include, but are not limited, to the following:

- Pricing benchmarks for crude oil and natural gas and underlying market supply and demand drivers;
- Industry advancement in alternative and improved extraction methods have rapidly evolved North American and international on-shore and offshore activity;
- Growing domestic production of natural gas and crude oil continues to reshape the U.S. energy economy, with U.S. crude oil production averaging an estimated 9.2 million bbls/day at the end of 2014, approaching the historical high achieved in 1970 of 9.6 million bbls/day;
- Accelerated growth of global crude oil production and inventory supplies relative to demand led to a sharp decline in key benchmarks such as West Texas Intermediate ("WTI") and Brent in the second half of 2014;
- Increased transportation of Western Canadian crude oil by rail which narrowed differentials relative to WTI and other key benchmarks;
- Expected continued production growth from the Western Canadian oil sands;
- Economic conditions remain uncertain as national indebtedness among countries continues to impact global GDP growth;
- Continued global economic uncertainty has led to a tightening of investment from historical norms, creating greater competition among companies within capital markets;
- Increasing globalization, larger projects with major partners and economies of scale;
- Strong demand for natural gas in Asian markets has led to robust gas pricing in the region;
- Domestic and international political, regulatory and tax system changes; and
- A continuing emphasis on environmental, health and safety, enterprise risk management, resource sustainability and corporate social responsibility.

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 2014 Annual Information Form.

Commodity prices, foreign exchange rates and refining crack spreads are some of the most significant factors that affect the results of Husky's operations.

Average Benchmarks		2014	2013
WTI crude oil[1]	(U.S. $/bbl)	**93.00**	97.97
Brent crude oil[2]	(U.S. $/bbl)	**98.99**	107.91
Canadian light crude 0.3% sulphur	($/bbl)	**85.08**	93.85
Western Canada Select @ Hardisty[3]	(U.S. $/bbl)	**73.60**	72.77
Lloyd heavy crude oil @ Lloydminster	($/bbl)	**73.28**	64.41
NYMEX natural gas[4]	(U.S. $/mmbtu)	**4.42**	3.65
NIT natural gas	($/GJ)	**4.19**	3.00
WTI/Lloyd crude blend differential	(U.S. $/bbl)	**19.41**	25.33
New York Harbor 3:2:1 crack spread	(U.S. $/bbl)	**18.61**	22.21
Chicago 3:2:1 crack spread	(U.S. $/bbl)	**17.28**	21.30
U.S./Canadian dollar exchange rate	(U.S. $)	**0.906**	0.971
Canadian Equivalents[5]			
WTI crude oil	($/bbl)	**102.65**	100.90
Brent crude oil	($/bbl)	**109.26**	111.13
Western Canada Select @ Hardisty	($/bbl)	**81.24**	74.94
WTI/Lloyd crude blend differential	($/bbl)	**21.42**	26.08
NYMEX natural gas	($/mmbtu)	**4.88**	3.76

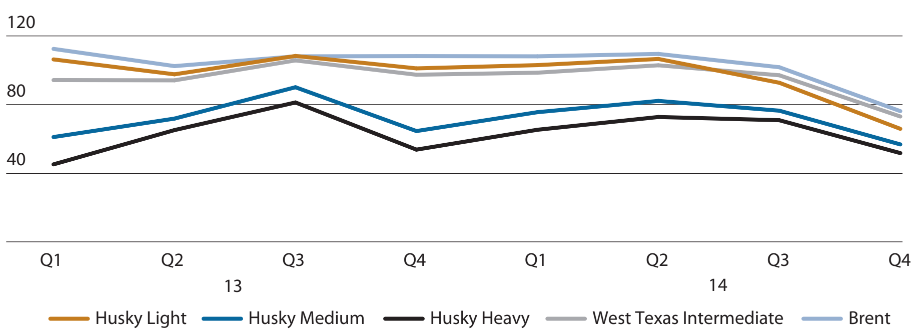
(1) *Prices quoted are near-month contract prices for settlement during the next month.*
(2) *Quoted Brent prices are dated less than 15 days prior to loading for delivery.*
(3) *Western Canadian Select is a heavy crude blend primarily based on existing Canadian heavy conventional and bitumen crude oils and is traded at Hardisty, Alberta. Quoted prices are based on the average price during the month.*
(4) *Prices quoted are average settlement prices for deliveries during the period.*
(5) *Prices quoted are calculated using U.S. 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 specific buyers with long-term contracts. For the Liwan 3-1 gas field, the price is fixed for the initial five years and then will be linked to local benchmark pricing for the years following. For the Liuhua 34-2 field, the price is fixed during the contract delivery period.

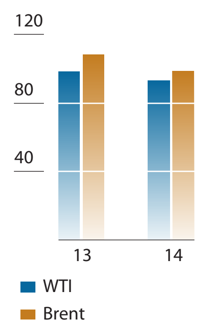
The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil. In the upgrading business segment, heavy crude oil feedstock is processed into light synthetic crude oil. Husky's U.S. refining operations process 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 refined products business in Canada 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 exchanged with production from the Husky Prince George Refinery.

Crude Oil

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



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

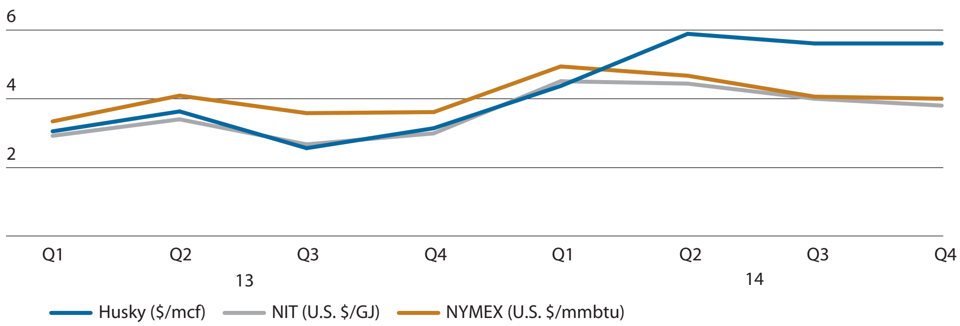


The price Husky receives for production from Western Canada is primarily driven by changes in the price of WTI and discounts or premiums to Western Canadian crude prices, while the majority of the Company's production in the Atlantic Region and the Asia Pacific Region is referenced to the price of Brent, a light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2014 at U.S. $53.27/bbl compared to U.S. $98.42/bbl on December 31, 2013 and averaged U.S. $93.00/bbl in 2014 compared to U.S. $97.97/bbl in 2013. The price of Canadian light crude ended 2014 at $51.15/bbl compared to $97.49/bbl on December 31, 2013 and averaged $85.08/bbl in 2014 compared to $93.85/bbl in 2013. The price of Brent ended 2014 at U.S. $54.98/bbl, compared to U.S. $110.28/bbl on December 31, 2013 and averaged U.S. $98.99/bbl in 2014 compared to U.S. $107.91/bbl in 2013.

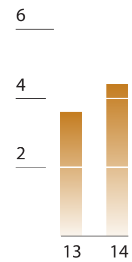
A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2014, 56 percent of Husky's crude oil and NGL production was heavy crude oil or bitumen compared to 54 percent in 2013. The light/heavy crude oil differential averaged U.S. $19.41/bbl or 21 percent of WTI in 2014 compared to U.S. $25.33/bbl or 26 percent of WTI in 2013.

Natural Gas

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



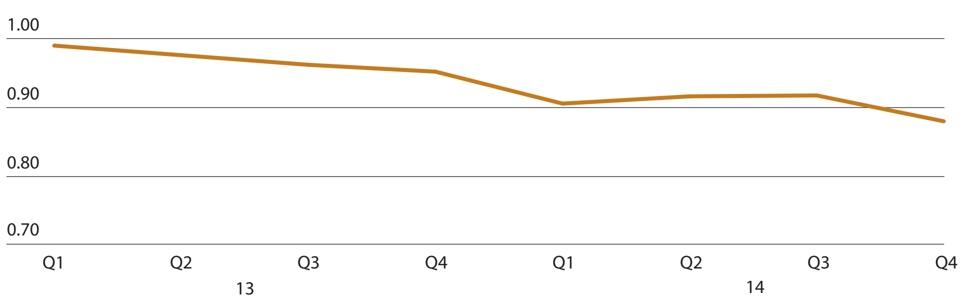
Average NYMEX
(U.S. $/mmbtu)



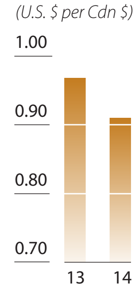
In 2014, 30 percent of Husky's total oil and gas production was natural gas compared with 27 percent in 2013, reflecting new production from the Liwan Gas Project, partially offset by a shift in investment in Western Canada from dry gas development to higher netback liquids-rich natural gas and crude oil production. The near-month natural gas price quoted on the NYMEX ended 2014 at U.S. $2.89/mmbtu compared with U.S. $4.23/mmbtu at December 31, 2013. During 2014, the NYMEX near-month contract price of natural gas averaged U.S. $4.42/mmbtu compared with U.S. $3.65/bbl in 2013. The near-month natural gas contract price for NOVA Inventory Transfer ("NIT"), which is a Canadian natural gas benchmark, was $2.64/mmbtu at the end of 2014 compared with $3.73/mmbtu at December 31, 2013. During 2014, the NIT near-month contract price of natural gas averaged $4.19/mmbtu compared to $3.00/mmbtu in 2013.

Foreign Exchange

Average U.S./Canadian Dollar Exchange Rate
(U.S. $ per Cdn $)



Average U.S./Canadian Dollar Exchange Rate
(U.S. $ per Cdn $)

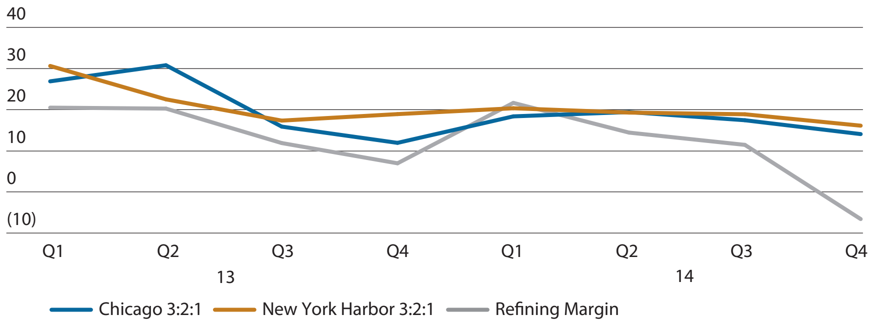


The majority of the Company's revenues from the sale of oil and gas commodities receive prices determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the revenues received from the sale of oil and gas commodities. Correspondingly, an increase in the value of the Canadian dollar relative to the U.S. dollar decreases the revenues received from the sale of oil and gas commodities. The majority of the Company's long-term debt is denominated in U.S. dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the principal amount owing on long-term debt at maturity and the associated interest payments. The majority of the Company's expenditures are in Canadian dollars. In addition, changes in foreign exchange rates impact the translation of U.S. Downstream and international Upstream operations.

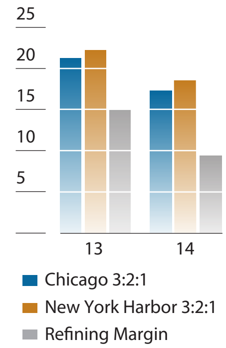
The Canadian dollar ended 2014 at U.S. $0.862 on December 31, 2014 compared to U.S. $0.940 on December 31, 2013. In 2014, the Canadian dollar averaged U.S. $0.906, weakening by 7 percent compared with U.S. $0.971 during 2013. Crude oil prices realized by Husky in 2014 benefited from the weakening of the Canadian dollar against the U.S. dollar compared to 2013. In 2014, the price of WTI in U.S. dollars decreased by 5 percent while the price of WTI in Canadian dollars increased by 2 percent when compared to 2013.

Refining Crack Spreads

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



Average Crack Spread
(U.S. $/bbl)



The 3:2:1 refining crack spread is the key indicator for refining margins, as refinery gasoline output is approximately twice the distillate output. This crack spread is equal to the price of two-thirds of a barrel of gasoline plus one-third of a barrel of fuel oil (distillate) 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 necessarily reflect the actual crude oil purchase costs or product configuration of a specific refinery. Each refinery has a unique crack spread depending on several variables. Realized refining margins are affected by the product configuration of each refinery, crude oil feedstock, product slates, transportation costs to benchmark hubs and the time lag between the purchase and delivery of crude oil, which is accounted for on a first in first out ("FIFO") basis in accordance with International Financial Reporting Standards ("IFRS").

The New York Harbor 3:2:1 refining crack spread benchmark is calculated as the difference between the price of a barrel of WTI crude oil and the sum of the price of two-thirds of a barrel of reformulated gasoline and the price of one-third of a barrel of heating oil. The Chicago 3:2:1 refining crack spread benchmark is calculated based on WTI, regular unleaded gasoline and ultra low sulphur diesel.

The New York Harbor 3:2:1 refining crack spread averaged U.S. $18.61/bbl in 2014 compared to U.S. $22.21/bbl in 2013, and the Chicago 3:2:1 refining crack spread averaged U.S. $17.28/bbl in 2014 compared to U.S. $21.30/bbl in 2013.

The following table is indicative of the relative annualized effect on pre-tax earnings and net earnings from changes in certain key variables in 2014. The table below shows what the effect would have been on 2014 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2014. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable 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 when greater magnitudes of change are occurring.

Sensitivity Analysis	2014 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]	**93.00**	*U.S. $1.00/bbl*	**83**	**0.08**	**61**	**0.06**
NYMEX benchmark natural gas price[5]	**4.42**	*U.S. $0.20/mmbtu*	**33**	**0.03**	**24**	**0.02**
WTI/Lloyd crude blend differential[6]	**19.41**	*U.S. $1.00/bbl*	**(27)**	**(0.03)**	**(21)**	**(0.02)**
Canadian light oil margins	**0.050**	*Cdn $0.005/litre*	**14**	**0.01**	**11**	**0.01**
Asphalt margins	**22.12**	*Cdn $1.00/bbl*	**11**	**0.01**	**8**	**0.01**
New York Harbor 3:2:1 crack spread	**18.61**	*U.S. $1.00/bbl*	**48**	**0.05**	**29**	**0.03**
Exchange rate (U.S. $ per Cdn $)[3][7]	**0.906**	*U.S. $0.01*	**(82)**	**(0.08)**	**(60)**	**(0.06)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 983.7 million common shares outstanding as of December 31, 2014.*
(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 maintain and enhance production in its Heavy Oil and Western Canada foundation as it repositions these areas toward 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

Husky has a substantial portfolio of assets in Western Canada. New technologies are making it possible to economically access new pools and recover more production from existing reservoirs. The Company is active in the exploration and production of heavy oil, light crude oil, natural gas and natural gas liquids. The Western Canada strategy is comprised of maintaining production while refocusing by growing oil and liquids-rich natural gas resource plays and expanding thermal and horizontal drilling in heavy oil. The Company advanced its oil and gas resource play positions in 2014 with development activities ongoing in the Bakken, Cardium, Duvernay, Falher, Lower Shaunavon, Montney, Muskwa, Second White Specks, Viking and Wilrich formations.

Husky has an extensive portfolio of oil sands leases, encompassing approximately 2,500 square kilometres in northern Alberta. During 2014, Husky advanced the development of the Sunrise Energy Project, a multiple stage in-situ oil sands development, where first steam was achieved on Phase 1 of the project in December 2014 and first oil is anticipated towards the end of the first quarter of 2015. The first phase is expected to produce approximately 60,000 bbls/day (30,000 bbls/day net Husky share). Sunrise will use 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), and planning has advanced for the next phase of the project.

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 and MBH development fields, five discoveries offshore Indonesia and rights to additional exploration blocks in the South China Sea located 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 China National Offshore Oil Corporation, 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.

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 2014, the Company and its partner began an 18-month appraisal drilling program around the Bay du Nord discovery in the Northern Flemish Pass. 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 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

Downstream supports heavy oil and oil sands production and makes prudent investments in respect of feedstock, product and market access flexibility. Husky plans to continue to pursue projects to optimize, integrate and reconfigure the Lima, Ohio Refinery for additional crude oil feedstock and product flexibility and reconfigure and increase capacity at the BP-Husky Toledo Refinery to accommodate Sunrise production as its primary feedstock.

4.3 Financial

Husky is committed to ensuring sufficient liquidity, financial flexibility and access to long-term capital to fund the Company's growth and support dividend payments. 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 strong balance sheet to provide financial flexibility. The Company's target is to maintain a debt to cash flow 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 11.3). Husky is committed to retaining its investment grade credit ratings to support access to debt capital markets.

The significant asset base in the Company's foundation businesses in Western Canada provides a steady source of cash flow to reinvest in its growth projects, including in the Asia Pacific Region, the Oil Sands and the Atlantic Region. As these significant growth projects are developed, the Company expects that they will provide steady sources of cash for the Company.

5.0 Key Growth Highlights

The 2014 Capital Program built on the momentum achieved over the past three years, repositioning the Heavy Oil and Western Canada foundation by accelerating heavy oil production growth and repositioning Western Canada to focus on oil and liquids-rich natural gas resource plays and advancing three major growth areas in the Asia Pacific Region, the Oil Sands and the Atlantic Region.

5.1 Upstream

Western Canada (excluding Heavy Oil and Oil Sands)

Husky continued to progress crude oil and liquids-rich gas resource plays as a core element of its Western Canada foundation. Total production from these resource plays in 2014 was approximately 34,000 boe/day, representing a more than one-third increase when compared to 2013.

Liquids-Rich Natural Gas Resource Plays

During 2014, the Company continued to advance exploration and development projects on its extensive liquids-rich natural gas resource land base. A total of 51 wells (gross) were drilled and 45 wells (gross) were completed in 2014 in key plays across the liquids-rich natural gas resource plays.

The following table summarizes the key liquids-rich natural gas drilling and completion activity for the year ended December 31, 2014:

Liquids-Rich Natural Gas Resource Plays – Drilling and Completion Activity[(1)(2)]

Project	Location	Year ended December 31, 2014 Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	**31**	**23**
Duvernay	Kaybob, Alberta	**–**	**2**
Wilrich	Kakwa, Alberta	**10**	**7**
Strachan Cardium	Rocky Mountain House, Alberta	**9**	**11**
Bivouac Muskwa	Bivouac, B.C.	**1**	**2**
Total Gross		**51**	**45**
Total Net		**41**	**36**

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

The liquids-rich gas formations at Ansell in west central Alberta continue to be a key area of focus, with 31 wells (gross) drilled and 23 wells (gross) completed in 2014. To date, the Company has drilled and completed over 350 (gross) wells at the play with average production of 17,500 boe/day in 2014, an increase of 27 percent when compared to 2013.

Husky completed a two-well pad in 2014 at the Duvernay liquids-rich natural gas resource play at Kaybob, Alberta. Results from the four-well pad drilled and completed in 2013 and the two-well pad completed in 2014 continue to be in line with expectations.

Drilling commenced in the year at the Wilrich Kakwa liquids-rich natural gas resource play. The Company drilled ten wells (gross) and completed seven wells (gross) in the year and production is in line with expectations.

At the Strachan Cardium liquids-rich natural gas resource play, development continued in the year with nine wells (gross) drilled and 11 wells (gross) completed. Production continues to be in line with expectations.

Oil Resource Plays

During 2014, the Company advanced exploration and development projects on its extensive oil resource land base. A total of 41 horizontal wells (gross) were drilled and 49 horizontal wells (gross) were completed in 2014.

The following table summarizes the key oil resource play drilling and completion activity for the year ended December 31, 2014:

Oil Resource Plays – Drilling and Completion Activity[1]

Project	Location	Year ended December 31, 2014 Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	**7**	**7**
Lower Shaunavon	S.W. Saskatchewan	–	**2**
Viking[2]	Alberta and S.W. Saskatchewan	**27**	**25**
N.Cardium	Wapiti, Alberta	**6**	**13**
Muskwa	Rainbow, Northern Alberta	**1**	**2**
Total Gross		**41**	**49**
Total Net		**36**	**44**

(1) *Excludes service/stratigraphic test wells for evaluation purposes.*
(2) *Viking is comprised of project activity at Redwater in central Alberta, Alliance in Southeastern Alberta and drilling in Southwestern Saskatchewan.*

In the Northwest Territories, construction of the all-season road at the Slater River Canol shale play was completed in 2014. During the second quarter of 2014, Husky withdrew its application to drill four horizontal wells.

Heavy Oil

Production commenced in early 2014 ahead of schedule at the Sandall heavy oil development with rates exceeding the 3,500 bbls/day design rate capacity throughout the year. Production at the end of 2014 was approximately 5,700 bbls/day.

Construction work continued at the 10,000 bbls/day Rush Lake heavy oil thermal development with first production expected in the third quarter of 2015.

Site clearing, detailed engineering and module fabrication commenced at the two 10,000 bbls/day Edam East and Vawn developments in 2014 with first production expected in the second half of 2016.

The Company sanctioned a 3,500 bbls/day thermal project at Edam West in early 2014. Site clearing, detailed engineering and module fabrication commenced in the year with first production expected in the second half of 2016.

Total production from the Company's existing heavy oil thermal developments averaged approximately 44,000 bbls/day in 2014.

Husky completed a successful 2013/2014 winter delineation program at the McMullen thermal development property including the drilling of 40 stratigraphic wells, the acquisition of 25 square kilometers of three-dimensional ("3-D") seismic survey data and the completion of environmental field study work. Additional drilling commenced in December 2014 which will continue into the first quarter of 2015 to further progress the play.

Ninety-four horizontal heavy oil wells (gross) and 153 cold heavy oil production with sand ("CHOPS") wells (gross) were drilled in 2014.

Asia Pacific Region

China

Block 29/26

At the Liwan Gas Project, first gas from the deepwater wells from the Liwan 3-1 gas field was achieved on March 30, 2014 and gas sales into the Guangdong market natural gas grid commenced on April 24, 2014. In addition, the tie-in of the Liuhua 34-2 gas field single production well into the Liwan 3-1 field deepwater infrastructure was completed and commissioned with first production achieved in December 2014. Production from the Liwan Gas Project continues to increase with natural gas production averaging 114.2 mmcf/day and NGL production averaging 4.2 mbbls/day in 2014. Market opportunities for the sale of gas and liquids from the third deepwater field, Liuhua 29-1, continue to be assessed.

Offshore Taiwan

The acquisition of the second phase of two-dimensional seismic survey data on the Company's offshore Taiwan block was completed in 2014, and evaluation of the data is in progress.

Indonesia

Madura Strait

Progress continued on the shallow water gas developments in the Madura Strait Block during 2014. Work related to the BD field engineering, procurement, installation and construction contract is ongoing and approximately 29 percent complete with construction moving forward on the wellhead platform and pipeline infrastructure in preparation for planned first production in 2017. The contract for the construction and lease of a floating production, storage and offloading ("FPSO") vessel received final approval in the second quarter of 2014 and was signed in December 2014.

Tender plans for the MDA and MBH development projects were approved by SKK Migas, the Indonesia oil and gas regulator, and the tendering process is in progress. The Gas Sales Agreement for the first tranche of gas from this development is complete and awaiting final approval from the regulator. The development plan for the MDK field to tie into the MDA/MBH combined development was approved by SKK Migas in July.

Anugerah

During 2014, Husky signed a production Production Sharing Contract ("PSC") for the Anugerah contract area. The contract area covers approximately 8,215 square kilometres and is primarily offshore East Java, Indonesia, with water depths of up to 1,400 metres. The main prospective locations are in water depths of 800 to 1,300 metres. The contract area is located approximately 150 kilometres east of the Madura Strait Block. Under the PSC, Husky has an obligation to carry out seismic surveys to assess the petroleum potential of the exploration block within the first three years. Exploration work, including planning for a 3-D seismic survey covering the contract area, is in progress.

Oil Sands

Sunrise Energy Project

The Company completed all remaining work and commissioning on Plant 1A, the first of two 30,000 bbls/day plants, at the Sunrise Energy Project. Steam injection into the reservoir commenced in December 2014, with first oil anticipated towards the end of the first quarter of 2015.

At Plant 1B, all welding is substantially completed, and construction activities are focused on completing electrical, instrumentation and insulation work. Plant 1B is on track to begin steaming in mid-2015.

In early 2014, an additional 38 square kilometers of 3-D seismic survey data was acquired and 12 stratigraphic wells were drilled to support continued field development of the Sunrise Energy Project.

Emerging Oil Sands

The Company completed a successful winter delineation program in the first quarter of 2014 at the Caribou and Cadotte North emerging oil sands properties.

Atlantic Region

White Rose Field and Satellite Extensions

At the South White Rose Extension project, gas injection commenced in early 2014 which is expected to increase reservoir pressure and oil recovery. Fabrication of production equipment was completed and installed in the second half of the year with development drilling commencing on the first production wells in late 2014. First oil is anticipated in mid-2015.

Drilling continued in 2014 at the Hibernia-formation well at the North Amethyst field which targeted a deeper zone beneath the main North Amethyst field. Production from the well, originally planned to commence in late 2014, has been delayed due to rig scheduling and is now expected to commence producing in the second half of 2015.

Hearings for the public review of the application for a wellhead platform to facilitate full field development at West White Rose were held during 2014. Construction continued on the dry-dock in Argentia, Newfoundland and early site preparation was advanced, including construction of a graving dock. Husky has deferred a final investment decision on the project.

Atlantic Exploration

The Company and its partner commenced an 18-month appraisal and exploration drilling program in November 2014 in the Bay du Nord discovery area in the Flemish Pass basin offshore Newfoundland and Labrador. The drilling program will involve the appraisal and delineation of the Bay du Nord discovery. The Company holds a 35 percent working interest in the Bay du Nord discovery.

Drilling of an exploration well on the Aster prospect in the Flemish Pass Basin commenced on December 19, 2014, and results are being evaluated.

In addition, a 3-D seismic program over the Bay du Nord discovery was completed in 2014.

Infrastructure and Marketing

The Hardisty terminal expansion project includes multiple initiatives intended to increase pipeline connectivity and blending capacity that would expand Husky's terminalling business, support Upstream production growth and provide additional flexibility through the inclusion of the Company's production in various crude streams. Construction of the two 300,000-barrel storage tanks and the expanded piping and blending infrastructure is complete. The project is now in the commissioning phase with start up expected in the first quarter of 2015.

The Company completed an expansion of its pipeline system from the Sandall heavy oil thermal development to the existing gathering system that leads to Hardisty, Alberta. In addition, the Saskatchewan Gathering System is undergoing an extension and capacity expansion into Lloydminster in order to accommodate the anticipated production from the Rush Lake, Edam East, Vawn and Edam West thermal developments.

5.2 Downstream

Lima Refinery
Front-end engineering design ("FEED") on the Company's feedstock flexibility project was completed in 2014. The project is expected to give the refinery flexibility to take up to 40,000 bbls/day of Western Canadian heavy oil while overall nameplate capacity would remain unchanged at 160,000 bbls/day. The initial planned completion date has been deferred with the project now expected to be completed in the 2018-2019 time frame.

BP-Husky Toledo Refinery
The Hydrotreater Recycle Gas Compressor Project was completed and became operational in late 2014. The project is expected to improve operational integrity and plant performance.

6.0 Results of Operations

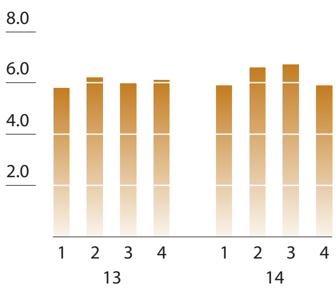
6.1 Segment Earnings

	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[1]	
($ millions)	**2014**	2013	**2014**	2013	**2014**	2013
Upstream						
Exploration and Production	**1,337**	1,283	**992**	952	**4,189**	4,264
Infrastructure and Marketing	**153**	392	**114**	292	**211**	96
Downstream						
Upgrading	**227**	401	**168**	297	**50**	205
Canadian Refined Products	**287**	260	**214**	194	**86**	109
U.S. Refining and Marketing	**(30)**	522	**(19)**	339	**374**	220
Corporate	**(190)**	(230)	**(211)**	(245)	**113**	134
Total	**1,784**	2,628	**1,258**	1,829	**5,023**	5,028

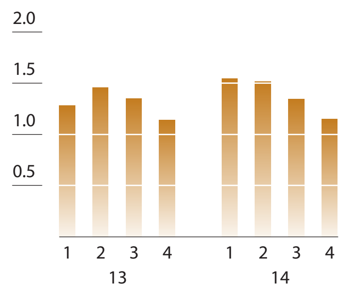
[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

6.2 Summary of Quarterly Results

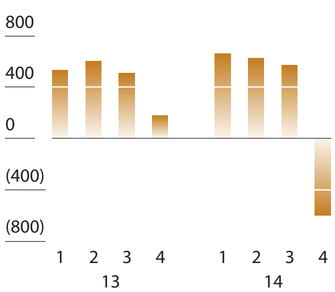
Gross Revenues
($ billions)



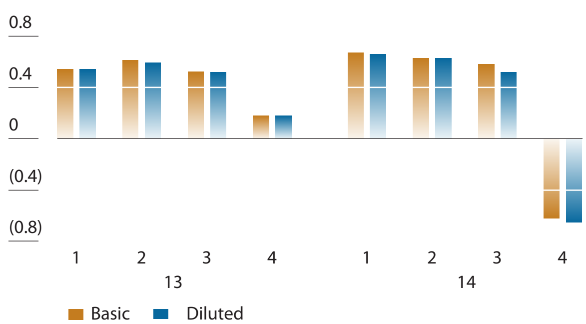
Cash Flow from Operations[(1)]
($ billions)



Net Earnings
($ millions)



Net Earning Per Share
($ per share)

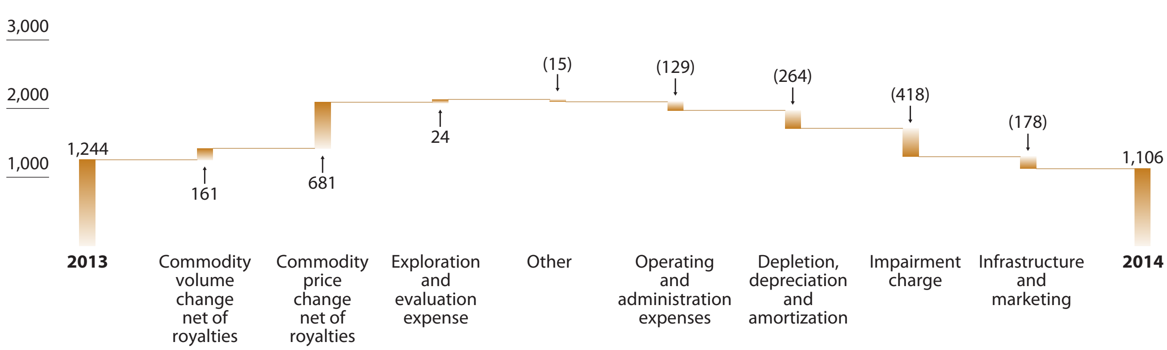


[(1)] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*

6.3 Upstream

2014 Total Upstream Earnings $1,106 million

After Tax Earnings Variance Analysis
($ millions)

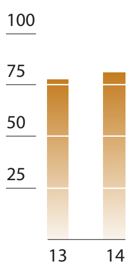


Exploration and Production

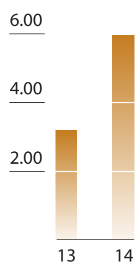
Exploration and Production Earnings Summary *($ millions)*	**2014**	2013
Gross revenues	**8,634**	7,333
Royalties	**(1,030)**	(864)
Net revenues	**7,604**	6,469
Purchases, operating, transportation and administrative expenses	**2,521**	2,347
Depletion, depreciation, amortization and impairment	**3,434**	2,515
Exploration and evaluation expenses	**214**	246
Other expenses	**98**	78
Income taxes	**345**	331
Net earnings	**992**	952

Excluding an after-tax impairment charge of $622 million and $204 million recognized in 2014 and 2013, respectively, Exploration and Production net earnings in 2014 were $1,614 million, an increase of $458 million compared to 2013 primarily due to new natural gas and NGL production from the Liwan Gas Project and new heavy crude oil production at the Sandall heavy oil thermal development, higher realized commodity prices in the first half of 2014 and lower exploration and evaluation expenses partially offset by lower realized crude oil prices due to declines in market benchmarks in the second half of 2014.

Average Price Realized
Crude Oil
($/bbl)

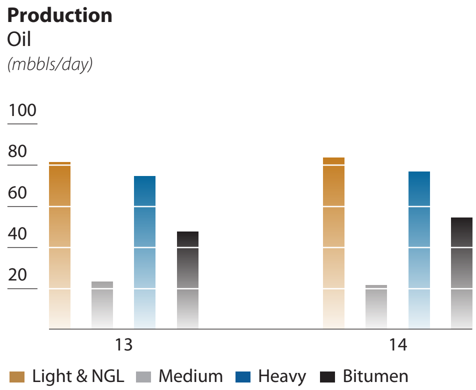


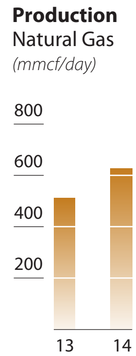
Average Price Realized
Natural Gas
($/mcf)

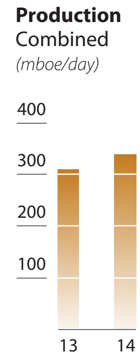


Average Sales Prices Realized	**2014**	2013
Crude oil and NGL *($/bbl)*		
Light crude oil & NGL	**96.70**	102.35
Medium crude oil	**80.69**	74.29
Heavy crude oil	**71.91**	63.44
Bitumen	**70.57**	61.68
Total crude oil and NGL average	**81.10**	78.12
Natural gas average *($/mcf)*	**5.99**	3.19
Total average *($/boe)*	**67.38**	61.96

During 2014, the average realized price for crude oil, NGL and bitumen was $81.10/bbl compared to $78.12/bbl in 2013, an increase of 4 percent. Lower average realized Brent and WTI market prices during 2014 were offset by a weaker Canadian dollar and narrower heavy crude oil and bitumen differentials. During 2014, the average realized natural gas price was $5.99/mcf compared to $3.19/mcf in 2013, an increase of 88 percent primarily due to higher realized fixed prices on production from the Liwan Gas Project and higher natural gas benchmark prices in Canada.







Daily Gross Production	2014	2013
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**30.1**	29.7
Medium crude oil	**21.5**	23.2
Heavy crude oil	**76.8**	74.5
Bitumen(1)	**54.6**	47.7
	183.0	175.1
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**38.6**	39.3
Terra Nova – light crude oil	**6.0**	4.8
	44.6	44.1
Asia Pacific Region		
Light crude oil & NGL(2)	**9.0**	7.3
Crude oil *(mbbls/day)*	**236.6**	226.5
Natural gas *(mmcf/day)*		
Western Canada	**506.8**	512.7
Asia Pacific Region(2)	**114.2**	–
	621.0	512.7
Total *(mboe/day)*	**340.1**	312.0

(1) *Bitumen production included heavy oil thermal average daily gross production of 43.8 mbbls/day and 37.4 mbbls/day for the years ended December 31, 2014 and 2013, 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 which are allocated to Husky until full project exploration cost recovery is attained.*

Total production increased 9 percent in 2014 when compared to 2013.

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	2014	2013
Crude oil		
Light crude oil & NGL	**36%**	43%
Medium crude oil	**7%**	9%
Heavy crude oil	**24%**	25%
Bitumen	**17%**	15%
Crude oil	**84%**	92%
Natural gas	**16%**	8%
Total	**100%**	100%

During 2014, crude oil, bitumen and NGL production increased by 10.1 bbls/day or 4 percent compared to 2013, primarily due to new heavy oil thermal production at the Sandall heavy oil thermal development, new NGL production from the Liwan Gas Project, increased production at the Ansell liquids-rich natural gas resource play and higher production from Terra Nova where turnaround activity was lower in 2014 compared to 2013. Production increases were partially offset by natural reservoir declines from mature properties in Western Canada. Production from the White Rose and satellite fields in the Atlantic Region in 2014 was comparable to 2013 with new production from the multilateral well at North Amethyst offsetting natural declines at the mature main field.

Natural gas production increased by 108.3 mmcf/day or 21 percent in 2014 compared to 2013 due to new production from the Liwan Gas Project and increased production at the Ansell liquids-rich natural gas resource play, partially offset by natural reservoir declines in Western Canada mature properties.

2015 Production Guidance and 2014 Actual

Gross Production	Guidance 2015	Year ended December 31 2014	Guidance 2014
Canada			
Light / Medium crude oil & NGL *(mbbls/day)*	87 - 92	**96**	100 - 103
Heavy crude oil & bitumen *(mbbls/day)*	125 - 135	**131**	125 - 130
Natural gas *(mmcf/day)*	440 - 480	**507**	420 - 480
Canada total *(mboe/day)*	285 - 307	**312**	295 - 313
Asia Pacific			
Light crude oil & NGL *(mbbls/day)*	13 - 15	**9**	10 - 12
Natural gas *(mmcf/day)*	160 - 195	**114**	150 - 180
Asia Pacific total *(mboe/day)*	40 - 48	**28**	35 - 42
Total *(mboe/day)*	325 - 355	**340**	330 - 355

The Company's total production for the year ended December 31, 2014 was within production guidance. Husky expects that production levels in 2015 will be comparable to 2014 as increasing production from the Liwan Gas Project in the Asia Pacific Region and new production at the Sunrise Energy Project will be offset by decreasing production from natural gas properties in Western Canada due to natural reservoir declines.

Factors that could potentially impact Husky's production performance for 2015 include, but are not limited to:

- 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;
- significant declines in crude oil and natural gas commodity prices, which may result in the decision to temporarily shut-in production or delay capital expenditures;
- defaults by contracting parties whose services or facilities are necessary for the Company's production; and
- foreign operations and related assets, which are subject to a number of political, economic and socio-economic risks.

Royalties

Royalty rates averaged 12 percent of gross revenues in both 2014 and 2013. Royalty rates in Western Canada averaged 12 percent in both 2014 and 2013. Royalty rates in the Atlantic Region averaged 17 percent in 2014 compared to 13 percent in 2013 due to Tier 1 and super royalty rates being reached at the North Amethyst and West White Rose Satellite Extensions. Royalty rates in the Asia Pacific Region averaged 8 percent in 2014 compared to 24 percent in 2013 due to lower royalty rates associated with production from the Liwan Gas Project which started producing late in March 2014.

Operating Costs

($ millions)	2014	2013
Western Canada	**1,819**	1,745
Atlantic Region	**218**	201
Asia Pacific	**82**	31
Total	**2,119**	1,977
Unit operating costs *($/boe)*	**16.12**	16.28

Total Exploration and Production operating costs were $2,119 million in 2014 compared to $1,977 million in 2013. Total Upstream unit operating costs in 2014 averaged $16.12/boe compared to $16.28/boe in 2013 primarily due to lower per unit operating costs on production from the Liwan Gas Project, which started producing in late March 2014, and lower unit operating costs on production from thermal projects. The decrease was partially offset by increased natural gas prices and maintenance activities in Western Canada and higher logistics and ice management costs and the completion of maintenance turnarounds on the SeaRose FPSO in the Atlantic Region.

Operating costs in Western Canada increased to $17.39/boe in 2014 compared to $17.05/boe in 2013 primarily due to increased natural gas prices and maintenance activities partially offset by the impact of production from lower unit operating cost thermal projects.

Operating costs in the Atlantic Region averaged $13.38/boe in 2014 compared to $12.47/boe in 2013 primarily due to higher logistics and ice management costs and the completion of maintenance turnarounds on the SeaRose FPSO.

Operating costs in the Asia Pacific Region averaged $8.06/boe in 2014 compared to $11.39/boe in 2013 primarily due to lower unit cost production from the Liwan Gas Project which commenced in late March 2014.

Exploration and Evaluation Expenses

($ millions)	**2014**	2013
Seismic, geological and geophysical	**111**	133
Expensed drilling	**45**	102
Expensed land	**58**	11
Total	**214**	246

Exploration and evaluation expenses in 2014 were $214 million compared to $246 million in 2013. Expensed land in 2014 was primarily in Western Canada. Expensed drilling in 2013 included costs related to the winter program at the Slater River Canol shale project, as well as drilling costs associated with activities in the Atlantic Region. Seismic, geological and geophysical costs in 2013 included a one-time work commitment penalty in the Atlantic Region.

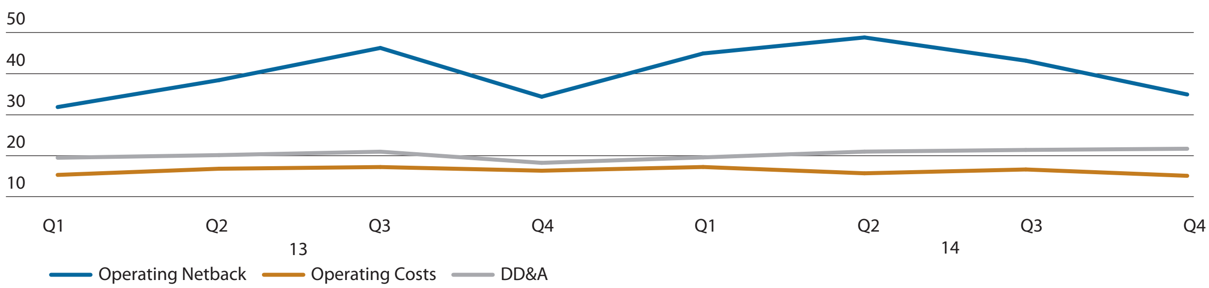
Depletion, Depreciation, Amortization ("DD&A") and Impairment

During 2014, the Company recognized a pre-tax impairment charge of $838 million on certain conventional crude oil and natural gas assets located in Western Canada compared to a pre-tax impairment charge of $275 million in 2013. The impairment charge was the result of lower estimated short and long-term crude oil and natural gas prices.

During 2014, total DD&A was $20.92/boe compared to $19.67/boe in 2013, both excluding impairment charges. The increase in DD&A in 2014 was primarily attributable to higher depletion rates per boe on production from the Liwan Gas Project.

At December 31, 2014, capital costs in respect of assets under construction and major development projects were $6.9 billion compared to $8.3 billion at the end of 2013. These costs are excluded from the Company's DD&A calculation until the properties are developed and have started producing or the project is deemed to be impaired.

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



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

Exploration and Production Capital Expenditures

In 2014, Upstream Exploration and Production capital expenditures were $4,189 million. Capital expenditures were $2,334 million (56%) in Western Canada including Heavy Oil, $713 million (17%) in Oil Sands, $746 million (18%) in the Atlantic Region and $396 million (9%) in the Asia Pacific Region.

Exploration and Production Capital Expenditures[1] *($ millions)*	2014	2013
Exploration		
Western Canada	**209**	353
Oil Sands	**5**	–
Atlantic Region	**96**	201
Asia Pacific Region	**16**	21
	326	575
Development		
Western Canada	**2,074**	2,029
Oil Sands	**708**	552
Atlantic Region	**650**	437
Asia Pacific Region	**380**	633
	3,812	3,651
Acquisitions		
Western Canada	**51**	38
	4,189	4,264

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

Western Canada, Heavy Oil & Oil Sands

The following table discloses the number of gross and net exploration and development wells Husky completed in Western Canada, Heavy Oil and Oil Sands during the periods indicated:

	2014		2013	
Wells Drilled *(wells)*[1]	Gross	Net	Gross	Net
Exploration				
Oil	**53**	**45**	39	24
Gas	**9**	**5**	19	14
Dry	**3**	**3**	–	–
	65	**53**	58	38
Development				
Oil	**469**	**419**	768	709
Gas	**78**	**68**	68	41
Dry	**3**	**3**	1	–
	550	**490**	837	750
Total	**615**	**543**	895	788

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

The Company drilled 543 net wells in the Western Canada, Heavy Oil and Oil Sands business units in 2014 resulting in 464 net oil wells and 73 net natural gas wells compared to 788 net wells resulting in 733 net oil wells and 55 net natural gas wells in 2013.

During 2014, Husky invested $2,334 million on exploration, development and acquisitions, including Heavy Oil, throughout the Western Canada Sedimentary Basin compared to $2,420 million in 2013. Property acquisitions totalling $51 million were completed in 2014 compared to $38 million in 2013. Oil related exploration and development in 2014 was $392 million compared to $576 million in 2013. Investment in natural gas related exploration and development, primarily liquids-rich, was $502 million in 2014 compared to $596 million in 2013.

In addition, $829 million was spent on production optimization, cost reduction initiatives, facilities, land acquisition and retention and environmental protection in 2014 compared to $581 million in 2013.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling were $560 million in 2014 compared to $629 million in 2013.

Oil Sands

During 2014, $713 million was invested in Oil Sands projects, compared to $552 million in 2013, primarily for Phase 1 of the Sunrise Energy Project.

Atlantic Region

The following table discloses Husky's offshore Atlantic Region drilling activity during 2014:

Atlantic Region Offshore Drilling Activity

Well	Working Interest	Well Type
Terra Nova L-98-1Y	WI 13%	Development (Producer)
South White Rose J-05-1	WI 68.875%	Development (Gas Injector)
Terra Nova L-98-13	WI 13%	Development (Water Injector)
North Amethyst E-18-12A	WI 68.875%	Delineation
Bay de Verde F-67	WI 35%	Exploration

During 2014, $746 million was invested in Atlantic Region projects compared to $638 million in 2013, primarily on the continued development of the White Rose Extension projects, including the North Amethyst, West White Rose and South White Rose Extensions.

Asia Pacific Region

During 2014, $396 million was invested in the Asia Pacific Region projects, compared to $654 million in 2013, primarily on the continued development of the Liwan Gas Project.

2015 Upstream Capital Program

($ millions)	
Western Canada	**1,500**
Oil Sands	**200**
Atlantic Region	**600**
Asia Pacific Region	**200**
Total Upstream capital expenditures[(1)]	**2,500**

(1) *Capital program excludes capitalized administration costs, capitalized interest and asset retirement obligations incurred.*

The 2015 Capital Program enables Husky to build on the momentum achieved over the past four years while maintaining prudent capital management and pacing of the Company's growth projects and exploration plans in a weak commodity price environment.

The Company has budgeted $200 million for the Asia Pacific Region in 2015, primarily for the continued development of the Liwan Gas Project and the development of the Madura Strait block in Indonesia.

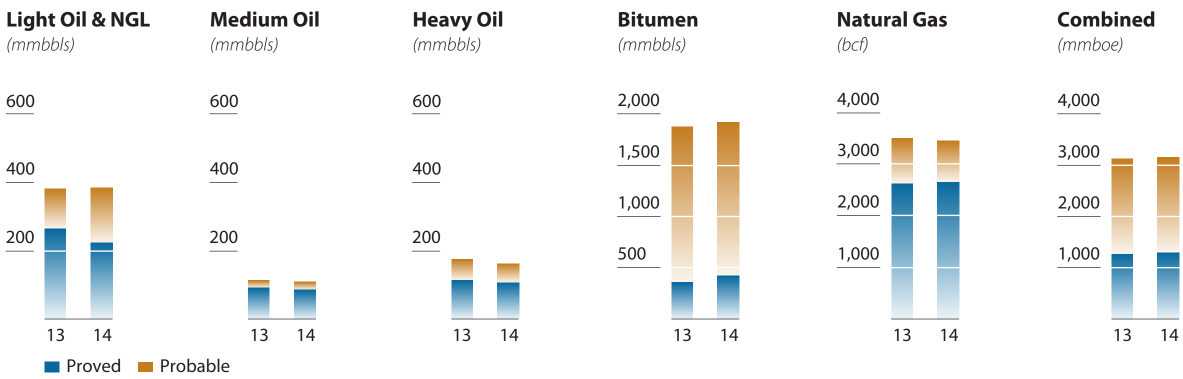
The Company has budgeted $200 million in Oil Sands in 2015, primarily for the continued development of Phase 1 of the Sunrise Energy Project.

The Company has budgeted $600 million in the Atlantic Region in 2015, primarily for continued development of the White Rose fields and extensions. The Company has commenced an 18-month exploration and appraisal program in the Bay du Nord discovery area offshore Newfoundland and Labrador.

In addition to advancing mid and long-term growth, the 2015 Capital Program provides support to the Company's efforts to continue to reinvigorate and transform its foundation in Western Canada. The Company is making progress in its strategy to transition a greater percentage of its heavy oil production to long-life thermal. Husky will continue its development of the 10,000 bbls/day Rush Lake thermal project, with expected first production in the third quarter of 2015 and the two 10,000 bbls/day Edam East and Vawn and the 3,500 bbls/day Edam West thermal developments, with first production from all three projects expected in the second half of 2016.

Oil and Gas Reserves

The following oil and gas reserves disclosure has been 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, 2014. Husky received approval from the Canadian Securities Administrators to also disclose its reserves using U.S. disclosure requirements as supplementary disclosure to the reserves and oil and gas activities disclosure required by NI 51-101. The reserves information prepared in accordance with the U.S. disclosure requirements is included in the Company's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com.



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

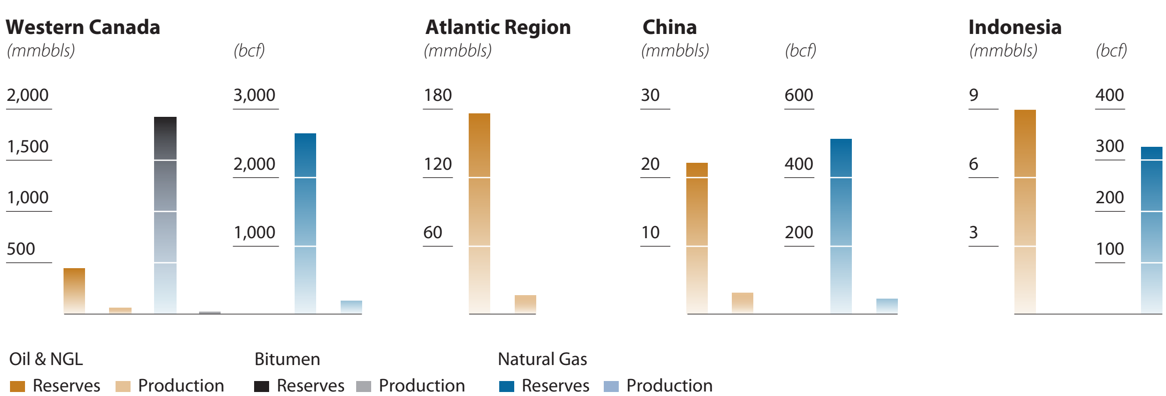
The Company's complete Oil and Gas Reserves Disclosure, prepared in accordance with NI 51-101, is contained in Husky's Annual Information Form, which is available at www.sedar.com, or Husky's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com.

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

Sproule Unconventional Limited ("Sproule"), an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct a full evaluation of Husky's crude oil, natural gas and natural gas products reserves for the Company's Heavy Oil and Gas business unit, excluding the Tucker property.

At December 31, 2014, Husky's proved oil and gas reserves were 1,279 mmboe, up from 1,265 mmboe at the end of 2013. Additions to proved reserves, including acquisitions and divestitures, represent 115 percent excluding economic revisions (111 percent including economic revisions) of 2014 production. Major additions to proved reserves in 2014 included:

- The extension through additional drilling locations at the Sunrise Energy Project that resulted in the booking of an additional 40 mmbbls of bitumen in proved undeveloped reserves;
- Extensions, improved recovery and strong performance in Heavy Oil and Gas thermal projects that resulted in the booking of an additional 36 mmbbls of Bitumen in proved reserves;
- Strong performance from Liwan 3-1 that resulted in the booking of an additional 19 mmboe of natural gas and natural gas liquids in proved developed producing reserves; and
- The extension through additional drilling locations at the Ansell liquids-rich natural gas resource play that resulted in the booking of an additional 10 mmboe of natural gas and natural gas liquids in proved undeveloped reserves.



Note: Reserves reported represent proved plus probable reserves.

Reconciliation of Proved Reserves

	Canada						International		Total		
	Western Canada					Atlantic Region					
(forecast prices and costs before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(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 & NGL *(mmbbls)*	Natural Gas (bcf)	Equivalent Units *(mmboe)*
Proved reserves											
December 31, 2013	167	91	113	359	2,175	74	23	452	827	2,627	1,265
Revision of previous estimate	(31)	–	23	(6)	65	5	3	98	(6)	163	21
Purchase of reserves in place	–	–	2	1	–	–	–	–	3	–	3
Sale of reserves in place	–	–	(7)	–	(1)	–	–	–	(7)	(1)	(7)
Discoveries, extensions and improved recovery	12	2	20	70	123	–	1	–	105	123	125
Economic revision	–	–	(1)	–	(23)	–	–	–	(1)	(23)	(4)
Production	(11)	(8)	(44)	(4)	(185)	(16)	(3)	(42)	(86)	(227)	(124)
Proved reserves December 31, 2014	**137**	**85**	**106**	**420**	**2,154**	**63**	**24**	**508**	**835**	**2,662**	**1,279**
Proved and probable reserves December 31, 2014	**176**	**107**	**162**	**1,917**	**2,637**	**177**	**31**	**836**	**2,570**	**3,473**	**3,149**
December 31, 2013	223	112	176	1,870	2,669	125	33	859	2,539	3,528	3,127

[(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 Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(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 & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved developed reserves											
December 31, 2013	146	85	92	66	1,702	60	15	267	464	1,969	792
Revision of previous estimate	(29)	1	23	(8)	97	6	4	116	(3)	213	33
Transfer from proved undeveloped	4	1	9	66	63	–	–	–	80	63	90
Purchase of reserves in place	–	–	1	–	–	–	–	–	1	–	1
Sale of reserves in place	–	–	(3)	–	(1)	–	–	–	(3)	(1)	(3)
Discoveries, extensions and improved recovery	4	1	12	1	19	–	1	–	19	19	22
Economic revision	–	–	(1)	–	(23)	–	–	–	(1)	(23)	(4)
Production	(11)	(8)	(44)	(4)	(185)	(16)	(3)	(42)	(86)	(227)	(124)
Proved developed reserves December 31, 2014	**114**	**80**	**89**	**121**	**1,672**	**50**	**17**	**341**	**471**	**2,013**	**807**

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

Planned Turnarounds

- Planned turnarounds at the Ansell liquids-rich gas resource play and Ram River plant in Western Canada are expected to have an impact of about 4,700 boe/day in the second quarter of 2015.
- Other scheduled third-party shutdowns are expected to impact Western Canada production by approximately 3,300 boe/day in the third quarter of 2015.
- A three-week maintenance shutdown is planned at the Tucker heavy oil thermal project in the second quarter of 2015.
- Partial shut-downs are scheduled at several heavy oil thermal projects to perform routine maintenance, with an estimated aggregate impact of 8,000 bbls/day in June 2015.
- An 18-day turnaround on the SeaRose FPSO vessel is scheduled for the third quarter of 2015.
- A planned ten-week maintenance event at Terra Nova has been scheduled to commence in the second quarter of 2015.

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 United States.

Infrastructure and Marketing Earnings Summary *($ millions, except where indicated)*	**2014**	2013
Infrastructure gross margin	**146**	130
Marketing and other gross margin	**70**	312
Gross margin	**216**	442
Operating and administrative expenses	**40**	33
Depletion, depreciation and amortization	**25**	20
Other expenses	**(2)**	(3)
Income taxes	**39**	100
Net earnings	**114**	292
Commodity trading volumes managed (mboe/day)	**252.3**	174.5

Infrastructure and Marketing net earnings decreased by $178 million in 2014 compared with 2013 primarily due to the narrowing product price differentials between Canada and the United States. 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. The increase to commodity trading volumes managed relates primarily to additional pipeline capacity.

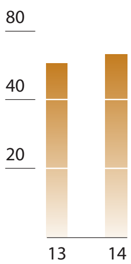
Infrastructure and Marketing capital expenditures totalled $211 million in 2014 compared with $96 million in 2013 primarily related to the Hardisty terminal expansion project and the extension and capacity expansion of the Saskatchewan Gathering System into Lloydminster.

6.4 Downstream

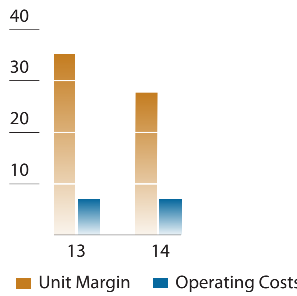
2014 Total Downstream Earnings $363 million

Upgrader

Upgrader
Synthetic Crude Sales
(mbbls/day)



Upgrader
Unit Margin & Operating Costs
($/bbl)



Upgrader Earnings Summary *($ millions, except where indicated)*	2014	2013
Gross revenues	**2,212**	2,023
Gross margin	**536**	645
Operating and administrative expenses	**189**	168
Depreciation and amortization	**108**	96
Other income (expense)	**12**	(20)
Income taxes	**59**	104
Net earnings	**168**	297
Upgrader throughput[(1)] *(mbbls/day)*	**72.7**	66.1
Synthetic crude oil sales *(mbbls/day)*	**53.3**	50.5
Upgrading differential *($/bbl)*	**21.80**	29.14
Unit margin ($/bbl)	**27.55**	34.99
Unit operating cost[(2)] ($/bbl)	**6.78**	6.96

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

The Upgrading operations add value by processing heavy sour 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.

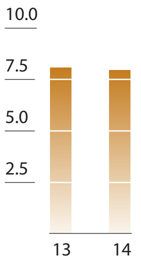
Upgrader net earnings in 2014 decreased by $129 million compared with 2013. The decrease in net earnings was primarily due to lower realized upgrading differentials as slightly higher realized prices for Husky Synthetic Blend were offset by higher feedstock costs.

During 2014, the price of Husky Synthetic Blend averaged $101.38/bbl compared to the average cost of blended heavy crude oil from the Lloydminster area of $79.58/bbl. During 2013, the price of Husky Synthetic Blend averaged $100.57/bbl compared to an average cost of blended heavy crude oil from the Lloydminster area of $71.43/bbl. This resulted in an average synthetic/heavy crude oil differential of $21.80/bbl in 2014 compared to $29.14/bbl in 2013 and a gross unit margin of $27.55/bbl in 2014 compared to $34.99/bbl in 2013.

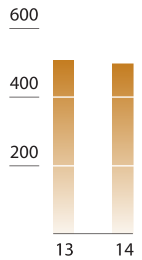
The operating cost of upgrading averaged $6.78/bbl in 2014 compared to $6.96/bbl in 2013 which resulted in a net margin for upgrading heavy crude of $20.77/bbl, down 26 percent compared to $28.03/bbl in 2013. Higher energy costs and maintenance contributed to the increase in operating and administrative expenses and a recovery of upside interest, associated with the remaining payment obligation to Natural Resources Canada and the Alberta Department of Energy, recognized in 2013 contributed to the increase in other expenses in 2014 compared to 2013.

Canadian Refined Products

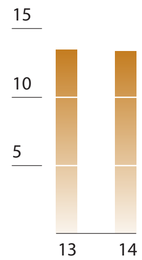
Canadian Refined Products
Volume
(millions of litres/day)



Outlets



Volume per Outlet
(thousands of litres/day)



Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	2014	2013
Gross revenues	**4,020**	3,737
Gross margin		
Fuel	**147**	140
Refining	**251**	175
Asphalt	**246**	233
Ancillary	**57**	55
	701	603
Operating and administrative expenses	**307**	253
Depreciation and amortization	**102**	90
Other expense	**5**	–
Income taxes	**73**	66
Net earnings	**214**	194
Number of fuel outlets[1]	**497**	509
Fuel sales volume, including wholesale		
Fuel sales *(million of litres/day)*	**8.0**	8.1
Fuel sales per outlet *(thousand of litres/day)*	**13.4**	13.5
Refinery throughput		
Prince George refinery *(mbbls/day)*	**11.7**	10.3
Lloydminster refinery *(mbbls/day)*	**28.8**	26.4
Ethanol production *(thousand of litres/day)*	**780.7**	742.4

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

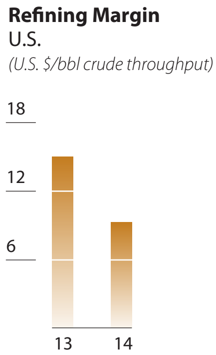
Fuel gross margins increased in 2014 compared to 2013 primarily due to higher realized gasoline margins.

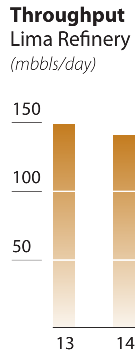
Refining gross margins increased in 2014 compared to 2013 primarily due to higher refinery throughput and lower feedstock costs at the ethanol plants.

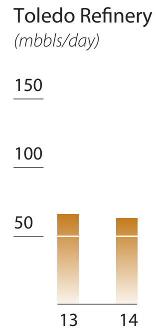
Asphalt gross margins increased in 2014 compared to 2013 primarily due to higher asphalt throughput resulting from a scheduled refinery turnaround completed in 2013.

Higher energy costs contributed to the increase in operating and administrative expenses in 2014 when compared to 2013.

U.S. Refining and Marketing







U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	**2014**	2013
Gross revenues	**10,663**	10,728
Gross refining margin	**722**	1,182
Operating and administrative expenses	**481**	424
Depreciation and amortization	**268**	233
Other expenses	**3**	3
Income taxes	**(11)**	183
Net earnings (loss)	**(19)**	339
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**141.6**	149.4
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**63.2**	65.0
Refining margin *(U.S. $/bbl crude throughput)*	**9.37**	15.06
Refinery inventory (feedstocks and refined products) *(mmbbls)*[1]	**10.8**	10.3

[1] *Included in refinery inventory is feedstock and refined products.*

U.S. Refining and Marketing net earnings decreased by $358 million in 2014 compared with 2013 primarily due to lower market crack spreads combined with FIFO losses and provisions booked to reduce inventory to net realizable value resulting from falling crack spreads and crude oil prices at year end.

The after-tax impact from provisions booked to reduce inventories to net realizable value was $128 million in 2014. Excluding this provision, the Company's U.S. refining margin for 2014 was U.S. $11.83/bbl. In addition, lower refinery throughput resulting from planned maintenance at the Lima Refinery contributed to the decrease in net earnings.

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 FIFO accounting, which reflects purchases made in the previous year when crude oil prices were higher. The estimated FIFO impact was a reduction in net earnings of approximately $108 million in 2014 compared to a reduction in net earnings of $18 million in 2013.

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 2014, Downstream capital expenditures totalled $510 million compared to $534 million in 2013. In Canada, capital expenditures of $136 million were primarily related to upgrades at retail stations and projects at the Upgrader and Prince George Refinery. In the United States, capital expenditures totalled $374 million for 2014 compared to $220 million in 2013. At the Lima Refinery, $260 million was spent primarily on the feedstock flexibility project and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $114 million (Husky's 50 percent share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

A turnaround at the partner-operated refinery in Toledo is scheduled to commence in the third quarter of 2015.

6.5 Corporate

2014 Loss $211 million

Corporate Summary *($ millions) income (expense)*	2014	2013
Selling, general and administration expenses	**(139)**	(217)
Depreciation and amortization	**(73)**	(51)
Other income	**5**	17
Foreign exchange gains	**81**	21
Interest expense	**(64)**	–
Income taxes	**(21)**	(15)
Net loss	**(211)**	(245)

The Corporate segment reported a loss of $211 million in 2014 compared to a loss of $245 million in 2013. Selling, general, and administrative expenses decreased in 2014 compared to 2013 primarily due to lower stock-based compensation expense associated with a decrease in the Company's share price in 2014. Other income decreased by $12 million in 2014 compared to 2013 primarily due to the recovery of an insurance provision in 2013. Foreign exchange gains increased by $60 million in 2014 compared to 2013 due to the weakening of the Canadian dollar against the U.S. dollar which positively impacted the translation of the Company's foreign currency denominated working capital. Interest expense increased by $64 million in 2014 compared to 2013 due to a decrease in the amount of capitalized interest related to production being achieved at the Liwan Gas Project and a decrease in interest income associated with the Sunrise Oil Sands Partnership contribution receivable which was paid in full in the second quarter of 2014.

Foreign Exchange Summary *($ millions, except exchange rate amounts)*	2014	2013
Gains (losses) on translation of U.S. dollar denominated long-term debt	**7**	(11)
Gains on contribution receivable	**6**	27
Gains on non-cash working capital	**42**	33
Other foreign exchange gains (losses)	**26**	(28)
Foreign exchange gains	**81**	21
U.S./Canadian dollar exchange rates:		
At beginning of year	**U.S. $0.940**	U.S. $1.005
At end of year	**U.S. $0.862**	U.S. $0.940

Consolidated Income Taxes

Consolidated income taxes decreased in 2014 to $526 million from $799 million in 2013, resulting in an effective tax rate of 29 percent in 2014 compared to 30 percent in 2013. The decrease was primarily due to a recovery of non-deductible stock-based compensation recorded in 2014 compared to an expense recorded in 2013.

($ millions)	2014	2013
Income taxes as reported	**526**	799
Cash taxes paid	**661**	433

Corporate Capital Expenditures

Corporate capital expenditures were $113 million in 2014 compared to $134 million in 2013 and were primarily related to computer hardware and software and leasehold improvements.

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 its integrated management system that considers the environmental requirements and process and occupational safety (Husky Operational Integrity Management System). Failure to manage the risks effectively could result in potential fatalities, serious injury, asset damage or environmental impact. Enterprise risk management, emergency preparedness, business continuity and security policies and programs are in place for all operating areas and are adhered to on an ongoing basis. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

Commodity Price Volatility

The Company's results of operations and financial condition are dependent on the prices received for its crude oil and natural gas production. Lower prices for crude oil and natural gas could adversely affect the value and quantity of the Company's oil and gas reserves. The Company's reserves include significant quantities of heavier grades of crude oil that trade at a discount to light crude oil. Heavier grades of crude oil are typically more expensive to produce, process, transport and refine into high value refined products. Refining and transportation capacity for heavy crude oil is limited and planned increases of North American heavy crude oil production may create the need for additional heavy oil refining and transportation capacity. As a result, wider price differentials could have adverse effects on the Company's financial performance and condition, reduce the value and quantities of the Company's heavier crude oil reserves and delay or cancel projects that involve the development of heavier crude oil resources. There is no guarantee that planned 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 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, prevailing weather patterns and the availability of alternate sources of energy.

The Company's natural gas production is currently located in Western Canada and Asia Pacific. Western Canada 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 or from storage facilities, prevailing weather patterns, the price of crude oil, the U.S. and Canadian economies, the occurrence of natural disasters and pipeline restrictions.

In Asia or in North America, 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. The natural gas Husky produces in the Asia Pacific Region is sold to specific buyers with long-term contracts. The price is fixed for the initial 5 years for the Liwan 3-1 gas field and then linked to city-gas pricing adjustment. For Liuhua 34-2, the price is fixed during the delivery period.

In certain instances, the Company uses derivative commodity instruments to manage exposure to price volatility on a portion of its crude oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

The fluctuations in 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 2014 commodity price sensitivities, refer to Section 3.0 within this Management's Discussion and Analysis.

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

The Company'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 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 position, medium to long-term business strategy, cash flow and corporate reputation. Unplanned shutdowns and closures of the Company's refineries and or upgrader may limit the Company'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 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 position, 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, and unreasonable taxation. This could adversely affect the Company's interest in its foreign operations and future profitability.

Gas Storage

The potential inability to deliver an effective gas storage solution as inventories grow over the life of the White Rose field may potentially result in prolonged shutdown of these operations, which may have a material impact on the Company's financial position, medium to long-term business strategy and cash flow.

Skills and Human Resource Shortage

The Company recognizes that a robust, productive and healthy workforce drives efficiency, effectiveness and financial performance. Attracting and retaining qualified and skilled labour is critical to the successful execution of the Company's current and future business strategies. A tight labour market, an insufficient number of qualified candidates and an aging workforce are factors that can precipitate a human resource risk for the Company if not properly managed. Failure to retain current employees and attract new skilled employees could materially affect the Company's ability to conduct its business.

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 a decline in the market value of the Company’s oil and gas products. 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 the Company's assets in which the Company has an ownership interest. The Company is at times dependent upon its partners for the successful execution of various projects. If a dispute with partners were to occur over the development and operation of a project or if partners were unable to fund their contractual share of the capital expenditures, a project 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 Management's Discussion and Analysis 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 resource plays. In general, estimates of economically recoverable crude oil and 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 governmental 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 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 and efficacy 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 the Company's operations, the Company is subject to regulation and intervention by governments at the federal, provincial, state and municipal levels in the countries in which it conducts its operations 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, increase capital expenditures and operating expenses and expose the Company to other risks including environmental and safety risks. Examples of the Company's regulatory risks include, but are not limited to, uncertain or negative interactions with governments, uncertain energy 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 licenses to operate.

Environmental Regulation

Changes in environmental regulation could have a material adverse effect on the Company'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 on the Company. The Company engages in the dialogue on proposed changes, both directly and through industry associations, to ensure the Company’s interests are recognized and the Company is sufficiently prepared to fully comply when new regulations come into force.

The Company anticipates further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, increased compliance costs and approval delays for critical licenses and permits, which could have a material adverse effect on the Company'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:

- water use, withdrawals and discharges;
- the use of hydraulic fracturing to aid in oil and gas production;
- targets for reduced purchases of unconventional oils, such as bitumen;
- new greenhouse gas ("GHG") regulations in jurisdictions where the Company has operations;
- jurisdictional calculation and regulation of fuel life-cycle carbon content;
- fuel reformulation to support reduced combustion emissions;
- new regulations for managing air pollutants at facility and equipment levels; and
- regulations affecting the transportation of product by rail.

Transportation of Dangerous Goods Regulation

The transportation of flammable liquids (crude, ethanol, gasoline, etc.) by rail is an emerging issue for the petroleum industry. Throughout 2014, Transport Canada and the Pipeline and Hazardous Materials Safety Administration ("PHMSA") in the United States have issued a series of orders and directives that are intended to enhance the safe transport of flammable liquids. Among these changes is greater oversight by the regulators, enhancements to emergency preparedness and response requirements, rail car design, testing and classification practices as well as discussions on a federal rail liability and compensation regime. Some of the enhancements came into effect in 2014; however the details of the other measures are still being worked on by the Canadian Association of Petroleum Producers, Canadian Fuels and other trade associations. On August 1, 2014, PHMSA published a Notice of Proposed Rulemaking concerning more stringent standards and operational controls for trains transporting high volumes of crude oil and other flammable materials and an Advance Notice of Proposed Rulemaking for oil spill response plans for these trains. If finalized, the rules would require the replacement of existing railcars and the implementation of other compliance measures. The final impact to the Company and the industry due to additional transportation costs imposed by the PHMSA rules and other developing standards has yet to be determined.

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 equivalent in a year to reduce their emissions intensity by up to 12 percent below an established baseline emissions intensity. These regulations currently affect the Company's Ram River Gas Plant and Tucker Thermal Facility and are expected to affect the Sunrise Energy Project when it starts production.

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

British Columbia currently has a $30 per tonne carbon tax that is placed 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 Low Carbon Fuel Standard in place that requires a reduction in the allowable carbon intensities of all fuels, with penalties applied after 2016 for intensities that do not meet targets. Due to the geographical location of the Company's Prince George Refinery, the Company is already at the blend-wall as the cloud point of the Company's produced diesel has to meet the requirements for vehicle engines operating at low temperatures. These regulations may impact the Company's current and future operations in that province.

The Federal Government of Canada has announced its intention to take a sector based approach to future climate change regulations although it is not clear how new regulations will be structured or what compliance mechanisms will be available for the Company's affected operations. Climate change regulations may become more onerous over time as public and political pressures increase to implement initiatives that 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.

The Company's U.S. refining business may be materially impacted by implementation of the Environmental Protection Agency ("EPA") climate change rules or by future U.S. GHG legislation that applies to the oil and gas industry or the consumption of petroleum products. 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.

Internal Credit Risk

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

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. 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 is expected to 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. revenue dollars 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 which are considered as a foreign functional currency. At December 31, 2014, the amount that the Company designated was U.S. $2.9 billion (December 31, 2013 – U.S. $3.2 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.

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 capital markets, including under its shelf prospectuses. The availability of capital under its shelf prospectuses is dependent on market conditions.

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

	Outlook	Rating
Moody's:		
Senior Unsecured Debt	Stable	Baa2
Standard and Poor's:		
Senior Unsecured Debt	Stable	BBB+
Series 1 Preferred Shares	Stable	P-2 (low)
Series 3 Preferred Shares	Stable	P-2 (low)
Dominion Bond Rating Service:		
Senior Unsecured Debt	Stable	A (low)
Series 1 Preferred Shares	Stable	Pfd-2 (low)
Series 3 Preferred Shares	Stable	Pfd-2 (low)
Commercial Paper	Stable	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, accounts receivable, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, inventories measured at fair value, other assets and other long-term liabilities.

The following table summarizes by measurement classification, derivatives, contingent consideration and hedging instruments that are carried at fair value through profit or loss ("FVTPL") in the consolidated balance sheets:

Financial Instruments at Fair Value *($ millions)*	**As at December 31, 2014**	As at December 31, 2013
Commodity contracts – FVTPL		
Natural gas[(1)]	**(5)**	32
Crude oil[(2)]	**4**	41
Foreign currency contracts – FVTPL		
Foreign currency forwards	**(1)**	–
Other assets – FVTPL	**2**	2
Contingent consideration	**(40)**	(60)
Hedging instruments[(3)]		
Derivatives designated as a cash flow hedge[(4)]	–	37
Hedge of net investment[(5)]	**(353)**	(93)
	(393)	(41)

(1) *Natural gas contracts include a $12 million decrease as at December 31, 2014 (December 31, 2013 – $27 million increase) to the fair value of held-for-trading inventory, recognized in the Condensed Consolidated Balance Sheets, related to third party physical purchase and sale contracts for natural gas held in storage. Total fair value of the related natural gas storage inventory was $87 million at December 31, 2014.*

(2) *Crude oil contracts include a $21 million decrease as at December 31, 2014 (December 31, 2013 – $49 million increase) to the fair value of held-for-trading inventory, recognized in the condensed consolidated balance sheets, related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory was $199 million at December 31, 2014.*

(3) *Hedging instruments are presented net of tax.*

(4) *Forward starting swaps previously designated as a cash flow hedge were discontinued during the first quarter of 2014.*

(5) *Represents the translation of the Company's U.S. dollar denominated long-term debt designated as a hedge of the Company's net investment in its U.S. refining operations.*

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

In 2014, the Company funded its capital programs and dividend payments through cash generated from operating activities, cash on hand, the issuance of commercial paper and the issuance of preferred shares. At December 31, 2014, the Company had total debt of $5,292 million, partially offset by cash on hand of $1,267 million for $4,025 million of net debt compared to $3,022 million of net debt as at December 31, 2013. At December 31, 2014, the Company had $2,792 million of unused credit facilities of which $2,335 million are long-term committed credit facilities and $457 million are short-term uncommitted credit facilities. In addition, the Company had $2.75 billion in unused capacity under its December 31, 2012 Canadian universal short form base shelf prospectus (the "2012 Canadian Shelf Prospectus") and U.S. $2.25 billion in unused capacity under its 2013 U.S. universal short form base shelf prospectus (the "U.S. Shelf Prospectus"). The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions. Refer to Section 8.2.

Cash Flow Summary *($ millions, except ratios)*	**2014**	2013
Cash flow		
Operating activities	**5,585**	4,645
Financing activities	**(6)**	(846)
Investing activities	**(5,423)**	(4,722)
Financial Ratios[1]		
Debt to capital employed *(percent)*[2]	**20.5**	17.0
Debt to cash flow *(times)*[3][4]	**1.0**	0.8
Corporate reinvestment ratio *(percent)*[3][5]	**101**	108
Interest coverage on long-term debt only[3][6]		
Earnings	**6.7**	11.2
Cash flow	**23.6**	22.4
Interest coverage on total debt[3][7]		
Earnings	**6.6**	11.3
Cash flow	**23.2**	22.6

(1) *Financial ratios constitute non-GAAP measures. (Refer to Section 11.3)*
(2) *Debt to capital employed is equal to long-term debt, long-term debt due within one year and commercial paper divided by capital employed. (Refer to Section 11.3)*
(3) *Calculated for the 12 months ended for the dates shown.*
(4) *Debt to cash flow (times) is equal to long-term debt, long-term debt due within one year and commercial paper divided by cash flow from operations. (Refer to Section 11.3)*
(5) *Corporate reinvestment ratio is equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations. (Refer to Section 11.3)*
(6) *Interest coverage on long-term debt on a net earnings basis is equal to net earnings before finance expense on long-term debt and income taxes divided by finance expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow – operating activities before finance expense on long-term debt and current income taxes divided by finance expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.*
(7) *Interest coverage on total debt on a net earnings basis is equal to net earnings before finance expense on total debt and income taxes divided by finance expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow – operating activities before finance expense on total debt and current income taxes divided by finance expense on total debt and capitalized interest. Total debt includes long-term debt, the current portion of long-term debt and commercial paper.*

Cash Flow from Operating Activities

Cash generated from operating activities was $5,585 million in 2014 compared to $4,645 million in 2013. The increase in cash flow generated from operating activities resulted from a decrease in non-cash working capital primarily due to the timing of accounts receivable and accounts payable settlements and lower investments in inventory due to falling commodity prices.

Cash Flow used for Financing Activities

Cash used for financing activities was $6 million in 2014 compared to $846 million in 2013. The decrease in cash flow used for financing activities was primarily resulting from the issuance of Cumulative Redeemable Preferred Shares, Series 3 and proceeds from the issuance of commercial paper.

Cash Flow used for Investing Activities

Cash used for investing activities was $5,423 million in 2014 compared to $4,722 million in 2013. Cash invested in both periods was primarily for capital expenditures.

8.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2014, Husky's working capital deficiency was $1,314 million compared to working capital of $754 million at December 31, 2013.

Movement in Working Capital

($ millions)	December 31, 2014	December 31, 2013	Change
Cash and cash equivalents	**1,267**	1,097	170
Accounts receivable	**1,324**	1,458	(134)
Income taxes receivable	**353**	461	(108)
Inventories	**1,385**	1,812	(427)
Prepaid expenses	**166**	89	77
Accounts payable and accrued liabilities	**(2,989)**	(3,155)	166
Asset retirement obligations	**(97)**	(210)	113
Short-term debt	**(895)**	–	(895)
Contribution payable	**(1,528)**	–	(1,528)
Long-term debt due within one year	**(300)**	(798)	498
Net working capital (deficiency)	**(1,314)**	754	(2,068)

The increase in cash was primarily due to higher cash flow from operating activities in the year, proceeds from the issuance of commercial paper and proceeds from the issuance of the Series 3 Shares. Movements in accounts receivable and accounts payable were due to the timing of settlements compared to 2013. The decrease in inventories was primarily due to lower investments in inventory due to falling commodity prices. The increase in short-term debt resulted from the issuance of commercial paper. The increase in contribution payable resulted from the reclassification of the BP-Husky Toledo contribution payable from long-term to short-term to reflect the repayment scheduled in 2015. The decrease in long-term debt due within one year was due to repayment of the maturing U.S. $750 million 5.90 percent notes issued under a trust indenture dated September 11, 2007, partially offset by the reclassification of the $300 million 3.75 percent medium-term notes maturing in 2015.

Sources and Uses of Cash

Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fund capital programs necessary to maintain and increase production and develop reserves, to acquire strategic oil and gas assets and to repay maturing debt and pay dividends. The Company is currently able to fund its capital programs principally by cash generated from operating activities, cash on hand, issuances of equity, issuances of long-term and short-term debt and borrowings under committed and uncommitted credit facilities. During times of low oil and gas prices, a portion of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining 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 options with respect to sources of short and long-term capital resources. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines. At December 31, 2014, no production was hedged.

At December 31, 2014, Husky had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[(1)]	**645**	**457**
Syndicated bank facilities	**3,230**	**2,335**
	3,875	**2,792**

(1) *Consists of demand credit facilities.*

Cash and cash equivalents at December 31, 2014 totalled $1,267 million compared to $1,097 million at the beginning of the year.

At December 31, 2014, Husky had unused short and long-term borrowing credit facilities totalling $2.8 billion. A total of $188 million of the Company's short-term uncommitted borrowing credit facilities was used in support of outstanding letters of credit and $895 million of the Company's long-term committed borrowing credit facilities was used in support of commercial paper.

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, 2014.

At the special meeting of shareholders held on February 28, 2011, the Company's shareholders approved amendments to the common share terms, which provide shareholders with the ability to receive dividends in common shares or in cash. Under the amended terms, quarterly dividends may be declared in an amount expressed in dollars per common share and paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares is calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares. During the year ended December 31, 2014, the Company declared dividends payable of $1.20 per common share, resulting in dividends of $1,180 million. An aggregate of $1,169 million was paid in cash during 2014. At December 31, 2014, $295 million, including $292 million in cash and $3 million in common shares, was payable to shareholders on account of dividends declared on October 23, 2014.

On December 14, 2012, the Company amended and restated both of its revolving syndicated credit facilities to allow the Company to borrow up to $1.5 billion and $1.6 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The maturity date for the $1.5 billion facility was extended to December 14, 2016, and in February 2013, the limit on the $1.5 billion facility was increased to $1.6 billion. On June 19, 2014, the $1.6 billion revolving syndicated credit facility previously set to expire on August 31, 2014 was increased to $1.63 billion, and its maturity was extended to June 19, 2018. The Company also increased the limit on one of the operating facilities from $50 million to $100 million.

On December 31, 2012, the Company filed the 2012 Canadian Shelf Prospectus with applicable securities regulators in each of the provinces of Canada, other than Quebec, that enabled the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units in Canada up to and including January 30, 2015. During 2014, the Company issued $250 million of Cumulative Redeemable Preferred Shares, Series 3 (the "Series 3 Preferred Shares"), resulting in unused capacity of $2.75 billion under the 2012 Canadian Shelf Prospectus as at December 31, 2014.

On October 31, 2013 and November 1, 2013, the Company filed the U.S. Shelf Prospectus with the Alberta Securities Commission and the SEC, respectively, 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 November 30, 2015. During the 25-month period that the U.S. Shelf Prospectus is effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On March 17, 2014, the Company issued U.S. $750 million of 4 percent notes due April 15, 2024 pursuant to the U.S. Shelf Prospectus. 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. As at December 31, 2014, the Company had U.S. $2.25 billion in unused capacity under its U.S. Shelf Prospectus.

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, 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, 2014 was 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 under the 2012 Canadian Shelf Prospectus. 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.

Subsequent to December 31, 2014, on February 23, 2015, the Company filed a short form base shelf prospectus (the "2015 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including March 22, 2017.

The ability of the Company to raise capital utilizing the 2015 Canadian Shelf Prospectus or U.S. Shelf Prospectus is dependent on market conditions at the time of sale.

Capital Structure	December 31, 2014	
($ millions)	**Outstanding**	**Available[1]**
Total debt	**5,292**	**2,792**
Common shares, retained earnings and other reserves	**20,575**	

(1) *Available long-term debt includes committed and uncommitted credit facilities.*

8.3 Cash Requirements

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)	2015	2016-2017	2018-2019	Thereafter	Total
Long-term debt and interest on fixed rate debt	537	1,026	1,593	3,065	6,221
Operating leases	115	478	440	1,019	2,052
Firm transportation agreements	351	669	648	3,275	4,943
Unconditional purchase obligations[1]	2,495	750	468	329	4,042
Lease rentals and exploration work agreements	321	292	176	1,219	2,008
Asset retirement obligations[2]	95	315	243	14,920	15,573
	3,914	3,530	3,568	23,827	34,839

(1) *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases. Unconditional purchase obligations have been updated for changes to commitments subsequent to the release of the Company's 2014 fourth quarter Management's Discussion and Analysis.*

(2) *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 updated its estimates for Asset Retirement Obligations ("ARO") as outlined in Note 16 to the 2014 Consolidated Financial Statements. On an undiscounted basis, the ARO increased from $12.3 billion as at December 31, 2013 to $15.5 billion as at December 31, 2014, due to increased cost estimates and asset growth in both the Upstream and Downstream segments an increased estimated time to retirement in the Upstream segment.

The Company is in the process of renegotiating certain purchase, distribution and terminal commitments related to light oil and asphalt products as the existing contracts are approaching expiration.

The Company has entered into new firm transportation agreements in 2014, and future payments on transportation agreements settled in U.S. dollars have been impacted by a weaker Canadian dollar.

Other Obligations

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

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

Husky provides a defined contribution 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 79 active employees, 89 participants with deferred benefits and 539 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. Husky completed the full wind up of the defined benefit pension plan in the United States effective May 2014. Husky also assumed a post-retirement welfare plan covering all qualified employees at the Lima Refinery and contributes to a 401(k) plan (Refer to Note 19 to the 2014 Consolidated Financial Statements).

The Company has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery (Refer to Note 8 to the 2014 Consolidated Financial Statements), which is payable between December 31, 2011 and December 31, 2015 with the final balance due and payable by December 31, 2015. The timing of payments during this period will be determined by the capital expenditures made at the refinery during this same period. At December 31, 2014, Husky's share of this obligation was U.S. $1.3 billion, including accrued interest.

Subsequent to December 31, 2014, the Company amended the terms of repayment of the Company's contribution payable with BP-Husky Refining LLC. In accordance with the amendment, U.S. $1 billion of the net contribution payable was paid on February 2, 2015. As a result of prepayment, the accretion rate has been reduced from 6 percent to 2.5 percent for the future term of the agreement. The remaining amount of approximately U.S. $300 million will be paid by way of funding all capital contributions of the BP- Husky Refining LLC joint operation with full payment required on or before December 31, 2017.

The Company is also subject to various contingent obligations that become payable only if certain events or rulings were to 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 and have not been reflected in the Company's financial statements beyond the associated ARO. 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.

8.4 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 material 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.

8.5 Transactions with Related Parties

On May 11, 2009, the Company issued U.S. $251 million aggregate principal amount of 5-year 5.90 percent senior notes to certain management, shareholders, affiliates and directors. Subsequent to this offering, U.S. $122 million of the 5.90 percent notes issued to related parties were sold to third parties. On June 15, 2014, the Company repaid the maturing 5.90 percent notes. As a result, U.S. $133 million was repaid to related parties which included interest of U.S. $4 million. These transactions were measured at fair market value at the date of the transaction and have been carried out on the same terms as applied to unrelated parties.

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.

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 and Hutchison Whampoa Luxembourg Holdings S.à r.l.

The Company sells natural gas to and purchases steam from Meridian and other cogeneration facilities owned by a related party. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the year ended December 31, 2014, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $78 million. For the year ended December 31, 2014, the amount of steam purchased by the Company from Meridian totalled $25 million. In addition, the Company provides facility services to Meridian which are measured and reimbursed at cost. For the year ended December 31, 2014, the total cost recovery for these services was $9 million.

8.6 Outstanding Share Data

Authorized:

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

Issued and outstanding: February 23, 2015

• common shares	983,840,282
• cumulative redeemable preferred shares, series 1	12,000,000
• cumulative redeemable preferred shares, series 3	10,000,000
• stock options	25,994,288
• stock options exercisable	13,285,074

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 2014 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 and Amortization

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.

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 Non-Financial Assets and 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 including future net cash flows from oil and gas reserves, future third-party pricing, inflation factors, discount rates and other uncertainties. Future revisions to these assumptions impact the recoverable amount.

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

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 adoption of the standard is not expected to have a material impact on the Company's Consolidated Financial Statements.

Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to replace IAS 18 which establishes principles for reporting useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. The standard is effective for the Company for annual periods beginning on January 1, 2017, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the standard on January 1, 2017. The company is assessing the impact of this standard and does not expect it to have a material impact on the Company's Consolidated Financial Statements.

Change in Accounting Policy

Impairment of Assets

The IASB issued amendments to IAS 36, "Impairment of Assets" which was adopted by the Company on January 1, 2014. The amendments require disclosure of information about the recoverable amount of impaired assets. The adoption of this amended standard had no impact on the Company's Consolidated Financial Statements.

Levies

The IASB issued International Financial Reporting Interpretations Committee Interpretation ("IFRIC") 21, "Levies" which was adopted by the Company on January 1, 2014. The IFRIC clarifies that an entity should recognize a liability for a levy when the activity that triggers payment occurs. The adoption of this interpretation had 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 2015 production guidance, including weighting of production among product types; and the Company’s 2015 Upstream capital program;

- with respect to the Company's Asia Pacific Region: planned timing of first gas from the Madura Strait BD field;

- with respect to the Company's Atlantic Region: expected benefits of gas injection at the Company’s South White Rose Extension project; anticipated timing of first production at the Company’s South White Rose Extension project; scheduled timing of first production from the North Amethyst Hibernia-formation well; the scheduled duration and timing of a turnaround for the SeaRose FPSO; and the scheduled timing and duration of a maintenance event at Terra Nova;

- with respect to the Company's Oil Sands properties: anticipated timing of first oil at the Company’s Sunrise Energy Project Phase 1; anticipated timing of, and volume of production from, the Company's Sunrise Energy Project; and anticipated timing of first steam at Plant 1B at the Company’s Sunrise Energy Project;

- with respect to the Company's Heavy Oil properties: anticipated future volume of production for the Company’s Heavy Oil business segment; expected timing of first production and anticipated volumes of production at the Company’s Rush Lake, Edam East, Edam West and Vawn heavy oil thermal developments; the scheduled timing and duration of a turnaround at the Tucker heavy oil thermal project; and the scheduled timing and anticipated impact of partial shut-downs at several heavy oil thermal projects;

- with respect to the Company's Western Canadian oil and gas resource plays: scheduled timing and anticipated impact of turnarounds at the Ansell liquids-rich natural gas resource play and Ram River plant; and scheduled timing and anticipated impact of third-party shutdowns in Western Canada;

- with respect to the Company’s Infrastructure and Marketing operating segment: scheduled timing of completion of, and anticipated outcome of, the Hardisty terminal expansion project; and

- with respect to the Company's Downstream operating segment: the anticipated timing of completion and benefits from the Lima, Ohio Refinery feedstock flexibility project and the anticipated processing capacity of Western Canadian heavy oil once reconfiguration is complete; the anticipated benefits of the Hydrotreater Recycle Gas Compressor Project at the BP-Husky Toledo Refinery; and the scheduled timing of a turnaround 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, 2014 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe the 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 an effective date of December 31, 2014 and represent Husky's share. Unless otherwise noted, historical production numbers given represent Husky's share.

The Company uses the term barrels of oil equivalent ("boe"), which is calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

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.

11.3 Non-GAAP Measures

Disclosure of non-GAAP Measurements

Husky uses measurements primarily based on IFRS as issued by the IASB and also certain secondary non-GAAP measurements. The non-GAAP measurements included in this Management's Discussion and Analysis are net operating earnings, cash flow from operations, operating netback, debt to capital employed, debt to cash flow, corporate reinvestment ratio, interest coverage on long-term debt, interest coverage on total debt, return on equity, return on capital employed and return on capital in use. Return on capital employed and return on capital in use were adjusted for an after-tax impairment charge on property, plant and equipment of $622 million and $204 million for the years ended December 31, 2014 and 2013, respectively. Return on capital employed including impairment for the years ended December 31, 2014 and 2013 was 5.3 percent and 7.9 percent, respectively. Return on capital in use including impairment for the years ended December 31, 2013 and 2012 was 7.5 percent and 11.3 percent, respectively. None of these measurements are used to enhance the Company's reported financial performance or position. With the exception of net operating earnings and cash flow from operations, there are no comparable measures to these non-GAAP measures in accordance with IFRS. These non-GAAP measurements are considered to be useful as complementary measurements in assessing the Company's financial performance, efficiency and liquidity. The non-GAAP measurements do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable by definition to similar measures presented by other companies. Except as described below, the definitions of these measurements are found in Section 11.4, "Additional Reader Advisories."

Disclosure of Net Operating Earnings

The metric "Net Operating Earnings" is a non-GAAP measure comprised of net earnings excluding extraordinary and non-recurring items such as property, plant and equipment impairment charges and inventory write-downs not considered indicative of the Company's ongoing financial performance. Net operating earnings is a complementary measure used in assessing Husky's financial performance through providing comparability between periods.

The following table shows the reconciliation of net earnings to net operating earnings and the related per share amounts for the years ended December 31:

($ millions)		**2014**	2013	2012
GAAP	Net earnings	**1,258**	1,829	2,022
	Impairment of property, plant and equipment, net of tax	**622**	204	–
	Inventory write-downs, net of tax	**135**	1	1
Non-GAAP	Net operating earnings[1]	**2,015**	2,034	2,023

[1] *Net Operating Earnings were redefined in 2014 to include after-tax inventory write-downs. Prior periods have been adjusted to conform with current period presentation.*

Disclosure of Cash Flow from Operations

Husky uses the term "cash flow from operations," 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. Husky's determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash, which include accretion, depletion, depreciation, amortization and impairment, 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.

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

($ millions)	2014	2013	2012
GAAP cash flow – operating activities	**5,585**	4,645	5,193
Settlement of asset retirement obligations	**167**	142	123
Income taxes paid	**661**	433	575
Interest received	**(7)**	(19)	(34)
Change in non-cash working capital	**(871)**	21	(847)
Non-GAAP cash flow from operations	**5,535**	5,222	5,010
Cash flow from operations – basic	**5.63**	5.31	5.13
Cash flow from operations – diluted	**5.62**	5.31	5.13

Disclosure of Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. 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.

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 23, 2015. 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 should be read in conjunction with the 2014 Consolidated Financial Statements and related notes. The readers are also encouraged to refer to Husky's interim reports filed for 2014, which contain the Management's Discussion and Analysis and Consolidated Financial Statements, and Husky's 2014 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, 2014 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, 2014 and 2013 and Husky's financial position as at December 31, 2014 and at December 31, 2013. 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;
- Prices are presented before the effect of hedging;
- Light crude oil is 31° API and above;
- Medium crude oil is 22° API and above but below 31° API;
- Heavy crude oil is above 10° API but below 22° API; and
- Bitumen is solid or semi-solid with a viscosity greater than 10,000 centipoise at original temperature in the deposit and atmospheric pressure.

Terms

Brent Crude Oil	*Brent Crude is a major trading classification of sweet light crude oil that serves as a major benchmark price for purchases of oil worldwide. Brent Crude is sourced from the North Sea and is dated less than 15 days prior to loading for delivery*
Capital Employed	*Long-term debt including current portion, commercial paper 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 plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, exploration and evaluation expenses, deferred income taxes, foreign exchange, stock-based compensation, gains or losses on sale of property, plant and equipment and other non-cash items*
Corporate Reinvestment Ratio	*Equal to capital expenditures plus exploration and evaluation expenses, capitalized interest and settlements of asset retirement obligations less proceeds from asset disposals divided by cash flow from operations*
Debt to Capital Employed	*Long-term debt, long-term debt due within one year and commercial paper divided by capital employed*
Debt to Cash Flow	*Long-term debt, long-term debt due within one year and commercial paper divided by cash flow from operations*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
Feedstock	*Raw materials that are processed into petroleum products*
Front-End Engineering Design ("FEED")	*Preliminary engineering and design planning which, among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
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*
Interest Coverage on Long-term Debt	*Interest coverage on long-term debt on a net earnings basis is equal to net earnings before finance expense on long-term debt and income taxes divided by finance expense on long-term debt and capitalized interest. Interest coverage on long-term debt on a cash flow basis is equal to cash flow – operating activities before finance expense on long-term debt and current income taxes divided by finance expense on long-term debt and capitalized interest. Long-term debt includes the current portion of long-term debt.*
Interest Coverage on Total Debt	*Interest coverage on total debt on a net earnings basis is equal to net earnings before finance expense on total debt and income taxes divided by finance expense on total debt and capitalized interest. Interest coverage on total debt on a cash flow basis is equal to cash flow – operating activities before finance expense on total debt and current income taxes divided by finance expense on total debt and capitalized interest. Total debt includes long-term debt, the current portion of long-term debt and commercial paper.*
Interest Coverage Ratio	*A calculation of a company's ability to meet its interest payment obligation. It is equal to net earnings or cash flow – operating activities before finance expense divided by finance expense and capitalized interest*
Net Operating Earnings	*Net earnings before property, plant and equipment impairment charges and inventory write-downs*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Operating Netback	*Net revenues after deduction of operating costs, transportation and royalty payments*
Return on Capital Employed	*Non-GAAP measure used to assist in analyzing shareholder value and return on average capital. Net earnings plus after tax interest expense divided by the two-year average capital employed*
Return on Capital in Use	*Non-GAAP measure used to assist in analyzing shareholder value and return on capital. Net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not generating cash flows*
Return on Equity	*Non-GAAP measure used to assist in analyzing shareholder value. Net earnings divided by the two-year average shareholders' equity*
Seismic	*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	*Shares, retained earnings and other reserves*
Total Debt	*Long-term debt including long-term debt due within one year, commercial paper and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

"Proved reserves" are those 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" are those reserves that are expected to be recovered from existing wells and installed facilities or , if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production.

"Proved undeveloped reserves" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable, possible) to which they are assigned. 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" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Abbreviations

3-D	*three-dimensional*
ARO	*asset retirement obligations*
bbls	*barrels*
bbls/day	*barrels per day*
bcf	*billion cubic feet*
boe	*barrels of oil equivalent*
boe/day	*barrels of oil equivalent per day*
bps	*basis points*
CGUs	*cash generating units*
CHOPS	*cold heavy oil production with sand*
CSA	*Canadian Securities Administrators*
DD&A	*depletion, depreciation and amortization*
EOR	*enhanced oil recovery*
EPA	*Environmental Protection Agency*
FIFO	*first in first out*
FPSO	*floating production, storage and offloading vessel*
FVTPL	*fair value through profit or loss*
GAAP	*Generally Accepted Accounting Principles*
GHG	*greenhouse gas*
GJ	*gigajoule*
IASB	*International Accounting Standards Board*
IFRIC	*International Financial Reporting Interpretations Committee Interpretation*
IFRS	*International Financial Reporting Standards*
LIFO	*last in first out*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mcf	*thousand cubic feet*
mcfge	*thousand cubic feet of gas equivalent*
MD&A	*Management's Discussion and Analysis*
mmbbls	*million barrels*
mmboe	*million barrels of oil equivalent*
mmbtu	*million British Thermal Units*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
NGL	*natural gas liquids*
NIT	*NOVA Inventory Transfer*
NYMEX	*New York Mercantile Exchange*
OPEC	*Organization of Petroleum Exporting Countries*
PHMSA	*Pipeline and Hazardous Materials Safety Administration*
PSC	*production sharing contract*
S&P	*Standard and Poor's*
SAGD	*Steam assisted gravity drainage*
SEC	*U.S. Securities and Exchange Commission*
SEDAR	*System for Electronic Document Analysis and Retrieval*
TSX	*Toronto Stock Exchange*
WI	*working interest*
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, 2014, 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, 2014, 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, 2014, 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 management's assessment of 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, 2014, that have materially affected or are reasonably likely to materially affect its internal control over financial reporting.

12.0 Selected Quarterly Financial & Operating Information

Segmented Operational Information

	2014				2013			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream								
Daily production, before royalties								
Light crude oil & NGL *(mbbls/day)*	89.8	76.9	77.9	90.4	78.3	77.7	82.3	86.4
Medium crude oil *(mbbls/day)*	19.7	20.2	22.4	23.7	23.4	23.2	22.9	23.0
Heavy crude oil *(mbbls/day)*	77.5	76.1	78.1	75.5	75.9	75.3	72.3	74.4
Bitumen *(mbbls/day)*	55.7	56.2	54.6	52.0	46.7	48.0	48.3	47.9
Total crude oil production *(mboe/day)*	242.7	229.4	233.0	241.6	224.3	224.2	225.8	231.7
Natural gas *(mmcf/day)*	701.5	670.3	603.6	505.9	503.8	505.5	504.7	537.3
Total production *(mboe/day)*	359.6	341.1	333.6	325.9	308.3	308.5	309.9	321.3
Average sales prices								
Light crude oil & NGL *($/bbl)*	71.77	96.47	110.29	110.48	101.95	107.83	96.22	103.59
Medium crude oil *($/bbl)*	64.60	83.35	89.67	83.47	67.86	93.67	73.62	61.74
Heavy crude oil *($/bbl)*	58.86	77.29	79.45	72.18	56.51	84.45	66.77	45.67
Bitumen *($/bbl)*	58.21	75.50	77.87	70.78	54.08	83.17	65.71	43.12
Natural gas *($/mcf)*	6.37	6.11	6.42	4.82	3.30	2.66	3.72	3.08
Operating costs *($/boe)*	15.07	16.61	15.68	17.21	16.31	17.20	16.79	15.29
Operating netbacks[(1)]								
Lloydminster – Thermal Oil *($/boe)*[(2)]	43.73	58.92	61.67	53.32	38.76	67.57	50.57	32.55
Lloydminster – Non-Thermal Oil *($/boe)*[(2)]	30.54	45.50	48.81	40.29	27.32	49.69	37.70	19.06
Oil Sands – Bitumen *($/boe)*[(2)]	27.75	43.68	45.29	35.99	21.45	52.68	35.30	12.32
Western Canada – Crude Oil *($/boe)*[(2)]	31.84	44.04	49.42	45.39	37.60	54.41	39.24	31.17
Western Canada – Natural gas *($/mcf)*[(3)]	2.16	2.29	2.90	3.40	1.93	1.21	1.81	1.68
Atlantic – Light Oil *($/boe)*[(2)]	55.50	65.78	84.47	83.74	83.90	87.14	78.66	89.37
Asia Pacific – Light Oil & NGL *($/boe)*[(2)]	55.10	67.21	76.56	78.41	70.35	74.60	62.52	73.46
Total *($/boe)*[(2)]	34.84	43.05	48.70	44.81	34.29	46.15	38.32	31.78
Net wells drilled[(4)]								
Exploration Oil	–	1	1	43	7	8	–	9
Gas	1	1	1	2	5	–	4	5
Dry	3	–	–	–	–	–	–	–
	4	2	2	45	12	8	4	14
Development Oil	93	132	7	187	201	249	30	229
Gas	8	25	24	11	12	12	2	15
Dry	2	1	–	–	–	–	–	–
	103	158	31	198	213	261	32	244
Total net wells drilled	107	160	33	243	225	269	36	258
Success ratio *(percent)*	95	99	100	100	100	100	100	100
Upgrader								
Synthetic crude oil sales *(mbbls/day)*	54.8	56.1	48.2	56.1	52.0	37.5	56.7	56.1
Upgrading differential *($/bbl)*	14.96	19.98	25.27	38.51	26.63	23.59	27.39	38.51
Canadian Refined Products								
Fuel sales *(million litres/day)*	8.1	8.5	7.5	7.7	7.9	8.3	8.0	8.2
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	29.0	28.3	29.0	29.0	28.4	28.7	18.7	28.3
Prince George refinery *(mbbls/day)*	11.7	11.7	11.3	12.0	12.0	11.8	6.3	11.2
Refinery utilization *(percent)*	99	98	97	99	96	61	100	100
U.S. Refining and Marketing								
Refinery throughput								
Lima refinery *(mbbls/day)*	162.8	156.0	135.9	110.5	151.8	148.8	149.8	146.9
BP-Husky Toledo refinery *(mbbls/day)*	63.8	64.2	59.4	65.5	66.3	59.1	68.1	66.3

(1) *Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.*
(2) *Includes associated co-products converted to boe.*
(3) *Includes associated co-products converted to mcfge.*
(4) *Includes Western Canada, Heavy Oil and Oil Sands.*

Segmented Capital Expenditures[1]

	2014				2013			
($ millions)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Upstream								
Exploration								
Western Canada	**37**	**42**	**56**	**74**	80	99	64	110
Oil Sands	–	–	–	**5**	–	–	–	–
Atlantic Region	**62**	**12**	**15**	**7**	55	102	39	5
Asia Pacific Region	**5**	**2**	–	**9**	14	1	–	6
	104	**56**	**71**	**95**	149	202	103	121
Development								
Western Canada	**559**	**456**	**468**	**591**	744	505	267	513
Oil Sands	**225**	**203**	**147**	**133**	111	146	137	158
Atlantic Region	**205**	**201**	**90**	**154**	34	148	116	139
Asia Pacific Region	**12**	**139**	**80**	**149**	215	133	156	129
	1,001	**999**	**785**	**1,027**	1,104	932	676	939
Acquisitions								
Western Canada	**31**	**15**	**3**	**2**	27	1	4	6
Total Exploration and Production	**1,136**	**1,070**	**859**	**1,124**	1,280	1,135	783	1,066
Infrastructure and Marketing	**98**	**59**	**30**	**24**	41	27	17	11
Total Upstream	**1,234**	**1,129**	**889**	**1,148**	1,321	1,162	800	1,077
Downstream								
Upgrader	**14**	**23**	**9**	**4**	43	129	20	13
Canadian Refined Products	**31**	**25**	**19**	**11**	32	24	41	12
U.S. Refining and Marketing	**118**	**89**	**92**	**75**	99	52	42	27
	163	**137**	**120**	**90**	174	205	103	52
Corporate	**22**	**13**	**47**	**31**	42	40	29	23
	1,419	**1,279**	**1,056**	**1,269**	1,537	1,407	932	1,152

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

Segmented Financial Information

	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 and operating 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 tax	**(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

	Upstream								Downstream			
	Exploration and Production[1]				Infrastructure and Marketing				Upgrading			
2013 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	1,734	2,111	1,843	1,645	457	646	664	367	484	437	573	529
Royalties	(215)	(237)	(208)	(204)	–	–	–	–	–	–	–	–
Marketing and other	–	–	–	–	76	17	57	162	–	–	–	–
Revenues, net of royalties	1,519	1,874	1,635	1,441	533	663	721	529	484	437	573	529
Expenses												
Purchases of crude oil and products	29	17	20	25	438	609	622	335	362	341	388	287
Production and operating expenses	502	528	503	483	2	3	9	7	45	39	40	37
Selling, general and administrative expenses	44	60	85	51	3	4	3	2	2	1	2	2
Depletion, depreciation, amortization and impairment	791	594	568	562	2	6	6	6	25	24	23	24
Exploration and evaluation expenses	28	56	74	88	–	–	–	–	–	–	–	–
Other – net	(63)	11	(24)	41	(2)	–	(1)	–	(23)	(2)	(1)	(1)
Earnings from operating activities	188	608	409	191	90	41	82	179	73	34	121	180
Share of equity investment	(5)	1	(6)	–	–	–	–	–	–	–	–	–
Net foreign exchange gains (losses)	1	(1)	–	–	–	–	–	–	–	–	–	–
Finance income	2	–	2	–	–	–	–	–	–	–	–	–
Finance expenses	(27)	(28)	(23)	(29)	–	–	–	–	(1)	(2)	(2)	(2)
	(24)	(29)	(21)	(29)	–	–	–	–	(1)	(2)	(2)	(2)
Earnings (loss) before income taxes	159	580	382	162	90	41	82	179	72	32	119	178
Provisions for (recovery of) income taxes												
Current	54	86	(30)	52	43	(3)	90	92	6	6	1	6
Deferred	(13)	64	129	(11)	(20)	14	(69)	(47)	13	2	30	40
	41	150	99	41	23	11	21	45	19	8	31	46
Net earnings (loss)	118	430	283	121	67	30	61	134	53	24	88	132
Capital expenditures[3]	1,280	1,135	783	1,066	41	27	17	11	43	129	20	13
Total assets	24,653	24,058	23,603	23,250	1,670	1,766	1,554	1,476	1,355	1,214	1,217	1,214

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to the 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
1,288	993	613	843	2,690	2,405	2,922	2,711	(597)	(573)	(466)	(450)	6,056	6,019	6,149	5,645
–	–	–	–	–	–	–	–	–	–	–	–	(215)	(237)	(208)	(204)
–	–	–	–	–	–	–	–	–	–	–	–	76	17	57	162
1,288	993	613	843	2,690	2,405	2,922	2,711	(597)	(573)	(466)	(450)	5,917	5,799	5,998	5,603
1,129	875	468	662	2,543	2,174	2,504	2,325	(597)	(573)	(466)	(450)	3,904	3,443	3,536	3,184
59	57	57	54	102	109	107	102	–	–	–	–	710	736	716	683
6	9	7	4	–	–	1	3	90	55	20	52	145	129	118	114
23	23	22	22	60	58	58	57	17	13	11	10	918	718	688	681
–	–	–	–	–	–	–	–	–	–	–	–	28	56	74	88
1	(3)	(2)	(1)	–	(1)	1	–	–	(8)	5	(14)	(87)	(3)	(22)	25
70	32	61	102	(15)	65	251	224	(107)	(60)	(36)	(48)	299	720	888	828
–	–	–	–	–	–	–	–	–	–	–	–	(5)	1	(6)	–
–	–	–	–	–	–	–	–	12	7	10	(8)	13	6	10	(8)
–	–	–	–	–	–	–	–	13	11	12	11	15	11	14	11
(1)	(1)	(2)	(1)	(1)	(1)	–	(1)	(4)	(10)	(13)	(20)	(34)	(42)	(40)	(53)
(1)	(1)	(2)	(1)	(1)	(1)	–	(1)	21	8	9	(17)	(6)	(25)	(16)	(50)
69	31	59	101	(16)	64	251	223	(86)	(52)	(27)	(65)	288	696	866	778
11	17	7	30	(43)	(25)	44	42	22	33	62	(14)	93	114	174	208
6	(9)	8	(4)	38	47	44	36	(6)	(48)	(55)	21	18	70	87	35
17	8	15	26	(5)	22	88	78	16	(15)	7	7	111	184	261	243
52	23	44	75	(11)	42	163	145	(102)	(37)	(34)	(72)	177	512	605	535
32	24	41	12	99	52	42	27	42	40	29	23	1,537	1,407	932	1,152
1,788	1,704	1,656	1,714	5,537	5,665	5,525	5,397	1,901	2,193	2,439	2,468	36,904	36,600	35,994	35,519

Management's Report

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

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

The Company maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that the Company's internal control over financial reporting was effective as of December 31, 2014. The system of internal controls is further supported by an internal audit function.

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

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

Asim Ghosh

President & Chief Executive Officer

Darren Andruko

Acting Chief Financial Officer

Calgary, Canada

February 23, 2015

Independent Auditors' Report

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

We have audited the accompanying consolidated financial statements of Husky Energy Inc., which comprise the consolidated balance sheets as at December 31, 2014 and December 31, 2013, the consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Husky Energy Inc. as at December 31, 2014 and December 31, 2013, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

KPMG LLP

KPMG LLP

Chartered Accountants

Calgary, Canada

February 23, 2015

Consolidated Financial Statements

Consolidated Balance Sheets

(millions of Canadian dollars)	**December 31, 2014**	December 31, 2013
Assets		
Current assets		
Cash and cash equivalents *(note 9)*	**1,267**	1,097
Accounts receivable *(notes 4, 22)*	**1,324**	1,458
Income taxes receivable	**353**	461
Inventories *(note 5)*	**1,385**	1,812
Prepaid expenses	**166**	89
	4,495	4,917
Exploration and evaluation assets *(note 6)*	**1,149**	1,144
Property, plant and equipment, net *(note 7)*	**31,987**	29,750
Goodwill *(note 10)*	**746**	698
Contribution receivable *(note 8)*	**–**	136
Investment in joint ventures *(note 8)*	**237**	153
Other assets	**234**	106
Total Assets	**38,848**	36,904
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities *(note 12)*	**2,989**	3,155
Asset retirement obligations *(note 16)*	**97**	210
Short-term debt *(note 13)*	**895**	–
Contribution payable due within one year *(notes 8, 26)*	**1,528**	–
Long-term debt due within one year *(note 13)*	**300**	798
	5,809	4,163
Long-term debt *(note 13)*	**4,097**	3,321
Other long-term liabilities *(note15)*	**585**	271
Contribution payable *(notes 8, 22, 26)*	**–**	1,421
Deferred tax liabilities *(note 17)*	**4,814**	4,942
Asset retirement obligations *(note 16)*	**2,968**	2,708
Commitments and contingencies *(note 20)*		
Total Liabilities	**18,273**	16,826
Shareholders' equity		
Common shares *(note 18)*	**6,986**	6,974
Preferred shares *(note 18)*	**534**	291
Retained earnings	**12,666**	12,615
Other reserves	**389**	198
Total Shareholders' Equity	**20,575**	20,078
Total Liabilities and Shareholders' Equity	**38,848**	36,904

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

On behalf of the Board:

Asim Ghosh
Director

William Shurniak
Director

Consolidated Statements of Income

(millions of Canadian dollars, except share data)	Year ended December 31, 2014	2013
Gross revenues	**25,052**	23,869
Royalties	**(1,030)**	(864)
Marketing and other	**70**	312
Revenues, net of royalties	**24,092**	23,317
Expenses		
Purchases of crude oil and products	**14,409**	14,067
Production and operating expenses	**3,119**	2,845
Selling, general and administrative expenses	**462**	506
Depletion, depreciation, amortization and impairment *(note 7)*	**4,010**	3,005
Exploration and evaluation expenses *(note 6)*	**214**	246
Other – net	**(56)**	(87)
	22,158	20,582
Earnings from operating activities	**1,934**	2,735
Share of equity investment *(note 8)*	**(6)**	(10)
Financial items *(note 14)*		
Net foreign exchange gains	**81**	21
Finance income	**8**	51
Finance expenses	**(233)**	(169)
	(144)	(97)
Earnings before income taxes	**1,784**	2,628
Provisions for (recovery of) income taxes *(note 17)*		
Current	**717**	589
Deferred	**(191)**	210
	526	799
Net earnings	**1,258**	1,829
Earnings per share *(note 18)*		
Basic	**1.26**	1.85
Diluted	**1.20**	1.85
Weighted average number of common shares outstanding *(note 18)*		
Basic *(millions)*	**983.6**	983.0
Diluted *(millions)*	**985.3**	983.6

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

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars)	Year ended December 31, 2014	2013
Net earnings	**1,258**	1,829
Other comprehensive income (loss)		
Items that will not be reclassified into earnings, net of tax:		
Remeasurements of pension plans, net of tax *(note 19)*	**(14)**	20
Items that may be reclassified into earnings, net of tax:		
Derivatives designated as cash flow hedges *(note 22)*	**(14)**	36
Exchange differences on translation of foreign operations	**465**	361
Hedge of net investment *(note 22)*	**(260)**	(180)
Other comprehensive income	**177**	237
Comprehensive income	**1,435**	2,066

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

Consolidated Statements of Changes in Shareholders' Equity

(millions of Canadian dollars)	Common Shares	Preferred Shares	Retained Earnings	Other Reserves: Foreign Currency Translation	Other Reserves: Hedging	Total Shareholders' Equity
	Attributable to Equity Holders					
Balance as at December 31, 2012	6,939	291	11,950	(20)	1	19,161
Net earnings	–	–	1,829	–	–	1,829
Other comprehensive income (loss)						
Remeasurements of pension plans (net of tax of $7 million) *(note 19)*	–	–	20	–	–	20
Derivatives designated as cash flow hedges (net of tax of $13 million) *(note 22)*	–	–	–	–	36	36
Exchange differences on translation of foreign operations (net of tax of $58 million)	–	–	–	361	–	361
Hedge of net investment (net of tax of $27 million) *(note 22)*	–	–	–	(180)	–	(180)
Total comprehensive income (loss)	–	–	1,849	181	36	2,066
Transactions with owners recognized directly in equity:						
Stock dividends paid *(note 18)*	8	–	–	–	–	8
Stock options exercised *(note 18)*	27	–	–	–	–	27
Dividends declared on common shares *(note 18)*	–	–	(1,180)	–	–	(1,180)
Dividends declared on preferred shares *(note 18)*	–	–	(13)	–	–	(13)
Change in accounting policy	–	–	9	–	–	9
Balance as at December 31, 2013	6,974	291	12,615	161	37	20,078
Net earnings	**–**	**–**	**1,258**	**–**	**–**	**1,258**
Other comprehensive income (loss)						
Remeasurements of pension plans (net of tax of $4 million) *(note 19)*	**–**	**–**	**(14)**	**–**	**–**	**(14)**
Derivatives designated as cash flow hedges (net of tax of $5 million) *(note 22)*	**–**	**–**	**–**	**–**	**(14)**	**(14)**
Exchange differences on translation of foreign operations (net of tax of $109 million)	**–**	**–**	**–**	**465**	**–**	**465**
Hedge of net investment (net of tax of $39 million) *(note 22)*	**–**	**–**	**–**	**(260)**	**–**	**(260)**
Total comprehensive income (loss)	**–**	**–**	**1,244**	**205**	**(14)**	**1,435**
Transactions with owners recognized directly in equity:						
Preferred shares issuance *(note 18)*	**–**	**250**	**–**	**–**	**–**	**250**
Share issue costs *(note 18)*	**–**	**(7)**	**–**	**–**	**–**	**(7)**
Stock dividends paid *(note 18)*	**11**	**–**	**–**	**–**	**–**	**11**
Stock options exercised *(note18)*	**1**	**–**	**–**	**–**	**–**	**1**
Dividends declared on common shares *(note 18)*	**–**	**–**	**(1,180)**	**–**	**–**	**(1,180)**
Dividends declared on preferred shares *(note 18)*	**–**	**–**	**(13)**	**–**	**–**	**(13)**
Balance as at December 31, 2014	**6,986**	**534**	**12,666**	**366**	**23**	**20,575**

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

Consolidated Statements of Cash Flows

(millions of Canadian dollars)	Year ended December 31, 2014	2013
Operating activities		
Net earnings	**1,258**	1,829
Items not affecting cash:		
Accretion *(note 14)*	**134**	125
Depletion, depreciation, amortization and impairment *(note 7)*	**4,010**	3,005
Inventory write-down to net realizable value *(note 5)*	**211**	–
Exploration and evaluation expenses *(note 6)*	**6**	10
Deferred income taxes *(note 17)*	**(191)**	210
Foreign exchange	**71**	11
Stock-based compensation *(note 18)*	**(17)**	105
Gain on sale of assets	**(36)**	(27)
Other	**89**	(46)
Settlement of asset retirement obligations *(note 16)*	**(167)**	(142)
Income taxes paid	**(661)**	(433)
Interest received	**7**	19
Change in non-cash working capital *(note 9)*	**871**	(21)
Cash flow – operating activities	**5,585**	4,645
Financing activities		
Long-term debt issuance *(note 13)*	**829**	–
Long-term debt repayment *(note 13)*	**(814)**	–
Settlement of interest rate swaps	**33**	–
Commercial paper issuance *(note 13)*	**895**	–
Proceeds from preferred share issuance, net of share issue costs *(note 18)*	**243**	–
Proceeds from exercise of stock options *(note 18)*	**1**	27
Dividends on common shares *(note 18)*	**(1,169)**	(1,171)
Dividends on preferred shares *(note 18)*	**(13)**	(13)
Interest paid	**(284)**	(243)
Contribution receivable receipt *(note 8)*	**143**	520
Other	**97**	53
Change in non-cash working capital *(note 9)*	**33**	(19)
Cash flow – financing activities	**(6)**	(846)
Investing activities		
Capital expenditures	**(5,023)**	(5,028)
Proceeds from asset sales	**66**	37
Contribution payable payment *(note 8)*	**(106)**	(87)
Other	**(27)**	(8)
Change in non-cash working capital *(note 9)*	**(333)**	364
Cash flow – investing activities	**(5,423)**	(4,722)
Increase (decrease) in cash and cash equivalents	**156**	(923)
Effect of exchange rates on cash and cash equivalents	**14**	(5)
Cash and cash equivalents at beginning of year	**1,097**	2,025
Cash and cash equivalents at end of year	**1,267**	1,097

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

Notes to the Consolidated Financial Statements

Note 1 Description of Business and Segmented Disclosures

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

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

Upstream includes exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, natural gas liquids, 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). The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada, offshore China and offshore Indonesia.

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil (Upgrading), refining in Canada of crude oil and 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).

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2014**	2013	**2014**	2013	**2014**	2013
Gross revenues	**8,634**	7,333	**2,202**	2,134	**10,836**	9,467
Royalties	**(1,030)**	(864)	–	–	**(1,030)**	(864)
Marketing and other	–	–	**70**	312	**70**	312
Revenues, net of royalties	**7,604**	6,469	**2,272**	2,446	**9,876**	8,915
Expenses						
Purchases of crude oil and products	**96**	91	**2,056**	2,004	**2,152**	2,095
Production and operating expenses	**2,172**	2,016	**32**	21	**2,204**	2,037
Selling, general and administrative expenses	**253**	240	**8**	12	**261**	252
Depletion, depreciation, amortization and impairment	**3,434**	2,515	**25**	20	**3,459**	2,535
Exploration and evaluation expenses	**214**	246	–	–	**214**	246
Other – net	**(60)**	(35)	**(2)**	(3)	**(62)**	(38)
Earnings (loss) from operating activities	**1,495**	1,396	**153**	392	**1,648**	1,788
Share of equity investment	**(6)**	(10)	–	–	**(6)**	(10)
Financial items						
Net foreign exchange gains	–	–	–	–	–	–
Finance income	**(1)**	4	–	–	**(1)**	4
Finance expenses	**(151)**	(107)	–	–	**(151)**	(107)
Earnings (loss) before income taxes	**1,337**	1,283	**153**	392	**1,490**	1,675
Provisions for (recovery of) income taxes						
Current	**386**	162	**99**	222	**485**	384
Deferred	**(41)**	169	**(60)**	(122)	**(101)**	47
Total income tax provision (recovery)	**345**	331	**39**	100	**384**	431
Net earnings (loss)	**992**	952	**114**	292	**1,106**	1,244
Intersegment revenues	**2,229**	1,714	–	–	**2,229**	1,714
Other non-cash items						
Gain (loss) on sale of assets	**39**	19	–	–	**39**	19

(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

Downstream								Corporate and Eliminations[(2)]		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2014	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
2,212	2,023	**4,020**	3,737	**10,663**	10,728	**16,895**	16,488	**(2,679)**	(2,086)	**25,052**	23,869
–	–	**–**	–	**–**	–	**–**	–	**–**	–	**(1,030)**	(864)
–	–	**–**	–	**–**	–	**–**	–	**–**	–	**70**	312
2,212	2,023	**4,020**	3,737	**10,663**	10,728	**16,895**	16,488	**(2,679)**	(2,086)	**24,092**	23,317
1,676	1,378	**3,319**	3,134	**9,941**	9,546	**14,936**	14,058	**(2,679)**	(2,086)	**14,409**	14,067
180	161	**263**	227	**472**	420	**915**	808	**–**	–	**3,119**	2,845
9	7	**44**	26	**9**	4	**62**	37	**139**	217	**462**	506
108	96	**102**	90	**268**	233	**478**	419	**73**	51	**4,010**	3,005
–	–	**–**	–	**–**	–	**–**	–	**–**	–	**214**	246
11	(27)	**–**	(5)	**–**	–	**11**	(32)	**(5)**	(17)	**(56)**	(87)
228	408	**292**	265	**(27)**	525	**493**	1,198	**(207)**	(251)	**1,934**	2,735
–	–	**–**	–	**–**	–	**–**	–	**–**	–	**(6)**	(10)
–	–	**–**	–	**–**	–	**–**	–	**81**	21	**81**	21
–	–	**–**	–	**–**	–	**–**	–	**9**	47	**8**	51
(1)	(7)	**(5)**	(5)	**(3)**	(3)	**(9)**	(15)	**(73)**	(47)	**(233)**	(169)
227	401	**287**	260	**(30)**	522	**484**	1,183	**(190)**	(230)	**1,784**	2,628
47	19	**80**	65	**1**	18	**128**	102	**104**	103	**717**	589
12	85	**(7)**	1	**(12)**	165	**(7)**	251	**(83)**	(88)	**(191)**	210
59	104	**73**	66	**(11)**	183	**121**	353	**21**	15	**526**	799
168	297	**214**	194	**(19)**	339	**363**	830	**(211)**	(245)	**1,258**	1,829
249	172	**201**	200	**–**	–	**450**	372	**–**	–	**2,679**	2,086
–	–	**1**	8	**(4)**	–	**(3)**	8	**–**	–	**36**	27

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2014**	2013	**2014**	2013	**2014**	2013
Expenditures on exploration and evaluation assets[2]	**326**	575	–	–	**326**	575
Expenditures on property, plant and equipment[2]	**3,863**	3,689	**211**	96	**4,074**	3,785
As at December 31,						
Exploration and evaluation assets	**1,149**	1,144	–	–	**1,149**	1,144
Developing and producing assets at cost	**47,969**	43,128	–	–	**47,969**	43,128
Accumulated depletion, depreciation, amortization and impairment	**(23,686)**	(20,439)	–	–	**(23,686)**	(20,439)
Other property, plant and equipment at cost	**48**	–	**1,250**	1,033	**1,298**	1,033
Accumulated depletion, depreciation and amortization	**(34)**	–	**(495)**	(448)	**(529)**	(448)
Total exploration and evaluation assets and property, plant and equipment, net	**25,446**	23,833	**755**	585	**26,201**	24,418
Total assets	**26,035**	24,653	**1,969**	1,670	**28,004**	26,323

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

(2) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the year. Includes assets acquired through acquisitions.*

Geographical Financial Information

($ millions)	Canada	
Year ended December 31,	**2014**	2013
Gross revenues[1]	**12,484**	11,926
Royalties	**(964)**	(794)
Marketing and other	**70**	316
Revenue, net of royalties	**11,590**	11,448
As at December 31,		
Exploration and evaluation assets	**876**	855
Property, plant and equipment, net	**23,900**	22,928
Goodwill	**160**	160
Total non-current assets	**25,129**	24,152

(1) *Based on the geographical location of legal entities.*

Upgrading 2014	Upgrading 2013	Canadian Refined Products 2014	Canadian Refined Products 2013	U.S. Refining and Marketing 2014	U.S. Refining and Marketing 2013	Downstream Total 2014	Downstream Total 2013	Corporate and Eliminations 2014	Corporate and Eliminations 2013	Total 2014	Total 2013
–	–	–	–	–	–	–	–	–	–	**326**	575
50	205	**86**	109	**374**	220	**510**	534	**113**	134	**4,697**	4,453
–	–	–	–	–	–	–	–	–	–	**1,149**	1,144
–	–	–	–	–	–	–	–	–	–	**47,969**	43,128
–	–	–	–	–	–	–	–	–	–	**(23,686)**	(20,439)
2,274	2,221	**2,433**	2,332	**5,874**	5,020	**10,581**	9,573	**889**	775	**12,768**	11,381
(1,154)	(1,046)	**(1,144)**	(1,046)	**(1,641)**	(1,257)	**(3,939)**	(3,349)	**(596)**	(523)	**(5,064)**	(4,320)
1,120	1,175	**1,289**	1,286	**4,233**	3,763	**6,642**	6,224	**293**	252	**33,136**	30,894
1,243	1,355	**1,676**	1,788	**5,788**	5,537	**8,707**	8,680	**2,137**	1,901	**38,848**	36,904

United States 2014	United States 2013	Other International 2014	Other International 2013	Total 2014	Total 2013
11,725	11,663	**843**	280	**25,052**	23,869
–	–	**(66)**	(70)	**(1,030)**	(864)
–	(4)	–	–	**70**	312
11,725	11,659	**777**	210	**24,092**	23,317
–	–	**273**	289	**1,149**	1,144
4,233	3,764	**3,854**	3,058	**31,987**	29,750
586	538	–	–	**746**	698
4,838	4,320	**4,386**	3,515	**34,353**	31,987

Note 2 Basis of Presentation

a) Basis of Measurement and Statement of Compliance

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

These consolidated financial statements were approved and signed by the Chair of the Audit Committee and the Chief Executive Officer on February 23, 2015 having been duly authorized to do so by the Board of Directors.

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

b) Principles of Consolidation

The consolidated financial statements include the accounts of Husky Energy Inc. and its subsidiaries. Subsidiaries are defined as any entities, including unincorporated entities such as partnerships, for which the Company has the power to govern their financial and operating policies to obtain benefits from their activities. Substantially all of the Company's Upstream activities are conducted jointly with third parties, and accordingly, the accounts reflect the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows from these activities. Intercompany balances, net earnings and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements.

c) Use of Estimates, Judgments and Assumptions

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

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

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

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

d) Functional and Presentation Currency

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

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

Note 3 Significant Accounting Policies

a) Cash and Cash Equivalents

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

b) Inventories

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

c) Precious Metals

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

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

i) Cost

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

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

ii) Exploration and evaluation costs

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

The application of the Company's accounting policy for exploration and evaluation costs requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Judgments may change as new information becomes available.

iii) Development costs

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

iv) Other property, plant and equipment

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

v) Depletion, depreciation and amortization

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

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

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

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

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

Any gain or loss arising on disposal of exploration and evaluation assets or property, plant and equipment is included in other – net in the consolidated statements of income in the period of disposal.

vi) Finance Leases

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

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

e) Joint Arrangements

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

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

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

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 of assets and its involvement and responsibility for settling liabilities associated with the arrangement.

f) Investments in Associates

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

g) Business Combinations

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

h) Goodwill

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

i) Impairment of Non-Financial Assets

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

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 any indication of impairment exists, an estimate of the asset's recoverable amount is calculated as the higher of the fair value less costs to sell ("FVLCS") and the asset's value in use ("VIU") for an individual asset or CGU. If the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, the asset is tested as part of a CGU, which is the smallest identifiable group of assets, liabilities and associated goodwill that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. Determination of the Company's CGUs is subject to management's judgment.

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

VIU is the net present value of the estimated future cash flows expected to arise from the continued use of the asset in its present form and its eventual disposal. VIU is determined by applying assumptions specific to the Company's continued use and can only take into account sanctioned future development costs. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, marketing supply and demand, product margins 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, which are risk-weighted utilizing geological, production, recovery, market price and economic projections. Either the cash flow estimates or the discount rate is risk-adjusted to reflect local conditions as appropriate.

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

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

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

j) Asset Retirement Obligations ("ARO")

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

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

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

k) Legal and Other Contingent Matters

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

l) Share Capital

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

m) Financial Instruments

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

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

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

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

n) Derivative Instruments and Hedging Activities

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

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

i) Derivative Instruments

All derivative instruments, other than those designated as effective hedging instruments, are classified as held for trading and are recorded at fair value. Gains and losses on these instruments are recorded in the consolidated statements of income in the period they occur.

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

ii) Embedded Derivatives

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

iii) Hedging Activities

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

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

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

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

o) Comprehensive Income

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

p) Impairment of Financial Assets

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

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

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

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

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

q) Pensions and Other Post-employment Benefits

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

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

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

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

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

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

r) Income Taxes

Current income taxes are recognized in net earnings, except when they relate to equity, which includes OCI, and are recognized directly in equity. Management periodically evaluates positions taken in the Company's tax returns with respect to situations in which applicable tax regulations are subject to interpretation and reassessment and establishes provisions where appropriate.

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

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

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

s) Asset Exchange Transactions

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

t) Revenue Recognition

Revenue from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured. Revenues associated with the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recognized when the title passes to the customer. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

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

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

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

u) Foreign Currency

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

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

v) Share-based Payments

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

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

The Company's Performance Share Unit Plan provides a time-vested award to certain officers and employees of the Company. Performance Share Units ("PSU") entitle participants to receive cash based on the Company's share price at the time of vesting. The amount of cash payment is contingent on the Company's total shareholder return relative to a peer group of companies and achieving certain corporate performance targets. A liability for expected cash payments is accrued over the vesting period of the PSUs and is revalued at each reporting date based on the market price of the Company's common shares and the expected vesting percentage. Upon vesting, a cash payment is made to the participants and the outstanding liability is reduced by the payment amount.

w) Earnings per Share

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

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

x) Government Grants

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

y) Recent Accounting Standards

i) 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 adoption of the standard is not expected to have a material impact on the Company's annual consolidated financial statements.

ii) Revenue from Contracts with Customers

In May 2014, the IASB issued IFRS 15, "Revenue from Contracts with Customers" to replace IAS 18 which establishes principles for reporting useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. The standard is effective for the Company for annual periods beginning on January 1, 2017, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the standard on January 1, 2017. The company is assessing the impact of this standard and does not expect it to have a material impact on the Company's annual consolidated financial statements.

z) Change in Accounting Policy

i) Impairment of Assets

The IASB issued amendments to IAS 36, "Impairment of Assets" which was adopted by the Company on January 1, 2014. The amendments require disclosure of information about the recoverable amount of impaired assets. The adoption of this amended standard had no impact on the Company's consolidated financial statements.

ii) Levies

The IASB issued International Financial Reporting Interpretations Committee Interpretation ("IFRIC") 21, "Levies" which was adopted by the Company on January 1, 2014. The IFRIC clarifies that an entity should recognize a liability for a levy when the activity that triggers payment occurs. The adoption of this interpretation had no impact on the Company's consolidated financial statements.

Note 4 Accounts Receivable

Accounts Receivable

($ millions)	**December 31, 2014**	December 31, 2013
Trade receivables	**1,282**	1,383
Allowance for doubtful accounts	**(29)**	(27)
Derivatives due within one year	**53**	22
Other	**18**	80
	1,324	1,458

Note 5 Inventories

Inventories

($ millions)	December 31, 2014	December 31, 2013
Crude oil, natural gas and sulphur [(1)]	**419**	634
Refined petroleum products [(1)]	**522**	608
Trading inventories measured at fair value	**286**	421
Materials, supplies and other	**158**	149
	1,385	1,812

[(1)] *Prior year amounts have been reclassified to conform with current year presentation*

Impairment of inventory to net realizable value for the year ended December 31, 2014 was $211 million (December 31, 2013 – $1 million), as a result of declining market benchmark prices. During 2014, there were no inventory impairment reversals (2013 – nil).

Trading inventories measured at fair value less costs to sell consist of natural gas inventories and crude oil inventories. The fair value measurement incorporates exit commodity prices and adjustments for quality and location. Refer to Note 22.

Note 6 Exploration and Evaluation Costs

Exploration and Evaluation Assets

($ millions)	2014	2013
Beginning of year	**1,144**	773
Additions	**341**	574
Acquisitions	–	1
Transfers to oil and gas properties *(note 7)*	**(352)**	(209)
Expensed exploration expenditures previously capitalized	**(6)**	(10)
Exchange adjustments	**22**	15
End of year	**1,149**	1,144

The following exploration and evaluation expenses for the years ended December 31, 2014 and 2013 relate to activities associated with the exploration for and evaluation of oil and natural gas resources and were recorded in the Upstream segment:

Exploration and Evaluation Expense Summary

($ millions)	2014	2013
Seismic, geological and geophysical	**111**	133
Expensed drilling	**45**	104
Expensed land	**58**	9
	214	246

Note 7 Property, Plant and Equipment

Property, Plant and Equipment

($ millions)	Oil and Gas Properties	Processing, Transportation and Storage	Upgrading	Refining	Retail and Other	Total
Cost						
December 31, 2012	38,781	981	2,006	5,094	2,225	49,087
Additions	3,890	93	206	282	179	4,650
Acquisitions	38	–	–	–	–	38
Transfers from exploration and evaluation *(note 6)*	209	–	–	–	–	209
Transfers between categories	–	–	–	(27)	27	–
Changes in asset retirement obligations	68	17	9	12	35	141
Disposals and derecognition	(66)	(11)	–	(1)	(16)	(94)
Exchange adjustments	161	–	–	316	–	477
December 31, 2013	43,081	1,080	2,221	5,676	2,450	54,508
Additions	**4,274**	**216**	**50**	**413**	**163**	**5,116**
Acquisitions	**123**	–	–	–	–	**123**
Transfers from exploration and evaluation *(note 6)*	**352**	–	–	–	–	**352**
Transfers between categories	**(3)**	**2**	–	**1**	–	–
Changes in asset retirement obligations	**128**	**(2)**	**3**	**15**	**23**	**167**
Disposals and derecognition	**(281)**	–	–	**(13)**	**(4)**	**(298)**
Exchange adjustments	**300**	–	–	**469**	–	**769**
December 31, 2014	**47,974**	**1,296**	**2,274**	**6,561**	**2,632**	**60,737**
Accumulated depletion, depreciation, amortization and impairment						
December 31, 2012	(17,947)	(443)	(950)	(1,260)	(1,133)	(21,733)
Depletion, depreciation, amortization and impairment[1]	(2,501)	(36)	(96)	(255)	(119)	(3,007)
Transfers between categories	–	–	–	12	(12)	–
Disposals and derecognition	55	–	–	1	13	69
Exchange adjustments	(15)	–	–	(72)	–	(87)
December 31, 2013	(20,408)	(479)	(1,046)	(1,574)	(1,251)	(24,758)
Depletion, depreciation, amortization and impairment[1]	**(3,400)**	**(47)**	**(108)**	**(288)**	**(145)**	**(3,988)**
Transfers between categories	**2**	**(1)**	–	**(1)**	–	–
Disposals and derecognition	**176**	–	–	**10**	**2**	**188**
Exchange adjustments	**(57)**	–	–	**(135)**	–	**(192)**
December 31, 2014	**(23,687)**	**(527)**	**(1,154)**	**(1,988)**	**(1,394)**	**(28,750)**
Net book value						
December 31, 2013	22,673	601	1,175	4,102	1,199	29,750
December 31, 2014	**24,287**	**769**	**1,120**	**4,573**	**1,238**	**31,987**

[1] *Depletion, depreciation, amortization and impairment for the year ended December 31, 2014 does not include an amortization recovery of research and development assets of nil (2013 – recovery of $1 million), and an exchange adjustment of $22 million (2013 – $1 million).*

Included in depletion, depreciation, amortization and impairment expense in the fourth quarter of 2014 is a non-cash impairment charge of $838 million (2013 – $275 million) on conventional oil and natural gas assets located in Western Canada in the Upstream segment. The impairment charge, attributed to the Rainbow Development and Northern cash generating units, was the result of declines in estimated short and long-term crude oil and natural gas prices. The recoverable amount was $1,630 million for the Rainbow Development and $131 million for Northern as at December 31, 2014 and was estimated based on value-in-use methodology using estimated discounted cash flows based on proved plus probable reserves and discounted using an average pre-tax discount rate of 8% (2013 – 8%).

Costs of property, plant and equipment, including major development projects, excluded from costs subject to depletion, depreciation and amortization as at December 31, 2014 were $5.7 billion (December 31, 2013 – $7.1 billion) including undeveloped land assets of $115 million as at December 31, 2014 (December 31, 2013 – $408 million).

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

Assets Under Finance Lease

($ millions)	Refining	Oil and Gas Properties	Total
December 31, 2013	29	–	29
December 31, 2014	**27**	**256**	**283**

Note 8 Joint Arrangements

Joint Operations

BP-Husky Refining LLC

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

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

Contribution Payable

($ millions)	2014	2013
Beginning of year	**1,421**	1,336
Accretion *(note 14)*	**85**	80
Paid	**(106)**	(87)
Foreign exchange	**128**	92
End of year	**1,528**	1,421

The contribution payable accretes at a rate of 6% and is payable between December 31, 2014 and December 31, 2015 with the final balance due by December 31, 2015. The timing of payments made during this period will be determined by the capital expenditures at the refinery during the same period. The entity is included as part of U.S. Refining and Marketing in the Downstream segment. Subsequent to year-end, the Company amended the repayment terms. See Note 26.

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

Results of Operations

($ millions)	2014	2013
Revenues	**2,673**	2,856
Expenses	**(2,847)**	(2,762)
Proportionate share of net earnings	**(174)**	94

Balance Sheets

($ millions)	December 31, 2014	December 31, 2013
Current assets	**379**	442
Non-current assets	**2,073**	1,938
Current liabilities	**(336)**	(264)
Non-current liabilities	**(630)**	(664)
Proportionate share of net assets	**1,486**	1,452

Sunrise Oil Sands Partnership

The Company holds a 50% interest in the Sunrise Oil Sands Partnership, which is engaged in developing an oil sands project in Northern Alberta. On March 31, 2008, the Company completed a transaction with BP whereby the Company contributed Sunrise oil sands assets with a fair value of U.S. $2.5 billion and BP contributed U.S. $250 million in cash and a contribution receivable of U.S. $2.25 billion. The contribution receivable accreted at a rate of 6% per annum up to the receipt of the final balance during the second quarter of 2014.

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

Contribution Receivable

($ millions)	**2014**	2013
Beginning of year	**136**	607
Accretion *(note 14)*	**1**	22
Received	**(143)**	(520)
Foreign exchange	**6**	27
End of year	**–**	136

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

Results of Operations

($ millions)	**2014**	2013
Revenues	**–**	–
Expenses	**(24)**	(10)
Financial items	**(16)**	48
Proportionate share of net earnings	**(40)**	38

Balance Sheets

($ millions)	**December 31, 2014**	December 31, 2013
Current assets	**2**	149
Non-current assets	**3,124**	1,890
Current liabilities	**(74)**	(113)
Non-current liabilities	**(258)**	(21)
Proportionate share of net assets	**2,794**	1,905

Atlantic Region Joint Operations

The Company holds interests in the White Rose oil field, with a 72.5% interest in the core field and a 68.875% interest in the satellite fields. The Company also holds 35% interests in two exploration licenses and two significant discovery licenses in the Flemish Pass Basin related to the Bay Du Nord, Harpoon and Mizzen discoveries. Both areas are located off the coast of Newfoundland and Labrador and are a part of Husky's offshore East Coast exploration and development program. The Company's proportionate share of operating results and financial position in the White Rose oil field and Flemish Pass Basin have been included in the consolidated statements of income and the consolidated balance sheets in Exploration and Production in the Upstream segment.

Joint Venture

Husky-CNOOC Madura Ltd.

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

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

Results of Operations

($ millions, except share of equity investment)	**2014**	2013
Revenues	–	–
Expenses	**(49)**	(24)
Share of equity investment (percent)	**40%**	40%
Proportionate share of equity investment	**(6)**	(10)

Balance Sheets

($ millions, except share of equity investment)	**December 31, 2014**	December 31, 2013
Current assets[1]	**43**	28
Non-current assets	**574**	439
Current liabilities	**(25)**	(50)
Non-current liabilities	**(359)**	(188)
Net assets	**233**	229
Share of net assets (percent)	**40%**	40%
Carrying amount in statement of financial position	**237**	153

[1] *Current assets include cash and cash equivalents of $15 million (2013- $14 million).*

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

Note 9 Cash Flows – Change in Non-cash Working Capital

Non-cash Working Capital

($ millions)	**2014**	2013
Decrease (increase) in non-cash working capital		
Accounts receivable	**964**	200
Inventories	**191**	30
Prepaid expenses	**(76)**	(22)
Accounts payable and accrued liabilities	**(508)**	116
Change in non-cash working capital	**571**	324
Relating to:		
Operating activities	**871**	(21)
Financing activities	**33**	(19)
Investing activities	**(333)**	364

Cash and cash equivalents at December 31, 2014 included $188 million of cash (December 31, 2013 – $305 million) and $1,079 million of short-term investments with original maturities less than three months at the time of purchase (December 31, 2013 – $792 million).

Note 10 Goodwill

Goodwill

($ millions)	2014	2013
Beginning of year	**698**	663
Exchange adjustments	**48**	35
End of year	**746**	698

As at December 31, 2014, goodwill related primarily to the Lima Refinery CGU included in the Downstream segment with the remaining balance allocated to various Upstream CGUs located in Western Canada. For impairment testing purposes, the recoverable amount of the Lima Refinery CGU was estimated using value-in-use methodology based on cash flows expected over a 40-year period and discounted using a pre-tax discount rate of 8% (2013 – 8%). The discount rate was determined in relation to the Company's incremental borrowing rate adjusted for risks specific to the refinery. Cash flow projections for the initial five-year period are based on budgeted future cash flows and inflated by a 2% long-term growth rate for the remaining 35-year period. The inflation rate was based upon an average expected inflation rate for the U.S. of 2% (2013 – 2%). At December 31, 2014, the recoverable amount exceeded the carrying amount of the relevant CGUs. The value-in-use calculation for the Lima Refinery CGU is particularly sensitive to changes in discount rates, forecasted crack spreads and refining margins. The values assigned to key assumptions reflect past experience from both internal and external sources.

Note 11 Bank Operating Loans

At December 31, 2014, the Company had unsecured short-term borrowing lines of credit with banks totalling $645 million (December 31, 2013 – $595 million) and letters of credit under these lines of credit totalling $188 million (December 31, 2013 – $224 million). As at December 31, 2014, bank operating loans were nil (December 31, 2013 – nil). Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates. For 2014, the Company's weighted average interest rate on unsecured short-term borrowing lines of credit was approximately 1.3% (2013 – 1.2%).

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share of the liability for any drawings under this credit facility is $5 million. As at December 31, 2014, there was no balance outstanding under this credit facility (December 31, 2013 – nil).

Note 12 Accounts Payable and Accrued Liabilities

Accounts Payable and Accrued Liabilities

($ millions)	December 31, 2014	December 31, 2013
Trade payables	**550**	82
Accrued liabilities	**1,917**	2,466
Dividend payable *(note 18)*	**295**	295
Stock-based compensation	**53**	122
Derivatives due within one year	**27**	21
Contingent consideration *(note 22)*	**40**	29
Other	**107**	140
	2,989	3,155

Note 13 Debt and Credit Facilities

Short-term Debt

($ millions)	**December 31, 2014**	December 31, 2013
Commercial paper [(1)]	**895**	–

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

Long-term Debt

($ millions)	Maturity	Canadian $ Amount **December 31, 2014**	Canadian $ Amount December 31, 2013	U.S. $ Denominated **December 31, 2014**	U.S. $ Denominated December 31, 2013
Long-term debt					
3.75% medium-term notes[(6)]	2015	–	300	–	–
7.55% debentures[(1)(3)]	2016	**232**	213	**200**	200
6.20% notes[(1)(5)]	2017	**348**	319	**300**	300
6.15% notes[(1)(4)]	2019	**348**	319	**300**	300
7.25% notes[(1)(5)]	2019	**870**	798	**750**	750
5.00% medium-term notes[(6)]	2020	**400**	400	–	–
3.95% senior unsecured notes[(1)(5)]	2022	**580**	532	**500**	500
4.00% senior unsecured notes [(1)(5)]	2024	**870**	–	**750**	–
6.80% notes[(1)(5)]	2037	**449**	411	**387**	387
Debt issue costs[(2)]		**(26)**	(21)	–	–
Unwound interest rate swaps *(note 22)*		**26**	50	–	–
Long-term debt		**4,097**	3,321	**3,187**	2,437
Long-term debt due within one year					
5.90% notes[(1)(5)]	2014	–	798	–	750
3.75% medium-term notes[(6)]	2015	**300**	–	–	–

[(1)] *A portion of the Company's U.S. denominated debt is designated as a hedge of the Company's net investment in its U.S. refining operations. Refer to Note 22.*
[(2)] *Calculated using the effective interest rate method.*
[(3)] *The 7.55% debentures represent unsecured securities under a trust indenture dated October 31, 1996.*
[(4)] *The 6.15% notes represent unsecured securities under a trust indenture dated June 14, 2002.*
[(5)] *The 5.90%, the 6.20%, the 7.25%, the 3.95% and the 6.80% notes represent unsecured securities under a trust indenture dated September 11, 2007.*
[(6)] *The 3.75% and the 5.00% medium-term notes represent unsecured securities under a trust indenture dated December 21, 2009.*

Credit Facilities

On December 14, 2012, the Company amended and restated both of its revolving syndicated credit facilities to allow the Company to borrow up to $1.5 billion and $1.6 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The maturity date for the $1.5 billion facility was extended to December 14, 2016 and in February 2013, the limit on the $1.50 billion facility was increased to $1.6 billion. On June 19, 2014 the maturity of the $1.6 billion facility was increased to $1.63 billion and extended to June 19, 2018. The Company also increased the limit on one of the operating facilities from $50 million to $100 million.

There continues to be no difference between the terms of these facilities, other than their maturity dates. Interest rates vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt.

At December 31, 2014, the Company had $895 million outstanding of commercial paper (December 31, 2013 – nil), which is supported by its revolving syndicated credit facilities.

Notes and Debentures

On December 31, 2012, the Company filed a short form base shelf prospectus (the "Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada, other than Quebec, that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units in Canada up to and including January 30, 2015. As at December 31, 2014, the Company had not issued any notes or debentures under the Canadian Shelf Prospectus. See Note 18 regarding the issuance of preferred shares under this prospectus. Subsequent to December 31, 2014, on February 23, 2015, the Company filed a short form base shelf prospectus (the "2015 Canadian Shelf Prospectus") with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including March 22, 2017.

On October 31, 2013 and November 1, 2013, Husky filed a universal short form base shelf prospectus (the "U.S. Shelf Prospectus") with the Alberta Securities Commission and the U.S. Securities and Exchange Commission, respectively, 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 November 30, 2015. During the 25-month period that the U.S. Shelf Prospectus is effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On March 17, 2014, the Company issued U.S. $750 million of 4.00 percent notes due April 14, 2024 under the U.S. Shelf Prospectus, equivalent to $829 million in Canadian dollars. 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, including interest of $25 million.

The ability of the Company to raise capital utilizing the Canadian Shelf Prospectus or U.S. Shelf Prospectus is dependent on market conditions at the time of sale.

The notes and debentures disclosed above are redeemable (unless otherwise stated) at the option of the Company, at any time, at a redemption price equal to the greater of the par value of the securities and the sum of the present values of the remaining scheduled payments discounted at a rate calculated using a comparable U.S. Treasury Bond rate (for U.S. dollar denominated securities) or Government of Canada Bond rate (for Canadian dollar denominated securities) plus an applicable spread. Interest on the notes and debentures disclosed above is payable semi-annually.

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

Note 14 Financial Items

Financial Items

($ millions)	**2014**	2013
Foreign exchange		
Gains (losses) on translation of U.S. dollar denominated long-term debt	**7**	(11)
Gains on contribution receivable	**6**	27
Gains on non-cash working capital	**42**	33
Other foreign exchange gains (losses)[(1)]	**26**	(28)
Net foreign exchange gains	**81**	21
Finance income		
Contribution receivable *(note 8)*	**1**	22
Interest income	**7**	19
Other	**–**	10
Finance income	**8**	51
Finance expenses		
Long-term debt	**(267)**	(233)
Contribution payable *(note 8)*	**(85)**	(80)
Other	**(5)**	3
	(357)	(310)
Interest capitalized[(2)]	**258**	266
	(99)	(44)
Accretion of asset retirement obligations *(note 16)*	**(133)**	(118)
Accretion of other long-term liabilities *(note 22)*	**(1)**	(7)
Finance expenses	**(233)**	(169)
	(144)	(97)

(1) *Other foreign exchange gains and losses primarily include realized and unrealized foreign exchange gains and losses on purchases of property, plant and equipment, and working capital.*

(2) *Interest capitalized on project costs in 2014 is calculated using the Company's annualized effective interest rate of 6% (2013 – 6%).*

Note 15 Other Long-term Liabilities

Other Long-term Liabilities

($ millions)	**December 31, 2014**	December 31, 2013
Employee future benefits *(note 19)*	**142**	116
Finance lease obligations	**264**	31
Stock-based compensation	**26**	39
Contingent consideration *(note 22)*	**–**	31
Other	**153**	54
	585	271

Finance lease obligations

The Company, on behalf of the Sunrise Oil Sands Partnership, entered into an arrangement for the construction and use of pipeline and storage facilities in its oil sands operations. The substance of the arrangement has been determined to be a lease and has been classified as a finance lease. The assets are to be used for a minimum period of 20 years with options to renew.

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

	Within 1 year		After 1 year but no more than 5 years		More than 5 years		Total	
($ millions)	**2014**	2013	**2014**	2013	**2014**	2013	**2014**	2013
Future minimum lease payments	**33**	4	**141**	14	**852**	28	**1,026**	46
Interest	**31**	2	**119**	7	**581**	6	**731**	15
Present value of minimum lease payments	**31**	1	**104**	15	**160**	16	**295**	32

Note 16 Asset Retirement Obligations

At December 31, 2014, the estimated total undiscounted inflation-adjusted amount required to settle the Company's ARO was $15.5 billion (December 31, 2013 – $12.3 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 52 years into the future. This amount has been discounted using credit-adjusted risk-free rates of 2.9% to 4.8% (December 31, 2013 – 3.1% to 5.3%). Obligations related to future environmental remediation and cleanup of oil and gas producing assets are included in the estimated ARO.

The change in estimates in 2014 is related to lower average discount rates, increased cost estimates and asset growth that is partially offset by a revision of the timing of future ARO cash flows.

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

A reconciliation of the carrying amount of asset retirement obligations at December 31, 2014 and 2013 is set out below:

Asset Retirement Obligations

($ millions)	**2014**	2013
Beginning of year	**2,918**	2,793
Additions	**48**	78
Liabilities settled	**(167)**	(142)
Liabilities disposed	**(8)**	(6)
Change in discount rate	**279**	(288)
Change in estimates	**(156)**	351
Exchange adjustment	**18**	14
Accretion *(note 14)*	**133**	118
End of year	**3,065**	2,918
Expected to be incurred within 1 year	**97**	210
Expected to be incurred beyond 1 year	**2,968**	2,708

Note 17 Income Taxes

The major components of income tax expense for the years ended December 31, 2014 and 2013 were as follows:

Income Tax Expense

($ millions)	**2014**	2013
Current income tax		
Current income tax charge	**684**	413
Adjustments to current income tax estimates	**33**	176
	717	589
Deferred income tax		
Relating to origination and reversal of temporary differences	**(186)**	364
Adjustments to deferred income tax estimates	**(5)**	(154)
	(191)	210

Deferred Tax Items in OCI

($ millions)	**2014**	2013
Deferred tax items expensed (recovered) directly in OCI		
Derivatives designated as cash flow hedges	**(5)**	13
Remeasurement of pension plans	**(4)**	7
Exchange differences on translation of foreign operations	**109**	58
Hedge of net investment	**(39)**	(27)
	61	51

The provision for income taxes in the consolidated statements of income reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31, 2014 and 2013 were accounted for as follows:

Reconciliation of Effective Tax Rate

($ millions, except tax rate)	**2014**	2013
Earnings before income taxes		
Canada	**1,515**	2,110
United States	**(180)**	379
Other foreign jurisdictions	**449**	139
	1,784	2,628
Statutory Canadian income tax rate (percent)	**25.8%**	25.8%
Expected income tax	**461**	678
Effect on income tax resulting from:		
Capital gains and losses	**(2)**	(10)
Foreign jurisdictions	**(26)**	64
Non-taxable items	**4**	33
Revaluation of foreign tax pools	**47**	–
Other – net	**42**	34
Income tax expense	**526**	799

The statutory tax rate was 25.8% in 2014 (2013 – 25.8%). The 2014 to 2013 tax rates were unchanged as there were no significant changes to applicable tax rates.

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

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2014	Recognized in Earnings	Recognized in OCI	Other	**December 31, 2014**
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(5,789)	**75**	**(124)**	**(2)**	**(5,840)**
Foreign exchange gains taxable on realization	(60)	**(19)**	**44**	–	**(35)**
Debt issue costs	3	**(4)**	–	–	**(1)**
Deferred tax assets					
Pension plans	35	–	**4**	–	**39**
Asset retirement obligations	812	**50**	**8**	–	**870**
Loss carry-forwards	51	**29**	**7**	–	**87**
Financial assets at fair value	(8)	**20**	–	–	**12**
Other temporary differences	14	**40**	–	–	**54**
	(4,942)	**191**	**(61)**	**(2)**	**(4,814)**

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2013	Recognized in Earnings	Recognized in OCI	Other	December 31, 2013
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(5,425)	(258)	(65)	(41)	(5,789)
Foreign exchange gains taxable on realization	(64)	(10)	14	–	(60)
Financial assets at fair value	(7)	(1)	–	–	(8)
Deferred tax assets					
Pension plans	39	3	(7)	–	35
Asset retirement obligations	778	30	4	–	812
Loss carry-forwards	30	18	3	–	51
Debt issue costs	6	(3)	–	–	3
Other temporary differences	3	11	–	–	14
	(4,640)	(210)	(51)	(41)	(4,942)

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At December 31, 2014, the Company had no deferred tax liabilities in respect of these temporary differences (December 31, 2013 – nil).

At December 31, 2014, the Company had $234 million (December 31, 2013 – $138 million) of U.S. tax losses that will expire between 2030 and 2034. The Company has recorded deferred tax assets in respect of these losses, as there are sufficient taxable temporary differences in the U.S. jurisdiction to utilize these losses.

Note 18 Share Capital

Common Shares

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

Common Shares	Number of Shares	Amount ($ millions)
December 31, 2012	982,229,220	6,939
Stock dividends	290,667	8
Options exercised	859,187	27
December 31, 2013	983,379,074	6,974
Stock dividends	**315,419**	**11**
Options exercised	**43,569**	**1**
December 31, 2014	**983,738,062**	**6,986**

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

During the year ended December 31, 2014, the Company declared dividends payable of $1.20 per common share (2013 – $1.20 per common share), resulting in dividends of $1,180 million (2013 – $1,180 million). An aggregate of $1,169 million was paid in cash and $11 million in common shares during 2014 (2013 – $1,171 million in cash and $8 million in common shares). At December 31, 2014, $295 million, including $292 million in cash and $3 million in common shares, was payable to shareholders on account of dividends declared on October 23, 2014 (December 31, 2013 – $295 million, including $291 million in cash and $4 million in common shares).

Preferred Shares

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

Preferred Shares	Number of Shares	Amount *($ millions)*
Cumulative Redeemable Preferred Shares, Series 1 issued, net of share issue costs	12,000,000	291
Cumulative Redeemable Preferred Shares, Series 3 issued, net of share issue costs	**10,000,000**	**243**
December 31, 2014	**22,000,000**	**534**

Holders of the Cumulative Redeemable Preferred Shares, Series 1 ("Series 1 Preferred Shares") are entitled to receive a cumulative quarterly fixed dividend yielding 4.45% annually for an initial period ending March 31, 2016, as and when declared by the Company's Board of Directors. Thereafter, the dividend rate will be reset every five years at a rate equal to the 5-year Government of Canada bond yield plus 1.73%. Holders of Series 1 Preferred Shares have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares"), subject to certain conditions, on March 31, 2016 and on March 31 every five years thereafter. Holders of the Series 2 Preferred Shares are entitled to receive a cumulative quarterly floating rate dividend at a rate equal to the three-month Government of Canada Treasury Bill yield plus 1.73%, as and when declared by the Company's Board of Directors.

In the event of liquidation, dissolution or winding-up of the Company, the holders of the Series 1 Preferred Shares will be entitled to receive $25 per share. All accrued unpaid dividends will be paid before any amounts are paid or any assets of the Company are distributed to the holders of any other shares ranking junior to the Series 1 Preferred Shares. The holders of the Series 1 Preferred Shares will not be entitled to share in any further distribution of the assets of the Company.

During the year ended December 31, 2014, the Company declared dividends payable of $13 million on the Series 1 Preferred Shares (2013 – $13 million) representing approximately $1.11 per Series 1 Preferred Share (2013 – $1.11 per Series 1 Preferred Share). At December 31, 2014, there were no amounts payable as dividends on the Series 1 Preferred Shares (December 31, 2013 – nil). A total of $13 million was paid during 2014 (2013 – $13 million), representing approximately $0.28 per quarter per Series 1 Preferred Share (2013 – $0.28 per Series 1 Preferred Share).

On December 9, 2014, the Company issued 10 million Cumulative Redeemable Preferred Shares, Series 3 (the "Series 3 Preferred Shares") at a price of $25.00 per share for aggregate gross proceeds of $250 million by way of a prospectus supplement dated December 2, 2014, under the Canadian short form base shelf prospectus dated December 31, 2012. Net proceeds after share issue costs were $243 million. Holders of the Series 3 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending December 31, 2019 as and when declared by the Company's Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.13 percent. Holders of Series 3 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 4 (the "Series 4 Preferred Shares"), subject to certain conditions, on December 31, 2019 and on December 31 every five years thereafter. Holders of the Series 4 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.13 percent.

Stock Option Plan

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

Certain options granted under the Option Plan and henceforth referred to as performance options vest only if certain shareholder return targets are met. The ultimate number of performance options that vest will depend upon the Company's performance measured over three calendar years. If the Company's performance is below the specified level compared with its industry peer group, the performance options awarded will be forfeited. If the Company's performance is at or above the specified level compared with its industry peer group, the number of performance options exercisable shall be determined by the Company's relative ranking. Stock compensation expense related to the performance options is accrued based on the price of the common shares at the end of the period and the anticipated performance factor. The term of each performance option is five years and the compensation expense is recognized over the three-year vesting period of the performance options. Performance options are no longer granted and the last grant was on August 7, 2009. All outstanding performance options expired during the year ended December 31, 2014.

Included in accounts payable and accrued liabilities and other long-term liabilities in the consolidated balance sheets at December 31, 2014 was $41 million (December 31, 2013 – $134 million) representing the estimated fair value of options outstanding. The total recovery recognized in selling, general and administrative expenses in the consolidated statements of income for the Option Plan for the year ended December 31, 2014 was $39 million (2013 – $83 million expense). At December 31, 2014, stock options exercisable for cash had an intrinsic value of $15 million (December 31, 2013 – $135 million).

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

Outstanding and Exercisable Options	2014		2013	
	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
Outstanding, beginning of year	**28,937**	**28.20**	29,021	28.85
Granted[(1)]	**6,769**	**33.41**	6,314	31.46
Exercised for common shares	**(44)**	**27.57**	(859)	27.75
Surrendered for cash	**(7,289)**	**27.94**	(1,857)	28.43
Expired or forfeited	**(1,631)**	**30.20**	(3,682)	38.92
Outstanding, end of year	**26,742**	**29.47**	28,937	28.20
Exercisable, end of year	**13,717**	**27.97**	13,574	27.87

(1) *Options granted during the year ended December 31, 2014 were attributed a fair value of $4.08 per option (2013 – $4.02) at grant date.*

Outstanding and Exercisable Options	Outstanding Options			Exercisable Options	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
$20.00 – $29.99	15,236	27.12	1.67	12,102	27.50
$30.00 – $36.20	11,506	32.59	3.72	1,615	31.50
December 31, 2014	**26,742**	**29.47**	**2.55**	**13,717**	**27.97**

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

Black-Scholes Assumptions [(1)]	December 31, 2014		December 31, 2013	
	Tandem Options	Tandem Performance Options[(1)]	Tandem Options	Tandem Performance Options
Dividend per option	**1.20**	–	1.20	1.20
Range of expected volatilities used *(percent)*	**20.9 - 61.8**	–	15.5 - 24.5	15.5 - 17.4
Range of risk-free interest rates used *(percent)*	**0.9 - 1.4**	–	0.9 - 1.9	0.9 - 1.0
Expected life of share options from vesting date *(years)*	**1.81**	–	1.85	1.85
Expected forfeiture rate *(percent)*	**9.8**	–	10.2	10.2
Weighted average exercise price	**28.90**	–	27.95	30.54
Weighted average fair value	**1.85**	–	5.74	3.22

(1) *All outstanding performance options expired during the year ended December 31, 2014.*

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

Performance Share Units

In February 2010, the Compensation Committee of the Board of Directors of the Company established the Performance Share Unit Plan for executive officers and certain employees of the Company. The term of each PSU is three years, and the PSU vests on the second and third anniversary dates of the grant date in percentages determined by the Compensation Committee based on the Company reaching certain shareholder return and corporate performance targets. Upon vesting, PSU holders receive a cash payment equal to the number of vested PSUs multiplied by the weighted average trading price of the Company's common shares for the five preceding trading days. As at December 31, 2014, the carrying amount of the liability relating to PSUs was $38 million (December 31, 2013 – $27 million). The total expense recognized in selling, general and administrative expenses in the consolidated statements of income for the PSUs for the year ended December 31, 2014 was $22 million (2013 – expense of $22 million). The weighted average contractual life of the PSUs at December 31, 2014 was two years (December 31, 2013 – two years).

The number of PSUs outstanding was as follows:

Performance Share Units	2014	2013
Beginning of year	**2,791,875**	864,500
Granted	**2,064,100**	2,194,015
Exercised	**(357,628)**	(209,331)
Forfeited	**(339,119)**	(57,309)
Outstanding, end of year	**4,159,228**	2,791,875
Vested, end of year	**1,372,974**	809,947

Earnings per Share

Earnings per Share

($ millions)	2014	2013
Net earnings	**1,258**	1,829
Effect of dividends declared on preferred shares in the year	**(13)**	(13)
Net earnings – basic	**1,245**	1,816
Dilutive effect of accounting for share options as equity-settled[1]	**(65)**	–
Net earnings – diluted	**1,180**	1,816
(millions)		
Weighted average common shares outstanding – basic	**983.6**	983.0
Effect of stock dividends declared in the year	**1.7**	0.6
Weighted average common shares outstanding – diluted	**985.3**	983.6
Earnings per share – basic ($/share)	**1.26**	1.85
Earnings per share – diluted ($/share)	**1.20**	1.85

[1] *Stock-based compensation recovery was $39 million based on cash-settlement for the year ended December 31, 2014 (2013 – $83 million expense). Stock-based compensation expense was $26 million based on equity-settlement for the year ended December 31, 2014 (2013 - $29 million expense). For the year ended December 31, 2014, equity-settlement of share options was considered more dilutive than the cash-settlement of share options and as such, was used to calculate earnings per share - diluted.*

For the year ended December 31, 2014, 19 million tandem options (2013 – 26 million) were excluded from the calculation of diluted earnings per share as these options were anti-dilutive. For the year ended December 31, 2014, there were no tandem performance options (2013 – 96,150 anti-dilutive tandem performance options) excluded from the calculation of diluted earnings per share as these options expired during the year ended December 31, 2014.

Note 19 Pensions and Other Post-employment Benefits

The Company currently provides defined contribution pension plans for all qualified employees and two other post-employment benefit plans to its retirees. The Company also maintains a defined benefit pension plan, which is closed to new entrants. The measurement date of all plan assets and the accrued benefit obligations was December 31, 2014. The most recent actuarial valuation was December 31, 2013 for the Canadian defined benefit plan. The most recent actuarial valuation was December 31, 2011 for the Canadian Other Post-employment benefit plan. The most recent actuarial valuation of the U.S. Other Post-employment benefit plan was January 1, 2014. The U.S. defined benefit plan was settled in 2014.

Defined Contribution Pension Plan

During the year ended December 31, 2014, the Company recognized a $42 million expense (2013 – $37 million) for the defined contribution plan and the two U.S. 401(k) plans in net earnings.

Defined Benefit Pension Plan ("DB Pension Plan") and Other Post-employment Benefit Plans ("OPEB Plans")

The Company has accrued the total net liability for the DB Pension Plan and the OPEB Plans in the consolidated balance sheets in other long-term liabilities as follows:

DB Pension Plan

($ millions)	**December 31, 2014**	December 31, 2013	December 31, 2012
Fair value of plan assets	**180**	173	156
Defined benefit obligation	**(179)**	(180)	(189)
Funded status	**1**	(7)	(33)
Net asset (liability)	**1**	(7)	(33)
Non-current asset (liability)	**1**	(7)	(33)

OPEB Plans

($ millions)	**December 31, 2014**	December 31, 2013	December 31, 2012
Fair value of plan assets	**–**	–	–
Defined benefit obligation	**(143)**	(109)	(105)
Funded status	**(143)**	(109)	(105)
Net liability	**(143)**	(109)	(105)
Non-current liability	**(143)**	(109)	(105)

The following tables summarize the experience adjustments arising on the DB Pension Plan's and the OPEB Plans' liabilities:

DB Pension Plan

($ millions)	**2014**	2013	2012
Experience adjustments arising on plan liabilities	**(1.5)**	0.4	(0.5)

OPEB Plans

($ millions)	**2014**	2013	2012
Experience adjustments arising on plan liabilities	**(0.2)**	(0.5)	1.6

The following tables summarize changes to the net balance sheet position and amounts recognized in net earnings and OCI for the DB Pension Plan and the OPEB Plans for the years ended December 31, 2014 and 2013:

DB Pension Plan and OPEB Plans Net Asset (Liability)

	DB Pension Plan		OPEB Plans	
($ millions)	**2014**	2013	**2014**	2013
Beginning of year	**(7)**	(33)	**(109)**	(105)
Employer contributions	**4**	8	**–**	–
Benefit cost	**(1)**	(3)	**(12)**	(11)
Benefit paid	**–**	–	**1**	1
Remeasurements				
Actuarial gain (loss) due to liability experience	**2**	–	**–**	1
Actuarial gain (loss) due to liability assumption changes	**(19)**	8	**(23)**	5
Return on plan assets (greater) less than discount rate	**22**	13	**–**	–
End of year	**1**	(7)	**(143)**	(109)

DB Pension Plan and OPEB Plans

	DB Pension Plan		OPEB Plans	
($ millions)	**2014**	2013	**2014**	2013
Amounts recognized in net earnings				
Current service cost	**2**	2	**7**	7
Net Interest cost	**1**	1	**5**	4
Gain on settlement	**(2)**	–	**–**	–
Benefit cost (gain)	**1**	3	**12**	11
Remeasurements				
Actuarial (gain) loss due to liability experience	**(2)**	–	**–**	(1)
Actuarial (gain) loss due to liability assumption changes	**19**	(8)	**23**	(5)
Loss (gain) on plan assets	**(22)**	(13)	**–**	–
Remeasurement effects recognized in OCI	**(5)**	(21)	**23**	(6)

The following tables summarize changes to the defined benefit obligation for the DB Pension Plan and the OPEB Plans:

Defined Benefit Obligation

	DB Pension Plan		OPEB Plans	
($ millions)	**2014**	2013	**2014**	2013
Beginning of year	**180**	189	**109**	105
Current service cost	**2**	2	**7**	7
Interest cost	**8**	8	**5**	4
Benefits paid	**(10)**	(11)	**(1)**	(1)
Gain on settlements	**(2)**	–	**–**	–
Settlements	**(16)**	–	**–**	–
Remeasurements				
Actuarial (gain) loss – experience	**(2)**	–	**–**	(1)
Actuarial (gain) loss – demographic assumptions	**3**	6	**3**	9
Actuarial (gain) loss – financial assumptions	**16**	(14)	**20**	(14)
Curtailment gain	**–**	–	**–**	–
End of year	**179**	180	**143**	109

The following table summarizes changes to the DB Pension Plan assets during the year:

Fair Value of Plan Assets

($ millions)	2014	2013
Beginning of year	173	156
Contributions by employer	4	8
Benefits paid	(10)	(11)
Interest income	7	7
Return on plan assets greater (less) than discount rate	22	13
Settlements	(16)	–
End of year	180	173

The following long-term assumptions were used to estimate the value of the defined benefit obligations, the plan assets and the OPEB Plans:

DB Pension Plan Long-term Assumptions

	Canada - DB Pension Plan		U.S. - DB Pension Plan[1]	
(percent)	2014	2013	2014	2013
Discount rate for benefit expense	4.5	3.8	–	3.2
Discount rate for benefit obligation	3.7	4.5	–	4.1
Rate of compensation expense	3.5	3.5	–	4.5

[1] The U.S. Defined Benefit Plan was wound up in 2014.

OPEB Plans Long-term Assumptions

	OPEB Plans	
(percent)	2014	2013
Discount rate for benefit expense	4.4 - 4.7	3.3 - 4.0
Discount rate for benefit obligation	3.7 - 3.9	4.3 - 4.7
Dental care escalation rate	4.5	4.0
Provincial health care premium	2.5	2.5

The average health care cost trend rate used for the benefit expense for the Canadian OPEB Plan was 7.0% for 2014, grading 0.5% per year for 4 years to 5.0% in 2018 and thereafter. The average health care cost trend rate used for the obligation related to the Canadian OPEB Plan was 6.5% for 2015, grading 0.5% per year for 3 years to 5.0% in 2018 and thereafter.

The average health care cost trend rate used for the benefit expense for the U.S. OPEB Plan was 7.0% for 2014, grading 0.25% per year for 8 years to 5.0% per year in 2022 and thereafter. The average health care cost trend rate used for the obligation related to the U.S. OPEB Plan was 6.8% for 2015, grading 0.25% per year for 8 years to 5.0% in 2022 and thereafter.

The medical cost trend rate assumption has a significant effect on amounts reported for the OPEB plans. A 1% increase or decrease in the estimated trend rate would have the following effects:

Medical Cost Trend Rate Sensitivity Analysis

($ millions)	1% increase	1% decrease
Effect on benefit cost recognized in net earnings	2.7	(2.1)
Effect on defined benefit obligation	26.0	(21.1)

During 2014, the Company contributed $4 million (2013 – $8 million) to the defined benefit pension plan assets and is expecting to contribute $2 million in 2015. Benefits of $10 million are expected to be paid in 2015.

The Company adheres to a Statement of Investment Policies and Procedures (the "Policy"). Plan assets are allocated in accordance with the long-term nature of the obligation and comprise a balanced investment based on interest rate and inflation sensitivities. The Policy explicitly prescribes diversification parameters for all classes of investment.

The composition of the DB Pension Plan assets at December 31, 2014 and 2013 was as follows:

DB Pension Plan Assets

(percent)	Target allocation range	**2014**	2013
Money market type funds	0 – 5	**0.5**	0.5
Equity securities	30 – 50	**40.6**	64.5
Debt securities	50 – 65	**58.9**	34.5
Other	–	**–**	0.5

Note 20 Commitments and Contingencies

At December 31, 2014, the Company had commitments that require the following minimum future payments, which are not accrued in the consolidated balance sheet:

Minimum Future Payments for Commitments

($ millions)	Within 1 year	After 1 year but not more than 5 years	More than 5 years	Total
Operating leases	115	918	1,019	2,052
Firm transportation agreements	351	1,317	3,275	4,943
Unconditional purchase obligations	2,495	1,218	329	4,042
Lease rentals and exploration work agreements	321	468	1,219	2,008
	3,282	3,921	5,842	13,045

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, and management believes that it has adequately provided for current and deferred income taxes.

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

Note 21 Related Party Transactions

Significant subsidiaries and jointly controlled entities at December 31, 2014 and the Company's percentage equity interest (to the nearest whole number) are set out below:

Significant Subsidiaries and Joint Operations	%	Jurisdiction
Subsidiary of Husky Energy Inc.		
Husky Oil Operations Limited	100	Alberta
Subsidiaries and jointly controlled entities of Husky Oil Operations Limited		
Husky Oil Limited Partnership	100	Alberta
Husky Terra Nova Partnership	100	Alberta
Husky Downstream General Partnership	100	Alberta
Husky Energy Marketing Partnership	100	Alberta
Husky Energy International Corporation	100	Alberta
Sunrise Oil Sands Partnership	50	Alberta
BP-Husky Refining LLC	50	Delaware
Lima Refining Company	100	Delaware
Husky Marketing and Supply Company	100	Delaware

Each of the related party transactions described below was made on terms equivalent to those that prevail in arm's length transactions unless otherwise noted.

On May 11, 2009, the Company issued 5-year and 10-year senior notes of U.S. $251 million and U.S. $107 million, respectively, to certain management, shareholders, affiliates and directors. The coupon rates offered were 5.90% and 7.25% for the 5-year and 10-year tranches, respectively. Subsequent to this offering, U.S. $122 million of the 5-year senior notes and U.S. $75 million of the 10-year senior notes issued to related parties were sold to third parties. On June 15, 2014, the Company repaid the maturing 5.90% notes. As a result, U.S. $133 million was repaid to related parties, including interest of U.S. $4 million. These transactions were measured at fair market value at the date of the transaction and have been carried out on the same terms as would have applied with unrelated parties. At December 31, 2014, the 7.25% senior notes are included in long-term debt in the Company's consolidated balance sheets.

The Company sells natural gas to, and purchases steam from, Meridian cogeneration facility ("Meridian") and other cogeneration facilities owned by a related party. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the year ended December 31, 2014, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $78 million (2013 – $55 million). For the year ended December 31, 2014, the amount of steam purchases by the Company from Meridian totalled $25 million (2013 – $17 million). In addition, the Company provides cogeneration and facility support services to Meridian, measured on a cost recovery basis. For the year ended December 31, 2014, the total cost recovery for these services was $9 million (2013 – $9 million).

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.

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 and Hutchison Whampoa Luxembourg Holdings S.à r.l.

The Company defines its key management as the officers and executives within the executive department of the Company. The amounts disclosed in the table below are the amounts recognized as an expense during the reporting period related to key management personnel:

Compensation of Key Management Personnel

($ millions)	**2014**	2013
Short-term employee benefits[(1)]	**18**	13
Post-employment benefits[(2)]	–	–
Stock-based compensation[(3)]	**10**	10
	28	23

(1) *Short-term employee benefits are comprised of salary and benefits earned during the year, plus cash bonuses awarded during the year. Annual bonus awards settled in shares are included in stock-based compensation expense.*
(2) *Post-employment benefits represent the estimated cost to the Company to provide either a defined benefit pension plan or a defined contribution pension plan, and other post-retirement benefits for the current year of service. Refer to Note 19.*
(3) *Stock-based compensation expense represents the cost to the Company for participation in share-based payment plans. Refer to Note 18.*

Note 22 Financial Instruments and Risk Management

Financial Instruments

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

The following table summarizes by measurement classification, derivatives, contingent consideration and hedging instruments that are carried at fair value in the consolidated balance sheets:

Financial Instruments at Fair Value

($ millions)	**December 31, 2014**	December 31, 2013
Commodity contracts - fair value through profit or loss		
Natural gas[(1)]	**(5)**	32
Crude oil[(2)]	**4**	41
Foreign currency contracts - FVTPL		
Foreign currency forwards	**(1)**	–
Other assets - FVTPL	**2**	2
Contingent consideration	**(40)**	(60)
Hedging instruments[(3)]		
Derivatives designated as a cash flow hedge[(4)]	–	37
Hedge of net investment[(5)]	**(353)**	(93)
	(393)	(41)

(1) *Natural gas contracts include a $12 million decrease at December 31, 2014 ($27 million increase at December 31, 2013) to the fair value of held-for-trading inventory, recognized in the consolidated balance sheets, related to third party physical purchase and sale contracts for natural gas held in storage. Total fair value of the related natural gas storage inventory at December 31, 2014 was $87 million (December 31, 2013 - $124 million).*
(2) *Crude oil contracts include a $21 million decrease as at December 31, 2014 ($49 million increase at December 31, 2013) to the fair value of held-for-trading inventory, recognized in the consolidated balance sheets, related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory at December 31, 2014 was $199 million (December 31, 2013 - $297 million)*
(3) *Hedging instruments are presented net of tax.*
(4) *Forward starting swaps previously designated as a cash flow hedge were discontinued during the first quarter of 2014.*
(5) *Represents the translation of the Company's U. S. denominated long-term debt designated as a hedge of the Company's net investment in its U.S. refining operations.*

The Company's other financial instruments that are not related to derivatives, contingent consideration or hedging activities are included in cash and cash equivalents, accounts receivable, contribution receivable, accounts payable and accrued liabilities, short-term debt, long-term debt, other long-term liabilities and contribution payable. These financial instruments are classified as loans and receivables or other financial liabilities and are carried at amortized cost. Excluding long-term debt, the carrying values of these financial instruments approximate their fair values.

The fair value of long-term debt represents the present value of future cash flows associated with the debt. Market information, such as treasury rates and credit spreads, are used to determine the appropriate discount rates. These fair value determinations are compared to quotes received from financial institutions to ensure reasonability. The estimated fair value of long-term debt at December 31, 2014 was $4.8 billion (December 31, 2013 – $4.6 billion).

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 estimation of the fair value of commodity derivatives and held-for-trading inventories incorporates exit prices and adjustments for quality and location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability. The estimation of the fair value of the net investment hedge incorporates foreign exchange rates and market interest rates from financial institutions. All financial assets and liabilities are classified as Level 2 measurements with the exception of contingent consideration payments. During the year ended December 31, 2014, there were no transfers between Level 1 and Level 2 fair value measurements, and no transfers into and out of Level 3 fair value measurements.

Contingent consideration payments, based on the average differential between heavy and synthetic crude oil prices, are classified as Level 3 fair value measurements and included in accounts payable and accrued liabilities and other long-term liabilities. The fair value of the contingent consideration is determined through forecasts of synthetic crude oil volumes, crude oil prices and forward price differentials deemed specific to the Company's Upgrader.

A reconciliation of changes in the fair value of contingent consideration payments is provided below:

Contingent consideration payments

($ millions)	**2014**	2013
Beginning of year	**60**	105
Accretion *(note 14)*	**1**	7
Upside interest payment	**(32)**	(25)
Increase (decrease) on revaluation[1]	**11**	(27)
End of year	**40**	60
Expected to be incurred within 1 year	**40**	29
Expected to be incurred beyond 1 year *(note 15)*	**–**	31

[1] *Revaluation of the contingent consideration liability is recorded in other – net in the consolidated statements of income.*

Risk Management Overview

The Company is exposed to risks related to the volatility of commodity prices, foreign exchange rates and interest rates. It is also exposed to financial risks related to liquidity and credit and contract risks. In certain instances, the Company uses derivative instruments to manage the Company's exposure to these risks. The Company employs risk management strategies and policies to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels.

Responsibility for risk management is held by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

a) Market Risk

i) Commodity Price Risk Management

In certain instances, the Company uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

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

ii) Foreign Exchange Risk Management

The Company's results are affected by the exchange rates between various currencies, including the Canadian and U.S. dollar. The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. The majority of the Company's expenditures are in Canadian dollars. The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. revenue dollars to hedge against these fluctuations and to mitigate its exposure to foreign exchange risk.

A change in the value of the Canadian dollar against the U.S. dollar will also result in an increase or decrease in the Company's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as the related finance expense. In order to mitigate the Company's exposure to long-term debt affected by the U.S./Canadian dollar exchange rate, the Company may enter into cash flow hedges using cross currency debt swap arrangements. In addition, a portion of the Company's U.S. dollar denominated debt has been designated as a hedge of a net investment in a foreign operation that has a U.S. dollar functional currency. The unrealized foreign exchange gain related to this hedge is recorded in OCI.

At December 31, 2014, the Company had designated U.S. $2.9 billion denominated debt as a hedge of the Company's net investment in its U.S. refining operations (December 31, 2013 – U.S. $3.2 billion). For the year ended December 31, 2014, the unrealized loss arising from the translation of the debt was $260 million (2013 – unrealized loss of $180 million), net of tax of $39 million (2013 – $27 million), which was recorded in hedge of net investment within OCI.

iii) Interest Rate Risk Management

Interest rate risk is the impact of fluctuating interest rates on earnings, cash flows and valuations. To mitigate risk related to interest rates, the Company may enter into fair value hedges using interest rate swaps. At December 31, 2014, the balance in long-term debt related to deferred gains resulting from unwound interest rate swaps that had previously been designated as a fair value hedge was $26 million (December 31, 2013 – $50 million). The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $24 million for the year ended December 31, 2014 (2013 – $22 million).

During the first quarter of 2014, the Company discontinued its cash flow hedge with respect to the forward starting interest rate swaps. These forward interest rate swaps were settled and derecognized. Accordingly, the accrued gain in other reserves – hedging, within the consolidated statement of changes in shareholders' equity, is being amortized into net earnings over the remaining life of the underlying long-term debt to which the hedging relationship was originally designated. The amortization period is ten years.

At December 31, 2014, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was $23 million (December 31, 2013 – $37 million), net of tax of $8 million (December 31, 2013 – net of tax of $13 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in an addition to finance income of $3 million for the year ended December 31, 2014 (2013 – nil).

iv) Earnings Impact of Market Risk Management Contracts

The gains (losses) recognized on risk management positions for the years ended December 31, 2014 and 2013 are set out below:

Earnings Impact *($ millions)*	2014 Marketing and Other	 Purchases of Crude Oil and Products	 Other – Net	 Net Foreign Exchange Gains (Losses)
Commodity Price				
Natural gas	**(37)**	–	–	–
Crude oil	**(37)**	–	–	–
	(74)	–	–	–
Foreign Currency				
Foreign currency forwards[(1)]	–	–	**(1)**	**(47)**
	(74)	–	**(1)**	**(47)**

(1) *Unrealized gains or losses from short-dated foreign currency forwards are included in other – net, while realized gains or losses are included in net foreign exchange gains in the consolidated statements of income.*

Earnings Impact ($ millions)	2013 Marketing and Other	 Purchases of Crude Oil and Products	 Other – Net	 Net Foreign Exchange Gains (Losses)
Commodity Price				
Natural gas	16	12	1	–
Crude oil	(9)	–	–	–
	7	12	1	–
Foreign Currency				
Foreign currency forwards[1]	–	–	1	(27)
	7	12	2	(27)

[1] *Unrealized gains or losses from short-dated foreign currency forwards are included in other – net, while realized gains or losses are included in net foreign exchange gains in the consolidated statements of income.*

Offsetting Financial Assets and Liabilities

The tables below outline the financial assets and financial liabilities that are subject to set-off rights and related arrangements, and the effect of those rights and arrangements on the consolidated balance sheets:

Offsetting Financial Assets and Liabilities ($ millions)	As at December 31, 2014 Gross Amount	 Amount Offset	 Net Amount
Financial Assets			
Financial derivatives	**264**	**(222)**	**42**
Normal purchase and sale agreements	**1,078**	**(616)**	**462**
	1,342	**(838)**	**504**
Financial Liabilities			
Financial derivatives	**(17)**	**11**	**(6)**
Normal purchase and sale agreements	**(588)**	**219**	**(369)**
	(605)	**230**	**(375)**

Offsetting Financial Assets and Liabilities ($ millions)	As at December 31, 2013 Gross Amount	 Amount Offset	 Net Amount
Financial Assets			
Financial derivatives	22	(5)	17
Normal purchase and sale agreements	551	(170)	381
	573	(175)	398
Financial Liabilities			
Financial derivatives	(293)	271	(22)
Normal purchase and sale agreements	(778)	284	(494)
	(1,071)	555	(516)

Market Risk Sensitivity Analysis

A sensitivity analysis for commodities, foreign currency exchange and interest rate risks has been calculated by increasing or decreasing commodity prices, foreign currency exchange rates or interest rates, as appropriate. These sensitivities represent the increase or decrease in earnings before income taxes resulting from changing the relevant rates, with all other variables held constant. These sensitivities have only been applied to financial instruments held at fair value. The Company's process for determining these sensitivities has not changed during the year.

Commodity Price Risk[(1)]

($ millions)	10% price increase	10% price decrease
Crude oil price	32	(32)
Natural gas price	(11)	11

Foreign Exchange Rate[(2)]

($ millions)	Canadian dollar $0.01 increase	Canadian dollar $0.01 decrease
U.S. dollar per Canadian dollar	2	(2)

(1) *Based on average crude oil and natural gas market prices as at December 31, 2014.*
(2) *Based on the U.S./Canadian dollar exchange rate as at December 31, 2014.*

b) Financial Risk

i) Liquidity Risk Management

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and capability to raise capital from various debt capital markets under its shelf prospectuses. The Company prepares annual capital expenditure budgets, which are monitored and updated as required. In addition, the Company requires authorizations for expenditures on projects, which assists with the management of capital.

Since the Company operates in the upstream oil and gas industry, it requires significant cash to fund capital programs necessary to maintain or increase production, develop reserves, acquire strategic oil and gas assets, repay maturing debt and pay dividends. The Company's upstream capital programs are funded principally by cash provided from operating activities and issuances of debt and equity. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow of maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of short and long-term capital resources. Occasionally, the Company will economically hedge a portion of its production to protect cash flow in the event of commodity price declines.

The Company had the following available credit facilities as at December 31, 2014:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[(1)] *(note 11)*	**645**	**457**
Syndicated bank facilities *(note 13)*	**3,230**	**2,335**
	3,875	**2,792**

(1) *Consists of demand credit facilities.*

In addition to the credit facilities listed above, the Company had unused capacity under the universal short form base shelf prospectus filed in Canada of $2.8 billion and unused capacity under the universal short form base shelf prospectus filed in the United States of U.S. $2.3 billion. The ability of the Company to raise additional capital utilizing these prospectuses is dependent on market conditions.

The Company believes it has sufficient funding through the use of these facilities and access to the capital markets to meet its future capital requirements.

The following are the contractual maturities of the Company's financial liabilities as at December 31, 2014:

Contractual Maturities of Financial Liabilities

($ millions)	2015	2016	2017	2018	2019	Thereafter
Accounts payable and accrued liabilities	2,989	–	–	–	–	–
Other long-term liabilities	31	32	27	24	21	160
Long-term debt	537	464	562	193	1,400	3,065

The Company's contribution payable pursuant to the joint arrangement with BP is payable between December 31, 2014 and December 31, 2015, with the final balance due and payable by December 31, 2015. See Note 26 for amendments to these repayment terms.

Refer to Note 20 for additional contractual obligations.

ii) Credit and Contract Risk Management

Credit and contract risk represent the financial loss that the Company would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms. The Company actively manages its exposure to credit and contract execution risk from both a customer and a supplier perspective. The Company's accounts receivables are broad based with customers in the energy industry and midstream and end user segments and are subject to normal industry risks. The Company's policy to mitigate credit risk includes granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of all accounts. The Company did not have any external customers that constituted more than 10% of gross revenues during the years ended December 31, 2014 or December 31, 2013, with the exception of the Company's joint venture partner BP, relating to revenues from the BP-Husky Toledo Refinery.

Cash and cash equivalents include cash bank balances and short-term deposits maturing in less than three months. The Company manages the credit exposure related to short-term investments by monitoring exposures daily on a per issuer basis relative to predefined investment limits.

The carrying amounts of cash and cash equivalents, accounts receivable and contribution receivable represent the Company's maximum credit exposure.

The Company's accounts receivable was aged as follows at December 31, 2014:

Accounts Receivable Aging

($ millions)	**December 31, 2014**
Current	**1,224**
Past due (1 – 30 days)	**85**
Past due (31 – 60 days)	**11**
Past due (61 – 90 days)	**7**
Past due (more than 90 days)	**26**
Allowance for doubtful accounts	**(29)**
	1,324

The Company recognizes a valuation allowance when collection of accounts receivable is in doubt. Accounts receivable are impaired directly when collection of accounts receivable is no longer expected. For the year ended December 31, 2014, the Company impaired $1 million (2013 – $1 million) of uncollectible receivables.

Note 23 Capital Disclosures

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk, and to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes adjustments as economic conditions and the risk characteristics of its underlying assets change. The Company considers its capital structure to include shareholders' equity and debt which, was $25.9 billion as at December 31, 2014 (December 31, 2013 – $24.2 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 capital based on the current and projected ratios of debt to cash flow (defined as total debt divided by cash flow – operating activities plus non-cash charges before settlement of asset retirement obligations, income taxes paid, interest received and changes in non-cash working capital) and debt to capital employed (defined as total debt divided by total debt and shareholders' equity). The Company's objective is to maintain a debt to capital employed target of less than 25% and a debt to cash flow ratio of less than 1.5 times. At December 31, 2014, debt to capital employed was 20% (December 31, 2013 – 17%) which was below the long-term range, providing the financial flexibility to fund the Company's capital program and profitable growth opportunities. At December 31, 2014, debt to cash flow was 1.0 times (December 31, 2013 – 0.8 times). The ratio may increase at certain times as a result of capital spending. To facilitate the management of this ratio, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company's share capital is not subject to external restrictions; however, the syndicated credit facilities include a debt to cash flow covenant. The Company was in compliance with these covenants at December 31, 2014.

There were no changes in the Company's approach to capital management from the previous year.

Note 24 Government Grants

The Company has government assistance programs in place where it receives funding based on ethanol production and sales from the Lloydminster and Minnedosa ethanol plants from the Department of Natural Resources and the Government of Manitoba. Applications for funding are submitted quarterly. During 2014, the Company received $33 million (2013 – $26 million) under these programs. The grants are accrued for operational purposes and have been recorded as revenues in the consolidated statements of income. The programs will expire in 2015.

Note 25 Employee Salaries and Benefit Expenses

The total compensation expense recognized in purchases of crude oil and products and selling, general and administrative expenses in the consolidated statements of income for the year ended December 31, 2014 was $734 million (2013 – $778 million) as follows:

Compensation of Employees

($ millions)	**2014**	2013
Short-term employee benefits[1]	**786**	711
Post-employment benefits[2]	**55**	48
Stock-based compensation[3]	**(17)**	105
	824	864
Less: capitalized portion	**(90)**	(86)
	734	778

[1] *Short-term employee benefits are comprised of salary and benefits earned during the year, plus cash bonuses awarded during the year. Annual bonus awards settled in shares are included in stock-based compensation expense.*
[2] *Post-employment benefits represent the estimated cost to the Company to provide either a defined benefit pension plan or a defined contribution pension plan, and other post-retirement benefits for the current year of service. Refer to Note 19.*
[3] *Stock-based compensation expense (recovery) represents the cost to the Company for participation in share-based payment plans. Refer to Note 18.*

Note 26 Subsequent Event

Subsequent to December 31, 2014, the Company amended the terms of repayment of the Company's contribution payable with BP-Husky Refining LLC. In accordance with the amendment, U.S. $1 billion of the net contribution payable was paid on February 2, 2015. As a result of prepayment, the accretion rate has been reduced from 6 percent to 2.5 percent for the future term of the agreement. The remaining amount of approximately U.S. $300 million will be paid by way of funding all capital contributions of the BP- Husky Refining LLC joint operation with full payment required on or before December 31, 2017.

Supplemental Financial and Operating Information

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	**2014**	2013	2012[1]	2011[1]	2010[2]	2009[2][3]	2008[2][3]	2007[2][3]	2006[2][3]	2005[2][3]
Financial Highlights										
Gross Revenues	**25,122**	24,181	22,948	22,829	18,085	15,935	26,744	16,583	13,478	11,085
Net earnings	**1,258**	1,829	2,022	2,224	947	1,416	3,751	3,201	2,734	1,996
Earnings per share										
Basic	**1.26**	1.85	2.06	2.40	1.11	1.67	4.42	3.77	3.21	2.35
Diluted	**1.20**	1.85	2.06	2.34	1.05	1.67	4.42	3.77	3.21	2.35
Expenditures on PP&E[4]	**5,023**	5,028	4,701	4,618	3,571	2,797	4,108	2,974	3,201	3,099
Total debt[9]	**5,292**	4,119	3,918	3,911	4,187	3,229	1,957	2,814	1,611	1,886
Debt to capital employed *(percent)*[5]	**20**	17	17	18	22	18	12	19	14	20
Corporate reinvestment ratio *(percent)*[5]	**101**	108	106	98	134	111	66	86	71	80
Return on capital employed *(percent)*[5]	**7.7**	8.7	9.5	12.1	6.4	9.1	25.1	25.6	27.1	22.7
Return on equity *(percent)*[5]	**6.2**	9.3	10.9	13.8	6.7	9.8	28.9	30.1	31.9	29.2
Upstream										
Daily production, before royalties										
Light crude oil and NGL *(mbbls/day)*	**83.7**	81.1	72.3	87.6	80.4	89.1	122.9	138.7	111.0	64.6
Medium crude oil *(mbbls/day)*	**21.5**	23.2	24.1	24.5	25.4	25.4	26.9	27.1	28.5	31.1
Heavy crude oil *(mbbls/day)*	**76.8**	74.5	76.9	74.5	74.5	78.6	84.3	86.5	88.5	88.0
Bitumen *(mbbls/day)*	**54.6**	47.7	35.9	24.7	22.3	23.1	22.7	20.4	19.6	18.0
	236.6	226.5	209.2	211.3	202.6	216.2	256.8	272.7	247.6	201.7
Natural gas *(mmcf/day)*	**621.0**	512.7	554.0	607.0	506.8	541.7	594.4	623.3	672.3	680.0
Total production *(mboe/day)*	**340.1**	312.0	301.5	312.5	287.1	306.5	355.9	376.6	359.7	315.0
Total proved reserves, before royalties *(mmboe)*[6]	**1,279**	1,265	1,192	1,172	1,081	933	896	1,014	1,004	985
Downstream										
Upgrading										
Synthetic crude oil sales *(mbbls/day)*	**53.3**	50.5	60.4	55.3	54.1	61.8	58.7	53.1	62.5	57.5
Upgrading differential *($/bbl)*	**21.80**	29.14	22.34	27.34	14.52	11.89	28.77	30.73	26.16	30.70
Canadian Refined Products										
Fuel sales *(million of litres/day)*[7]	**8.0**	8.1	8.7	9.5	8.2	7.6	7.9	8.7	8.7	8.9
Refinery throughput										
Prince George refinery *(mbbls/day)*	**11.7**	10.3	11.1	10.6	10.0	10.3	10.1	10.5	9.0	9.7
Lloydminster refinery *(mbbls/day)*	**28.8**	26.4	28.3	28.1	27.8	24.1	26.1	25.3	27.1	25.5
Refinery utilization *(percent)*[8]	**98**	89	96	92	92	86	91	90	90	101
US Refining and Marketing										
Refinery throughput										
Lima Refinery (mbbls/day)	**141.6**	149.4	150	144.3	136.6	114.6	136.6	143.8	–	–
Toledo Refinery (mbbls/day)	**63.2**	65.0	60.6	63.9	64.4	64.9	60.6	–	–	–
Refining Margin *(U.S. $/bbl crude throughput)*	**9.37**	15.06	17.48	17.60	7.29	11.37	(0.86)	12.42	–	–

(1) Gross revenues and U.S. refining margin have been recast for 2012 and 2011 to reflect a change in the classification of certain trading transactions.
(2) Results reported for 2010 and previous years have not been adjusted for the change in presentation of the former Midstream.
(3) Results are reported in accordance with previous Canadian GAAP. Certain reclassifications have been made to conform with current presentation.
(4) Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.
(5) The financial ratios constitute non-GAAP measures. Refer to Section 11.3 of the Management's Discussion and Analysis for disclosures on non-GAAP measures.
(6) Total proved reserves, before royalties for 2010 onwards were prepared in accordance with the Canadian Securities Administrators' National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Prior to 2010, reserves were prepared in accordance with the rules of the United States Securities and Exchange Commission guidelines and the United States Financial Accounting Standards Board. Refer to Section 11.2 of the Management's Discussion and Analysis for a discussion.
(7) Fuel sales have been recast to exclude non-retail products, results reported for 2010 and previous years have not been adjusted for the change in presentation.
(8) Refinery utilization averages Prince George and Lloydminster utilization percentages.
(9) Total debt includes long-term debt, long-term debt due within one year and commercial paper.

Segmented Financial Information

	Upstream								Downstream			
	Exploration and Production				Infrastructure and Marketing				Upgrading			
($ millions)	**2014**	2013	2012	2011	**2014**	2013	2012	2011	**2014**	2013	2012	2011
Year ended December 31												
Gross revenues[(2)(3)]	**8,634**	7,333	6,581	7,556	**2,202**	2,134	2,377	1,945	**2,212**	2,023	2,191	2,217
Royalties	**(1,030)**	(864)	(693)	(1,125)	**–**	–	–	–	**–**	–	–	–
Marketing - other[(2)(3)]	**–**	–	–	–	**70**	312	398	94	**–**	–	–	–
Revenues, net of royalties	**7,604**	6,469	5,888	6,431	**2,272**	2,446	2,775	2,039	**2,212**	2,023	2,191	2,217
Expenses												
Purchase of crude oil and products[(2)]	**96**	91	73	99	**2,056**	2,004	2,258	1,818	**1,676**	1,378	1,636	1,628
Production and operating expenses[(3)]	**2,172**	2,016	1,875	1,751	**32**	21	12	6	**180**	161	150	146
Selling, general and administrative expenses	**253**	240	175	153	**8**	12	21	17	**9**	7	3	3
Depletion, depreciation, amortization and impairment	**3,434**	2,515	2,121	2,018	**25**	20	22	24	**108**	96	102	164
Exploration and evaluation expenses	**214**	246	344	470	**–**	–	–	–	**–**	–	–	–
Other – net	**(60)**	(35)	(105)	(261)	**(2)**	(3)	–	1	**11**	(27)	(17)	67
Total Expenses	**6,109**	5,073	4,483	4,230	**2,119**	2,054	2,313	1,866	**1,984**	1,615	1,874	2,008
Earnings from operating activities	**1,495**	1,396	1,405	2,201	**153**	392	462	173	**228**	408	317	209
Share of equity investment	**(6)**	(10)	(11)	–	**–**	–	–	–	**–**	–	–	–
Net financial items	**(152)**	(103)	(73)	(64)	**–**	–	–	–	**(1)**	(7)	(11)	(7)
Earnings (loss) before income tax	**1,337**	1,283	1,321	2,137	**153**	392	462	173	**227**	401	306	202
Current income taxes	**386**	162	134	41	**99**	222	171	64	**47**	19	31	(2)
Deferred income taxes	**(41)**	169	211	515	**(60)**	(122)	(55)	(20)	**12**	85	49	54
Total income tax provision (recovery)	**345**	331	345	556	**39**	100	116	44	**59**	104	80	52
Net earnings (loss)	**992**	952	976	1,581	**114**	292	346	129	**168**	297	226	150
Total assets as at December 31	**26,035**	24,653	22,774	20,141	**1,969**	1,670	1,506	1,509	**1,243**	1,355	1,242	1,316

(1) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*
(2) *Gross revenues, marketing and other and purchases have been recast for the comparative periods presented above to reflect a change in the classification of certain trading transactions.*
(3) *Results have been restated for the change in presentation of reclassification of processing facilities from Infrastructure and Marketing to Exploration and Production.*

Downstream								Corporate and Eliminations[1]				Total			
Canadian Refined Products				U.S. Refining and Marketing											
2014	2013	2012	2011	**2014**	2013	2012	2011	**2014**	2013	2012	2011	**2014**	2013	2012	2011
4,020	3,737	3,848	3,877	**10,663**	10,728	9,856	9,500	**(2,679)**	(2,086)	(2,303)	(2,360)	**25,052**	23,869	22,550	22,735
–	–	–	–	**–**	–	–	–	**–**	–	–	–	**(1,030)**	(864)	(693)	(1,125)
–	–	–	–	**–**	–	–	–	**–**	–	–	–	**70**	312	398	94
4,020	3,737	3,848	3,877	**10,663**	10,728	9,856	9,500	**(2,679)**	(2,086)	(2,303)	(2,360)	**24,092**	23,317	22,255	21,704
3,319	3,134	3,208	3,265	**9,941**	9,546	8,544	8,200	**(2,679)**	(2,086)	(2,303)	(2,360)	**14,409**	14,067	13,416	12,650
263	227	184	182	**472**	420	385	391	**–**	–	4	–	**3,119**	2,845	2,610	2,476
44	26	58	49	**9**	4	13	12	**139**	217	178	194	**462**	506	448	428
102	90	83	80	**268**	233	212	195	**73**	51	40	38	**4,010**	3,005	2,580	2,519
–	–	–	–	**–**	–	–	–	**–**	–	–	–	**214**	246	344	470
–	(5)	(2)	–	**–**	–	4	–	**(5)**	(17)	(3)	–	**(56)**	(87)	(123)	(193)
3,728	3,472	3,531	3,576	**10,690**	10,203	9,158	8,798	**(2,472)**	(1,835)	(2,084)	(2,128)	**22,158**	20,582	19,275	18,350
292	265	317	301	**(27)**	525	698	702	**(207)**	(251)	(219)	(232)	**1,934**	2,735	2,980	3,354
–	–	–	–	**–**	–	–	–	**–**	–	–	–	**(6)**	(10)	(11)	–
(5)	(5)	(6)	(6)	**(3)**	(3)	(5)	(4)	**17**	21	(38)	(133)	**(144)**	(97)	(133)	(214)
287	260	311	295	**(30)**	522	693	698	**(190)**	(230)	(257)	(365)	**1,784**	2,628	2,836	3,140
80	65	89	25	**1**	18	(1)	76	**104**	103	112	150	**717**	589	536	354
(7)	1	(9)	50	**(12)**	165	258	178	**(83)**	(88)	(176)	(215)	**(191)**	210	278	562
73	66	80	75	**(11)**	183	257	254	**21**	15	(64)	(65)	**526**	799	814	916
214	194	231	220	**(19)**	339	436	444	**(211)**	(245)	(193)	(300)	**1,258**	1,829	2,022	2,224
1,676	1,788	1,646	1,632	**5,788**	5,537	5,326	5,476	**2,137**	1,901	2,667	2,352	**38,848**	36,904	35,161	32,426

Segmented Financial Information

	Upstream		Downstream			Corporate and Eliminations[1]	Total
	Exploration and Production	Infrastructure and Marketing	Upgrading	Canadian Refined Products	U.S. Refining and Marketing		
($ millions)	2010	2010	2010	2010	2010	2010	2010
Year ended December 31							
Gross revenues[2]	5,744	7,002	1,570	2,975	7,107	(6,313)	18,085
Royalties	(978)	–	–	–	–	–	(978)
Revenues, net of royalties	4,766	7,002	1,570	2,975	7,107	(6,313)	17,107
Expenses							
Purchase of crude oil and products and production and operating expenses[2]	1,403	6,684	1,439	2,679	6,935	(6,251)	12,889
Selling, general and administrative expenses	152	22	–	49	7	61	291
Depletion, depreciation, amortization and impairment	1,521	43	74	88	191	75	1,992
Exploration and evaluation expenses	438	–	–	–	–	–	438
Other – net	1	34	(41)	(2)	–	(7)	(15)
Total expenses	3,515	6,783	1,472	2,814	7,133	(6,122)	15,595
Earnings from operating activities	1,251	219	98	161	(26)	(191)	1,512
Net financial items	40	–	9	2	6	238	295
Earnings (loss) before income tax	1,211	219	89	159	(32)	(429)	1,217
Current income taxes	(23)	62	1	56	–	92	188
Deferred income taxes	373	(3)	25	(14)	(12)	(287)	82
Total income tax provision	350	59	26	42	(12)	(195)	270
Net earnings (loss)	861	160	63	117	(20)	(234)	947
Total assets - as at December 31	17,354	1,325	1,987	1,517	5,092	775	28,050

[1] *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.*
[2] *Results have not been restated for the change in presentation of the former Midstream segment, the reclassification of certain trading activities, and reclassification of processing facilities from Infrastructure and Marketing.*

Upstream Operating Information

	2014	2013	2012	2011	2010
Daily Production, before royalties					
Light crude oil and NGL *(mmbls/day)*	**83.7**	81.1	72.3	87.6	80.4
Medium crude oil *(mmbls/day)*	**21.5**	23.2	24.1	24.5	25.4
Heavy crude oil *(mmbls/day)*	**76.8**	74.5	76.9	74.5	74.5
Bitumen *(mmbls/day)*	**54.6**	47.7	35.9	24.7	22.3
	236.6	226.5	209.2	211.3	202.6
Natural gas *(mmcf/day)*	**621.0**	512.7	554.0	607.0	506.8
Total production *(mboe/day)*	**340.1**	312.0	301.5	312.5	287.1
Average sales prices					
Light crude oil and NGL *($/bbl)*	**96.70**	102.35	99.22	104.06	76.90
Medium crude oil *($/bbl)*	**80.69**	74.29	71.51	76.59	64.92
Heavy crude oil *($/bbl)*	**71.91**	63.44	61.91	68.13	58.91
Bitumen *($/bbl)*	**70.57**	61.68	59.49	65.75	57.84
Natural gas *($/mcf)*	**5.99**	3.19	2.60	3.89	3.86
Operating costs *($/boe)*	**16.12**	16.28	15.49	14.01	13.35
Operating netbacks (1)(2)(3)					
Light crude oil and NGL *($/boe)*	**61.60**	69.42	66.13	70.86	47.58
Medium crude oil *($/boe)*	**43.66**	41.53	38.22	42.41	36.88
Heavy crude oil *($/boe)*	**41.95**	34.61	38.31	41.72	34.51
Bitumen *($/boe)*	**51.17**	43.92	42.32	39.34	28.96
Natural gas *($/mcf)*	**2.12**	1.06	0.77	1.96	1.93

(1) *The operating netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing. Operating netback is a non-GAAP measure.*

(2) *Operating netbacks are determined as realized price less royalties and operating costs and transportation on a per unit basis. Operating costs exclude accretion, which is included in administrative expenses and other.*

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

Western Canada and Oil Sands Wells Drilled [(1)]

		2014		2013		2012		2011		2010	
		Gross	**Net**	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	**53**	**45**	39	24	47	30	50	40	60	51
	Gas	**9**	**5**	19	14	19	12	24	24	37	31
	Dry	**3**	**3**	–	–	–	–	3	3	8	8
		65	**53**	58	38	66	42	77	67	105	90
Development	Oil	**469**	**419**	768	709	775	715	880	765	815	722
	Gas	**78**	**68**	68	41	23	17	57	42	73	53
	Dry	**3**	**3**	1	–	5	4	4	4	10	9
		550	**490**	837	750	803	736	941	811	898	784
		615	**543**	895	788	869	778	1,018	878	1,003	874
Success Ratio *(percent)*		**99**	**99**	100	100	99	99	99	99	98	98

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

Supplemental Upstream Operating Statistics

Netback Analysis [1]	2014	2013	2012
Total Upstream [1]			
Crude Oil Equivalent *($/boe)*[2]			
Sales volume *(mboe/day)*	**340.1**	312.0	301.5
Price received *($/boe)*	**67.38**	61.96	57.16
Royalties *($/boe)*	**8.30**	7.59	6.29
Operating costs *($/boe)*[3]	**16.12**	16.28	15.49
Offshore transportation *($/boe)*[4]	**0.33**	0.37	0.24
Operating netback *($/boe)*	**42.63**	37.72	35.14
Depletion, depreciation, amortization and impairment *($/boe)*	**27.63**	22.09	19.20
Administration expenses and other ($/boe)[3]	**3.30**	2.51	1.75
Earnings before taxes	**11.70**	13.12	14.19
Lloydminster Heavy Oil			
Thermal Oil			
Bitumen			
Sales volumes *(mbbls/day)*	**43.8**	37.4	26.3
Price received *($/bbl)*	**71.64**	63.36	61.03
Royalties *($/bbl)*	**6.50**	5.69	3.82
Operating costs *($/boe)*[3]	**10.78**	9.90	10.34
Operating netback *($/boe)*	**54.36**	47.77	46.87
Non Thermal Oil			
Medium Oil			
Sales volumes *(mbbls/day)*	**1.8**	1.9	2.1
Price received *($/bbl)*	**76.83**	71.41	70.22
Royalties *($/bbl)*	**5.88**	4.90	5.13
Heavy Oil			
Sales volumes *(mbbls/day)*	**61.8**	58.6	61.1
Price received *($/bbl)*	**72.53**	64.26	62.35
Royalties *($/bbl)*[5]	**8.40**	7.67	4.88
Natural Gas			
Sales volumes *(mmcf/day)*	**17.7**	19.6	25.4
Price received *($/mcf)*	**4.01**	2.89	2.25
Royalties *($/mcf)*	**0.53**	0.34	0.16
Non Thermal Oil Total [2]			
Sales volumes *(mboe/day)*	**66.6**	63.8	67.4
Price received *($/bbl)*	**70.50**	62.07	59.53
Royalties *($/boe)*	**8.10**	7.30	4.64
Operating costs *($/boe)*[3]	**21.14**	21.17	17.75
Operating netback *($/boe)*	**41.26**	33.60	37.14
Oil Sands			
Bitumen			
Total sales volumes *(mbbls/day)*	**10.8**	10.3	9.6
Price received *($/bbl)*	**66.24**	55.60	55.29
Royalties *($/boe)*	**5.50**	4.18	3.76
Operating costs *($/boe)*[3]	**22.49**	21.44	21.61
Operating netback *($/boe)*	**38.25**	29.98	29.92

Netback Analysis (continued)	2014	2013	2012
Western Canada Conventional			
Crude Oil			
Light Oil			
Sales volumes *(mbbls/day)*	**20.3**	20.5	21.3
Price received *($/bbl)*	**89.65**	88.27	80.98
Royalties *($/bbl)*	**11.67**	10.38	10.56
Medium Oil			
Sales volumes *(mbbls/day)*	**19.7**	21.3	22.0
Price received *($/bbl)*	**81.04**	74.56	71.63
Royalties *($/bbl)*	**14.24**	12.89	13.48
Heavy Oil			
Sales volumes *(mboe/day)*	**15.0**	15.9	15.8
Price received *($/bbl)*	**68.90**	60.41	60.21
Royalties *($/boe)*	**11.37**	10.12	10.55
Western Canada Crude Oil Total			
Total sales volumes *(mboe/day)*	**55.0**	57.7	59.1
Price received *($/bbl)*	**80.92**	75.54	71.96
Royalties *($/boe)*	**12.51**	11.23	11.64
Operating costs *($/boe)*[3]	**25.75**	23.58	20.93
Operating netback *($/boe)*	**42.66**	40.73	39.39
Natural Gas & NGLs			
Natural Gas Liquids			
Sales volumes *(mbbls/day)*	**9.8**	9.2	8.8
Price received *($/bbl)*	**67.85**	70.34	66.92
Royalties *($/bbl)*	**15.13**	18.45	18.69
Natural Gas			
Sales volumes *(mmcf/day)*	**489.1**	493.1	528.6
Price received *($/mcf)*[6]	**4.42**	3.20	2.61
Royalties *($/mcf)*[6][7]	**0.20**	(0.02)	(0.10)
Western Canada Natural Gas and NGL Total[2]			
Total sales volumes *(mmcf/day)*	**547.9**	548.3	581.4
Price received *($/mcf)*	**5.16**	4.05	3.39
Royalties *($/mcf)*	**0.45**	0.29	0.19
Operating costs *($/mcf)*[3]	**2.03**	2.08	1.88
Operating netback *($/mcf)*	**2.68**	1.68	1.32
Atlantic Region			
Light Oil			
Sales volumes *(mbbls/day)*	**44.6**	44.1	33.8
Price received *($/bbl)*	**107.50**	114.60	115.78
Royalties *($/boe)*	**18.43**	14.65	12.36
Operating costs *($/boe)*[3]	**13.38**	12.47	17.12
Transportation *($/boe)*[4]	**2.49**	2.62	2.14
Operating netback *($/boe)*	**73.20**	84.86	84.16

Netback Analysis (continued)	**2014**	2013	2012
Asia Pacific Region			
Light Oil and NGL[(2)]			
Sales volumes *(mboe/day)*	**9.0**	7.3	8.4
Price received *($/bbl)*	**90.14**	107.95	113.01
Royalties *($/boe)*	**12.04**	26.23	26.89
Natural Gas			
Sales volumes *(mmcf/day)*	**114.20**	–	–
Price received *($/mcf)*	**13.03**	–	–
Royalties *($/mcf)*	**0.64**	–	–
Asia Pacific Light Oil, NGL & Natural Gas Total[2)]			
Total sales volumes *(mboe/day)*	**28.0**	7.3	8.4
Price received *($/boe)*	**82.02**	107.95	113.01
Royalties *($/boe)*	**6.47**	26.23	26.89
Operating costs *($/boe)*[(3)]	**8.06**	11.39	10.08
Operating netback *($/boe)*	**67.49**	70.33	76.04

(1) *The Upstream netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing. Operating netback is a non-GAAP measure.*

(2) *Includes associated co-products converted to boe.*

(3) *Operating costs exclude accretion, which is included in administration expenses and other.*

(4) *Offshore transportation costs shown separately from price received.*

(5) *The year ended December 31, 2012 royalties includes a royalty credit adjustment received during the first quarter.*

(6) *Includes sulphur sales revenues/royalties.*

(7) *Alberta Gas Cost Allowance reported exclusively as gas royalties.*

Advisories

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

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

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; and anticipated proportion of total production from low sustaining capital cost projects by the end of 2016;
- with respect to the Company's Asia Pacific Region: planned timing of first gas from the Madura Strait BD, MDA, MBH and MDK fields;
- with respect to the Company's Atlantic Region: anticipated timing of first production from, and forecast net peak daily production from, the Company's South White Rose Extension and North Amethyst Hibernia well projects; and anticipated timing of first production from the Company's Bay du Nord development;
- with respect to the Company's Oil Sands properties: the estimated years of production from the reservoir at the Company's Sunrise Energy Project; and anticipating timing of, and volume of production from, the Company's Sunrise Energy Project;
- with respect to the Company's Heavy Oil properties: anticipated timing of first production from, and volume of production from, the Company's Rush Lake, Edam East, Edam West and Vawn heavy oil thermal projects; and
- with respect to the Company's Western Canadian oil and gas resource plays: anticipated timing of increases in production from the Ansell resource project.

In addition, statements relating to "reserves" and "resources" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves or resources described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and resources 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, resource and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this report are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources including third-party consultants, suppliers, 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, 2014 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.

Non-GAAP Measures

Husky uses measurements primarily based on IFRS and also on secondary non-GAAP measurements. The non-GAAP measurements included in this report are: cash flow from operations, net operating earnings, return on capital in use, return on capital employed, return on equity, debt to capital employed and debt to cash flow. For further details on these non-GAAP measurements, please refer to Non-GAAP Measures and Additional Reader Advisories contained in sections 11.3 and 11.4, respectively, of the Company's Management's Discussion and Analysis for the year ended December 31, 2014, which sections are incorporated by reference herein.

Disclosure of Oil and Gas Information

Unless otherwise stated, reserve and resource estimates in this report have an effective date of December 31, 2014 and represent Husky's share. The Sproule evaluation of the heavy oil resources in the Lloydminster region had an effective date of December 31, 2013. Unless otherwise noted, historical production numbers given represent Husky's share.

The Company uses the terms barrels of oil equivalent ("boe"), which is calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

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 estimate of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

The Company has disclosed best-estimate contingent resources of 14.8 billion boe in this report, which is comprised of 13.8 billion boe of crude oil and 6.2 tcf of natural gas. Of the total, 11.5 billion boe is economic at year-end 2014. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters, or a lack of markets. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

Contingent resources are reported as the working interest volumes and Husky's working interest in the properties. The properties assigned contingent resources are Western Canada gas resource plays and Enhanced Oil Recovery ("EOR") projects, Lloydminster Heavy Oil projects, N.W.T. conventional gas, Oil Sands, Atlantic Region and Asia Pacific Region gas.

Best estimate as it relates to resources is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. There is no certainty as to the timing of such development.

Specific contingencies preventing the classification of contingent resources in the Company's Western Canada resource plays as reserves include required improvement in gas prices, optimization of drilling and completion design to further reduce costs, preparation of firm developments plans, timing of development and Company approvals. Positive and negative factors relevant to the estimate of Western Canada resource play resources include a higher level of uncertainty in the estimates as a result of a lower number of wells and limited production history.

Specific contingencies preventing the classification of contingent resources at the Company's Lloydminster Heavy Oil discoveries as reserves include: it may not be viable to develop the estimated volumes in an economic manner;

the formulation of concrete development plans to pursue development of the large inventory of primary and EOR opportunities; Company commitment to dedicate the required capital to develop the inventory of opportunities; large inventory of contingent resource opportunities would likely necessitate development over a time frame much greater than the five-year reserve timing window; regulatory submissions and approval would be required for the thermal and major EOR projects to proceed; and verification of sustained economic productivity using CHOPS from zones with limited tests to date and zones with higher viscosity as well as verification of sub-zone continuity and quality that would enable feasible implementation of an EOR scheme.

The Company has disclosed total heavy oil initially in place in this report. Total petroleum initially in place is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. There is no certainty that any portion of the undiscovered petroleum initially in place will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the undiscovered petroleum initially in place.

The Company has disclosed discovered heavy oil initially in place in this report. Discovered petroleum initially-in-place is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable. There is no certainty that it will be commercially viable to produce any portion of the resources.

Positive and negative factors relevant to the estimation of Lloydminster Heavy Oil total heavy oil initially in place, discovered heavy oil initially in place and best estimate contingent resources include extensive well control, limited demonstrated sustained production in certain zones, potential reservoir heterogeneity in sub-zones which may limit the applicability of EOR schemes, and current lack of development plans.

Specific contingencies preventing the classification of contingent resources at the Company's Oil Sands properties as reserves include further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory applications and company approvals. Development is also contingent upon successful application of steam-assisted gravity drainage and/or Cyclic Steam Stimulation. Positive and negative factors relevant to the estimate of oil sands resources include a higher level of uncertainty in the estimates as a result of lower core-hole drilling density.

Specific contingencies preventing the classification of contingent resources at the Company's Atlantic Region discoveries as reserves include additional exploration and delineation drilling, well testing, facility design, preparation of firm development plans, regulatory applications, company and partner approvals. Positive and negative factors relevant to the estimate of Atlantic Region resources include water depth and distance from existing infrastructure.

Specific contingencies preventing the classification of contingent resources at the Company's Asia Pacific Region discoveries as reserves include additional exploration and delineation drilling, well testing, facility design, preparation of firm development plans, regulatory applications, company and partner approvals. Positive and negative factors relevant to the estimate of Asia Pacific resources include water depth and distance from existing infrastructure.

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 uses certain terms in this report, such as "best estimate contingent resources" that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the SEC.

All currency is expressed in Canadian dollars unless otherwise directed.

Corporate Information

Board of Directors

Victor T.K. Li, Co-Chairman

Canning K.N. Fok, Co-Chairman (2)

William Shurniak, Deputy Chairman (1)

Asim Ghosh, President & Chief Executive Officer

Stephen E. Bradley (1)(3)

Martin J.G. Glynn (2)(3)

Poh Chan Koh

Eva L. Kwok (2)(3)

Stanley T.L. Kwok (4)

Frederick S.H. Ma (1)(4)

George C. Magnus (1)

Neil D. McGee (4)

Colin S. Russel (1)(4)

Wayne E. Shaw (3)(4)

Frank J. Sixt (2)

(1) Audit Committee
(2) Compensation Committee
(3) Corporate Governance Committee
(4) Health, Safety & Environment Committee

The Management Information Circular and the Annual Information Form contain additional information regarding the Directors.

Executives

Asim Ghosh
President & Chief Executive Officer

Robert J. Peabody
Chief Operating Officer

Darren Andruko
Acting Chief Financial Officer

Brad Allison
Senior Vice President, Exploration

Bob I. Baird
Senior Vice President, Downstream

Edward T. Connolly
Senior Vice President, Heavy Oil

Nancy Foster
Senior Vice President, Human & Corporate Resources

David A. Gardner
Senior Vice President, Business Development

James D. Girgulis
Senior Vice President, General Counsel & Secretary

Robert Hinkel
Chief Operating Officer, Asia Pacific

Malcolm Maclean
Senior Vice President, Atlantic Region

Terry Manning
Senior Vice President, Safety, Engineering & Procurement

Sharon Murphy
Senior Vice President, Corporate Affairs

John Myer
Senior Vice President, Oil Sands

Rob W. Symonds
Senior Vice President, Western Canada Production

Roy C. Warnock
Vice President, U.S. Refining

Investor Information

Common Share Information

Year ended December 31		2014	2013	2012
Share price *(dollars)*	High	**37.31**	33.85	29.50
	Low	**21.39**	26.97	22.04
	Close at December 31	**27.50**	33.70	29.40
Average daily trading volumes *(thousands)*		**1,786**	1,533	1,496
Number of common shares outstanding *(thousands)*		**983,738**	983,379	982,229
Weighted average number of common shares outstanding *(thousands)*				
	Basic	**983,595**	983,028	975,808
	Diluted	**985,251**	983,618	975,883

Trading in the common shares of Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite, S&P/TSX Capped Energy Index and in the S&P/TSX 60 indices.

Toronto Stock Exchange Listing
HSE, HSE.PR.A and HSE.PR.C

Outstanding Shares
The number of common shares outstanding at December 31, 2014 was 983,738,062.

Transfer Agent and Registrar
Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company N.A. Share certificates may be transferred at Computershare's principal offices in Calgary, Toronto, Montreal and Vancouver, and at Computershare's principal office in Denver, Colorado, in the United States.

Queries regarding share certificates, dividends and estate transfers should be directed to Computershare Trust Company at 1-800-564-6253 (in Canada and the United States) and 1-514-982-7555 (outside Canada and the United States).

Auditors
KPMG LLP
2700, 205 Fifth Avenue S.W.
Calgary, Alberta T2P 4B9

Annual and Special Meeting
The Annual and Special Meeting of Shareholders will be held at 10:30 a.m. on Wednesday, May 6, 2015 in the Palomino Room at the BMO Centre, Stampede Park, 20 Roundup Way S.E., Calgary, Alberta, Canada.

Additional Publications
The following publications are available on our website:

- Annual Information Form, filed with Canadian securities regulators
- Form 40-F, filed with the U.S. Securities and Exchange Commission
- Quarterly Reports

Corporate Office

Husky Energy Inc.
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Fax: (403) 298-7464

Corporate Affairs

Telephone: (403) 298-6111
Fax: (403) 298-6515
E-mail: corpcom@huskyenergy.com

Website

Visit Husky Energy online at www.huskyenergy.com

Dividends

The Board of Directors has approved a dividend policy that pays quarterly dividends.

Declaration Date	Quarter Dividend
October 2014	$ 0.300
July 2014	0.300
May 2014	0.300
February 2014	0.300
October 2013	0.300
July 2013	0.300
May 2013	0.300
February 2013	0.300
November 2012	0.300
July 2012	0.300
April 2012	0.300
February 2012	0.300
November 2011	0.300
July 2011	0.300
April 2011	0.300
February 2011	0.300
October 2010	0.300
July 2010	0.300
April 2010	0.300
February 2010	0.300

Husky Energy

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Design and Production: One Design
Printing: Hemlock Printers