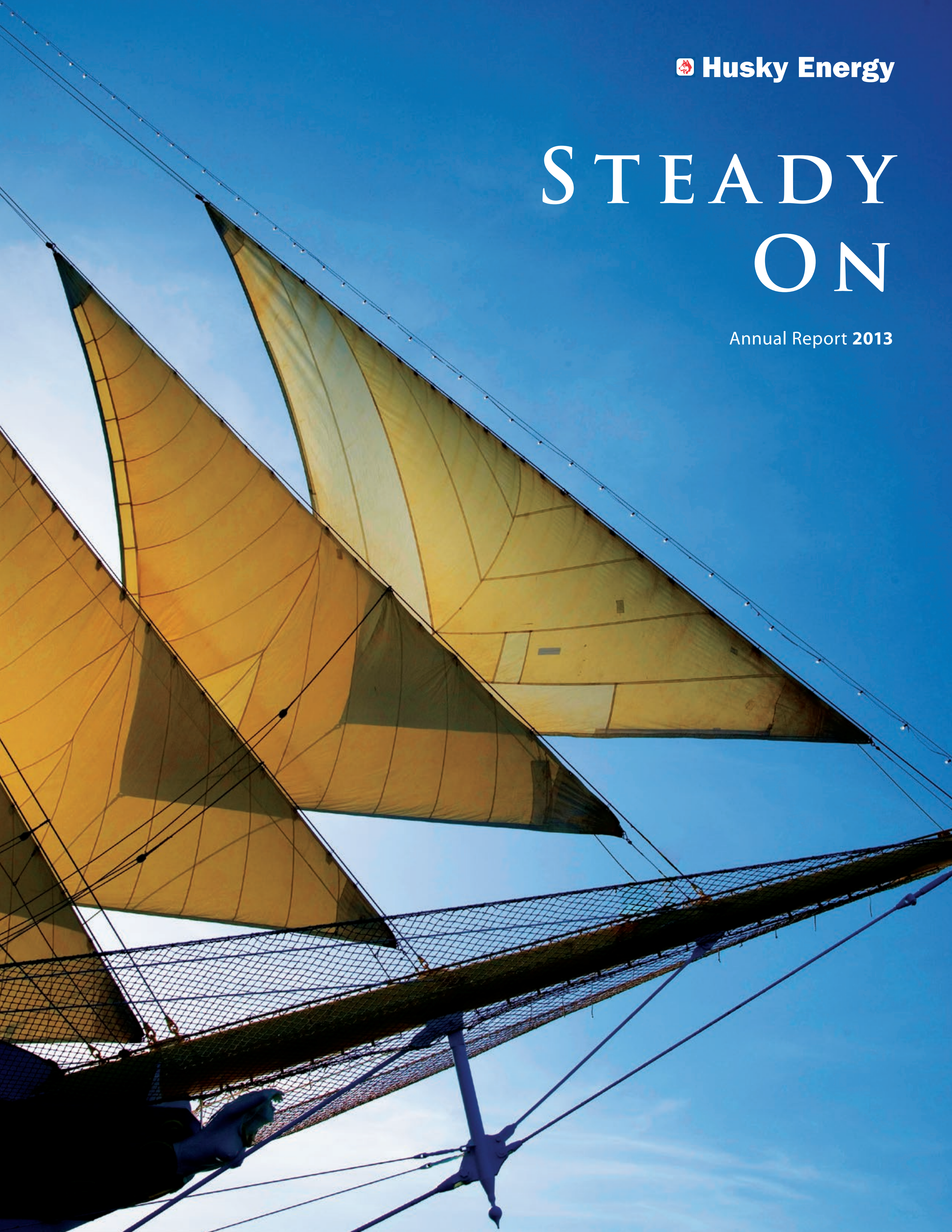
Husky Energy

STEADY ON

Annual Report **2013**




Liwan Gas Project


Sunrise Energy Project

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 symbols HSE and HSE.PR.A. The Company operates in Western and Atlantic Canada, the United States and the Asia Pacific Region with Upstream and Downstream business segments. Husky's balanced growth strategy focuses on consistent execution, disciplined financial management and safe and reliable operations.

Overview

01 Highlights
02 Report to Shareholders
03 Letter from the CEO
08 Business Results

Financial

12 Management's Discussion and Analysis
68 Management's Report
69 Independent Auditors' Report
70 Consolidated Financial Statements
75 Notes to the Consolidated Financial Statements
123 Supplemental Financial and Operating Information
132 Advisories
135 Corporate Information
136 Investor Information

Highlights

Financial Highlights[1]

Year ended December 31		2013	2012
(millions of dollars except where indicated)			
Gross revenue		**24,181**	22,948
Revenues, net of royalties		**23,317**	22,255
Cash flow from operations[2]		**5,222**	5,010
Per share *(dollars)*	Basic	**5.31**	5.13
	Diluted	**5.31**	5.13
Net earnings		**1,829**	2,022
Per share *(dollars)*	Basic	**1.85**	2.06
	Diluted	**1.85**	2.06
Dividends			
Per share *(dollars)*	Ordinary	**1.20**	1.20
Capital investment[3]		**5,028**	4,701
Return on capital in use *(%)*[2]		**12.6**	12.7
Return on capital employed *(%)*[2]		**8.7**	9.5
Return on equity *(%)*[2]		**9.3**	10.9
Debt to capital employed *(%)*[2]		**17.0**	17.0
Debt to cash flow *(times)*[2]		**0.8**	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 58.
(3) Excludes capitalized costs related to asset retirement obligations incurred during the period.

Operational Highlights

Year ended December 31	2013	2012
Daily production, before royalties		
Light crude oil & NGL *(mbbls/day)*	**81.1**	72.3
Medium crude oil *(mbbls/day)*	**23.2**	24.1
Heavy crude oil and bitumen *(mbbls/day)*	**122.2**	112.8
Total crude oil & NGL *(mbbls/day)*	**226.5**	209.2
Natural gas *(mmcf/day)*	**513**	554
Total *(mboe/day)*	**312.0**	301.5
Total proved reserves, before royalties *(mmboe)*[1]	**1,265**	1,192
Upgrader throughput *(mbbls/day)*	**66.1**	77.4
Fuel sales *(million litres/day)*	**8.1**	8.7
Lima Refinery throughput *(mbbls/day)*	**149.4**	150.0
Toledo Refinery throughput *(mbbls/day, 50% w.i.)*	**65.0**	60.6
Lloydminster Refinery throughput *(mbbls/day)*	**26.4**	28.3
Prince George Refinery throughput *(mbbls/day)*	**10.3**	11.1
Ethanol production *(thousand litres/day)*	**742.4**	721.2

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

Consistent Execution

Foundation

Heavy Oil and Western Canada

- Thermal production increased to 37,000 bbls/day, more than double since 2010
- Advanced 3,500 bbls/day Sandall thermal project to first oil in early 2014
- Three additional 10,000 bbls/day thermal developments underway
- Accelerated Ansell liquids-rich gas resource play

Downstream

- Increased flexibility of crude feedstock, product range and market access
- Installed new kerosene hydrotreater at the Husky Lima Refinery
- Further enhanced reliability and efficiency at Lloydminster Upgrader
- Advanced work on new gas compressor at partner-operated refinery in Toledo

Pillars of Growth

Asia Pacific Region

- Completed major infrastructure at Liwan Gas Project
- Sales agreements finalized for Liuhua 34-2 field

Oil Sands/Sunrise Energy Project

- Advanced Sunrise Energy Project to 85% completion with startup expected in the second half of 2014
- Completed six well pads for 60,000 bbls/day (30,000 net) first phase
- Design work underway for next phase of Sunrise

Atlantic Region

- Advanced development of White Rose satellite fields
- Confirmed wellhead platform concept as preferred option with partner for full field development of West White Rose and signed benefits agreement with Government of Newfoundland and Labrador
- Discovered two significant oil fields at Harpoon and Bay du Nord in the Flemish Pass Basin

Report to Shareholders

Steady On

Like a steady ship, a prudent company charts a disciplined business plan to provide for strong performance in choppy waters.

When we first mapped out our strategic course in the fall of 2010, we set out specific metrics to rejuvenate our historic foundation business in Heavy Oil and Western Canada and advance our three growth pillars in the Asia Pacific Region, the Oil Sands and the Atlantic Region. Our balanced growth strategy included a focus on financial discipline, a top-quartile sustainable dividend for our shareholders and most importantly, consistent execution across the business.

Three years is a good time to take a reckoning of what we have accomplished since we first embarked on our journey.

Over that interval, we have continued to meet our annual production guidance, hit our operational targets on schedule and maintained the compass setting for balanced growth.

Our major projects are nearing completion, with the Liwan Gas Project ramping up and the Sunrise Energy Project in sight.

Two significant discoveries with our partner in the Flemish Pass Basin offshore eastern Canada have re-energized our efforts to stabilize production and extract even greater value from our position in the Atlantic Region.

In Heavy Oil, which has been our 'bread and butter' business for most of our past 75 years, we are building on a strong suite of thermal projects with the recent sanction of two new developments at Vawn and Edam East. In Western Canada, we are continuing to develop our near-term oil and liquids-rich gas resource plays while evaluating new plays for the medium and long term and working to optimize the extensive infrastructure we have in this region.

The integration of our business proved its mettle once again by enabling the capture of world pricing for our Western Canada production.

As we move forward into 2014, we are raising our sights further by increasing production to a range of 330,000 to 355,000 barrels of oil equivalent per day. To support this, our capital spending program for 2014 will be $4.8 billion, comparable to our 2013 budget, which reflects our ongoing investment in heavy oil thermal projects and Downstream flexibility initiatives.

Our rich pipeline of projects, constantly analyzed through our lens of a rigorous portfolio management and capital allocation process, provides for a balance of near, medium, and long-term opportunities.

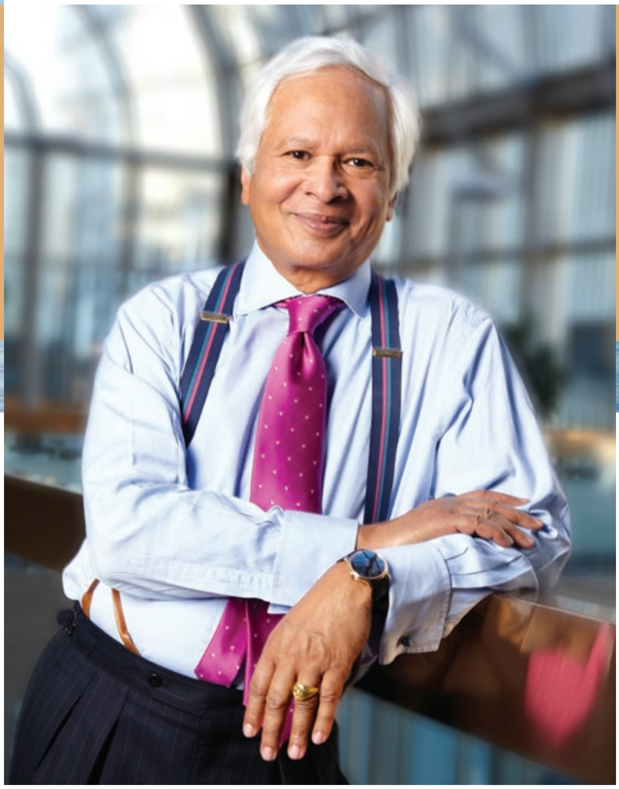
The results we have seen over the past three years have strengthened our resolve to keep the tiller steady and on course.

On behalf of the Board of Directors of Husky Energy, we would like to thank our shareholders for their continued support as we forge ahead.

Victor T.K. Li
Co-Chairman

Canning K.N. Fok
Co-Chairman

Letter from the CEO



Husky continued to steer a steady course in 2013, guided by a balanced growth strategy and consistent execution across its business.

The Company sharpened its focus on strengthening its historic foundation in Heavy Oil and Western Canada while setting the stage for accelerated growth from major growth projects in the Asia Pacific Region, the Oil Sands and the Atlantic Region. Strong financial and operational results speak to a seasoned business plan rooted in disciplined portfolio management and capital allocation, with an ongoing commitment to create shareholder value through a sustainable dividend.

Actions taken to further integrate operations provided substantial value to Husky's balance sheet by offsetting significant volatility in market crack spreads, as well as heavy oil and Western Canada differentials, through the capture of world prices for Western Canada crude production. Additional Downstream initiatives have improved the flexibility of crude feedstock, product range and market access to deliver the best returns. This has provided a measure of stability in both earnings and cash flow, which underpins the Company's growth strategy and dividends.

Husky's portfolio reflected an overall product mix of 73 percent oil and liquids compared to about 69 percent in 2012. More than 95 percent of all wells drilled in Western Canada targeted oil and liquids-rich gas.

With the advancement of the landmark Liwan Gas Project and steady progress towards first oil from the Sunrise Energy Project in late 2014, the Company is making headway as planned in delivering on its financial and operational targets.

Performance Highlights

- Net operating earnings for the year were $2 billion, comparable to 2012.
- Net earnings were approximately $1.8 billion, after a $204 million non-cash impairment charge on dry gas assets in Western Canada.
- Cash flow from operations was $5.2 billion, on plan with the target of six to eight percent compound annual growth per year.
- Average annual production was within guidance at 312,000 barrels of oil equivalent per day (boe/day), compared to 301,500 boe/day in 2012. This partially reflected unplanned maintenance and ongoing operational issues at the partner-operated *Terra Nova* FPSO (Floating Production, Storage and Offloading) vessel in the Atlantic Region, the deliberate reduction in dry gas production, and continuing third-party infrastructure outages and downtime in Western Canada.


Ansell liquids-rich gas production


Bolney Celtic thermal development

- Reserves growth consistently outpaced production, with an average proved reserves replacement ratio (excluding economic factors) over the past three years of 172 percent. Including economic factors, the average proved three-year reserves replacement ratio was 154 percent, ahead of the five-year average target of 140 percent per year.

Foundation

Heavy Oil

Husky's cornerstone business in Western Canada was further rejuvenated by consistent performance from its heavy oil thermal projects. Thermals are now producing more than 37,000 bbls/day of Husky's total heavy oil production of approximately 112,000 bbls/day. The technology has emerged as a central driver of the Company's expected steady growth in crude oil volumes in 2014 and beyond.

Low operating and finding and development costs, combined with a long lifespan, are contributing to a strong return on investment for these projects.

Construction on the 3,500 bbls/day Sandall thermal development was completed in preparation for first oil in 2014. Construction continued at the 10,000 bbls/day thermal project at Rush Lake, with first production scheduled for the second half of 2015.

Two new 10,000 bbls/day thermal developments were sanctioned at Edam East and Vawn in Saskatchewan. Construction is set to begin in 2014, and these projects are expected to deliver a total of 20,000 bbls/day of production once they begin operations in 2016.

Approximately 550 wells are scheduled to be drilled across the heavy oil portfolio in 2014, including 125 that will support thermal production.

In December 2012, Husky set a target to achieve 55,000 bbls/day of production from thermal projects by 2017. With the continued success of its thermal projects, this timeline has been accelerated to 2016.

Western Canada

The Company continued transforming its Western Canada business in 2013 with a continuing focus on driving down costs and advancing its liquids-rich gas and oil resource plays.

A four-rig horizontal drilling program commenced at the Ansell liquids-rich gas resource play as plans progressed to more than double production to approximately 30,000 boe/day from the multi-zone project in the next few years. Husky continued to reduce its dry gas production in Western Canada during the year to redirect capital into higher-netback resource play opportunities.

Substantial volumes of dry gas produced by operations are consumed internally, providing a natural hedge against market price variability. As its heavy oil thermal projects advance and the Sunrise Energy Project comes on line, it is anticipated that the Company will be consuming 50 percent of its own Canadian gas production by 2015.

Drilling and development activities on oil resource plays were focused on the near-term Bakken, Viking, Cardium and Lower Shaunavon plays.


Liwan gas terminal


Safety briefing

In the Canol Shale play at Slater River in the Northwest Territories, two vertical wells were completed and tested, construction of an all-season access road was substantially completed, and consultations continued with the local community to advance additional drilling plans.

Downstream

In Downstream, the Company worked to better position its assets with a number of cost-efficient initiatives. These included significant investments at the Lima Refinery to process heavier feedstock as the Company prepares to bring on more heavy oil thermal projects in Western Canada.

The Company continued to increase its market connectivity and storage through substantial pipeline commitments and by enhancing its midstream infrastructure.

An example of increased market access was the sale of one million barrels of oil from the White Rose field to the Indian Oil Corporation. White Rose oil is now approved for use in state-owned refineries in India, opening up potential new markets for the Company's production while further capturing world pricing.

Growth Pillars

Asia Pacific

The Liwan Gas Project has been brought from discovery to production in just seven years, one of the quickest large-scale deepwater developments on record.

The year was peppered with highlights towards this remarkable milestone, including the construction and installation of the offshore platform about 300 kilometres southeast of the Hong Kong Special Administrative Region (SAR) in the South China Sea.

The 30,000-tonne topsides infrastructure for the platform was floated over and placed on a steel jacket anchored to the sea floor in 200 metres of water.

Approximately 260 kilometres of pipeline was laid from the platform to the onshore gas terminal, which processes natural gas and associated liquids for markets in Mainland China and potentially the Hong Kong SAR.

Gas sales agreements were signed for two of the three fields on the Liwan block, Liwan 3-1 and Liuhua 34-2, while negotiations continued for sales gas from Liuhua 29-1. The three fields share transportation and gas processing infrastructure, with Liuhua 34-2 scheduled to be tied into Liwan 3-1 over a six to eight-week period in the second half of 2014 and Liuhua 29-1 expected to come onstream in the 2016-2017 timeframe.

Following the tie-in of Liuhua 34-2, initial natural gas sales are expected to rise to approximately 340 million cubic feet per day (gross) by the end of 2014 and increase to a range of 400 to 500 mmcf/day (gross) once Liuhua 29-1 is online.

Husky holds a 49 percent interest in the Production Sharing Contract (PSC) for the Liwan Gas Project and operates the deepwater infrastructure and the Mono-Ethylene Glycol (MEG) unit on the shallow water platform. China National Offshore Oil Corporation (CNOOC) operates the shallow water facilities and onshore gas terminal.


Moose Mountain gas facility

SeaRose FPSO

The Company's first producing project in the South China Sea at the Wenchang oil fields has delivered more than 137 million barrels of light, sweet crude oil (100% W.I.) since operations began in 2002. Husky has a 40 percent working interest in Wenchang, located in the Pearl River Mouth Basin about 400 kilometres southwest of the Hong Kong SAR.

Offshore Indonesia, Husky is progressing two shallow water projects in the Madura Strait. A plan of development for the MDA/MBH fields received government approval while construction is underway on the BD field following regulatory approval of infrastructure contracts. The Company holds a 40 percent ownership in both projects.

A new discovery was made late in the year in the Madura Strait and subject to final testing, could be tied into the planned infrastructure of the MDA/MBH fields nearby. Husky continues to evaluate four additional discoveries made in the area in 2012.

Oil Sands

The Sunrise Energy Project in northern Alberta was 85 percent complete at year end and is moving forward towards startup in the second half of 2014.

Construction of all field facilities for the 60,000 bbls/day (30,000 net) first phase of the project has been completed. The first of two trains within the Central Plant Facility is scheduled to be completed in the second half of 2014, with the second train brought online approximately six months afterwards.

Bitumen from Sunrise will be transported by pipeline to the partner-operated BP-Husky Refinery in Toledo, Ohio for processing and marketing. The Toledo refinery is continuing work on a feedstock optimization project to allow for efficient processing of the oil from Sunrise.

Preliminary design work has been completed on the next phase of Sunrise. Subject to Company and partner approvals, the next phase will be developed in two stages, each accommodating 70,000 bbls/day of production capacity. This would bring total Sunrise production capacity to 200,000 bbls/day (100,000 net).

Atlantic Region

Husky continued to forge ahead with its satellite development projects at the White Rose field, located approximately 350 kilometres east of St. John's. The continuing investments made to the *SeaRose* FPSO vessel have provided a platform for steady, reliable production from the region as the Company further extends its reach in the Jeanne d'Arc Basin and the Flemish Pass.

Near-Term Production

Gas injection is underway at the South White Rose extension, where the Company's proved plus probable plus possible reserves are 20 million barrels of oil (6.9 million barrels proved, 9.9 million barrels probable and 3.1 million barrels possible, Husky W.I. share, as of December 31, 2013). Oil production is scheduled to commence in the second half of 2014, with production tied back to the *SeaRose* FPSO.


Lloydminster Upgrader


Minnedosa Ethanol Plant

The Company also received regulatory approval to develop additional production opportunities at the southern tip of the main White Rose field.

A fifth production well at the North Amethyst subsea tieback, the first multi-lateral well on the field, was brought onstream late in the year.

Mid- to Long-Term Production
A fixed wellhead platform has been confirmed as the preferred option for the full field development of the West White Rose extension. Husky has signed a benefits agreement with the Government of Newfoundland and Labrador, and subject to corporate, partner and regulatory approvals, first oil production from the project is planned in the 2017 timeframe.

The Company and its partner are pioneering a new frontier in the Flemish Pass Basin, located approximately 500 kilometres northeast of St. John's, Newfoundland and Labrador.

Two exploration discoveries at Bay du Nord and Harpoon, as well as a previous discovery at Mizzen in 2009, look highly likely to be commercially viable and an appraisal and exploration program is planned to begin in 2014. Husky holds a 35 percent working interest in all three discoveries, which are in close proximity.

The Company is planning several exploration and delineation wells in the Flemish Pass and Jeanne d'Arc basins in the coming years to further unlock the potential of this region, including two exploration wells scheduled in 2014.

Construction of the new harsh environment semi-submersible rig *West Mira* is underway. The rig, which is under contract to Husky for five years commencing in 2015, is expected to support a range of drilling and exploration activities in the Atlantic Region.

Steady On

As stated by the Co-Chairs, the results we have seen over the past three years have strengthened our resolve to stay the course.

Asim Ghosh, CEO

Business Results

SeaRose FPSO

Pikes Peak South thermal project

Three years since it outlined its strategic plan to increase shareholder value, Husky remains on track to deliver on several key performance measures, and in several areas has raised the bar.

These business goals continue to be delivered through a combination of strong operational performance, sound financial management and consistent execution across all business segments.

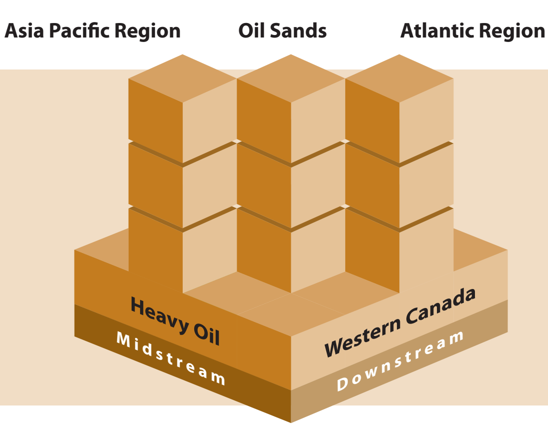
The Company has achieved several major operational milestones in this three-year period. It is transforming its Heavy Oil business and rejuvenating its Western Canada foundation. It has advanced the Liwan Gas Project and Sunrise Energy Project towards first production. And it has revived the Atlantic Region through new satellite developments in the White Rose field and significant oil discoveries in the Flemish Pass Basin.

Cash flow of $5.2 billion remained on pace with a planned six to eight percent increase in compound annual growth, backed by strong performance from Heavy Oil thermal operations such as Pikes Peak South and Paradise Hill and reliable throughputs in the Downstream business. With the addition of production from Liwan in 2014, Husky expects to be in a free cash-flow position, after capital expenditures.

While significant reductions in market crack spreads impacted U.S. refining and marketing earnings, the Company's focused integration model provided a safe harbour as pricing moved to the Upstream business.

Production

Husky is on track to achieve its five-year compound annual production growth target of five to eight percent through to 2017.



The Company's balanced growth strategy is built on its foundation in Heavy Oil and Western Canada, supported by focused integration. From that solid base, three pillars of growth are being developed in the Asia Pacific Region, the Oil Sands and the Atlantic Region.

Liwan gas terminal

Sunrise steam generators

Total Upstream production was within guidance at 312,000 bbls/day. This reflected an active turnaround year that included maintenance on the partner-operated *Terra Nova* FPSO, a scheduled six-day offstation of the *SeaRose* FPSO to tie in South White Rose infrastructure and a 14-day planned shutdown at the Tucker thermal project. In addition, the Company continued to deliberately reduce its dry gas production in favour of higher netback oil and liquids-rich gas resource plays.

Heavy oil thermal projects contributed to production growth. Better than anticipated performance from existing projects led to total production of approximately 37,000 bbls/day by the end of the year from thermals compared to 18,000 bbls/day by the end of 2010.

The Company received an average realized price of $78.12 per barrel for its light, medium, heavy oil, bitumen and natural gas liquids production, compared to the average realized price of $75.50 per barrel in 2012.

Based on the production from the Liwan Gas Project and strong results from its heavy oil thermal projects, Husky has raised its production guidance in 2014 to a range of 330,000 to 355,000 boe/day.

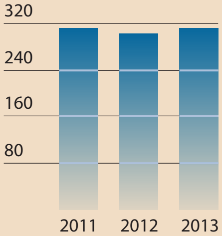
Reserves

Reserves growth reflected a deep portfolio of assets, which provide for organic growth without dependency on acquisitions and a flexible timeline for optimal development.

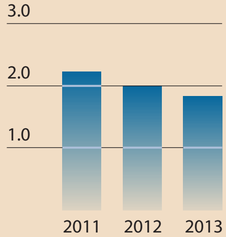
The Company continued to add more proved reserves compared to production in 2013. The reserve replacement ratio, excluding economic factors, was 166 percent (164 percent including economic factors).

The average proved reserves replacement ratio (excluding economic factors) over the past three years was 172 percent. Including economic factors, the average proved three-year reserves replacement ratio was 154 percent, ahead of the five-year average target of 140 percent per year.

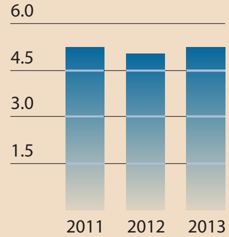
Production
(mboe/day)



Net Earnings
($ billions)



Cash Flow
($ billions)



Lloydminster Asphalt Refinery

Western Canada production

At year-end, Husky had total proved reserves before royalties of 1.3 billion boe, probable reserves of 1.9 billion boe and best estimate contingent resources of 13.2 billion boe.

The Oil Sands portfolio accounted for 11.6 billion boe of the total best estimate contingent resources.

Focused Integration and Throughputs

Husky's focused integration strategy continued to mitigate volatile market and product differentials by helping to capture world prices for its Western Canada production.

The Company initiated several projects to improve Downstream flexibility, including expansion of the Hardisty terminal to add two 300,000-barrel storage tanks and increase connectivity to the Keystone Pipeline, and securing additional storage capacity at Patoka, Illinois to maximize access to U.S. markets.

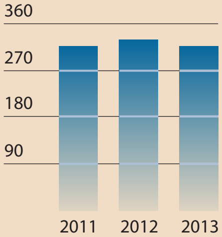
A new 20,000 bbls/day kerosene hydrotreater was brought online at the Husky Lima Refinery and is now providing increased distillate capacity as well as greater flexibility to swing between diesel and jet fuel production depending on market conditions.

Preliminary engineering work began on a feedstock flexibility project at the Lima Refinery, which will allow the refinery to process up to 40,000 bbls/day of Western Canadian heavy oil by 2017 while maintaining the capability to refine light crude oil.

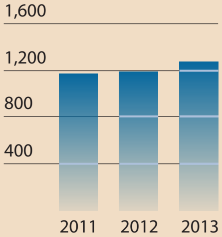
Downstream throughputs averaged 317,000 bbls/day, which partially reflected a 45-day shutdown of the Lloydminster Upgrader.

The Upgrader shipped its 500 millionth barrel of finished product, an important milestone in its 21-year history. The facility plays a key role in Husky's focused integration strategy by converting heavy oil from deposits in northeastern Alberta and western Saskatchewan into lighter, premium products such as Husky's own synthetic blend, ultra-low sulphur diesel and diluent.

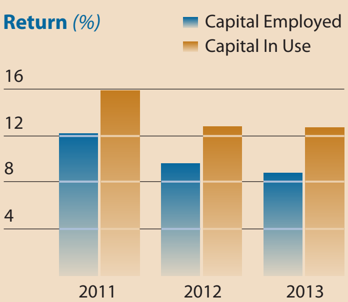
Total Downstream Throughputs *(mbbls/day)*



Total Proved Reserves Before Royalties *(mmboe)*



Return *(%)*




Atlantic Region


Lima Refinery

At the BP-Husky Refinery in Toledo, Ohio, a new gas compressor was installed to improve operational integrity and plant performance. Additional initiatives at the partner-operated refinery are increasing its ability to process bitumen from the first phase of the Sunrise Energy Project as it comes onstream in late 2014.

Safety

An ongoing focus on improving process and occupational safety performance has resulted in a reduction of process incidents by 60 percent since 2010, at the same time employee and contractor work has increased.

The Company has increased its efforts around preventative maintenance to improve reliability and integrity in both the Upstream and Downstream businesses. This contributes directly to enhanced safety and business performance.

The Husky Operational Integrity Management System (HOIMS) program works to identify or mitigate potential hazards and risks to better protect the public, the environment, employees and corporate assets. In addition, risk measurement, management and mitigation is built into all of the Company's strategic planning and operational processes to provide for greater reliability and efficiency across the business.

The commitment to safety was demonstrated during planned maintenance turnarounds at several facilities, all of which were conducted with no critical safety incidents or lost-time injuries.

Consistent Execution

The Company is guided by its commitment to consistent execution across its business. In 2013, it further proved its ability to progress its business plan, identify new discoveries and hit its major milestones.

With a clear focus on reliable and repeatable performance and a strong balance sheet to fund its future opportunities, Husky's strategy is standing the test of time as it embarks on the next phase of its growth.

The momentum we have built over the past three years has positioned us to deliver substantial production growth and create new value for shareholders.

— Asim Ghosh

Management's Discussion and Analysis

Lloydminster Upgrader

Prince George Refinery

February 25, 2014

Contents

1.0	**Financial Summary**	14
1.1	Financial Position	14
1.2	Financial Performance	14
1.3	Total Shareholder Returns	14
1.4	Selected Annual Information	15
2.0	**Husky Business Overview**	15
2.1	Upstream	15
2.2	Downstream	16
3.0	**The 2013 Business Environment**	17
4.0	**Strategic Plan**	21
4.1	Upstream	21
4.2	Downstream	21
4.3	Financial	22
5.0	**Key Growth Highlights**	22
5.1	Upstream	22
5.2	Downstream	25


Hardisty


Heavy oil thermal production

6.0 Results of Operations 26
- 6.1 Segment Earnings 26
- 6.2 Summary of Quarterly Results 26
- 6.3 Upstream 27
- 6.4 Downstream 36
- 6.5 Corporate 39

7.0 Risk and Risk Management 40
- 7.1 Enterprise Risk Management 40
- 7.2 Significant Risk Factors 40
- 7.3 Financial Risks 44

8.0 Liquidity and Capital Resources 46
- 8.1 Summary of Cash Flow 46
- 8.2 Working Capital Components 47
- 8.3 Cash Requirements 49
- 8.4 Off-Balance Sheet Arrangements 50
- 8.5 Transactions with Related Parties 50
- 8.6 Outstanding Share Data 50

9.0 Critical Accounting Estimates and Key Judgments 51
- 9.1 Accounting Estimates 51
- 9.2 Key Judgments 52

10.0 Recent Accounting Standards and Changes in Accounting Policies 53

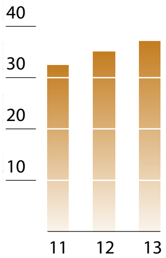
11.0 Reader Advisories 55
- 11.1 Forward-Looking Statements 55
- 11.2 Oil and Gas Reserves Reporting 57
- 11.3 Non-GAAP Measures 58
- 11.4 Additional Reader Advisories 59
- 11.5 Disclosure Controls and Procedures 61

12.0 Selected Quarterly Financial & Operating Information 62

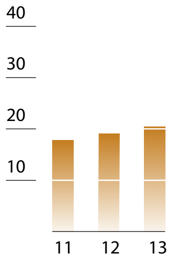
1.0 Financial Summary

1.1 Financial Position

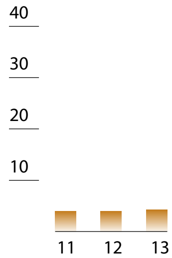
Total Assets
($ billions)



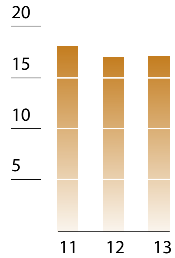
Total Equity
($ billions)



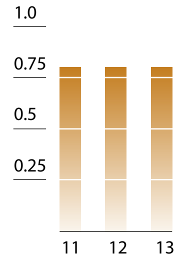
Total Long-term Debt
($ billions)



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

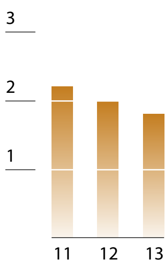


Debt to Cash Flow[(1)]
(times)

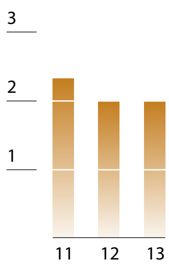


1.2 Financial Performance

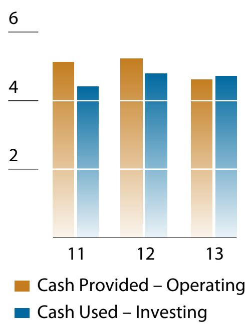
Net Earnings
($ billions)



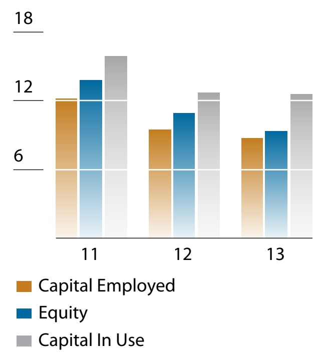
Net Operating Earnings[(1)]
($ billions)



Cash Flow
($ billions)



Return[(1)]
(%)

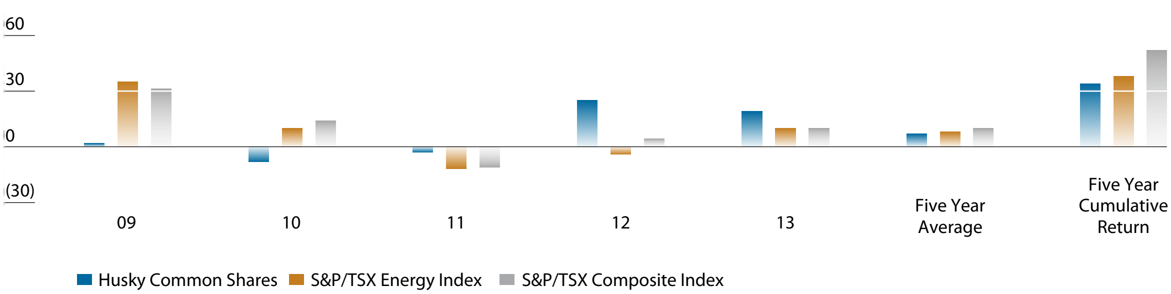


[(1)] *Debt to capital employed, debt to cash flow, return on capital employed, return on equity and return on capital in use constitute non-GAAP measures. (Refer to Section 11.3)*

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)	**2013**	2012	2011
Gross revenues[(1)]	**24,181**	22,948	22,829
Net earnings by segment[(1)]			
Upstream[(1)]	**1,244**	1,322	1,710
Downstream[(1)]	**830**	893	814
Corporate	**(245)**	(193)	(300)
Net earnings	**1,829**	2,022	2,224
Net earnings per share – basic	**1.85**	2.06	2.40
Net earnings per share – diluted	**1.85**	2.06	2.34
Ordinary dividends per common share	**1.20**	1.20	1.20
Dividends per cumulative redeemable preferred share, series 1	**1.11**	1.11	0.87
Cash flow from operations[(2)]	**5,222**	5,010	5,198
Total assets	**36,904**	35,161	32,426
Other long-term liabilities[(3)]	**271**	328	342
Long-term debt including current portion	**4,119**	3,918	3,911
Total non-current liabilities	**12,663**	12,908	11,263
Cash and cash equivalents	**1,097**	2,025	1,841
Return on equity *(percent)*[(2)(4)]	**9.3**	10.9	13.8
Return on capital in use (percent)[(2)(5)]	**12.6**	12.7	15.9
Return on capital employed *(percent)*[(2)(6)]	**8.7**	9.5	12.1

(1) Gross revenues, marketing and other and purchases have been recast for the comparative periods to reflect a change in the classification of certain trading transactions.
(2) Cash flow from operations and financial ratios constitute non-GAAP measures. (Refer to Section 11.3)
(3) As at December 31, 2013, 2012 or 2011, the Company did not have long-term financial liabilities.
(4) Return on equity equals net earnings divided by the two-year average shareholder's equity. (Refer to Section 11.3)
(5) Return on capital in use for the years ended December 31, 2013 and 2011 was adjusted for after-tax impairments on property, plant and equipment of $204 million and $52 million, respectively. Return on capital in use, based on the calculation used in prior periods for the years ended December 31, 2013 and 2011, was 11.3% and 15.6%, respectively. (Refer to Section 11.3)
(6) Return on capital employed for the years ended December 31, 2013 and 2011 was adjusted for after-tax impairments on property, plant and equipment of $204 million and $52 million, respectively. Return on capital employed, based on the calculation used in prior periods for the years ended December 31, 2013 and 2011, was 7.9% and 11.8%, 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. It is based in Calgary, Alberta, and is publicly traded on the TSX under the symbols HSE and HSE.PR.A. 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

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;
- Thermal production for Heavy Oil grew from 17,000 boe/day in 2010 to approximately 37,000 boe/day in 2013, due to the addition of two new steam-assisted gravity drainage ("SAGD") projects, Pikes Peak South and Paradise Hills. Production is expected to be over 55,000 boe/day by 2016 from thermal projects such as the 3,500 boe/day project at Sandall, which achieved first oil in early 2014, the Rush Lake thermal project, with planned production in the second half of 2015, and the recently sanctioned Edam and Vawn SAGD projects;
- Expertise and experience exploring and developing the natural gas potential in the Alberta Deep Basin, Foothills, and northwest plains of Alberta and British Columbia;

- Husky and BP have advanced the development of the Sunrise Energy Project, which is a multiple stage, in-situ oil sands development, with start up of Phase 1 of the project expected in the second half of 2014. Phase 1 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 this next phase of the project;
- 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 development"). The Liwan Gas Project development on Block 29/26 in the South China Sea is substantially complete, with first production expected in the latter part of the first quarter of 2014;
- Husky has a 40% 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 and five discovered natural gas fields;
- Husky and its joint venture partner CPC Corporation have rights to an exploration block in the South China Sea covering approximately 10,000 square kilometers located 100 kilometers southwest of the island of Taiwan. Husky holds a 75% working interest during exploration, while CPC Corporation has the right to participate in the development program up to a 50% interest;
- Husky is the operator of the White Rose field with a 72.5% working interest in the core field and a 68.875% working interest in satellite tiebacks, including the North Amethyst, West White Rose and South White Rose extensions. Development continues at White Rose and its three satellite extensions. Husky has a 13% 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% 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 managed third-party commodity trading volumes of approximately 175 mboe/day in 2013 through access to capacity on third-party pipelines and storage facilities in both Canada and the United States and natural gas storage of 43 bcf, owned and leased.

2.2 Downstream

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% 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 503 retail marketing locations as at December 31, 2013, including bulk plants and travel centres with strategic land positions in Western Canada and Ontario.

3.0 The 2013 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 2013, that are anticipated to continue to impact the industry to varying degrees into 2014 and beyond. Business factors impacting Husky's industry during 2013 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 approaching the historical high achieved in 1970;
- Increased production from U.S. shale gas and liquids-rich gas plays continues to assert downward pressure on North American natural gas pricing;
- Key takeaway capacity constraints for Western Canadian crude oil in North America causing a widening of differentials of crude oil relative to key benchmarks, such as West Texas Intermediate ("WTI");
- Political unrest in the Middle East has caused continued unplanned production outages having an impact on crude oil benchmark pricing;
- Expected continued production growth from the Western Canadian oil sands, which is expected to grow to approximately 3.2 million bbls/day by 2020 from approximately 1.8 million bbls/day in 2012;
- 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 2013 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		2013	2012
WTI crude oil[1]	*(U.S. $/bbl)*	**97.97**	94.21
Brent crude oil[2]	*(U.S. $/bbl)*	**107.91**	111.54
Canadian light crude 0.3% sulphur	*($/bbl)*	**93.85**	86.57
Western Canada Select @ Hardisty[3]	*(U.S. $/bbl)*	**72.77**	73.18
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**64.41**	62.89
NYMEX natural gas[4]	*(U.S. $/mmbtu)*	**3.65**	2.79
NIT natural gas	*($/GJ)*	**3.00**	2.28
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**25.33**	21.46
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**22.21**	31.36
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**21.30**	27.63
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.971**	1.001
Canadian Equivalents[5]			
WTI crude oil	*($/bbl)*	**100.90**	94.12
Brent crude oil	*($/bbl)*	**111.13**	111.43
Western Canada Select @ Hardisty	*($/bbl)*	**74.94**	73.11
WTI/Lloyd crude blend differential	*($/bbl)*	**26.08**	21.44
NYMEX natural gas	*($/mmbtu)*	**3.76**	2.79

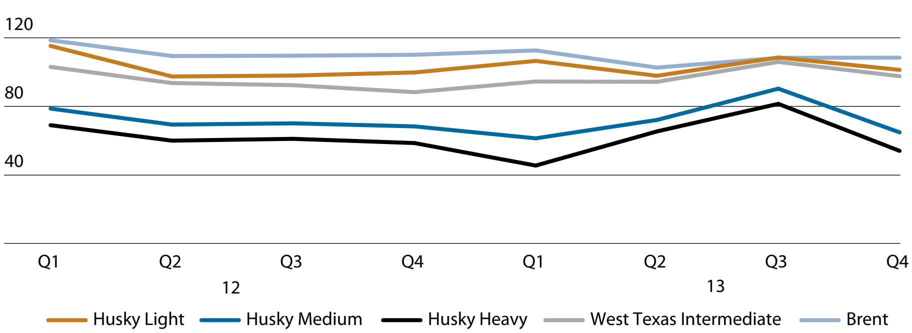
(1) *Prices quoted are near-month contract prices for settlement during the next month.*
(2) *Quoted Brent prices are dated less than 15 days prior to loading for delivery.*
(3) *Western Canadian Select is a heavy crude blend primarily based on existing Canadian heavy conventional and bitumen crude oils 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 market price for crude oil is determined largely by North American and global factors and is beyond the Company's control. The price for natural gas is determined more by North American fundamentals since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. Weather conditions also exert a significant effect on short-term supply and demand. Starting in 2014, natural gas produced from the Company's Liwan Gas Project in the Asia Pacific Region will supply the Guangdong Province and will receive a fixed price for five years in line with the current Guangdong gate station price set by the Chinese Government.

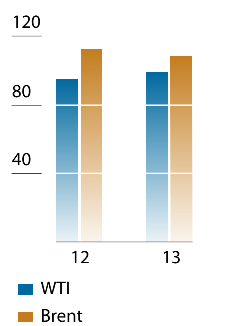
The Downstream segment is heavily impacted by the price of crude oil and natural gas, as the largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil. In the upgrading business segment, heavy crude oil feedstock is processed into light synthetic crude 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% 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)

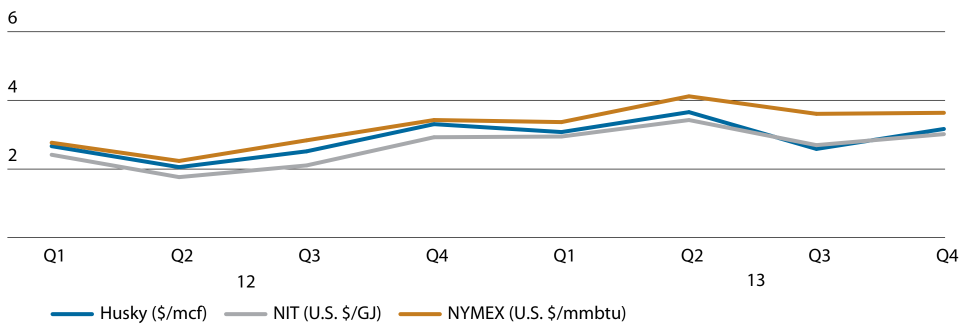


The price Husky receives for production from Western Canada is primarily driven by changes in the price of WTI and discounts or premiums to Western Canadian crude prices, while the majority of the Company's production in the Atlantic Region and the Asia Pacific Region is referenced to the price of Brent, a light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2013 at U.S. $98.42/bbl compared to U.S. $94.19/bbl on December 31, 2012, and averaged U.S. $97.97/bbl in 2013 compared with U.S. $94.21/bbl in 2012. The price of Canadian light crude ended 2013 at $97.49/bbl compared to $74.32/bbl on December 31, 2012 and averaged $93.85/bbl in 2013 compared with $86.57/bbl in 2012. The price of Brent ended 2013 at U.S. $110.28/bbl, compared to U.S. $111.66/bbl on December 31, 2012, and averaged U.S. $107.91/bbl in 2013 compared with U.S. $111.54/bbl in 2012.

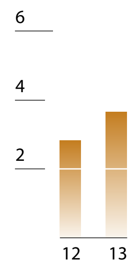
A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In both 2013 and 2012, 54% of Husky's crude oil production was heavy crude oil or bitumen. The light/heavy crude oil differential averaged U.S. $25.33/bbl or 26% of WTI in 2013 compared to U.S. $21.46/bbl or 23% of WTI in 2012.

Natural Gas

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



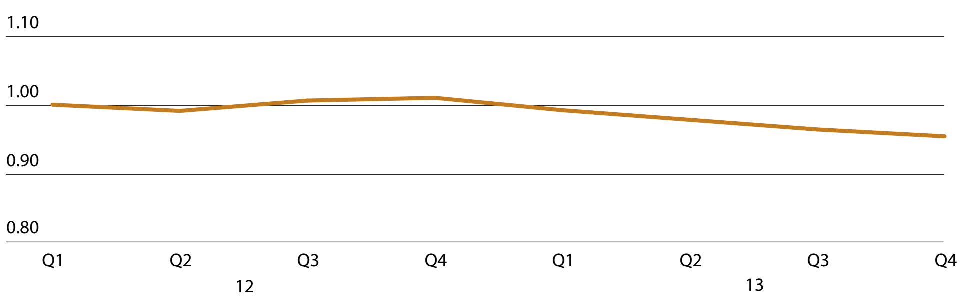
Average NYMEX
(U.S. $/mmbtu)



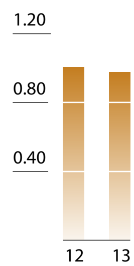
In 2013, 27% of Husky's total oil and gas production was natural gas compared with 31% in 2012, reflecting a shift in investment from dry gas development to higher netback liquids-rich natural gas and crude oil production. The near-month natural gas price quoted on the NYMEX ended 2013 at U.S. $4.23/mmbtu compared with U.S. $3.35/mmbtu at December 31, 2012. During 2013, the NYMEX near-month contract price of natural gas averaged U.S. $3.65/mmbtu compared with U.S. $2.79/mmbtu in 2012. The near-month natural gas contract price for NOVA Inventory Transfer ("NIT"), which is a Canadian natural gas benchmark, was $3.73/mmbtu at the end of 2013 compared with $2.87/mmbtu at December 31, 2012. During 2013, the NIT near-month contract price of natural gas averaged $3.00/mmbtu compared to $2.28/mmbtu in 2012.

Foreign Exchange

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



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

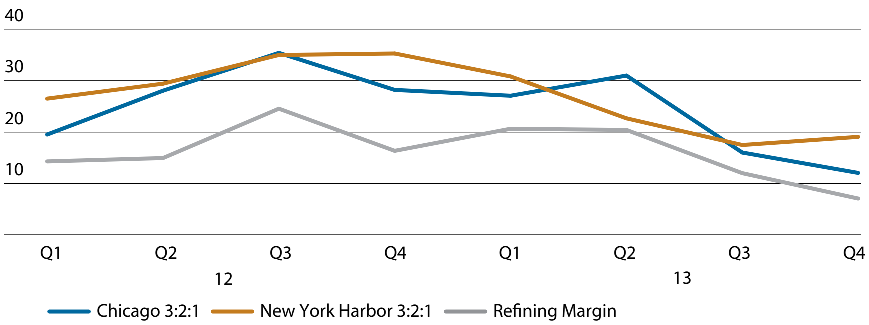


The majority of the Company's revenues from the sale of oil and gas commodities receive prices determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the revenues received from the sale of oil and gas commodities. Correspondingly, 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 the U.S. Downstream segment and the Asia Pacific Region.

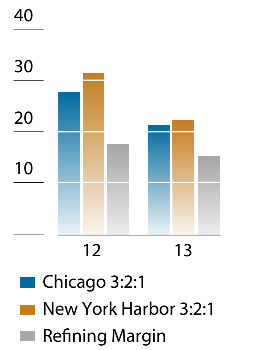
The Canadian dollar ended 2013 at U.S. $0.940 compared to U.S. $1.005 on December 31, 2012. In 2013, the Canadian dollar averaged U.S. $0.971, weakening by 3% compared with U.S. $1.001 during 2012. Crude oil prices realized by Husky in 2013 benefited from the weakening of the Canadian dollar against the U.S. dollar compared to 2012. In 2013, the price of WTI in U.S. dollars increased by 4% while the price of WTI in Canadian dollars increased by 7% when compared to 2012.

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 by 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. $22.21/bbl in 2013 compared to U.S. $31.36/bbl in 2012, and the Chicago 3:2:1 refining crack spread averaged U.S. $21.30/bbl in 2013 compared to U.S. $27.63/bbl in 2012.

The following table is indicative of the relative annualized effect on pre-tax earnings and net earnings from changes in certain key variables in 2013. The table below shows what the effect would have been on 2013 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2013. 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 greater magnitudes of change.

Sensitivity Analysis	2013 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]	**97.97**	*U.S. $1.00/bbl*	**74**	**0.08**	**55**	**0.06**
NYMEX benchmark natural gas price[5]	**3.65**	*U.S. $0.20/mmbtu*	**27**	**0.03**	**19**	**0.02**
WTI/Lloyd crude blend differential[6]	**25.33**	*U.S. $1.00/bbl*	**(23)**	**(0.02)**	**(17)**	**(0.02)**
Canadian light oil margins	**0.043**	*Cdn $0.005/litre*	**15**	**0.02**	**11**	**0.01**
Asphalt margins	**22.62**	*Cdn $1.00/bbl*	**10**	**0.01**	**7**	**0.01**
New York Harbor 3:2:1 crack spread[7]	**22.21**	*U.S. $1.00/bbl*	**55**	**0.06**	**35**	**0.04**
Exchange rate (U.S. $ per Cdn $)[3][8]	**0.971**	*U.S. $0.01*	**(54)**	**(0.06)**	**(40)**	**(0.04)**

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 983.4 million common shares outstanding as of December 31, 2013.*
(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) *Relates to U.S. Refining and Marketing.*
(8) *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 its three major growth pillars in the Asia Pacific Region, 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 2013 with development activities ongoing in the Bakken, Viking, Cardium, Lower Shaunavon, Muskwa, Canol, Duvernay, Spirit River, Montney, Second White Specs and Willrich formations.

Husky has an extensive portfolio of oil sands leases, encompassing 2,500 square kilometers in northern Alberta. Husky advanced the development of the Sunrise Energy Project in 2013, a multiple stage in-situ oil sands development. The first phase is expected to produce approximately 60,000 barrels per day, with start up expected in second half of 2014. Husky's working interest is 50%. Sunrise will use proven SAGD technology, keeping site disturbance to a minimum.

The Asia Pacific Region consists of the Wenchang oil field, the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields on Block 29/26 located offshore China, the Madura Strait block BD, MDA, MBH development fields, five discoveries offshore Indonesia, and the rights to an exploration block in the South China Sea located offshore Taiwan. The Liwan Gas Project development, located approximately 300 kilometers 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 has partnered with China National Offshore Oil Corporation ("CNOOC") on the development, with first gas production anticipated in the latter half of the first quarter of 2014.

In the Atlantic Region, the Company holds interests in eight Production Licences, 15 Exploration Licences 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 2013, the Company made two significant discoveries in the Flemish Pass Basin at the Harpoon and Bay du Nord prospects. With the Mizzen discovery made in 2009, this brings the total number of discoveries in the Flemish Pass Basin to three, making long-term development a viable option subject to further delineation and review. The Company has a 35% working interest in each of these 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 unit supports Upstream production while providing integration with the Company's Downstream assets through optimization of market access for Husky's Upstream production. 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. In support of the downstream strategy, the Company sanctioned a refinery reconfiguration project at the Lima, Ohio Refinery to allow the refinery to process up to 40,000 bbls/day of Western Canadian heavy oil while maintaining the capability and flexibility to refine existing light crude oil.

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%, 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 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 2013 Capital Program built on the momentum achieved over the past two years with respect to repositioning the Heavy Oil and Western Canada foundation by accelerating near-term production growth and advancing Husky's three major growth pillars 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 2013 was approximately 25,000 bbls/day, representing a 15% increase compared to 2012.

Oil Resource Plays

During 2013, the Company continued to advance exploration and development projects on its extensive oil resource land base. A total of 101 horizontal wells (gross) were drilled and two vertical and 94 horizontal wells (gross) were completed in 2013.

The following table summarizes the key oil resource play drilling and completion activity for the year ended December 31, 2013:

Oil Resource Plays - Drilling and Completion Activity(1)(2)

Project	Location	Year ended December 31, 2013 Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	14	12
Lower Shaunavon	S.W. Saskatchewan	9	7
Viking(3)	Alberta and S.W. Saskatchewan	59	64
N.Cardium	Wapiti, Alberta	13	9
Muskwa	Rainbow, Northern Alberta	6	2
Canol Shale	Northwest Territories	–	2
Total Gross		101	96
Total Net		96	92

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

In the Northwest Territories, the Slater River Canol shale play all-season road construction is substantially complete, and the Company plans to drill and complete two horizontal wells in 2015.

Liquids-Rich Natural Gas Resource Plays

During 2013, the Company continued to advance exploration and development projects on its extensive liquids-rich natural gas resource land base. A total of 31 wells (gross) were drilled and 36 wells (gross) were completed in 2013 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, 2013:

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

		Year ended December 31, 2013	
Project	Location	Gross Wells Drilled	Gross Wells Completed
Ansell Multi-Zone	Ansell/Edson, Alberta	25	30
Duvernay	Kaybob, Alberta	6	6
Total Gross		31	36
Total Net		29	34

(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 25 wells (gross) drilled and 30 wells (gross) completed in 2013. To date, the Company has drilled and completed over 300 (gross) wells at the play with average production of 13,800 boe/day in 2013.

At the Duvernay play in Kaybob, Alberta, the Company drilled and completed the first four well pad, with production from the pad commencing in late 2013. The Company also drilled a second two well pad in the year, which is scheduled to be completed and brought on production in early 2014.

Heavy Oil

Production in 2013 at the Pikes Peak South and Paradise Hill heavy oil thermal projects continued to exceed the combined 11,500 bbls/day design rate capacity. Average 2013 production levels from the developments were approximately 11,400 bbls/day at Pikes Peak South and 4,900 bbls/day at Paradise Hill.

Production commenced at the 3,500 bbls/day Sandall thermal development project in early 2014.

Construction work continued at the 10,000 bbls/day Rush Lake commercial project, with first production expected in the second half of 2015. Production performance from the two well pair pilot is in line with expectations.

Two 10,000 bbls/day thermal developments were sanctioned at Edam East and Vawn, both located in Saskatchewan. Construction is scheduled to begin in 2014 and these projects are expected to deliver a total of 20,000 bbls/day of production in 2016.

The Company advanced its horizontal drilling program in 2013 drilling 140 wells. In 2014, the Company plans to carry out a 144 well program. The Company also drilled 228 gross cold heavy oil production with sand ("CHOPS") wells during 2013. In 2014, the Company plans to carry out a 177 CHOPS well program.

Asia Pacific Region

China

Block 29/26

At the Liwan Gas Project development, testing and commissioning is underway. All nine wells on the Liwan 3-1 gas field are complete and ready for production and first production is expected in the latter part of the first quarter of 2014.

The platform topsides were completed and transported approximately 2,500 kilometers from Qingdao, China to the South China Sea and successfully installed onto the jacket. In addition, the 261 kilometers of shallow water pipeline from the central platform to the gas plant and construction of the onshore gas plant was completed. Five major construction vessels and their support vessels were in operation during 2013 while construction continued on the deep water facilities. Despite encountering unusually difficult weather conditions during an extended typhoon season in late 2013, all piping to connect the individual wells to the manifolds and the manifolds to the connecting infield production flow lines was installed. Final testing and commissioning of the gas plant and offshore infrastructure is now underway.

The single development well of the Liuhua 34-2 field is expected to be tied into the Liwan 3-1 field deep water facilities, with production expected later in the second half of 2014. Production from the Liwan Gas Project is scheduled to go off-line in the second half of 2014 for approximately six to eight weeks to tie in the Liuhua 34-2 field.

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

Offshore Taiwan

The acquisition of two-dimensional seismic survey data on the Company's offshore Taiwan block commenced in September 2013, and approximately half of the minimum committed survey distance was completed, with the remainder planned for the second half of 2014.

Indonesia

Progress continued on the shallow water gas developments in the Madura Strait Block during 2013. The BD field engineering and construction has commenced. The last outstanding tender for the BD field floating production, storage and offloading vessel ("FPSO") is awaiting government approval, and the tender plans for the combined MDA and MBH development projects are under final review by Indonesia's regulatory authority. The Government of Indonesia appointed a lead distributor for the majority of the gas to be produced from the MDA and MBH fields and the negotiation of a gas sales contract is in progress. Exploration drilling on the block resulted in an additional discovery, the MBF field, located west of the MBH field.

Oil Sands

Sunrise Energy Project

Phase 1 of the Sunrise Energy Project remains on track for start up in the second half of 2014.

The Central Processing Facility is more than 75% complete, with major equipment installed and field tanks and buildings for Plant 1A now in place. In addition, all modules have been delivered and major equipment installation has been completed for Plant 1B. Field facilities are substantially complete. The main power line to the plant is now energized and the testing of piping and the completion of remaining electrical and instrumentation work is an area of focus in advance of the planned systems turn over. Six of the eight well pads have been turned over, with commissioning underway on four well pads. The remaining two well pads are targeted to be turned over in early 2014. To date, approximately 90% of the project’s total cost estimate has been spent.

Development work continued on the next phase of the project with the Design Basis Memorandum completed in 2013. Early engineering is underway.

McMullen

During 2013, 51 wells were drilled and 49 wells were placed on production in the conventional portion of the Company's McMullen play. CHOPS production from 27 wells drilled and completed on three well pads commenced in late 2013. In addition, at the air injection pilot, the Company received approval from the Alberta Energy Regulator in 2013 to allow an additional three horizontal wells to be brought on production, bringing the total number of producing wells to six at the pilot.

Atlantic Region

White Rose Field and Satellite Extensions

Government and regulatory approval was granted for a development plan amendment to include gas injection and storage at the South White Rose Extension. The development plan amendment will also enable the production of additional reserves from the main White Rose field. Installation of gas injection equipment to support the South White Rose Extension was completed at the end of 2013, with gas injection commencing in early 2014. Installation of oil production equipment is scheduled in 2014, with first oil anticipated by the end of 2014.

A number of key milestones were met for the West White Rose Extension project, including approval of a benefits agreement with the Government of Newfoundland and Labrador, release of the environmental impact assessment for further federal and provincial approval, and submission of the Development Application to the Canada-Newfoundland and Labrador Offshore Petroleum Board. Husky and its partners progressed detailed engineering, design and due diligence in anticipation of a final investment decision.

At North Amethyst, development continued with the drilling and completion of the North Amethyst G-25-8 water injection well. In addition, the North Amethyst G-25-9 multilateral well was completed and brought online in late November, with average gross production of 20,000 bbls/day (14,000 bbls/day net Husky share). This concludes the wells proposed as part of the base plan for the North Amethyst field and the Company continues to examine additional oil recovery improvement opportunities. Drilling has commenced on the North Amethyst Hibernia formation well, which will target a secondary deeper zone below the main North Amethyst field. The well is expected to be brought on production later in 2014.

Atlantic Exploration

Husky and its partner made two significant discoveries in the year of a high-quality, light, sweet crude oil resource in the Flemish Pass Basin. The first discovery was made at the Harpoon O-85 well followed by a second discovery made at the Bay Du Nord prospect, both located approximately 500 kilometres offshore Newfoundland. The evaluation of well results at the Harpoon discovery is ongoing with further appraisal drilling required to assess the potential of the prospect. The evaluation of well results at the Bay Du Nord prospect has confirmed significant quantities of hydrocarbons with best estimate contingent resources estimated by Husky at 400 million barrels on a 100% working interest basis as at December 31, 2013. The two discoveries made in the year bring the total number of significant discoveries in the region to three with the 2009 Mizzen discovery of slightly heavier oil with best estimate contingent resources estimated by Husky at 130 million barrels on a 100% working interest basis as at December 31, 2013. Husky holds a 35% working interest in all three wells.

The Husky-operated White Rose H-70 delineation well, which is part of a near-field drilling program northwest of the main White Rose field, encountered hydrocarbons and the evaluation of results is ongoing. Husky holds a 68.875% working interest in the well. The non-operated Federation well in the southern Jeanne d'Arc Basin did not encounter commercial quantities of hydrocarbons and was expensed.

Infrastructure and Marketing

The Hardisty terminal expansion project includes multiple initiatives intended to increase pipeline connectivity and re-configure the existing terminal facility to accommodate the expansion and inclusion of the Company as a Western Canadian Select stream participant by 2015. In 2013, detailed engineering, procurement and construction progressed on two 300,000-barrel tanks and procurement of long lead equipment continued for the required terminal reconfigurations in order to accommodate Western Canadian Select.

In order to accommodate the anticipated increase in production from heavy oil thermal development projects, the Company has undertaken initiatives related to the extension of pipeline systems from the Sandall thermal development project to Lloydminster and expansion of the South Saskatchewan Gathering System for the Rush Lake commerical project. Both initiatives are on track to align with anticipated production from these projects.

5.2 Downstream

Lima Refinery

The Lima Refinery continues to progress reliability and profitability improvement projects. Construction of the 20 mbbls/day kerosene hydrotreater, which increased on-road diesel and jet fuel production volumes, was completed and brought on-line in early 2013. In addition, front-end engineering design commenced to revamp existing refinery process units and add new equipment to allow the refinery to process up to 40,000 bbls/day of Western Canadian heavy oil while maintaining the capability and flexibility to refine existing light crude oil. Regulatory approval was granted by the U.S. Environmental Protection Agency. The capability to refine heavy oil at the Husky Lima Refinery is anticipated by 2017.

BP-Husky Toledo Refinery

The Continuous Catalyst Regeneration Reformer Project at the BP-Husky Toledo Refinery was completed and became operational in early 2013. Work progressed on the Hydrotreater Recycle Gas Compressor Project during 2013 and is scheduled to be completed in 2014. The installation of a new recycle gas compressor in the existing hydrotreater is intended to improve operational integrity and plant performance. The refinery continues to advance a multi-year program to improve operational integrity and plant performance while reducing operating costs and environmental impacts.

6.0 Results of Operations

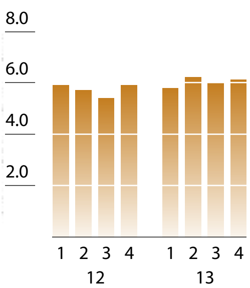
6.1 Segment Earnings

($ millions)	Earnings (Loss) before Income Taxes 2013	2012	Net Earnings (Loss) 2013	2012	Capital Expenditures[1] 2013	2012
Upstream[2]						
Exploration and Production[2]	**1,283**	1,321	**952**	976	**4,264**	4,106
Infrastructure and Marketing[2]	**392**	462	**292**	346	**96**	54
Downstream						
Upgrading	**401**	306	**297**	226	**205**	47
Canadian Refined Products	**260**	311	**194**	231	**109**	97
U.S. Refining and Marketing[2]	**522**	693	**339**	436	**220**	313
Corporate	**(230)**	(257)	**(245)**	(193)	**134**	84
Total	**2,628**	2,836	**1,829**	2,022	**5,028**	4,701

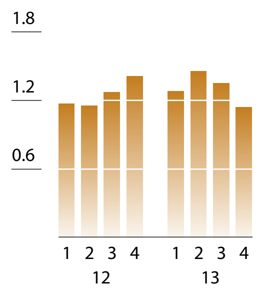
[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
[2] *Gross revenues, marketing and other and purchases have been recast for the comparative period to reflect a change in the classification of certain trading transactions.*

6.2 Summary of Quarterly Results

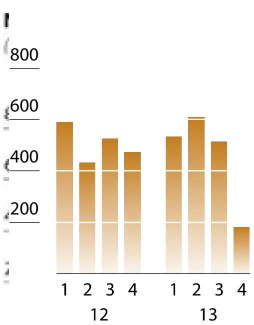
Gross Revenues
($ billions)



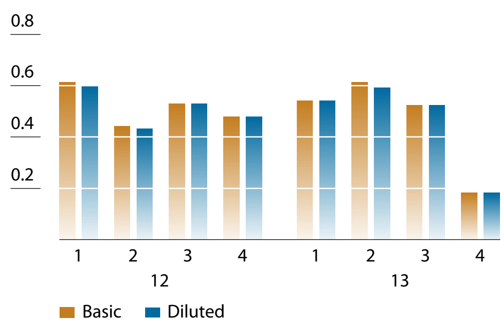
Cash Flow from Operations[1]
($ billions)



Net Earnings
($ millions)



Net Earning Per Share
($ per share)

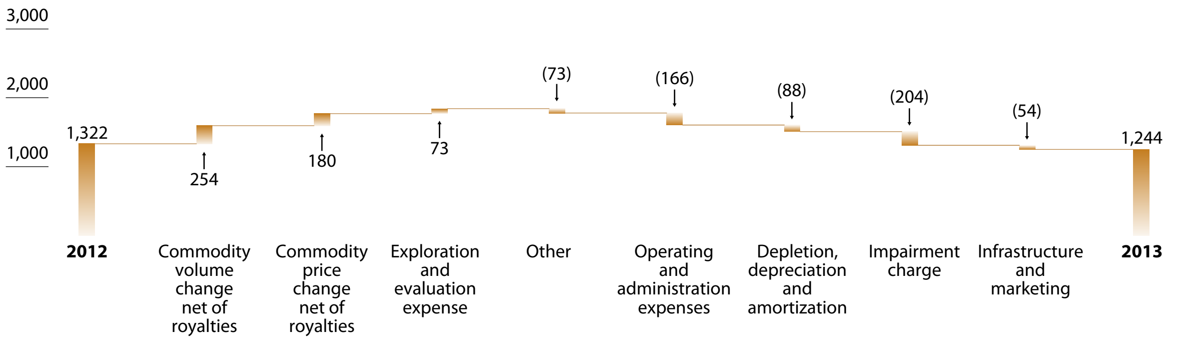


[1] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*

6.3 Upstream

2013 Total Upstream Earnings $1,244 million

After Tax Earnings Variance Analysis
($ millions)



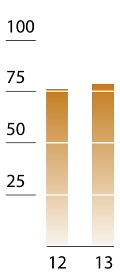
Exploration and Production

Exploration and Production Earnings Summary *($ millions)*	2013	2012
Gross revenues[(1)(2)]	7,333	6,581
Royalties	(864)	(693)
Net revenues	6,469	5,888
Purchases, operating, transportation and administrative expenses	2,347	2,123
Depletion, depreciation, amortization and impairment	2,515	2,121
Exploration and evaluation expenses	246	344
Other expenses (income)	78	(21)
Income taxes	331	345
Net earnings	952	976

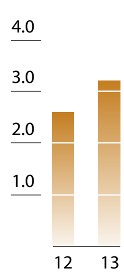
(1) *Gross revenues have been recast for the comparative period to reflect a change in the classification of certain trading transactions.*
(2) *In 2013, the Company reclassified its processing facilities from Infrastructure and Marketing to Exploration and Production. Prior period amounts have been adjusted to conform with current presentation.*

Exploration and Production net earnings, excluding an after-tax impairment of $204 million on Western Canada natural gas properties, were $180 million higher in 2013 compared with 2012, primarily due to higher average realized commodity prices, higher production from the Atlantic Region where the Company completed two major turnarounds in 2012, increased production from heavy oil thermal projects in Western Canada, and lower exploration and evaluation expenses. These were partially offset by higher depletion expense due to higher production and increased operating costs in Western Canada. Other expenses in 2013 were higher compared to 2012 due to an increase in accretion expense associated with increased remediation cost estimates associated with the growing asset base and a decrease in realized profits due to period changes in inventory balances.

Average Price Realized
Crude Oil
($/bbl)



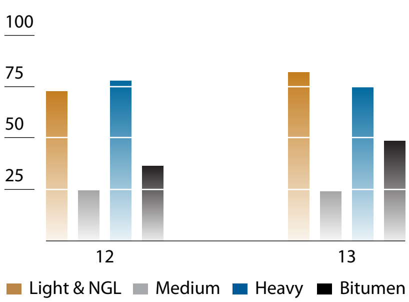
Average Price Realized
Natural Gas
($/mcf)



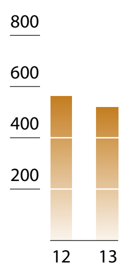
Average Sales Prices Realized	2013	2012
Crude oil and NGL *($/bbl)*		
Light crude oil & NGL	**102.35**	99.22
Medium crude oil	**74.29**	71.51
Heavy crude oil	**63.44**	61.91
Bitumen	**61.68**	59.49
Total crude oil and NGL average	**78.12**	75.50
Natural gas average *($/mcf)*	**3.19**	2.60
Total average *($/boe)*	**61.96**	57.16

During 2013, the average realized price for crude oil, NGL and bitumen increased 3% to $78.12/bbl compared with $75.50/bbl during 2012, primarily due to higher WTI prices combined with a weaker Canadian dollar partially offset by wider Western Canada crude oil differentials. Realized natural gas prices averaged $3.19/mcf during 2013 compared with $2.60/mcf in 2012, an increase of 23% as supply and demand fundamentals improved in 2013 compared to 2012.

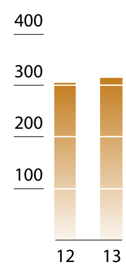
Production
Oil
(mbbls/day)



Production
Natural Gas
(mmcf/day)



Production
Combined
(mboe/day)



Daily Gross Production	2013	2012
Crude oil and NGL *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**29.7**	30.1
Medium crude oil	**23.2**	24.1
Heavy crude oil	**74.5**	76.9
Bitumen[(1)]	**47.7**	35.9
	175.1	167.0
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**39.3**	30.8
Terra Nova – light crude oil	**4.8**	3.0
	44.1	33.8
China		
Wenchang – light crude oil & NGL	**7.3**	8.4
Crude oil *(mbbls/day)*	**226.5**	209.2
Natural gas *(mmcf/day)*	**512.7**	554.0
Total *(mboe/day)*	**312.0**	301.5

(1) *Bitumen production includes heavy oil thermal average daily gross production of 37.4 mbbls/day for the year ended December 31, 2013. Heavy oil thermal production typically receives a higher price than bitumen production.*

Exploration and Production Revenue Mix *(Percentage of Upstream Net Revenues)*	2013	2012
Crude oil		
Light crude oil & NGL	**43%**	43%
Medium crude oil	**9%**	10%
Heavy crude oil	**25%**	28%
Bitumen	**15%**	12%
Crude oil	**92%**	93%
Natural gas	**8%**	7%
Total	**100%**	100%

During 2013, crude oil, bitumen and NGL production increased by 17.3 bbls/day or 8% compared with 2012, primarily due to increased production in Western Canada at the Pikes Peak South and Paradise Hill heavy oil thermal projects combined with higher production in the Atlantic Region, where the SeaRose and Terra Nova FPSO planned turnarounds were performed in 2012, partially offset by lower production at Wenchang due to typhoon related shut-ins.

Production from dry natural gas decreased by 41.3 mmcf/day or 7% in 2013 compared with 2012 due to natural reservoir declines in mature properties as capital investment continues to be directed at higher return oil and liquids-rich natural gas developments.

2014 Production Guidance and 2013 Actual

Gross Production	Guidance 2014	Year ended December 31 2013	Guidance 2013
Crude oil, NGL and Asia Pacific Region *(mbbls/day)*			
Light / Medium crude oil & NGL	110 - 115	**104**	110 - 120
Heavy crude oil & bitumen	125 - 130	**122**	110 - 120
Natural gas Asia Pacific Region (mboe/day)	25 - 30	**–**	–
Crude oil, NGL and Asia Pacific Region *(mbbls/day)*	260 - 275	**226**	220 - 240
Natural gas *(mmcf/day)*	420 - 480	**513**	540 - 580
Total *(mboe/day)*	330 - 355	**312**	310 - 330

The Company's total production for the year ended December 31, 2013 was within production guidance. In 2012, the Company set a compound annual production growth rate of 5% to 8% through the plan period of 2012 to 2017, which it is on track to achieve. Husky expects that production levels in 2014 will be higher compared to 2013 due to new production from the Liwan Gas Project in the Asia Pacific Region and new production at North Amethyst in the Atlantic Region.

Factors that could potentially impact Husky's production performance for 2014 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; and
- foreign operations and related assets, which are subject to a number of political, economic and socio-economic risks.

Royalties

Royalty rates averaged 12% of gross revenues in 2013 compared with 11% in 2012. Royalty rates in Western Canada averaged 12% in 2013 compared with 10% in 2012 due to a royalty credit adjustment received in 2012. Royalty rates in the Atlantic Region averaged 13% in 2013 compared with 11% in 2012 when lower rates reflected the ongoing SeaRose and Terra Nova FPSO turnarounds. Royalty rates in the Asia Pacific Region averaged 24% in both 2013 and 2012.

Operating Costs

($ millions)	2013	2012
Western Canada	**1,745**	1,571
Atlantic Region	**201**	212
Asia Pacific	**31**	31
Total	**1,977**	1,814
Unit operating costs *($/boe)*	**16.28**	15.49

Total operating costs increased to $1,977 million in 2013 from $1,814 million in 2012. Total Upstream unit operating costs in 2013 averaged $16.28/boe compared with $15.49/boe in 2012 due to higher energy consumption and increased natural gas and electricity prices associated with Western Canada crude oil production.

Operating costs in Western Canada increased to $17.05/boe in 2013 compared with $15.45/boe in 2012 primarily due to higher energy consumption and increased natural gas and electricity prices.

Operating costs in the Atlantic Region averaged $12.47/boe in 2013 compared with $17.12/boe in 2012. The decrease in operating costs was attributable to higher production and lower maintenance and supply costs compared to 2012 when the planned SeaRose and Terra Nova FPSO turnarounds were performed.

Operating costs in the Asia Pacific Region averaged $11.39/boe in 2013 compared with $10.08/boe in 2012. The increase was due to lower production associated with typhoon-related shut-ins in 2013.

Exploration and Evaluation Expenses

($ millions)	2013	2012
Seismic, geological and geophysical	**133**	140
Expensed drilling	**102**	188
Expensed land	**11**	16
Total	**246**	344

Total exploration and evaluation expenses decreased by $98 million in 2013 compared to 2012 primarily due to high drilling success rates, which resulted in more capitalized exploration costs. Expensed drilling in 2012 included costs related to the Searcher well in the Atlantic Region and the Liuhua 32-1-1 well in the Asia Pacific Region. The decrease in seismic, geological and geophysical expense in 2013 was primarily due to a shift from exploration to development activities in Western Canada and the Asia Pacific Region in 2013.

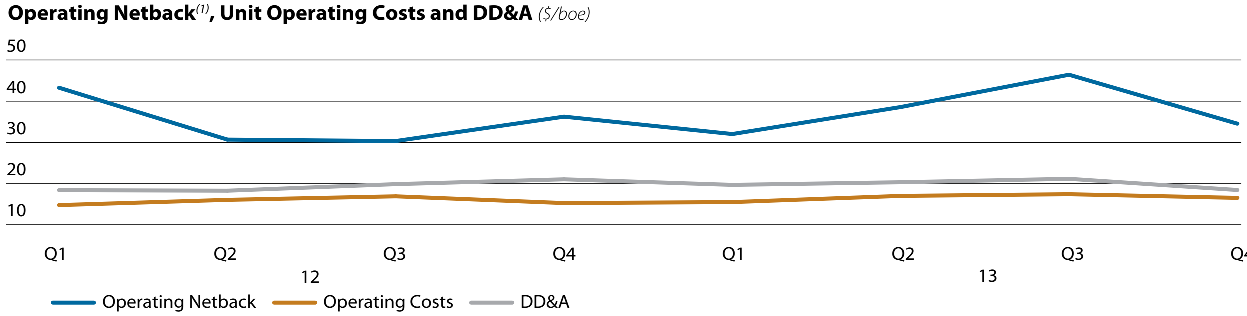
Depletion, Depreciation, Amortization ("DD&A") and Impairment

During 2013, the Company recognized a pre-tax impairment charge of $275 million on certain conventional natural gas assets located in Western Canada. The impairment charge was the result of low estimated long-term future natural gas prices and the redirection of capital investments to higher yield oil and liquids-rich natural gas opportunities.

During 2013, total unit DD&A, excluding the impairment charge, was $19.67/boe compared to $19.20/boe during 2012.

At December 31, 2013, capital costs in respect of unproved properties and major development projects were $8.3 billion compared with $6.1 billion at the end of 2012. These costs are excluded from the Company's DD&A calculation until the unproved properties are evaluated and developed, proved reserves are attributed to the project 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 2013, Upstream Exploration and Production capital expenditures were $4,264 million. Capital expenditures were $2,420 million (57%) in Western Canada, $552 million (13%) in Oil Sands, $638 million (15%) in the Atlantic Region and $654 million (15%) in the Asia Pacific Region.

Exploration and Production Capital Expenditures[1] *($ millions)*	2013	2012
Exploration		
Western Canada	**353**	238
Atlantic Region	**201**	13
Asia Pacific Region	**21**	22
	575	273
Development		
Western Canada	**2,029**	2,029
Oil Sands	**552**	658
Atlantic Region	**437**	400
Asia Pacific Region	**633**	725
	3,651	3,812
Acquisitions		
Western Canada	**38**	21
	4,264	4,106

(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:

	2013		2012	
Wells Drilled *(wells)*	Gross	Net	Gross	Net
Exploration				
Oil	**39**	**24**	47	30
Gas	**19**	**14**	19	12
Dry	–	–	–	–
	58	**38**	66	42
Development				
Oil	**768**	**709**	775	715
Gas	**68**	**41**	23	17
Dry	**1**	–	5	4
	837	**750**	803	736
Total	**895**	**788**	869	778

The Company drilled 788 net wells in the Western Canada, Heavy Oil and Oil Sands business units in 2013 resulting in 733 net oil wells and 55 net natural gas wells compared to 778 net wells resulting in 745 net oil wells and 29 net natural gas wells in 2012.

During 2013, Husky invested $2,420 million on exploration, development and acquisitions, including Heavy Oil, throughout the Western Canada Sedimentary Basin compared to $2,288 million in 2012. Property acquisitions totalling $38 million were completed in 2013 compared to $21 million in 2012. Investment in oil related exploration and development was $576 million in 2013 compared to $538 million in 2012. Investment in natural gas related exploration and development, primarily liquids-rich, was $596 million in 2013 compared to $500 million in 2012.

In addition, $232 million was spent on production optimization and cost reduction initiatives in 2013. Capital expenditures on facilities, land acquisition and retention, and environmental protection totalled $349 million.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling were $629 million during 2013 compared to $586 million in 2012.

Oil Sands

During 2013, $552 million was invested in Oil Sands projects, primarily for Phase 1 of the Sunrise Energy Project. In addition, the Company drilled 34 gross (17 net) evaluation wells for the next phase of the Sunrise Energy Project.

Atlantic Region

The following table discloses Husky's offshore Atlantic Region drilling activity during 2013:

Atlantic Region Offshore Drilling Activity

Well	Working Interest	Well Type
North Amethyst G-25 9	WI 68.875%	Development (Producer)
Terra Nova E-18-12Z	WI 13%	Development (Producer)
North Amethyst G-25-8	WI 68.875%	Development (Injector)
Harpoon 0-85	WI 35%	Exploration
Bay Du Nord C-78	WI 35%	Exploration
Federation K-78	WI 35%	Exploration
White Rose H-70	WI 68.875%	Delineation
White Rose H-70Z	WI 93.33%	Delineation
Terra Nova E-19	WI 13%	Delineation

During 2013, $638 million was invested in Atlantic Region projects, primarily on the continued development of the White Rose Extension projects, including the North Amethyst and South White Rose Extension satellite fields and exploration at the Bay Du Nord and Harpoon discoveries made during the year.

Asia Pacific Region

Total capital expenditures of $654 million were invested in the Asia Pacific Region in 2013, primarily for development of the Liwan Gas Project. In addition, the Company drilled the MBF-1 exploration well (50% interest) and the MAX-3 appraisal well (40% interest) at the Madura Strait in Indonesia in 2013.

2014 Upstream Capital Program

($ millions)	
Western Canada	**2,500**
Oil sands	**400**
Atlantic Region	**600**
Asia Pacific Region	**500**
Total Upstream capital expenditures[(1)]	**4,000**

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

The 2014 Capital Program will enable Husky to build on the momentum achieved over the past three years and will support the acceleration of near-term production and the continued execution of the Company's mid and long-term growth initiatives.

The Company has budgeted $500 million for the Asia Pacific Region in 2014, mainly for the completion of the Liwan Gas Project including the tie-in of the Liuhua 34-2 field into the Liwan deep water infrastructure and development of the Madura Strait block in Indonesia.

Oil Sands capital for 2014 will primarily be for completing the development of Phase 1 of the Sunrise Energy Project as well as planning, design and engineering for the next phase of the project.

Budgeted investment in the Atlantic Region of $600 million is for continued development of the White Rose fields and extensions. The Company plans to conduct additional drilling in 2014 in the Flemish Pass Basin to further assess the economic potential of oil development following the three major discoveries.

In addition to advancing mid and long-term growth pillars, the 2014 Capital Program provides support to the Company's efforts to continue to reinvigorate and transform its foundation in Western Canada. A substantial oil and liquids-rich natural gas resource play portfolio has been acquired and further drilling is scheduled to take place across the portfolio in 2014. The Company is making progress in its strategy to transition a greater percentage of its heavy oil production to long-life thermal. The Company will continue its development of the 10,000 bbls/day Rush Lake thermal project, with expected first production in the second half of 2015. In addition, two 10,000 bbls/day thermal developments were sanctioned in late 2013 at Edam East and Vawn, both located in Saskatchewan, with construction scheduled to begin in 2014.

Upstream Turnarounds

2013 Turnarounds

A planned maintenance turnaround was completed on the SeaRose FPSO during 2013. The six-day shutdown focused on annual regulatory inspections and maintenance and tie-in of equipment for the South White Rose Extension.

An 11-week turnaround of the Terra Nova FPSO was completed in 2013. The planned maintenance shutdown was extended to accommodate repair and replacement of nine mooring chains. The impact to Husky's 2013 annual production was approximately 2,100 bbls/day.

Planned Turnarounds

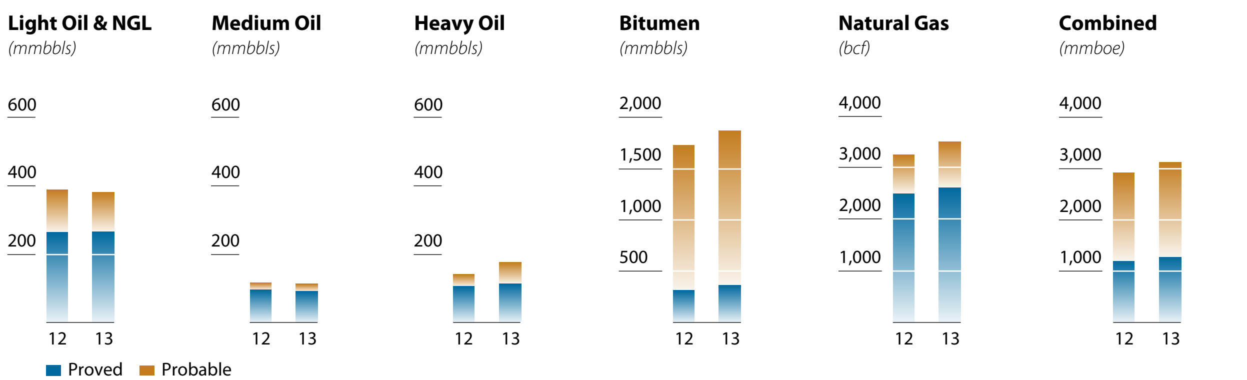
Planned plant maintenance activities for Western Canada are scheduled in the second and third quarters of 2014, including the full shutdown and maintenance of the Rainbow oil and gas facility for approximately four weeks in the second quarter.

In the Atlantic Region, the partner-operated Terra Nova FPSO is scheduled to undergo a 28-day turnaround in the third quarter of 2014.

A planned offstation for the Wenchang FPSO is scheduled for approximately five months in 2014. The offstation is intended to address dry dock maintenance and mooring line replacement.

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, 2013. 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.

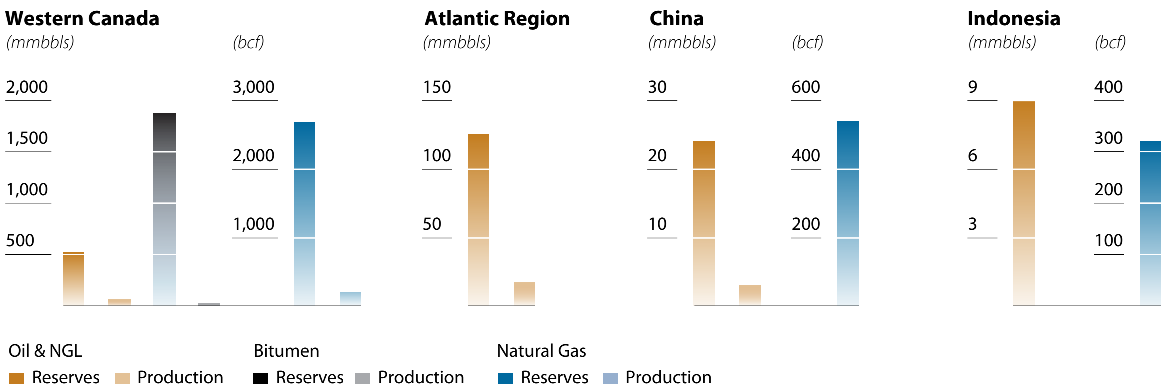
The Company's complete Oil and Gas Reserves Disclosure, prepared in accordance with NI 51-101, is contained in Husky's Annual Information Form, which is available at www.sedar.com, or Husky's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com.

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 Heavy Oil and Gas business unit, excluding the Tucker property.

McDaniel & Associates Consultants Ltd., an independent firm of oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and natural gas products reserves, excluding those estimated by Sproule. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally evaluated proved and probable reserves and net present values are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the Canadian Oil and Gas Evaluation Handbook.

At December 31, 2013, Husky's proved oil and gas reserves were 1,265 mmboe, up from 1,192 mmboe at the end of 2012. Additions to proved reserves, including acquisitions and divestitures, represent 166% excluding economic revisions (164% including economic revisions) of 2013 production. Major additions to proved reserves in 2013 included:

- The extension through additional drilling locations at the Sunrise Energy Project in the Oil Sands that resulted in the booking of an additional 39 mmbbls of bitumen in proved undeveloped reserves;
- The project sanction at the South White Rose Extension in the Atlantic Region that resulted in the booking of an additional 7 mmbbls of light oil in proved undeveloped reserves; and
- The extension through additional drilling locations at the Ansell liquids-rich natural gas resource play in the Alberta Deep Basin that resulted in the booking of an additional 32 mmboe of natural gas and NGL 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, 2012	173	95	105	311	2,073	68	22	434	774	2,507	1,192
Revision of previous estimate	(10)	(3)	7	24	79	13	3	–	34	79	48
Purchase of reserves in place	–	–	–	1	1	–	–	–	1	1	1
Sale of reserves in place	–	–	–	–	(3)	–	–	–	–	(3)	(1)
Discoveries, extensions and improved recovery	15	7	28	40	232	9	1	18	100	250	142
Economic revision	1	–	–	–	(20)	–	–	–	1	(20)	(3)
Production	(12)	(8)	(27)	(17)	(187)	(16)	(3)	–	(83)	(187)	(114)
Proved reserves December 31, 2013	**167**	**91**	**113**	**359**	**2,175**	**74**	**23**	**452**	**827**	**2,627**	**1,265**
Proved and probable reserves December 31, 2013	**223**	**112**	**176**	**1,870**	**2,669**	**125**	**33**	**859**	**2,539**	**3,528**	**3,127**
December 31, 2012	229	117	140	1,725	2,547	130	30	718	2,371	3,265	2,915

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

Reconciliation of Proved Developed Reserves

(forecast prices and costs before royalties)	Canada – Western Canada – Light Crude Oil & NGL (mmbbls)	Canada – Western Canada – Medium Crude Oil (mmbbls)	Canada – Western Canada – Heavy Crude Oil (mmbbls)[1]	Canada – Western Canada – Bitumen (mmbbls)	Canada – Western Canada – Natural Gas (bcf)	Canada – Atlantic Region – Light Crude Oil (mmbbls)	International – Light Crude Oil & NGL (mmbbls)	International – Natural Gas (bcf)	Total – Crude Oil & NGL (mmbbls)	Total – Natural Gas (bcf)	Total – Equivalent Units (mmboe)
Proved developed reserves											
December 31, 2012	149	88	84	59	1,714	56	8	–	444	1,714	729
Revision of previous estimate	(6)	(2)	14	11	106	12	2	–	31	106	50
Transfer from proved undeveloped	4	3	6	13	58	8	8	267	42	325	97
Purchase of reserves in place	–	–	–	–	1	–	–	–	–	1	–
Sale of reserves in place	–	–	–	–	(3)	–	–	–	–	(3)	(1)
Discoveries, extensions and improved recovery	10	4	15	–	33	–	–	–	29	33	34
Economic revision	1	–	–	–	(20)	–	–	–	1	(20)	(3)
Production	(12)	(8)	(27)	(17)	(187)	(16)	(3)	–	(83)	(187)	(114)
Proved developed reserves December 31, 2013	**146**	**85**	**92**	**66**	**1,702**	**60**	**15**	**267**	**464**	**1,969**	**792**

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

Infrastructure and Marketing

The Company is engaged in the marketing of 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)*	**2013**	2012
Infrastructure gross margin[1]	**130**	119
Marketing and other gross margin[2]	**312**	398
Gross margin	**442**	517
Operating and administrative expenses	**33**	33
Depletion, depreciation and amortization	**20**	22
Other expenses	**(3)**	–
Income taxes	**100**	116
Net earnings	**292**	346
Commodity trading volumes managed (mboe/day)	**174.5**	180.1

[1] *In 2013, the Company reclassified its processing facilities from Infrastructure and Marketing to Exploration and Production. Prior period amounts have been adjusted to conform with current presentation.*
[2] *Marketing and other gross margin has been recast to reflect a change in the classification of certain trading transactions.*

Infrastructure and Marketing net earnings decreased by $54 million in 2013 compared to 2012 due to lower marketing margins as a result of the narrowing of WTI to Brent crude oil price differentials in the second and third quarters of 2013 and fewer arbitrage opportunities available from utilizing the Company's access to infrastructure to move crude oil from Canada to the United States.

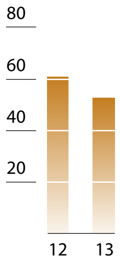
Infrastructure and Marketing capital expenditures totalled $96 million in 2013 compared to $54 million in 2012. The majority of Infrastructure and Marketing capital expenditures during the year related to pipeline maintenance and storage tank expenditures.

6.4 Downstream

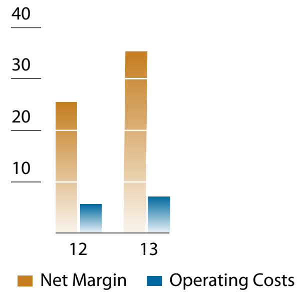
2013 Total Downstream Earnings $830 million

Upgrader

Upgrader
Synthetic Crude Sales
(mbbls/day)



Upgrader
Unit Margin & Operating Costs
($/bbl)



Upgrader Earnings Summary *($ millions, except where indicated)*	2013	2012
Gross revenues	**2,023**	2,191
Gross margin	**645**	555
Operating and administrative expenses	**168**	153
Depreciation and amortization	**96**	102
Other income	**(20)**	(6)
Income taxes	**104**	80
Net earnings	**297**	226
Upgrader throughput[(1)] *(mbbls/day)*	**66.1**	77.4
Synthetic crude oil sales *(mbbls/day)*	**50.5**	60.4
Upgrading differential *($/bbl)*	**29.14**	22.34
Unit margin ($/bbl)	**34.99**	25.17
Unit operating cost[(2)] ($/bbl)	**6.96**	5.42

(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.

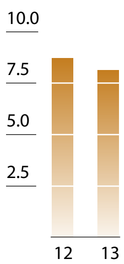
The increase in Upgrader earnings in 2013 compared to 2012 was primarily due to higher upgrading differentials that resulted from a deep discount on Lloyd Heavy Blend feedstock in early and late 2013 and higher realized prices for Husky Synthetic Blend crude oil, partially offset by lower throughput due to a major planned turnaround completed in the year.

During 2013, the price of Husky's synthetic crude oil averaged $100.57/bbl compared with the average cost of blended heavy crude oil from the Lloydminster area of $71.43/bbl. During 2012, the price of Husky's synthetic crude oil averaged $91.90/bbl compared with an average cost of blended heavy crude oil from the Lloydminster area of $69.56/bbl. This resulted in an average synthetic/heavy crude oil differential of $29.14/bbl in 2013 compared to $22.34/bbl in 2012 and a gross unit margin of $34.99/bbl in 2013 compared to $25.17/bbl in 2012. The cost of upgrading averaged $6.96/bbl in 2013 compared to $5.42/bbl in 2012, due to the major planned turnaround in 2013, which resulted in a net margin for upgrading heavy crude of $28.03/bbl, up 42% compared with $19.75/bbl in 2012.

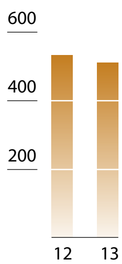
Canadian Refined Products

Fuel Sales Volumes

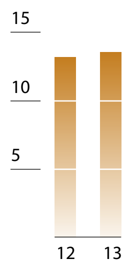
Volume
(millions of litres/day)



Outlets



Volume per Outlet
(thousands of litres/day)



Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	2013	2012
Gross revenues	**3,737**	3,848
Gross margin		
Fuel	**140**	153
Refining	**175**	180
Asphalt	**233**	257
Ancillary	**55**	50
	603	640
Operating and administrative expenses	**253**	242
Depreciation and amortization	**90**	83
Other expense	**–**	4
Income taxes	**66**	80
Net earnings	**194**	231
Number of fuel outlets[1]	**509**	531
Fuel sales volume, including wholesale		
Fuel sales *(million of litres/day)*[2]	**8.1**	8.7
Fuel sales per outlet *(thousand of litres/day)*[2]	**13.5**	13.1
Refinery throughput		
Prince George refinery *(mbbls/day)*	**10.3**	11.1
Lloydminster refinery *(mbbls/day)*	**26.4**	28.3
Ethanol production *(thousand of litres/day)*	**742.4**	721.2

(1) *Average number of fuel outlets for period indicated.*
(2) *Fuel sales have been recast to exclude non-retail products. Prior periods have been adjusted to conform with the current period presentation.*

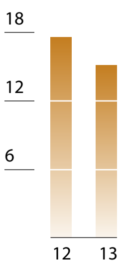
Fuel margins decreased in 2013 compared to 2012 primarily due to lower diesel margins, decreased wholesale sales volumes and lower fuel sales resulting from retail site construction and selected outlet closures.

Refining gross margins decreased slightly in 2013 compared to 2012 primarily due to higher priced feedstock costs and lower throughput and sales volumes, partially offset by higher realized prices for refined products.

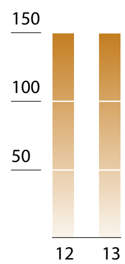
Asphalt gross margins decreased compared to the same period in 2012 primarily due to lower asphalt production as a result of a scheduled refinery turnaround in the year.

U.S. Refining and Marketing

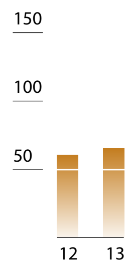
Refining Margin
U.S.
(U.S. $/bbl crude throughput)



Throughput
Lima Refinery
(mbbls/day)



Toledo Refinery
(mbbls/day)



U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	2013	2012
Gross revenues[(1)]	10,728	9,856
Gross refining margin[(1)]	1,182	1,312
Operating and administrative expenses	424	398
Depreciation and amortization	233	212
Other expenses	3	9
Income taxes	183	257
Net earnings	339	436
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	149.4	150.0
BP-Husky Toledo Refinery throughput *(mbbls/day)*	65.0	60.6
Refining margin *(U.S. $/bbl crude throughput)*[(1)]	15.06	17.48
Refinery inventory (feedstocks and refined products) *(mmbbls)*[(2)]	10.3	11.3

(1) *Gross revenues and purchases have been recast for the comparative period to reflect a change in the classification of certain trading transactions.*
(2) *Refinery inventory includes feedstock and refined products.*

U.S. Refining and Marketing net earnings in 2013 decreased compared to 2012 primarily due to a significant drop in the Chicago 3:2:1 market crack spread in the second half of 2013, resulting in an annual decrease of approximately $300 million in gross refining margin, partially offset by increased throughput at the BP-Husky Toledo Refinery due to turnaround activity in 2012.

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 earlier in the previous year when crude oil prices were lower. The estimated FIFO impact was a reduction in net earnings of approximately $18 million in 2013 compared to a reduction in net earnings of $28 million in 2012.

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

Downstream Capital Expenditures

Downstream capital expenditures totalled $534 million for 2013 compared to $457 million in 2012. In Canada, capital expenditures were $314 million related to upgrades at the Prince George Refinery, the Upgrader and at retail stations. In the United States, capital expenditures totalled $220 million. At the Lima Refinery, $143 million was spent on various process improvement projects, optimizations and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $77 million (Husky's 50% share) and were primarily for facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

The Lloydminster Upgrader is scheduled to undergo a partial outage in the fall of 2014 for planned maintenance. Plant rates are expected to remain at approximately 80% during the planned 42-day turnaround.

The Lima Refinery is scheduled to complete a major turnaround in 2015 on 70% of the operating units. The refinery is expected to be shut down for 45 days. The remaining 30% of the operating units are scheduled to be addressed in a turnaround currently planned for 2016. In addition, the Refinery is scheduled to undergo an 18-day outage in March 2014 for planned maintenance to prepare for the major turnaround in 2015. The Refinery is expected to operate at approximately 60% capacity during the outage.

The BP-Husky Toledo Refinery is scheduled to complete a turnaround in 2014 that will affect approximately 30% of its operating capacity. Refinery operations will be impacted for approximately 35 to 50 days depending on the unit. The remaining 70% of the operating units are scheduled to be addressed in a turnaround planned for 2015.

6.5 Corporate

2013 Loss $245 million

Corporate Summary *($ millions) income (expense)*	2013	2012
Administration expenses	**(112)**	(128)
Stock-based compensation	**(105)**	(54)
Depreciation and amortization	**(51)**	(40)
Other income	**17**	3
Foreign exchange gains	**21**	14
Interest - net	**–**	(52)
Income taxes	**(15)**	64
Net loss	**(245)**	(193)

The Corporate segment reported a loss in 2013 of $245 million compared to a loss of $193 million in 2012. Stock-based compensation expense increased by $51 million in 2013 due to a higher share price at the end of 2013 compared to 2012. Interest - net decreased by $52 million in 2013 compared to 2012 due to increases in amounts of capitalized interest related to projects in the Asia Pacific Region and the Sunrise Energy Project. Other income increased by $14 million in 2013 compared to 2012 primarily due to the recovery of an insurance provision from the prior year.

Foreign Exchange Summary *($ millions, except exchange rate amounts)*	2013	2012
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(11)**	43
Gains on cross currency swaps	**–**	2
Gains (losses) on contribution receivable	**27**	(7)
Other foreign exchange gains (losses)	**5**	(24)
Foreign exchange gains	**21**	14
U.S./Canadian dollar exchange rates:		
At beginning of year	**U.S. $1.005**	U.S. $0.983
At end of year	**U.S. $0.940**	U.S. $1.005

Consolidated Income Taxes

Consolidated income taxes decreased in 2013 to $799 million from $814 million in 2012, resulting in an effective tax rate of 30% in 2013 compared to 29% in 2012. The increase in the effective tax rate was attributable to the increase in non-deductible stock-based compensation expense.

($ millions)	2013	2012
Income taxes as reported	**799**	814
Cash taxes paid	**433**	575

Taxable income from Canadian operations is primarily generated through partnerships. This structure previously allowed a deferral of taxable income and related taxes to a future period. Starting in 2012, the Canadian government has removed this deferral, and any income taxes related to previously deferred taxable income are now payable over a five-year period that commenced in 2013.

Corporate Capital Expenditures

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

7.0 Risk and Risk Management

7.1 Enterprise Risk Management

Husky'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. Husky 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 Husky and its operations.

7.2 Significant Risk Factors

Operational, Environmental and Safety Incidents

The Company's businesses are subject to inherent operational risks and hazards in respect to safety and the environment that require continuous vigilance. The Company seeks to minimize these operational risks and hazards by carefully designing and building its facilities and conducting its operations in a safe and reliable manner. However, failure to manage these operational risks and hazards effectively could result in unexpected incidents, including the release of restricted substances, fires, explosions, well blow-outs, marine catastrophe or mechanical failures and pipeline failures. The consequences of such events include personal injuries, loss of life, environmental damage, property damage, loss of revenues, fines, penalties, legal liabilities, disruption to operations, asset repair costs, remediation and reclamation costs, monitoring post-cleanup and/or reputational impacts that may affect the Company's license to operate. Remediation may be complicated by a number of factors including shortages of specialized equipment or personnel, extreme operating environments and the absence of appropriate or proven countermeasures to effectively remedy such consequences. Enterprise risk management, emergency preparedness, business continuity and security policies and programs are in place for all operating areas, and are routinely exercised. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks and hazards. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks and hazards.

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 Husky's oil and gas reserves. Husky's reserves include significant quantities of heavier grades of crude oil that trade at a discount to light crude oil. Heavier grades of crude oil are typically more expensive to produce, process, transport and refine into high value refined products. Refining and transportation capacity for heavy crude oil is limited and planned increases of North American heavy crude oil production may create the need for additional heavy oil refining and transportation capacity. As a result, wider price differentials could have adverse effects on the Company's financial performance and condition, reduce the value and quantities of 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 entirely in Western Canada and is, therefore, 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 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 fluctuations in crude oil and natural gas prices are beyond the Company's control and accordingly, could have a material adverse effect on the Company's business, financial condition and cash flow.

For information on 2013 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 could negatively affect the Company's reputation, investor confidence and the Company's ability to deliver on its growth strategy.

To maintain the Company's future production of crude oil, natural gas and natural gas liquids 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. 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 potential development 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 by 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 our refineries or upgrader may limit our ability to deliver product with negative implications on sales from operating activities.

Security and Terrorist Threats

A security threat or terrorist attack on a facility owned or operated by the Company could result in the interruption or cessation of key elements of its operations. Security and terrorist threats may also impact the Company's personnel, which could result in death, injury, hostage taking and/or kidnapping. This could have a material impact on the Company's financial position, business strategy and cash flow.

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 Offtake

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. This could 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. However, a tight labour market, an insufficient number of qualified candidates, and an aging workforce are factors that could precipitate a human resource risk for the Company. Failure to manage any of the foregoing developments, 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 major projects relating to oil and gas exploration, development and production. Risks associated with the execution of the Company's major projects, as well as the commissioning and integration of new assets into its existing infrastructure, may result in cost overruns, project or production delays, and missed financial targets, thereby eroding project economics. Typical project execution risks include: the availability and cost of capital, inability to find mutually agreeable parameters with key project partners for large growth projects, availability of manufacturing and processing capacity, faulty construction and design errors, labour disruptions, bankruptcies, productivity issues affecting the Company directly or indirectly, unexpected changes in the scope of a project, health and safety incidents, need for government approvals or permits, unexpected cost increases, availability of qualified and skilled labour, availability of critical equipment, severe weather, and availability and proximity of pipeline capacity.

Partner Misalignment
Joint venture partners operate a portion of Husky'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 Husky project may be delayed and the Company may be partially or totally liable for its partner's share of the project.

Reserves Data, Future Net Revenue and Resource Estimates
The reserves data 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. Estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, prepared by different engineers or by the same engineers at different times, may vary substantially. All reserves estimates 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 may be 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, environmental and safety controls related to the reduction of greenhouse gasses and other emissions, penalties, taxes, royalties, government fees, anti-corruption laws, 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
The Company anticipates that changes in environmental legislation may require reductions in emissions from its operations and result in increased capital expenditures. Further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, and increased capital expenditures and operating costs, which could have a material adverse effect on the Company's financial condition and results of operations.

Following the 2010 Deepwater Horizon oil spill in the Gulf of Mexico, the United States implemented stricter regulation of offshore oil and gas operations with respect to operations in the Outer Continental Shelf, including in the Gulf of Mexico. Further regulation, increased financial assurance requirements and increased caps on liability are likely to be applied to offshore oil and gas operations in these areas. In the event that similar changes in environmental regulation occur with respect to the Company's operations in the Atlantic or Asia Pacific Regions, such changes could increase the cost of complying with environmental regulation in connection with these operations and have a material adverse impact on Husky's operations.

The transportation of crude oil by rail is an emerging issue for the petroleum industry. There have been four major incidents in the past eight months involving Bakken crude oil transported on rail, and federal and industry reviews of regulations and equipment standards are underway. In early 2014, Transport Canada announced proposed regulatory amendments to further improve the safety of the transportation of dangerous goods by rail. This may result in stricter standards, larger fines and liabilities, and increased capital expenditures for the petroleum industry.

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% below an established baseline emissions intensity. These regulations currently affect the Company's Ram River Gas Plant and Tucker Thermal Oil Facility and are anticipated to affect the Sunrise Energy Project when it begins to produce oil. British Columbia currently has a $30 per tonne carbon tax that is placed on fuel the Company uses in that jurisdiction, which affects all of the Company's operations in British Columbia. The Saskatchewan government is anticipated to release regulations similar to Alberta's and the Federal Government of Canada has announced pending regulations for the oil and gas sector. Climate change regulations may become more onerous over time as public and political pressures increase to implement initiatives that further reduce the emissions of greenhouse gases. Although the impact of emerging regulation is uncertain, they may adversely affect the Company's operations and increase costs.

In addition, the Company's operations may be materially impacted by application of the EPA'sclimate change rules or by future U.S. greenhouse gas legislation that applies to the oil and gas industry or the consumption of petroleum products or by these or any further restrictive regulations issued by the EPA. Such legislation or regulation could require U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may increase capital and operating expenditures.

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. 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 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 debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings or a negative change in ratings outlook, could adversely affect Husky's cost of financing and its access to sources of liquidity and capital. Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to 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 lack of availability of oil and gas field equipment could 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.

7.3 Financial Risks

Husky'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. For further details on the Company's derivative financial instruments, including assumptions made in the calculation of fair value and additional discussion of exposure to risks and mitigation activities, see Note 22 Financial Instrument and Risk Management within the Company's 2013 Consolidated Financial Statements and Section 3.0 of this Management's Discussion and Analysis. For a discussion on commodity price risk, refer to the Commodity Price Volatility section above.

Foreign Currency Risk

The Company's results are affected by the exchange rates between various currencies including the Canadian and U.S. dollar. The majority of Husky'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 Husky's U.S. dollar denominated debt and related interest expense, as expressed in Canadian dollars. The fluctuations in exchange rates are beyond Husky's control and, accordingly, 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. Husky 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, 2013, the amount that the Company designated was U.S. $3.2 billion (December 31, 2012 - U.S. $2.8 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, Husky 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. Husky 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. Husky actively manages this exposure to credit and contract execution risk from both a customer and a supplier perspective. Internal credit policies govern Husky's credit portfolio and limit transactions according to a counterparty's and a supplier's credit quality. Counterparties for all financial derivatives transacted by Husky 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.

Husky is committed to retaining investment grade credit ratings to support access to debt 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)
Dominion Bond Rating Service:		
Senior Unsecured Debt	Stable	A (low)
Series 1 Preferred Shares	Stable	Pfd-2 (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, contribution receivable, accounts payable and accrued liabilities, 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 through profit or loss ("FVTPL") in the consolidated balance sheets:

Financial Instruments at Fair Value ($ millions)	As at December 31, 2013	As at December 31, 2012
Derivatives – fair value through profit or loss ("FVTPL")		
Accounts receivable	**18**	13
Accounts payable and accrued liabilities	**(19)**	(5)
Other assets, including derivatives	**2**	1
Other – FVTPL[1]		
Accounts payable and accrued liabilities	**(29)**	(27)
Other long-term liabilities	**(31)**	(78)
Hedging instruments[2]		
Derivatives designated as cash flow hedge	**37**	1
Hedge of net investment[3]	**(93)**	88
	(115)	(7)
Net gains (losses) for the year related to financial instruments held at fair value	**(111)**	122
Included in net earnings	**33**	104
Included in OCI	**(144)**	18

[1] *Non-derivative items related to contingent consideration recognized as part of a business acquisition.*
[2] *Hedging instruments are presented net of tax.*
[3] *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.*

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

In 2013, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At December 31, 2013, Husky had total debt of $4,119 million partially offset by cash on hand of $1,097 million for $3,022 million of net debt compared to $1,893 million of net debt as at December 31, 2012. At December 31, 2013, the Company had $3.6 billion of unused credit facilities of which $3.2 billion was long-term committed credit facilities and $371 million was short-term uncommitted credit facilities. In addition, the Company had $3.0 billion in unused capacity under its December 2012 Canadian universal short form base shelf prospectus and U.S. $3.0 billion in unused capacity under its October 2013 U.S. universal short form base shelf prospectus. The ability of the Company to utilize the capacity under its base shelf prospectuses is dependent on market conditions at the time of sale. Refer to Section 8.2.

	2013	2012
Cash flow		
Operating activities *($ millions)*	**4,645**	5,193
Financing activities *($ millions)*	**(846)**	(162)
Investing activities *($ millions)*	**(4,722)**	(4,834)
Financial Ratios[(1)]		
Debt to capital employed *(percent)*[(2)]	**17.0**	17.0
Debt to cash flow *(times)*[(3)(4)]	**0.8**	0.8
Corporate reinvestment ratio *(percent)*[(3)(5)]	**108**	106
Interest coverage on long-term debt only[(3)(6)]		
Earnings	**11.2**	12.5
Cash flow	**22.4**	24.9
Interest coverage on total debt[(3)(7)]		
Earnings	**11.3**	12.3
Cash flow	**22.6**	24.6

(1) *Financial ratios constitute non-GAAP measures. (Refer to Section 11.3)*
(2) *Debt to capital employed is equal to long-term debt and long-term debt due within one year 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 and long-term debt due within one year 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 short and long-term debt.*

Cash Flow from Operating Activities

Cash generated from operating activities was $4,645 million in 2013 compared to $5,193 million in 2012, primarily due to a decrease in non-cash working capital resulting from the timing of accounts payable settlements and inventory movement. The decrease in cash flow generated from operating activities was partially offset by higher crude oil production and realized commodity prices in Exploration and Production.

Cash Flow used for Financing Activities

Cash used for financing activities was $846 million in 2013 compared to $162 million in 2012. The increase in cash flow used for financing activities was primarily due to higher cash versus stock dividends paid in 2013 compared to 2012.

Cash Flow used for Investing Activities

Cash used for investing activities was $4,722 million in 2013 compared to $4,834 million in 2012. 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, 2013, Husky's working capital was $754 million compared with $2,401 million at December 31, 2012.

Movement in Working Capital

($ millions)	**December 31, 2013**	December 31, 2012	Increase/ (Decrease)
Cash and cash equivalents	**1,097**	2,025	(928)
Accounts receivable	**1,458**	1,345	113
Income taxes receivable	**461**	323	138
Inventories	**1,812**	1,736	76
Prepaid expenses	**89**	64	25
Accounts payable and accrued liabilities	**(3,155)**	(2,985)	(170)
Asset retirement obligations	**(210)**	(107)	(103)
Long-term debt due within one year	**(798)**	–	(798)
Net working capital	**754**	2,401	(1,647)

The decrease in cash was primarily due to lower cash flow from operations in the year and higher cash versus stock dividends paid in 2013 compared to 2012. Movements in accounts receivable, income taxes receivable and accounts payable were due to the timing of settlements compared to 2012. The increase in long-term debt due within one year was due to the reclassification of long-term debt maturing in 2014 to current liabilities as at December 31, 2013.

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. Husky 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 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, Husky frequently evaluates the 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, 2013, no production was hedged.

At December 31, 2013, Husky had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[1]	**595**	**371**
Syndicated bank facilities	**3,200**	**3,200**
	3,795	**3,571**

[1] *Consists of demand credit facilities.*

Cash and cash equivalents at December 31, 2013 totalled $1,097 million compared to $2,025 million at the beginning of the year.

At December 31, 2013, Husky had unused short and long-term borrowing credit facilities totalling $3.6 billion. A total of $224 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

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.

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, 2013, the Company declared dividends payable of $1.20 per common share, resulting in dividends of $1,180 million. An aggregate of $1,171 million was paid in cash during 2013. At December 31, 2013, $295 million, including $291 million in cash and $4 million in common shares, was payable to shareholders on account of dividends declared on October 24, 2013. Commencing in the fourth quarter of 2013, the Board of Directors discontinued the payment of dividends by way of the issuance of common shares. The change became effective with the dividend declaration in February 2014.

On March 22, 2012, the Company issued U.S. $500 million of 3.95% senior unsecured notes due April 15, 2022 pursuant to a universal short form base shelf prospectus filed with the Alberta Securities Commission and the U.S. Securities and Exchange Commission ("SEC") on June 13, 2011 and an accompanying prospectus supplement. The notes are redeemable at the option of the Company at a make-whole premium and 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, 2012, the Company repaid the maturing 6.25% notes issued under a trust indenture dated June 14, 2002. The amount paid to note holders was U.S. $413 million, including U.S. $13 million of interest.

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 there was no change to the August 31, 2014 maturity date of the $1.6 billion facility. In February 2013, the limit on the $1.5 billion facility was increased to $1.6 billion. There continues to be no difference between the terms of these facilities, other than their maturity dates. As at December 31, 2013, there were no amounts drawn under the facilities.

On December 31, 2012, the Company filed a universal 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, 2013, the Company had not issued securities under the Canadian Shelf Prospectus.

On October 31, 2013 and November 1, 2013, the Company filed a universal short form base shelf prospectus (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. As at December 31, 2013, the Company had not issued securities under the U.S. Shelf Prospectus.

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

Capital Structure	**December 31, 2013**	
($ millions)	**Outstanding**	**Available[(1)]**
Total long-term debt	**4,119**	**3,571**
Common shares, retained earnings and other reserves	**20,078**	

[(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, Husky is obligated to make future payments. These obligations represent contracts and other commitments that are known and non-cancellable.

Contractual Obligations

Payments due by period ($ millions)	2014	2015-2016	2017-2018	Thereafter	Total
Long-term debt and interest on fixed rate debt	1,015	882	632	3,163	5,692
Operating leases	155	526	432	367	1,480
Firm transportation agreements	289	548	525	2,702	4,064
Unconditional purchase obligations(1)	2,287	1,977	51	71	4,386
Lease rentals and exploration work agreements	107	251	180	1,208	1,746
Asset retirement obligations(2)	132	226	221	11,666	12,245
	3,985	4,410	2,041	19,177	29,613

(1) *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases.*
(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 as outlined in Note 16 to the 2013 Consolidated Financial Statements. On an undiscounted basis, the ARO increased from $10.3 billion as at December 31, 2012 to $12.3 billion as at December 31, 2013, due to increased cost estimates and asset growth in both the Upstream and Downstream segments.

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.

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 86 active employees, 97 participants with deferred benefits and 532 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 provides a defined benefit pension plan for approximately 210 active union represented employees in the United States, which was curtailed effective July 31, 2013. A defined benefit pension plan for 175 active non-represented employees in the United States was curtailed effective April 1, 2011. Approximately 10 participants in both U.S. plans have deferred benefits and no participants were receiving benefits at year end. These pension plans were established effective July 1, 2007 in conjunction with the acquisition of the Lima Refinery. 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 2013 Consolidated Financial Statements).

Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery (Refer to Note 8 to the 2013 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, 2013, Husky's share of this obligation was U.S. $1.3 billion, including accrued interest.

Husky 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

Husky does not believe that it has any 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, Husky 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 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. 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, 2013, the senior notes are included in long-term debt in the Company's consolidated balance sheets.

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.

In April 2011, the Company sold its 50% interest in the Meridian cogeneration facility ("Meridian") to a related party. The consideration for the Company's share of Meridian was $61 million, resulting in no net gain or loss on the transaction.

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, 2013, the amounts of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $55 million. For the year ended December 31, 2013, the amounts of steam purchased by the Company from Meridian totalled $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, 2013, 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 25, 2014

• common shares	983,491,183
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	27,548,178
• stock options exercisable	12,311,092

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 2013 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, impairment, asset retirement obligations, 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 post-retirement health and dental care plan and the defined benefit pension plan 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 and 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.

Successful Efforts Assessments

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. Successful efforts assessments require significant judgment 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 indications of impairment requires significant judgment of internal and external indicators. 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 judgement 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

Impairment of Assets

In May 2013, the IASB published narrow-scope amendments to IAS 36, "Impairment of Assets," which requires the disclosure of information about the recoverable amount of impaired assets, particularly if that amount is based on fair value less costs of disposal. Amendments to IAS 36 are effective for the Company on January 1, 2014, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the amendments on January 1, 2014. The adoption of the standard is not expected to have a material impact on the Company's annual consolidated financial statements.

Change in Accounting Policy

Consolidated Financial Statements

In May 2011, the IASB published IFRS 10, "Consolidated Financial Statements," which provides a single model to be applied in the assessment of control for all entities in which the Company has an investment including special purpose entities currently in the scope of Standing Interpretations Committee ("SIC") 12. Under the new control model, the Company has control over an investment if the Company has the ability to direct the activities of the investment, is exposed to the variability of returns from the investment and there is a link between the ability to direct activities and the variability of returns. IFRS 10 was effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. The Company retrospectively adopted IFRS 10 on January 1, 2013. The adoption of the standard had no impact on the Company's annual consolidated financial statements.

Joint Arrangements

In May 2011, the IASB published IFRS 11, "Joint Arrangements," whereby joint arrangements are classified as either joint operations or joint ventures. Parties to a joint operation retain the rights and obligations to individual assets and liabilities of the operation, while parties to a joint venture have rights to the net assets of the venture. Joint operations shall be accounted for in a manner consistent with jointly controlled assets and operations whereby the Company's contractual share of the arrangement's assets, liabilities, revenues and expenses is included in the consolidated financial statements. Any arrangement structured through a separate vehicle that does effectively result in separation between the Company and the joint arrangement shall be classified as a joint venture and accounted for using the equity method of accounting. Under the previous standard, the Company had the option to account for any interests in joint arrangements using either proportionate consolidation or equity accounting. IFRS 11 was effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company retrospectively adopted IFRS 11 on January 1, 2013. The adoption of the standard resulted in the following cumulative balance sheet impact related to the Madura joint arrangement, applied prospectively from January 1, 2012:

Balance Sheet Impact *($ millions)*	December 31, 2012	January 1, 2012
Accounts receivable	(4)	(4)
Exploration and evaluation assets	(37)	(14)
Property, plant and equipment, net	(45)	(42)
Investment in joint ventures	132	91
Other assets	(25)	–
Accounts payable and accrued liabilities	1	18
Other long-term liabilities	3	(24)
Deferred tax liabilities	(25)	(25)
Total Balance Sheet Impact	–	–

Disclosure of Interests in Other Entities

In May 2011, the IASB published IFRS 12, "Disclosure of Interests in Other Entities," which contains new annual disclosure requirements for interests the Company has in subsidiaries, joint arrangements, associates and unconsolidated structured entities. Required disclosures aim to provide readers of the financial statements with information to evaluate the nature of and risks associated with the Company's interests in other entities and the effects of those interests on the Company's consolidated financial statements. IFRS 12 was effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company retrospectively adopted IFRS 12 on January 1, 2013. The adoption of the standard did not have a material impact on the Company's annual consolidated financial statements.

Investments in Associates and Joint Ventures

In May 2011, the IASB issued amendments to IAS 28, "Investments in Associates and Joint Ventures," which provides additional guidance applicable to accounting for interests in joint ventures or associates when a portion of an interest is classified as held for sale or when the Company ceases to have joint control or significant influence over an associate or joint venture. When joint control or significant influence over an associate or joint venture ceases, the Company will no longer be required to remeasure the investment at that date. When a portion of an interest in a joint venture or associate is classified as held for sale, the portion not classified as held for sale shall be accounted for using the equity method of accounting until the sale is completed at which time the interest is reassessed for prospective accounting treatment. Amendments to IAS 28 were effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. The Company retrospectively adopted these amendments on January 1, 2013. The adoption of the amendments had no impact on the Company's annual consolidated financial statements.

Fair Value Measurement

In May 2011, the IASB published IFRS 13, "Fair Value Measurement," which provides a single source of fair value measurement guidance and replaces the guidance contained in individual IFRSs. The standard provides a framework for measuring fair value and establishes new disclosure requirements to enable readers to assess the methods and inputs used to develop fair value measurements, for recurring valuations that are subject to measurement uncertainty, and for the effect of those measurements on the financial statements. IFRS 13 was effective for the Company on January 1, 2013, with required prospective application and early adoption permitted. The Company adopted IFRS 13 on January 1, 2013. The adoption of the standard did not have a material impact on the Company's annual consolidated financial statements.

Employee Benefits

In June 2011, the IASB issued amendments to IAS 19, "Employee Benefits" to eliminate the corridor method that permits the deferral of actuarial gains and losses, to revise the presentation requirements for changes in defined benefit plan assets and liabilities and to enhance the required disclosures for defined benefit plans. Amendments to IAS 19 were effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company retrospectively adopted these amendments on January 1, 2013.

The adoption of this amended standard resulted in the following balance sheet impact, applied retrospectively to January 1, 2010:

(millions of Canadian dollars) (unaudited)	2012	2011	2010	Total
Increase/(decrease) in net defined benefit liability	1	2	(12)	(9)
Increase/(decrease) in retained earnings	(1)	(2)	12	9
Total balance sheet impact	–	–	–	–

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IFRS 7, "Financial Instruments: Disclosures" and IAS 32, "Financial Instruments: Presentation" to clarify the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Amendments to IFRS 7 were effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. Amendments to IAS 32 were effective for the Company for reporting periods ending after January 1, 2014, with required retrospective application and early adoption permitted. The Company retrospectively adopted both IFRS 7 and IAS 32 amendments on January 1, 2013. The adoption of the amendments did not have a material impact on the Company's consolidated financial statements (refer to note 22 of the 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; target debt to cash flow and debt to capital employed ratios; the Company's 2014 production guidance, including weighting of production among product types; target compound annual production growth rate for 2012-2017; and the Company's 2014 Upstream capital program;
- with respect to the Company's Asia Pacific Region: expected timing of first production at the Company's Liwan Gas Project; expected timing of tie-in and production of the Company's Liuhua 34-2 field; expected timing of completion of the acquisition of a seismic survey at the Company's offshore Taiwan exploration block; scheduled timing and duration of the Liwan Gas Project production going off-line; and scheduled timing, duration and expected impact of the planned offstation for the Wenchang FPSO;
- with respect to the Company's Atlantic Region: expected timing of installation of oil production equipment and anticipated timing of first production at the Company's South White Rose Extension project; scheduled timing and duration of a planned turnaround of the Terra Nova FPSO; scheduled timing of first production from the North Amethyst Hibernia formation well; and plans for further drilling in the Flemish Pass Basin;
- with respect to the Company's Oil Sands properties: scheduled timing of start up and anticipated volumes of production at the Company's Sunrise Energy Project; and targeted timing of turn over of well pads at the Company's Sunrise Energy Project;
- with respect to the Company's Heavy Oil properties: anticipated volumes of production at the Company's Sandall heavy oil thermal development project; estimated timing and volume of production growth from the Company's thermal projects; expected timing of first production and anticipated volumes of production at the Company's Rush Lake heavy oil thermal development project; scheduled timing of construction and first production, and anticipated volumes of production, at the Company's Edam East and Vawn heavy oil thermal developments; and the Company's horizontal and CHOPS drilling program for 2014;
- with respect to the Company's Western Canadian oil and gas resource plays: the Company's drilling and completion plans for its Slater River Canol shale play in the Northwest Territories; anticipated timing of completion activities and production from the Company's Kaybob project in the Duvernay play; and planned maintenance activities for Western Canada, including scheduled timing and duration of a shutdown at the Rainbow oil and gas facility;
- with respect to the Company's Infrastructure and Marketing operations: plans to increase pipeline connectivity and re-configure the terminal facility at the Hardisty terminal; anticipated timing of the extension of pipeline systems from the Sandall thermal development to Lloydminster; and the expansion of the South Saskatchewan Gathering System for the Rush Lake commercial project; and
- with respect to the Company's Downstream operating segment: the anticipated benefits from and scheduled timing of completion of the Lima, Ohio refinery reconfiguration and the anticipated processing capacity once reconfiguration is complete; scheduled timing and duration of a partial outage of the Lloydminster Upgrader for planned maintenance; the anticipated benefits from and scheduled timing of completion of a Hydrotreater Recycle Gas Compressor Project at the BP-Husky Toledo Refinery; plans to reconfigure and increase capacity at the BP-Husky Toledo Ohio Refinery; scheduled timing, duration and expected impact of turnarounds at the BP-Husky Toledo Refinery; and scheduled timing, duration and expected impact of an outage for planned maintenance and turnarounds at the Lima Refinery.

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 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, 2013 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 and resource estimates in this document have an effective date of December 31, 2013 and represent Husky's share. Unless otherwise noted, historical production numbers given represent Husky's share.

The Company uses the terms barrels of oil equivalent ("boe"), which is 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.

The Company has disclosed best-estimate contingent resources in this document. 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 that 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.

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. Estimates of contingent resources have not been adjusted for risk based on the chance of development. There is no certainty as to the timing of such development. For movement of resources to reserves categories, all projects must have an economic depletion plan and may require, among other things: (i) additional delineation drilling for unrisked contingent resources; (ii) regulatory approvals; and (iii) Company and partner approvals to proceed with development.

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.

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 Management's Discussion and Analysis , 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.

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 $204 million and $52 million for the years ended December 31, 2013 and 2011, respectively. Return on capital employed based on the calculation used in prior periods for the years ended December 31, 2013 and 2011 was 7.9% and 11.8%, respectively. Return on capital in use based on the calculation used in prior periods for the years ended December 31, 2013 and 2011 was 11.3% and 15.6%, 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 Husky's financial performance, efficiency and liquidity. The non-GAAP measurements do not have a standardized meaning prescribed by IFRS and therefore are unlikely to be comparable 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 impairment charges 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)		**2013**	2012	2011
GAAP	Net earnings	**1,829**	2,022	2,224
	Impairment of property, plant and equipment, net of tax	**204**	–	52
Non-GAAP	Net operating earnings	**2,033**	2,022	2,276
	Net operating earnings – basic	**2.07**	2.07	2.44
	Net operating earnings – diluted	**2.07**	2.07	2.37

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 assets, 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)	**2013**	2012	2011
GAAP cash flow – operating activities	**4,645**	5,193	5,092
Settlement of asset retirement obligations	**142**	123	105
Income taxes paid	**433**	575	282
Interest received	**(19)**	(34)	(12)
Change in non-cash working capital	**21**	(847)	(269)
Non-GAAP cash flow from operations	**5,222**	5,010	5,198
Cash flow from operations – basic	**5.31**	5.13	5.63
Cash flow from operations – diluted	**5.31**	5.13	5.58

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 by taking upstream netback (gross revenues less operating costs less royalties) divided by upstream gross production.

11.4 Additional Reader Advisories

Intention of Management's Discussion and Analysis ("MD&A")

This MD&A 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 MD&A was reviewed by the Audit Committee and approved by Husky's Board of Directors on February 25, 2014. 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 MD&A should be read in conjunction with the Consolidated Financial Statements and related notes. The readers are also encouraged to refer to Husky's interim reports filed in 2013, which contain the Management's Discussion and Analysis and Consolidated Financial Statements, and Husky's 2013 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.

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, 2013 and 2012 and Husky's financial position as at December 31, 2013 and at December 31, 2012.

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 30° API and above;
- Medium crude oil is 21° API and above but below 30° API;
- Heavy crude oil is above 10° API but below 21° 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	*Short and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses, but does not include asset retirement obligations or capitalized interest*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations, income taxes paid, interest received and changes in non-cash working capital*
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 and long-term debt due within one year divided by capital employed*
Debt to Cash Flow	*Long-term debt and long-term debt due within one year divided by cash flow from operations*
Feedstock	*Raw materials that are processed into petroleum products*
Front-End Engineering Design	*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 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*
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 current portion 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

bbls	*barrels*
bpd	*barrels per day*
EOR	*enhanced oil recovery*
bps	*basis points*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mmbbls	*million barrels*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
bcf	*billion cubic feet*
tcf	*trillion cubic feet*
boe	*barrels of oil equivalent*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mmboe	*million barrels of oil equivalent*
mcfge	*thousand cubic feet of gas equivalent*
mmbtu	*million British Thermal Units*
mmlt	*million long tons*
tcfe	*trillion cubic feet equivalent*
tgal	*thousand gallons*
ASP	*alkali surfactant polymer*
CHOPS	*cold heavy oil production with sand*
CNOOC	*China National Offshore Oil Corporation*
CSA	*Canadian Securities Administrators*
FPSO	*Floating production, storage and offloading vessel*
GAAP	*Generally Accepted Accounting Principles*
GJ	*gigajoule*
LIBOR	*London Interbank Offered Rate*
MD&A	*Management's Discussion and Analysis*
MW	*megawatt*
NGL	*natural gas liquids*
NIT	*NOVA Inventory Transfer*
NYMEX	*New York Mercantile Exchange*
OPEC	*Organization of Petroleum Exporting Countries*
PSC	*production sharing contract*
SAGD	*Steam assisted gravity drainage*
SEC	*U.S. Securities and Exchange Commission*
SEDAR	*System for Electronic Document Analysis and Retrieval*
WI	*working interest*
WTI	*West Texas Intermediate*
C-NLOPB	*Canada-Newfoundland and Labrador Offshore Petroleum Board*
IFRS	*International Financial Reporting Standards*

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, 2013, 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 ("COSO") framework to evaluate the effectiveness of Husky's internal control over financial reporting.
3) As at December 31, 2013, 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, 2013, 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, 2013, 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

	2013				2012			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Upstream								
Daily production, before royalties								
Light crude oil & NGL *(mbbls/day)*	**78.3**	**77.7**	**82.3**	**86.4**	86.1	55.4	56.8	91.2
Medium crude oil *(mbbls/day)*	**23.4**	**23.2**	**22.9**	**23.0**	23.2	23.9	24.1	24.9
Heavy crude oil *(mbbls/day)*	**75.9**	**75.3**	**72.3**	**74.4**	76.0	77.1	78.1	76.2
Bitumen *(mbbls/day)*	**46.7**	**48.0**	**48.3**	**47.9**	46.7	37.8	29.6	29.6
Total crude oil production *(mboe/day)*	**224.3**	**224.2**	**225.8**	**231.7**	232.0	194.2	188.6	221.9
Natural gas *(mmcf/day)*	**503.8**	**505.5**	**504.7**	**537.3**	523.7	544.9	559.5	588.3
Total production *(mboe/day)*	**308.3**	**308.5**	**309.9**	**321.3**	319.3	285.0	281.9	319.9
Average sales prices								
Light crude oil & NGL *($/bbl)*	**101.95**	**107.83**	**96.22**	**103.59**	94.91	90.50	94.71	111.53
Medium crude oil *($/bbl)*	**67.86**	**93.67**	**73.62**	**61.74**	67.55	69.59	69.92	78.63
Heavy crude oil *($/bbl)*	**56.51**	**84.45**	**66.77**	**45.67**	57.90	60.58	60.42	68.93
Bitumen *($/bbl)*	**54.08**	**83.17**	**65.71**	**43.12**	55.74	60.10	58.09	65.83
Natural gas *($/mcf)*	**3.30**	**2.66**	**3.72**	**3.08**	3.25	2.48	2.05	2.64
Operating costs *($/boe)*	**16.31**	**17.20**	**16.79**	**15.29**	15.05	16.69	15.83	14.56
Operating netbacks[1]								
Lloydminster – Thermal Oil *($/boe)*[2]	**38.76**	**67.57**	**50.57**	**32.55**	45.47	48.42	43.42	50.25
Lloydminster – Non-Thermal Oil *($/boe)*[2]	**27.32**	**49.69**	**37.70**	**19.06**	30.09	33.35	37.07	47.94
Oil Sands – Bitumen *($/boe)*[2]	**21.45**	**52.68**	**35.30**	**12.32**	19.49	33.91	30.05	35.88
Western Canada – Crude Oil *($/boe)*[2]	**37.60**	**54.41**	**39.24**	**31.17**	38.31	37.12	38.52	43.67
Western Canada – Natural gas *($/mcf)*[3]	**1.93**	**1.21**	**1.81**	**1.68**	1.49	1.16	1.11	1.52
Atlantic – Light Oil *($/boe)*[2]	**83.90**	**87.14**	**78.66**	**89.37**	85.05	66.97	70.99	94.34
Asia Pacific – Light Oil & NGL *($/boe)*[2]	**70.35**	**74.60**	**62.52**	**73.46**	69.28	72.97	73.54	88.16
Total *($/boe)*[2]	**34.29**	**46.15**	**38.32**	**31.78**	35.99	30.08	30.43	43.00
Net wells drilled[4]								
Exploration Oil	**7**	**8**	–	**9**	8	1	3	18
Gas	**5**	–	**4**	**5**	–	2	–	10
Dry	–	–	–	–	–	–	–	–
	12	**8**	**4**	**14**	8	3	3	28
Development Oil	**201**	**249**	**30**	**229**	217	245	56	197
Gas	**12**	**12**	**2**	**15**	6	1	2	8
Dry	–	–	–	–	3	–	–	1
	213	**261**	**32**	**244**	226	246	58	206
Total net wells drilled	**225**	**269**	**36**	**258**	234	249	61	234
Success ratio *(percent)*	**100**	**100**	**100**	**100**	99	100	100	100
Upgrader								
Synthetic crude oil sales *(mbbls/day)*	**52.0**	**37.5**	**56.7**	**56.1**	63.4	64.1	53.1	61.1
Upgrading differential *($/bbl)*	**26.63**	**23.59**	**27.39**	**38.51**	24.27	22.04	22.64	20.38
Canadian Refined Products								
Fuel sales *(million litres/day)*[5]	**7.9**	**8.3**	**8.0**	**8.2**	8.8	9.0	8.4	8.3
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	**28.4**	**28.7**	**18.7**	**28.3**	28.3	28.7	29.1	27.2
Prince George refinery *(mbbls/day)*	**12.0**	**11.8**	**6.3**	**11.2**	11.4	11.3	10.4	11.1
Refinery utilization *(percent)*	**96**	**61**	**100**	**100**	97	97	96	93
U.S. Refining and Marketing								
Refinery throughput								
Lima refinery *(mbbls/day)*	**151.8**	**148.8**	**149.8**	**146.9**	155.9	153.9	150.7	139.4
BP-Husky Toledo refinery *(mbbls/day)*	**66.3**	**59.1**	**68.1**	**66.3**	58.1	52.7	64.9	67.3

[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.*
[5] *Fuel sales have been recast to exclude non-retail products. Prior periods have been adjusted to conform with the current period presentation.*

Segmented Capital Expenditures[1]

($ millions)	2013 Q4	2013 Q3	2013 Q2	2013 Q1	2012 Q4	2012 Q3	2012 Q2	2012 Q1
Upstream								
Exploration								
Western Canada	**80**	**99**	**64**	**110**	79	43	29	87
Atlantic Region	**55**	**102**	**39**	**5**	(28)	35	6	–
Asia Pacific Region	**14**	**1**	**–**	**6**	5	17	–	–
	149	**202**	**103**	**121**	56	95	35	87
Development								
Western Canada	**744**	**505**	**267**	**513**	662	497	293	577
Oil Sands	**111**	**146**	**137**	**158**	220	152	132	154
Atlantic Region	**34**	**148**	**116**	**139**	91	150	101	58
Asia Pacific Region	**215**	**133**	**156**	**129**	213	175	203	134
	1,104	**932**	**676**	**939**	1,186	974	729	923
Acquisitions								
Western Canada	**27**	**1**	**4**	**6**	–	16	–	5
Total Exploration and Production	**1,280**	**1,135**	**783**	**1,066**	1,242	1,085	764	1,015
Infrastructure and Marketing	**41**	**27**	**17**	**11**	19	14	11	10
Total Upstream	**1,321**	**1,162**	**800**	**1,077**	1,261	1,099	775	1,025
Downstream								
Upgrader	**43**	**129**	**20**	**13**	17	13	9	8
Canadian Refined Products	**32**	**24**	**41**	**12**	33	32	19	13
U.S. Refining and Marketing	**99**	**52**	**42**	**27**	113	92	65	43
	174	**205**	**103**	**52**	163	137	93	64
Corporate	**42**	**40**	**29**	**23**	49	16	14	5
	1,537	**1,407**	**932**	**1,152**	1,473	1,252	882	1,094

[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			
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	504	482	1	3	7	3	45	38	41	37
Selling, general and administrative expenses	44	60	84	52	4	4	5	6	2	2	1	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 tax	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 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
49	50	50	44	99	105	104	101	–	–	–	–	696	724	706	667
16	16	14	14	3	4	4	4	90	55	20	52	159	141	128	130
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

2012 ($ millions)	Upstream								Downstream			
	Exploration and Production(1)				Infrastructure and Marketing				Upgrading			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues(3)(4)	1,773	1,440	1,389	1,979	785	365	623	604	562	576	472	581
Royalties	(189)	(145)	(140)	(219)	–	–	–	–	–	–	–	–
Marketing and other(3)	–	–	–	–	79	122	124	73	–	–	–	–
Revenues, net of royalties	1,584	1,295	1,249	1,760	864	487	747	677	562	576	472	581
Expenses												
Purchases of crude oil and products(3)(5)	20	15	13	25	741	335	591	591	417	423	344	452
Production and operating expenses(4)(5)	513	456	441	465	–	6	4	2	40	33	42	35
Selling, general and administrative expenses	18	55	66	36	6	5	6	4	1	–	1	1
Depletion, depreciation, amortization and impairment	614	515	463	529	6	5	6	5	27	25	25	25
Exploration and evaluation expenses	157	59	53	75	–	–	–	–	–	–	–	–
Other – net	(72)	28	(60)	(1)	–	–	1	(1)	(17)	–	–	–
Earnings from operating activities	334	167	273	631	111	136	139	76	94	95	60	68
Share of equity investment	(11)	–	–	–	–	–	–	–	–	–	–	–
Net foreign exchange gains (losses)	–	–	–	–	–	–	–	–	–	–	–	–
Finance income	–	5	–	–	–	–	–	–	–	–	–	–
Finance expenses	(19)	(21)	(19)	(19)	–	–	–	–	(2)	(3)	(3)	(3)
	(19)	(16)	(19)	(19)	–	–	–	–	(2)	(3)	(3)	(3)
Earnings (loss) before income taxes	304	151	254	612	111	136	139	76	92	92	57	65
Provisions for (recovery of) income taxes												
Current	16	(44)	(47)	209	50	54	62	5	(1)	24	(11)	19
Deferred	62	85	114	(50)	(22)	(19)	(27)	13	25	–	26	(2)
	78	41	67	159	28	35	35	18	24	24	15	17
Net earnings (loss)	226	110	187	453	83	101	104	58	68	68	42	48
Capital expenditures(6)	1,242	1,085	764	1,015	19	14	11	10	17	13	9	8
Total assets	22,774	21,175	20,819	20,548	1,506	1,400	1,143	1,434	1,242	1,271	1,295	1,252

(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) *Gross revenues, marketing and other and purchases of crude oil products have been recast to reflect a change in the classification of certain trading transactions.*

(4) *In 2013, the Company reclassified its processing facilities from Infrastructure and Marketing to Exploration and Production. 2012 amounts have been adjusted to conform with current presentation.*

(5) *Certain hydrogen feedstock costs were reclassified in 2012 from production and operating expenses to purchases of of crude oil products.*

(6) *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
933	1,067	968	880	2,355	2,436	2,623	2,442	(598)	(596)	(484)	(625)	5,810	5,288	5,591	5,861
–	–	–	–	–	–	–	–	–	–	–	–	(189)	(145)	(140)	(219)
–	–	–	–	–	–	–	–	–	–	–	–	79	122	124	73
933	1,067	968	880	2,355	2,436	2,623	2,442	(598)	(596)	(484)	(625)	5,700	5,265	5,575	5,715
794	849	802	763	2,046	1,980	2,335	2,183	(598)	(596)	(484)	(625)	3,420	3,006	3,601	3,389
49	45	50	40	102	91	100	92	(1)	1	1	3	703	632	638	637
15	14	15	14	3	4	3	3	63	34	40	41	106	112	131	99
21	21	21	20	57	52	52	51	13	11	9	7	738	629	576	637
–	–	–	–	–	–	–	–	–	–	–	–	157	59	53	75
–	(2)	–	–	4	–	–	–	(19)	4	7	5	(104)	30	(52)	3
54	140	80	43	143	309	133	113	(56)	(50)	(57)	(56)	680	797	628	875
–	–	–	–	–	–	–	–	–	–	–	–	(11)	–	–	–
–	–	–	–	–	–	–	–	(1)	16	–	(1)	(1)	16	–	(1)
–	–	–	–	–	–	–	–	21	17	23	27	21	22	23	27
(1)	(2)	(2)	(1)	(1)	(1)	(2)	(1)	(22)	(28)	(43)	(47)	(45)	(55)	(69)	(71)
(1)	(2)	(2)	(1)	(1)	(1)	(2)	(1)	(2)	5	(20)	(21)	(25)	(17)	(46)	(45)
53	138	78	42	142	308	131	112	(58)	(45)	(77)	(77)	644	780	582	830
16	32	23	18	(49)	48	–	–	29	35	16	32	61	149	43	283
(2)	3	(3)	(7)	104	65	48	41	(58)	(29)	(50)	(39)	109	105	108	(44)
14	35	20	11	55	113	48	41	(29)	6	(34)	(7)	170	254	151	239
39	103	58	31	87	195	83	71	(29)	(51)	(43)	(70)	474	526	431	591
33	32	19	13	113	92	65	43	49	16	14	5	1,473	1,252	882	1,094
1,646	1,658	1,656	1,625	5,326	5,160	5,260	5,334	2,667	2,802	2,669	3,093	35,161	33,466	32,842	33,286

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, 2013. 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

Alister Cowan
Chief Financial Officer

Calgary, Canada
February 25, 2014

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, 2013 and December 31, 2012, 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, 2013 and December 31, 2012, 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 25, 2014

Consolidated Financial Statements

Consolidated Balance Sheets

(millions of Canadian dollars)	**December 31, 2013**	December 31, 2012
Assets		
Current assets		
Cash and cash equivalents *(note 9)*	**1,097**	2,025
Accounts receivable *(notes 3, 4)*	**1,458**	1,345
Income taxes receivable	**461**	323
Inventories *(note 5)*	**1,812**	1,736
Prepaid expenses	**89**	64
	4,917	5,493
Exploration and evaluation assets *(notes 3, 6)*	**1,144**	773
Property, plant and equipment, net *(notes 3, 7)*	**29,750**	27,354
Goodwill *(note 10)*	**698**	663
Contribution receivable *(note 8)*	**136**	607
Investment in joint ventures *(notes 3, 8)*	**153**	132
Other assets *(note 3)*	**106**	139
Total Assets	**36,904**	35,161
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities *(notes 3, 12)*	**3,155**	2,985
Asset retirement obligations *(note 16)*	**210**	107
Long-term debt due within one year *(note 13)*	**798**	–
	4,163	3,092
Long-term debt *(note 13)*	**3,321**	3,918
Other long-term liabilities *(notes 3, 15)*	**271**	328
Contribution payable *(notes 8, 22)*	**1,421**	1,336
Deferred tax liabilities *(notes 3, 17)*	**4,942**	4,640
Asset retirement obligations *(note 16)*	**2,708**	2,686
Commitments and contingencies *(note 20)*		
Total Liabilities	**16,826**	16,000
Shareholders' equity		
Common shares *(note 18)*	**6,974**	6,939
Preferred shares *(note 18)*	**291**	291
Retained earnings	**12,615**	11,950
Other reserves	**198**	(19)
Total Shareholders' Equity	**20,078**	19,161
Total Liabilities and Shareholders' Equity	**36,904**	35,161

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, 2013	2012
Gross revenues	**23,869**	22,550
Royalties	**(864)**	(693)
Marketing and other	**312**	398
Revenues, net of royalties	**23,317**	22,255
Expenses		
Purchases of crude oil and products	**14,067**	13,416
Production and operating expenses	**2,793**	2,610
Selling, general and administrative expenses	**558**	448
Depletion, depreciation, amortization and impairment *(note 7)*	**3,005**	2,580
Exploration and evaluation expenses *(note 6)*	**246**	344
Other – net	**(87)**	(123)
	20,582	19,275
Earnings from operating activities	**2,735**	2,980
Share of equity investment *(note 8)*	**(10)**	(11)
Financial items *(note 14)*		
Net foreign exchange gains	**21**	14
Finance income	**51**	93
Finance expenses	**(169)**	(240)
	(97)	(133)
Earnings before income taxes	**2,628**	2,836
Provisions for income taxes *(note 17)*		
Current	**589**	536
Deferred	**210**	278
	799	814
Net earnings	**1,829**	2,022
Earnings per share *(note 18)*		
Basic	**1.85**	2.06
Diluted	**1.85**	2.06
Weighted average number of common shares outstanding *(note 18)*		
Basic *(millions)*	**983.0**	975.8
Diluted *(millions)*	**983.6**	975.9

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, 2013	2012
Net earnings	**1,829**	2,022
Other comprehensive income (loss)		
Items that will not be reclassified into earnings, net of tax:		
Remeasurements of pension plans, net of tax *(note 19)*	**20**	15
Items that may be reclassified into earnings, net of tax:		
Derivatives designated as cash flow hedges *(note 22)*	**36**	3
Exchange differences on translation of foreign operations	**361**	(95)
Hedge of net investment *(note 22)*	**(180)**	15
Other comprehensive income (loss)	**237**	(62)
Comprehensive income	**2,066**	1,960

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

Consolidated Statements of Changes in Shareholders' Equity

	Attributable to Equity Holders					
				Other Reserves		
(millions of Canadian dollars)	Common Shares	Preferred Shares	Retained Earnings	Foreign Currency Translation	Hedging	Total Shareholders' Equity
Balance as at December 31, 2011	6,327	291	11,097	60	(2)	17,773
Net earnings	–	–	2,022	–	–	2,022
Other comprehensive income (loss)						
Remeasurements of pension plans (net of tax of $5 million)	–	–	15	–	–	15
Derivatives designated as cash flow hedges (net of tax of $1 million) *(note 22)*	–	–	–	–	3	3
Exchange differences on translation of foreign operations (net of tax of $12 million)	–	–	–	(95)	–	(95)
Hedge of net investment (net of tax of $2 million) *(note 22)*	–	–	–	15	–	15
Total comprehensive income (loss)	–	–	2,037	(80)	3	1,960
Transactions with owners recognized directly in equity:						
Stock dividends paid *(note 18)*	607	–	–	–	–	607
Stock options exercised *(note 18)*	5	–	–	–	–	5
Dividends declared on common shares *(note 18)*	–	–	(1,171)	–	–	(1,171)
Dividends declared on preferred shares *(note 18)*	–	–	(13)	–	–	(13)
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)	–	–	**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 *(note18)*	**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 *(note 3)*	–	–	**9**	–	–	**9**
Balance as at December 31, 2013	**6,974**	**291**	**12,615**	**161**	**37**	**20,078**

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, 2013	2012
Operating activities		
Net earnings	**1,829**	2,022
Items not affecting cash:		
Accretion *(note 14)*	**125**	97
Depletion, depreciation, amortization and impairment *(note 7)*	**3,005**	2,580
Exploration and evaluation expenses	**10**	60
Deferred income taxes *(note 17)*	**210**	278
Foreign exchange	**11**	(20)
Stock-based compensation *(note 18)*	**105**	54
Loss (gain) on sale of assets	**(27)**	1
Other	**(46)**	(62)
Settlement of asset retirement obligations *(note 16)*	**(142)**	(123)
Income taxes paid	**(433)**	(575)
Interest received	**19**	34
Change in non-cash working capital *(note 9)*	**(21)**	847
Cash flow – operating activities	**4,645**	5,193
Financing activities		
Long-term debt issuance	**–**	500
Long-term debt repayment *(note 13)*	**–**	(410)
Settlement of cross currency swaps	**–**	(89)
Debt issue costs	**–**	(9)
Proceeds from exercise of stock options *(note 18)*	**27**	5
Dividends on common shares *(note 18)*	**(1,171)**	(557)
Dividends on preferred shares *(note 18)*	**(13)**	(17)
Interest paid	**(243)**	(252)
Contribution receivable payment *(note 8)*	**520**	563
Other	**53**	25
Change in non-cash working capital *(note 9)*	**(19)**	79
Cash flow – financing activities	**(846)**	(162)
Investing activities		
Capital expenditures	**(5,028)**	(4,701)
Proceeds from asset sales	**37**	24
Contribution payable payment *(note 8)*	**(87)**	(152)
Other	**(8)**	(61)
Change in non-cash working capital *(note 9)*	**364**	56
Cash flow – investing activities	**(4,722)**	(4,834)
Increase (decrease) in cash and cash equivalents	**(923)**	197
Effect of exchange rates on cash and cash equivalents	**(5)**	(13)
Cash and cash equivalents at beginning of year	**2,025**	1,841
Cash and cash equivalents at end of year	**1,097**	2,025

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 and preferred shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and "HSE.PR.A", 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, offshore Indonesia and offshore Taiwan.

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,	**2013**	2012	**2013**	2012	**2013**	2012
Gross revenues[3]	**7,333**	6,581	**2,134**	2,377	**9,467**	8,958
Royalties	**(864)**	(693)	**–**	–	**(864)**	(693)
Marketing and other[3]	**–**	–	**312**	398	**312**	398
Revenues, net of royalties	**6,469**	5,888	**2,446**	2,775	**8,915**	8,663
Expenses						
Purchases of crude oil and products[3]	**91**	73	**2,004**	2,258	**2,095**	2,331
Production and operating expenses	**2,016**	1,875	**14**	12	**2,030**	1,887
Selling, general and administrative expenses	**240**	175	**19**	21	**259**	196
Depletion, depreciation, amortization and impairment	**2,515**	2,121	**20**	22	**2,535**	2,143
Exploration and evaluation expenses	**246**	344	**–**	–	**246**	344
Other – net	**(35)**	(105)	**(3)**	–	**(38)**	(105)
Earnings (loss) from operating activities	**1,396**	1,405	**392**	462	**1,788**	1,867
Share of equity investment	**(10)**	(11)	**–**	–	**(10)**	(11)
Financial items						
Net foreign exchange gains	**–**	–	**–**	–	**–**	–
Finance income	**4**	5	**–**	–	**4**	5
Finance expenses	**(107)**	(78)	**–**	–	**(107)**	(78)
Earnings (loss) before income taxes	**1,283**	1,321	**392**	462	**1,675**	1,783
Provisions for (recovery of) income taxes						
Current	**162**	134	**222**	171	**384**	305
Deferred	**169**	211	**(122)**	(55)	**47**	156
Total income tax provision (recovery)	**331**	345	**100**	116	**431**	461
Net earnings (loss)	**952**	976	**292**	346	**1,244**	1,322
Intersegment revenues	**1,714**	2,003	**–**	–	**1,714**	2,003
Other non-cash items						
Gain (loss) on sale of assets	**19**	1	**–**	–	**19**	1

(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) Gross revenues, marketing and other and purchases of crude oil and products have been recast to reflect a change in the classification of certain trading transactions.

Downstream								Corporate and Eliminations[2]		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2013	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012
2,023	2,191	3,737	3,848	10,728	9,856	16,488	15,895	(2,086)	(2,303)	23,869	22,550
–	–	–	–	–	–	–	–	–	–	(864)	(693)
–	–	–	–	–	–	–	–	–	–	312	398
2,023	2,191	3,737	3,848	10,728	9,856	16,488	15,895	(2,086)	(2,303)	23,317	22,255
1,378	1,636	3,134	3,208	9,546	8,544	14,058	13,388	(2,086)	(2,303)	14,067	13,416
161	150	193	184	409	385	763	719	–	4	2,793	2,610
7	3	60	58	15	13	82	74	217	178	558	448
96	102	90	83	233	212	419	397	51	40	3,005	2,580
–	–	–	–	–	–	–	–	–	–	246	344
(27)	(17)	(5)	(2)	–	4	(32)	(15)	(17)	(3)	(87)	(123)
408	317	265	317	525	698	1,198	1,332	(251)	(219)	2,735	2,980
–	–	–	–	–	–	–	–	–	–	(10)	(11)
–	–	–	–	–	–	–	–	21	14	21	14
–	–	–	–	–	–	–	–	47	88	51	93
(7)	(11)	(5)	(6)	(3)	(5)	(15)	(22)	(47)	(140)	(169)	(240)
401	306	260	311	522	693	1,183	1,310	(230)	(257)	2,628	2,836
19	31	65	89	18	(1)	102	119	103	112	589	536
85	49	1	(9)	165	258	251	298	(88)	(176)	210	278
104	80	66	80	183	257	353	417	15	(64)	799	814
297	226	194	231	339	436	830	893	(245)	(193)	1,829	2,022
172	134	200	166	–	–	372	300	–	–	2,086	2,303
–	–	8	(2)	–	–	8	(2)	–	–	27	(1)

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2013**	2012	**2013**	2012	**2013**	2012
Expenditures on exploration and evaluation assets[2]	**575**	273	**–**	–	**575**	273
Expenditures on property, plant and equipment[2]	**3,689**	3,833	**96**	54	**3,785**	3,887
As at December 31,						
Exploration and evaluation assets	**1,144**	773	**–**	–	**1,144**	773
Developing and producing assets at cost	**43,128**	38,781	**–**	–	**43,128**	38,781
Accumulated depletion, depreciation, amortization and impairment	**(20,439)**	(17,947)	**–**	–	**(20,439)**	(17,947)
Other property, plant and equipment at cost	**–**	47	**1,033**	934	**1,033**	981
Accumulated depletion, depreciation and amortization	**–**	(29)	**(448)**	(414)	**(448)**	(443)
Total exploration and evaluation assets and property, plant and equipment, net	**23,833**	21,625	**585**	520	**24,418**	22,145
Total assets	**24,653**	22,774	**1,670**	1,506	**26,323**	24,280

(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 period. Includes assets acquired through acquisitions.*

Geographical Financial Information

($ millions)	Canada	
Year ended December 31,	**2013**	2012
Gross revenues[1][2]	**11,926**	11,356
Royalties	**(794)**	(611)
Marketing and other[2]	**316**	395
Revenue, net of royalties[2]	**11,448**	11,140
As at December 31,		
Exploration and evaluation assets	**855**	496
Property, plant and equipment, net	**22,928**	21,718
Goodwill	**160**	160
Total non-current assets	**24,152**	23,090

(1) *Based on the geographical location of legal entities.*
(2) *Gross revenues and marketing and other have been recast to reflect a change in the classification of certain trading transactions..*

Downstream								Corporate and Eliminations		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2013	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012
–	–	–	–	–	–	–	–	–	–	575	273
205	47	109	97	220	313	534	457	134	84	4,453	4,428
–	–	–	–	–	–	–	–	–	–	1,144	773
–	–	–	–	–	–	–	–	–	–	43,128	38,781
–	–	–	–	–	–	–	–	–	–	(20,439)	(17,947)
2,221	2,006	2,332	2,189	5,020	4,487	9,573	8,682	775	643	11,381	10,306
(1,046)	(950)	(1,046)	(967)	(1,257)	(951)	(3,349)	(2,868)	(523)	(475)	(4,320)	(3,786)
1,175	1,056	1,286	1,222	3,763	3,536	6,224	5,814	252	168	30,894	28,127
1,355	1,242	1,788	1,646	5,537	5,326	8,680	8,214	1,901	2,667	36,904	35,161

United States		Other International		Total	
2013	2012	2013	2012	2013	2012
11,663	10,822	280	372	23,869	22,550
–	–	(70)	(82)	(864)	(693)
(4)	3	–	–	312	398
11,659	10,825	210	290	23,317	22,255
–	–	289	277	1,144	773
3,764	3,535	3,058	2,101	29,750	27,354
538	503	–	–	698	663
4,320	4,055	3,515	2,523	31,987	29,668

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 25, 2014, having been duly authorized to do so by the Board of Directors.

Certain prior years' amounts have been recast to conform with current presentation, including the change in classification of certain trading activities.

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 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.

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 composition of revenue and costs in the locations in which it 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. Technical feasibility and commercial viability are met when management determines that an exploration and evaluation asset will be developed, as evidenced by the classification of proved or probable reserves and the appropriate internal and external approvals. 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, 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, with the exception of certain Heavy Oil properties that are evaluated by independent qualified reserve engineers, and audited by independent qualified reserve engineers. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty. Changes in reserve estimates can have an impact on reported net earnings through revisions to depletion, depreciation and amortization expense, in addition to determining possible impairments 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.

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 arrangement with items of a similar nature 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. Both common and preferred share dividends are paid out in cash and 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 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 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 defined contribution pension plans (401(k)), a defined benefit pension plan and other post-retirement benefits.

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 present value of the defined benefit obligation and the fair value of plan assets from which the obligations are to be settled. 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 plans.

The determination of the cost of the defined benefit pension plans 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) Impairment of Assets

In May 2013, the IASB published narrow-scope amendments to IAS 36, "Impairment of Assets," which requires the disclosure of information about the recoverable amount of impaired assets, particularly if that amount is based on fair value less costs of disposal. Amendments to IAS 36 are effective for the Company on January 1, 2014, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the amendments on January 1, 2014. The adoption of the standard is not expected to have a material impact on the Company's annual consolidated financial statements.

z) Change in Accounting Policy

i) Consolidated Financial Statements

In May 2011, the IASB published IFRS 10, "Consolidated Financial Statements," which provides a single model to be applied in the assessment of control for all entities in which the Company has an investment including special purpose entities currently in the scope of Standing Interpretations Committee ("SIC") 12. Under the new control model, the Company has control over an investment if the Company has the ability to direct the activities of the investment, is exposed to the variability of returns from the investment and there is a link between the ability to direct activities and the variability of returns. IFRS 10 was effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. The Company retrospectively adopted IFRS 10 on January 1, 2013. The adoption of the standard had no impact on the Company's consolidated financial statements.

ii) Joint Arrangements

In May 2011, the IASB published IFRS 11, "Joint Arrangements," whereby joint arrangements are classified as either joint operations or joint ventures. Parties to a joint operation retain the rights and obligations to individual assets and liabilities of the operation, while parties to a joint venture have rights to the net assets of the venture. Joint operations shall be accounted for in a manner consistent with jointly controlled assets and operations whereby the Company's contractual share of the arrangement's assets, liabilities, revenues and expenses is included in the consolidated financial statements. Any arrangement structured through a separate vehicle that does effectively result in separation between the Company and the joint arrangement shall be classified as a joint venture and accounted for using the equity method of accounting. Under the previous standard, the Company had the option to account for any interests in joint arrangements using either proportionate consolidation or equity accounting. IFRS 11 was effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. The Company retrospectively adopted IFRS 11 on January 1, 2013.

The adoption of the standard resulted in the following cumulative balance sheet impact related to the Madura joint arrangement, applied prospectively from January 1, 2012:

Balance Sheet Impact *($ millions)*	December 31, 2012	January 1, 2012
Accounts receivable	(4)	(4)
Exploration and evaluation assets	(37)	(14)
Property, plant and equipment, net	(45)	(42)
Investment in joint ventures	132	91
Other assets	(25)	–
Accounts payable and accrued liabilities	1	18
Other long-term liabilities	3	(24)
Deferred tax liabilities	(25)	(25)
Total Balance Sheet Impact	–	–

iii) Disclosure of Interests in Other Entities

In May 2011, the IASB published IFRS 12, "Disclosure of Interests in Other Entities," which contains new annual disclosure requirements for interests the Company has in subsidiaries, joint arrangements, associates and unconsolidated structured entities. Required disclosures aim to provide readers of the financial statements with information to evaluate the nature of, and risks associated with, the Company's interests in other entities and the effects of those interests on the Company's consolidated financial statements. IFRS 12 was effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. The Company retrospectively adopted IFRS 12 on January 1, 2013. The adoption of the standard did not have a material impact on the Company's annual consolidated financial statements.

iv) Investments in Associates and Joint Ventures

In May 2011, the IASB issued amendments to IAS 28, "Investments in Associates and Joint Ventures," which provides additional guidance applicable to accounting for interests in joint ventures or associates when a portion of an interest is classified as held for sale or when the Company ceases to have joint control or significant influence over an associate or joint venture. When joint control or significant influence over an associate or joint venture ceases, the Company will no longer be required to remeasure the investment at that date. When a portion of an interest in a joint venture or associate is classified as held for sale, the portion not classified as held for sale shall be accounted for using the equity method of accounting until the sale is completed at which time the interest is reassessed for prospective accounting treatment. Amendments to IAS 28 were effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. The Company retrospectively adopted these amendments on January 1, 2013. The adoption of the amendments had no impact on the Company's consolidated financial statements.

v) Fair Value Measurement

In May 2011, the IASB published IFRS 13, "Fair Value Measurement," which provides a single source of fair value measurement guidance and replaces the guidance contained in individual IFRSs. The standard provides a framework for measuring fair value and establishes new disclosure requirements to enable readers to assess the methods and inputs used to develop fair value measurements, for recurring valuations that are subject to measurement uncertainty, and for the effect of those measurements on the financial statements. IFRS 13 was effective for the Company on January 1, 2013 with required prospective application and early adoption permitted. The Company adopted IFRS 13 on January 1, 2013. The adoption of the standard did not have a material impact on the Company's financial statements.

vi) Employee Benefits

In June 2011, the IASB issued amendments to IAS 19, "Employee Benefits" to eliminate the corridor method that permits the deferral of actuarial gains and losses, to revise the presentation requirements for changes in defined benefit plan assets and liabilities and to enhance the required disclosures for defined benefit plans. Amendments to IAS 19 were effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. The Company retrospectively adopted these amendments on January 1, 2013.

The adoption of this amended standard resulted in the following balance sheet impact, applied retrospectively to January 1, 2010:

Balance Sheet Impact

($ millions)	2012	2011	2010	Total
Increase/(decrease) in net defined benefit liability	1	2	(12)	(9)
Increase/(decrease) in retained earnings	(1)	(2)	12	9
Total balance sheet impact	–	–	–	–

vii) Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IFRS 7, "Financial Instruments: Disclosures" and IAS 32, "Financial Instruments: Presentation" to clarify the current offsetting model and develop common disclosure requirements to enhance the understanding of the potential effects of offsetting arrangements. Amendments to IFRS 7 were effective for the Company on January 1, 2013, with required retrospective application and early adoption permitted. Amendments to IAS 32 were effective for the Company for reporting periods ending after January 1, 2014, with required retrospective application and early adoption permitted. The Company retrospectively adopted both IFRS 7 and IAS 32 amendments on January 1, 2013. The adoption of the amendments did not have a material impact on the Company's consolidated financial statements. Refer to Note 22.

Note 4 Accounts Receivable

Accounts Receivable

($ millions)	**December 31, 2013**	December 31, 2012
Trade receivables	**1,383**	1,291
Allowance for doubtful accounts	**(27)**	(23)
Derivatives due within one year	**22**	14
Other[(1)]	**80**	63
	1,458	1,345

[(1)] *Accounts receivable as at December 31, 2012 has been adjusted to reflect the impact of equity method accounting with respect to the Madura joint arrangement.*

Note 5 Inventories

Inventories

($ millions)	December 31, 2013	December 31, 2012
Crude oil, natural gas and sulphur	**1,061**	1,113
Refined petroleum products	**181**	157
Trading inventories measured at fair value	**421**	328
Materials, supplies and other	**149**	138
	1,812	1,736

Impairment of inventory to net realizable value as at December 31, 2013 was $1 million (December 31, 2012 – $1 million), primarily due to a reduction in market prices for asphalt. During 2013, there were no inventory impairment reversals (2012 – 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)	2013	2012
Beginning of year	**773**	746
Additions	**574**	291
Acquisitions	**1**	16
Transfers to oil and gas properties *(note 7)*	**(209)**	(198)
Expensed exploration expenditures previously capitalized	**(10)**	(42)
Exchange adjustments	**15**	(3)
Change in accounting policy (note 3)	**–**	(37)
End of year	**1,144**	773

The following exploration and evaluation expenses for the years ended December 31, 2013 and 2012 relate to activities associated with the exploration for and evaluation of oil and natural gas resources and recorded in the Upstream segment:

Exploration and Evaluation Expense Summary

($ millions)	2013	2012
Seismic, geological and geophysical	**133**	146
Expensed drilling	**104**	188
Expensed land	**9**	16
Change in accounting policy (note 3)	**–**	(6)
	246	344

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, 2011	33,640	930	1,972	4,916	2,176	43,634
Additions	3,971	53	47	349	146	4,566
Acquisitions	16	–	–	–	–	16
Transfers from exploration and evaluation *(note 6)*	198	–	–	–	–	198
Changes in asset retirement obligations	1,097	(2)	(13)	(71)	29	1,040
Disposals and derecognition	(76)	–	–	(7)	(127)	(210)
Exchange adjustments	(20)	–	–	(93)	1	(112)
Change in accounting policy *(note 3)*	(45)	–	–	–	–	(45)
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**
Accumulated depletion, depreciation, amortization and impairment						
December 31, 2011	(15,900)	(407)	(848)	(1,046)	(1,154)	(19,355)
Depletion, depreciation, and amortization	(2,101)	(36)	(102)	(241)	(103)	(2,583)
Disposals and derecognition	49	–	–	3	124	176
Exchange adjustments	5	–	–	24	–	29
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)**
Transfer 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)**
Net book value						
December 31, 2012	20,834	538	1,056	3,834	1,092	27,354
December 31, 2013	**22,673**	**601**	**1,175**	**4,102**	**1,199**	**29,750**

(1) *Depletion, depreciation, amortization and impairment for the year ended December 31, 2013 does not include an amortization recovery of research and development assets of $1 million (2012 – expense of $5 million), and an exchange adjustment of $1 million (2012 – $8 million).*

Included in depletion, depreciation, amortization and impairment expense recognized in the fourth quarter of 2013 is a non-cash impairment charge of $275 million (2012 – nil) on conventional natural gas assets located in Western Canada and included within the Upstream segment. The impairment charge, attributed to East Central Alberta, was the result of low estimated long-term future natural gas prices and a reduction in the investment of natural gas property development. The recoverable amount was $384 million as at December 31, 2013 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% (2012 – 8%).

Costs of property, plant and equipment, including major development projects, excluded from costs subject to depletion, depreciation and amortization as at December 31, 2013 were $7.1 billion (December 31, 2012 – $5.2 billion) including undeveloped land assets of $408 million as at December 31, 2013 (December 31, 2012 – $397).

The net book values of assets under construction included within costs not subject to depletion, depreciation and amortization are as follows:

Assets Under Construction

($ millions)	
December 31, 2012	3,051
December 31, 2013	**3,044**

The net book values of development assets included within costs not subject to depletion, depreciation and amortization are as follows:

Development Assets

($ millions)	
December 31, 2012	1,796
December 31, 2013	**3,677**

The net book values of assets held under finance lease included in the "Refining" class within property, plant and equipment are as follows:

Assets Under Finance Lease

($ millions)	
December 31, 2012	30
December 31, 2013	**29**

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)	**2013**	2012
Beginning of year	**1,336**	1,437
Accretion *(note 14)*	**80**	81
Paid	**(87)**	(152)
Foreign exchange	**92**	(30)
End of year	**1,421**	1,336

The contribution payable accretes at a rate of 6% and is payable between December 31, 2013 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.

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)	**2013**	2012
Revenues	**2,856**	2,574
Expenses	**(2,762)**	(2,319)
Proportionate share of net earnings	**94**	255

Balance Sheets

($ millions)	**December 31, 2013**	December 31, 2012
Current assets	**442**	416
Non-current assets	**1,938**	1,864
Current liabilities	**(264)**	(210)
Non-current liabilities	**(664)**	(492)
Proportionate share of net assets	**1,452**	1,578

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 accretes at a rate of 6% and is payable between December 31, 2013 and December 31, 2015 with the final balance due by December 31, 2015. The contribution receivable is reflected as a long-term asset as amounts to be received within twelve months of the reporting date are reflected as additions to property, plant and equipment.

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

Contribution Receivable

($ millions)	2013	2012
Beginning of year	607	1,147
Accretion *(note 14)*	22	53
Received	(520)	(563)
Foreign exchange	27	(30)
End of year	136	607

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)	2013	2012
Revenues	–	–
Expenses	(10)	(9)
Financial items	48	30
Proportionate share of net earnings	38	21

Balance Sheets

($ millions)	December 31, 2013	December 31, 2012
Current assets	149	475
Non-current assets	1,890	1,407
Current liabilities	(113)	(106)
Non-current liabilities	(21)	(12)
Proportionate share of net assets	1,905	1,764

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)	**2013**	2012
Revenues	–	–
Expenses	**(24)**	(11)
Share of equity investment (percent)	**40%**	40%
Proportionate share of equity investment	**(10)**	(11)

Balance Sheets

($ millions, except share of equity investment)	**December 31, 2013**	December 31, 2012
Current assets[1]	**28**	34
Non-current assets	**439**	411
Current liabilities	**(50)**	(26)
Non-current liabilities	**(188)**	(149)
Net assets	**229**	270
Share of net assets (percent)	**40%**	40%
Carrying amount in statement of financial position	**153**	132

[1] *Current assets include cash and cash equivalents of $14 million (2012 - nil).*

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)	**2013**	2012
Decrease (increase) in non-cash working capital		
Accounts receivable[(1)]	**200**	318
Inventories	**30**	329
Prepaid expenses	**(22)**	(29)
Accounts payable and accrued liabilities	**116**	364
Change in non-cash working capital	**324**	982
Relating to:		
Operating activities[(1)]	**(21)**	847
Financing activities	**(19)**	79
Investing activities	**364**	56

(1) *Non-cash working capital for 2012 has been adjusted to reflect the impact of equity method accounting with respect to the Madura joint arrangement.*

Cash and cash equivalents at December 31, 2013 included $305 million of cash (December 31, 2012 – $127 million) and $792 million of short-term investments with original maturities less than three months at the time of purchase (December 31, 2012 – $1,898 million).

Note 10 Goodwill

Goodwill

($ millions)	**2013**	2012
Beginning of year	**663**	674
Exchange adjustments	**35**	(11)
End of year	**698**	663

As at December 31, 2013, 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% (2012 – 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% (2012 – 2%). At December 31, 2013, 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, 2013, the Company had unsecured short-term borrowing lines of credit with banks totalling $595 million (December 31, 2012 – $515 million) and letters of credit under these lines of credit totalling $224 million (December 31, 2012 – $235 million). As at December 31, 2013, bank operating loans were nil (December 31, 2012 – nil). Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates. During 2013, the Company's weighted average interest rate on short-term borrowings was approximately 1.2% (2012 – 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 is $5 million. As at December 31, 2013, there was no balance outstanding under this credit facility (December 31, 2012 – nil).

Note 12 Accounts Payable and Accrued Liabilities

Accounts Payable and Accrued Liabilities

($ millions)	**December 31, 2013**	December 31, 2012
Trade payables	**82**	152
Accrued liabilities[1]	**2,466**	2,291
Dividend payable *(note 18)*	**295**	295
Stock-based compensation	**122**	47
Derivatives due within one year	**21**	5
Contingent consideration *(note 22)*	**29**	27
Other	**140**	168
	3,155	2,985

[1] *Accrued liabilities as at December 31, 2012 has been adjusted to reflect the impact of equity method accounting with respect to the Madura joint arrangement.*

Note 13 Long-term Debt

Long-term Debt ($ millions)	Maturity	Canadian $ Amount December 31, 2013	Canadian $ Amount December 31, 2012	U.S. $ Denominated December 31, 2013	U.S. $ Denominated December 31, 2012
Long-term debt					
5.90% notes[1][5]	2014	–	746	–	750
3.75% medium-term notes[6]	2015	**300**	300	–	–
7.55% debentures[1][3]	2016	**213**	199	**200**	200
6.20% notes[1][5]	2017	**319**	298	**300**	300
6.15% notes[1][4]	2019	**319**	298	**300**	300
7.25% notes[1][5]	2019	**798**	746	**750**	750
5.00% medium-term notes[6]	2020	**400**	400	–	–
3.95% notes[1][5]	2022	**532**	498	**500**	500
6.80% notes[1][5]	2037	**411**	385	**387**	387
Debt issue costs[2]		**(21)**	(24)	–	–
Unwound interest rate swaps *(note 22)*		**50**	72	–	–
Long-term debt		**3,321**	3,918	**2,437**	3,187
Long-term debt due within one year					
5.90% notes[1][5]	2014	**798**	–	**750**	–

[1] *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 there was no change to the August 31, 2014 maturity date of the $1.6 billion facility. In February 2013, the limit on the $1.5 billion facility was increased to $1.6 billion.

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.

As at December 31, 2013, the Company had no borrowings under either revolving syndicated credit facility (December 31, 2012 – nil).

Notes and Debentures

On June 13, 2011, the Company filed a universal short form base shelf prospectus (the "U.S. Base Prospectus") with the Alberta Securities Commission and the U.S. Securities and Exchange Commission that enabled the Company to offer up to U.S. $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units in the United States. The unused capacity of $1.5 billion under the U.S. Base Prospectus expired in July 2013.

On June 15, 2012, the Company repaid the maturing 6.25% notes issued under a trust indenture dated June 14, 2002. The amount paid to note holders was U.S. $413 million, including U.S. $13 million of interest. The amount paid to note holders was equivalent to $410 million in Canadian dollars.

On December 31, 2012, the Company filed a universal 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, 2013, the Company had not issued securities under the Canadian Shelf Prospectus. This Canadian Shelf Prospectus replaced the universal short form base shelf prospectus filed in Canada during November 2010, which had remaining unused capacity of $1.4 billion and expired in December 2012.

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. As at December 31, 2013, the Company had not issued securities under the U.S. Shelf Prospectus.

The ability of the Company to raise capital utilizing the 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)	2013	2012
Foreign exchange		
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(11)**	43
Gains on cross currency swaps	–	2
Gains (losses) on contribution receivable	**27**	(7)
Other foreign exchange gains (losses)[1]	**5**	(24)
Net foreign exchange gains	**21**	14
Finance income		
Contribution receivable *(note 8)*	**22**	53
Interest income	**19**	34
Other	**10**	6
Finance income	**51**	93
Finance expenses		
Long-term debt	**(233)**	(232)
Contribution payable *(note 8)*	**(80)**	(81)
Other	**3**	(3)
	(310)	(316)
Interest capitalized[2]	**266**	173
	(44)	(143)
Accretion of asset retirement obligations *(note 16)*	**(118)**	(87)
Accretion of other long-term liabilities *(note 22)*	**(7)**	(10)
Finance expenses	**(169)**	(240)
	(97)	(133)

(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 2013 is calculated using the Company's annualized effective interest rate of 6% (2012 – 6%).*

Note 15 Other Long-term Liabilities

Other Long-term Liabilities

($ millions)	December 31, 2013	December 31, 2012
Employee future benefits *(notes 3, 19)*	**116**	147
Finance lease obligations	**31**	31
Stock-based compensation	**39**	21
Contingent consideration *(note 22)*	**31**	78
Other[1]	**54**	51
	271	328

(1) *Other long-term liabilities as at December 31, 2012 has been adjusted to reflect the impact of equity method accounting with respect to the Madura joint arrangement.*

Note 16 Asset Retirement Obligations

At December 31, 2013, the estimated total undiscounted inflation-adjusted amount required to settle the Company's ARO was $12.3 billion (December 31, 2012 – $10.3 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 49 years into the future. This amount has been discounted using credit-adjusted risk-free rates of 3.1% to 5.3% (December 31, 2012 – 2.8% to 4.7%). 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 2013 are related to increased cost estimates and asset growth offset by higher average discount rates and 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, 2013 and 2012 is set out below:

Asset Retirement Obligations

($ millions)	**2013**	2012
Beginning of year	**2,793**	1,767
Additions	**78**	154
Liabilities settled	**(142)**	(123)
Liabilities disposed	**(6)**	(1)
Change in discount rate	**(288)**	174
Change in estimates	**351**	737
Exchange adjustment	**14**	(2)
Accretion *(note 14)*	**118**	87
End of year	**2,918**	2,793
Expected to be incurred within 1 year	**210**	107
Expected to be incurred beyond 1 year	**2,708**	2,686

Note 17 Income Taxes

The major components of income tax expense for the years ended December 31, 2013 and 2012 were as follows:

Income Tax Expense

($ millions)	**2013**	2012
Current income tax		
Current income tax charge	**413**	529
Adjustments to current income tax estimates	**176**	7
	589	536
Deferred income tax		
Relating to origination and reversal of temporary differences	**364**	221
Adjustments to deferred income tax estimates	**(154)**	57
	210	278

Deferred Tax Items in OCI

($ millions)	**2013**	2012
Deferred tax items expensed (recovered) directly in OCI		
Derivatives designated as cash flow hedges	**13**	1
Remeasurement of pension plans	**7**	5
Exchange differences on translation of foreign operations	**58**	(12)
Hedge of net investment	**(27)**	2
	51	(4)

Deferred Tax Items in Equity

($ millions)	**2013**	2012
Deferred tax items expensed (recovered) directly in equity		
Share issue costs	**–**	–

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, 2013 and 2012 were accounted for as follows:

Reconciliation of Effective Tax Rate

($ millions, except tax rate)	**2013**	2012
Earnings before income taxes		
Canada	**2,110**	2,097
United States	**379**	575
Other foreign jurisdictions	**139**	164
	2,628	2,836
Statutory Canadian income tax rate (percent)	**25.8%**	25.8%
Expected income tax	**678**	732
Effect on income tax resulting from:		
Capital gains and losses	**(10)**	(10)
Foreign jurisdictions	**64**	37
Non-taxable items	**33**	12
Other – net	**34**	43
Income tax expense	**799**	814

The statutory tax rate was 25.8% in 2013 (2012 – 25.8%). The 2012 to 2013 tax rates were unchanged due to 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, 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)**

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2012	Recognized in Earnings	Recognized in OCI	Other	December 31, 2012
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment[(1)]	(4,939)	(487)	13	(12)	(5,425)
Foreign exchange gains taxable on realization	(84)	23	(3)	–	(64)
Financial assets at fair value	6	(13)	–	–	(7)
Deferred tax assets					
Pension plans	46	(2)	(5)	–	39
Asset retirement obligations	489	290	(1)	–	778
Loss carry-forwards	121	(91)	–	–	30
Debt issue costs	10	(4)	–	–	6
Other temporary differences	(3)	6	–	–	3
	(4,354)	(278)	4	(12)	(4,640)

[(1)] *Deferred tax liability and assets for the 2012 comparative has been adjusted to reflect the impact of equity method accounting with respect to the Madura joint arrangement.*

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At December 31, 2013, the Company has no deferred tax liabilities in respect of these temporary differences (December 31, 2012 – nil).

At December 31, 2013, the Company had $138 million (December 31, 2012 – $86 million) of U.S. tax losses that will expire after 2030. 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, 2011	957,537,098	6,327
Stock dividends	24,514,797	607
Options exercised	177,325	5
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**

Prior to December 2013, shareholders had the option to receive dividends in common shares or in cash. Quarterly dividends were 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 was 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. In the fourth quarter of 2013, the Board of Directors determined to discontinue the payment of dividends by way of the issuance of common shares. The change became effective with the dividend declaration in February of 2014.

During the year ended December 31, 2013, the Company declared dividends payable of $1.20 per common share (2012 – $1.20 per common share), resulting in dividends of $1,180 million (2012 – $1,171 million). An aggregate of $1,171 million was paid in cash during 2013 (2012 – $557 million). At December 31, 2013, $295 million, including $291 million in cash and $4 million in common shares, was payable to shareholders on account of dividends declared on October 24, 2013 (December 31, 2012 – $295 million, including $293 million in cash and $2 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)
December 31, 2011	12,000,000	291
Cumulative Redeemable Preferred Shares, Series 1 issued, net of share issue costs	–	–
December 31, 2012	12,000,000	291
Cumulative Redeemable Preferred Shares, Series 1 issued, net of share issue costs	–	–
December 31, 2013	**12,000,000**	**291**

Holders of the 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, 2013, the Company declared dividends payable of $13 million on the Series 1 Preferred Shares (2012 – $13 million) representing approximately $1.11 per Series 1 Preferred Share (2012 – $1.11 per Series 1 Preferred Share). At December 31, 2013, there were no amounts payable as dividends on the Series 1 Preferred Shares (December 31, 2012 – nil). A total of $13 million was paid during 2013 (2012 – $17 million), representing approximately $0.28 per quarter per Series 1 Preferred Share (2012 – $0.28 per Series 1 Preferred Share).

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 it 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.

Included in accounts payable and accrued liabilities and other long-term liabilities in the consolidated balance sheets at December 31, 2013 was $134 million (December 31, 2012 – $57 million) representing the estimated fair value of options outstanding. The total expense recognized in selling, general and administrative expenses in the consolidated statements of income for the Option Plan for the year ended December 31, 2013 was $83 million (2012 – $42 million). At December 31, 2013, stock options exercisable for cash had an intrinsic value of $135 million (December 31, 2012 – $31 million).

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

Outstanding and Exercisable Options	2013		2012	
	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
Outstanding, beginning of year	**29,021**	**28.85**	33,337	34.62
Granted[(1)]	**6,314**	**31.46**	11,137	25.61
Exercised for common shares	**(859)**	**27.75**	(177)	27.61
Surrendered for cash	**(1,857)**	**28.43**	–	–
Expired or forfeited	**(3,682)**	**38.92**	(15,276)	39.09
Outstanding, end of year	**28,937**	**28.20**	29,021	28.85
Exercisable, end of year	**13,574**	**27.87**	10,796	32.19

(1) *Options granted during the year ended December 31, 2013 were attributed a fair value of $4.02 per option (2012 – $3.94) at grant date.*

Outstanding and Exercisable Options	Outstanding Options			Exercisable Options	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
$24.96 – $29.99	22,780	27.31	2	13,465	27.84
$30.00 – $31.69	6,157	31.50	4	109	31.69
December 31, 2013	**28,937**	**28.20**	**3**	**13,574**	**27.87**

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	**December 31, 2013**		December 31, 2012	
	Tandem Options	Tandem Performance Options	Tandem Options	Tandem Performance Options
Dividend per option	**1.20**	**1.20**	1.31	1.31
Range of expected volatilities used *(percent)*	**15.5 - 24.5**	**15.5 - 17.4**	13.5 - 33.2	13.5 - 24.8
Range of risk-free interest rates used *(percent)*	**0.9 - 1.9**	**0.9 - 1.0**	0.9 - 1.4	0.9 - 1.1
Expected life of share options from vesting date *(years)*	**1.85**	**1.85**	1.82	1.82
Expected forfeiture rate *(percent)*	**10.2**	**10.2**	11.0	11.0
Weighted average exercise price	**27.95**	**30.54**	29.16	41.36
Weighted average fair value	**5.74**	**3.22**	2.84	0.28

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, 2013, the carrying amount of the liability relating to PSUs was $27 million (December 31, 2012 – $11 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, 2013 was $22 million (2012 – expense of $12 million). The weighted average contractual life of the PSUs at December 31, 2013 was two years.

The number of PSUs outstanding was as follows:

Performance Share Units	**2013**	2012
Beginning of year	**864,500**	500,000
Granted	**2,194,015**	539,500
Exercised	**(209,331)**	(82,000)
Forfeited	**(57,309)**	(93,000)
Outstanding, end of year	**2,791,875**	864,500
Vested, end of year	**809,947**	429,835

Earnings per Share

Earnings per Share

($ millions)	**2013**	2012
Net earnings	**1,829**	2,022
Effect of dividends declared on preferred shares in the year	**(13)**	(13)
Net earnings – basic and diluted[(1)]	**1,816**	2,009

(millions)		
Weighted average common shares outstanding – basic	**983.0**	975.8
Effect of stock dividends declared in the year	**0.6**	0.1
Weighted average common shares outstanding – diluted	**983.6**	975.9

Earnings per share – basic ($/share)	**1.85**	2.06
Earnings per share – diluted ($/share)	**1.85**	2.06

(1) *Stock-based compensation expense was $83 million based on cash-settlement for the year ended December 31, 2013 (2012 – $42 million). Stock-based compensation expense was $29 million based on equity-settlement for the year ended December 31, 2013 (2012 - $33 million). For the year ended December 31, 2013, cash-settlement of share options was considered more dilutive than the equity-settlement of share options and as such, was used to calculate earnings per share - diluted.*

For the year ended December 31, 2013, 26 million tandem options and 96,150 tandem performance options (2012 – 29 million tandem options and 1 million tandem performance options) were excluded from the calculation of diluted earnings per share as these options were anti-dilutive.

Note 19 Pensions and Other Post-employment Benefits

The Company currently provides a defined contribution pension plan for all qualified employees and an other post-employment benefit plan 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, 2013. The most recent actuarial valuation of the plans was December 31, 2012 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. plans was January 1, 2013.

Defined Contribution Pension Plan

During the year ended December 31, 2013, the Company recognized a $37 million expense (2012 – $33 million) for the defined contribution plan and the U.S. 401(k) plan in net earnings.

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

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

DB Pension Plan

($ millions)	**December 31, 2013**	December 31, 2012	December 31, 2011
Fair value of plan assets	**173**	156	147
Defined benefit obligation	**(180)**	(189)	(183)
Funded status	**(7)**	(33)	(36)
Net liability	**(7)**	(33)	(36)
Non-current liability	**(7)**	(33)	(36)

OPEB Plan

($ millions)	December 31, 2013	December 31, 2012	December 31, 2011
Fair value of plan assets	–	–	–
Defined benefit obligation	**(109)**	(105)	(120)
Funded status	**(109)**	(105)	(120)
Net liability	**(109)**	(105)	(120)
Non-current liability	**(109)**	(105)	(120)

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

DB Pension Plan

($ millions)	2013	2012	2011
Experience adjustments arising on plan liabilities	**0.4**	(0.5)	0.2

OPEB Plan

($ millions)	2013	2012	2011
Experience adjustments arising on plan liabilities	**(0.5)**	1.6	(1.2)

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 Plan for the years ended December 31, 2013 and 2012:

DB Pension Plan and OPEB Plan Net Asset (Liability)

	DB Pension Plan		OPEB Plan	
($ millions)	2013	2012	2013	2012
Beginning of year	**(33)**	(36)	**(105)**	(120)
Employer contributions	**8**	8	–	1
Benefit cost	**(3)**	(3)	**(11)**	(11)
Benefit paid	–	–	**1**	–
Remeasurements				
Actuarial gain (loss) due to liability experience	–	1	**1**	(2)
Actuarial gain (loss) due to liability assumption changes	**8**	(8)	**5**	27
Return on plan assets (greater) less than discount rate	**13**	5	–	–
End of year	**(7)**	(33)	**(109)**	(105)

DB Pension Plan and OPEB Plan

	DB Pension Plan		OPEB Plan	
($ millions)	2013	2012	2013	2012
Amounts recognized in net earnings				
Current service cost	**2**	2	**7**	7
Net Interest cost	**1**	1	**4**	4
Benefit cost	**3**	3	**11**	11
Remeasurements				
Actuarial (gain) loss due to liability experience	–	(1)	**(1)**	2
Actuarial (gain) loss due to liability assumption changes	**(8)**	8	**(5)**	(27)
Loss (gain) on plan assets	**(13)**	(5)	–	0
Remeasurement effects recognized in OCI	**(21)**	2	**(6)**	(25)

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

Defined Benefit Obligation	DB Pension Plan		OPEB Plan	
($ millions)	**2013**	2012	**2013**	2012
Beginning of year	**189**	183	**105**	120
Current service cost	**2**	2	**7**	7
Interest cost	**8**	7	**4**	4
Benefits paid	**(11)**	(10)	**(1)**	(1)
Remeasurements				
Actuarial (gain) loss - experience	**–**	(1)	**(1)**	2
Actuarial (gain) loss - demographic assumptions	**6**	–	**9**	–
Actuarial (gain) loss - financial assumptions	**(14)**	8	**(14)**	(27)
Curtailment gain	**–**	–	**–**	–
End of year	**180**	189	**109**	105

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

Fair Value of Plan Assets		
($ millions)	**2013**	2012
Beginning of year	**156**	147
Contributions by employer	**8**	8
Benefits paid	**(11)**	(10)
Interest income	**7**	6
Return on plan assets greater (less) than discount rate	**13**	5
End of year	**173**	156

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

DB Pension Plan Long-term Assumptions	Canada - DB Pension Plan		U.S. - DB Pension Plan	
(percent)	**2013**	2012	**2013**	2012
Discount rate for benefit expense	**3.8**	4.1	**3.2**	3.9
Discount rate for benefit obligation	**4.5**	3.8	**4.1**	3.2
Rate of compensation expense	**3.5**	3.5	**4.5**	4.5

OPEB Plan Long-term Assumptions	OPEB Plan	
(percent)	**2013**	2012
Discount rate for benefit expense	**3.3 - 4.0**	4.1 - 4.3
Discount rate for benefit obligation	**4.3 - 4.7**	3.3 - 4.0
Dental care escalation rate	**4.0**	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 2013 and 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 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 benefit expense for the U.S. OPEB Plan was 8.0% for 2013, and 7.0% for 2014, grading 0.5% per year for 4 years to 5.0% per year in 2018 and thereafter. The average health care cost trend rate used for the obligation related to the U.S. OPEB Plan was 7.0% for 2014, 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 plan. 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	(2.2)
Effect on defined benefit obligation	19.3	(15.7)

During 2013, the Company contributed $8 million (2012 – $8 million) to the defined benefit pension plan assets and is expecting to contribute $8 million in 2014. Benefits of $25 million are expected to be paid in 2014.

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, 2013 and 2012 was as follows:

DB Pension Plan Assets

(percent)	Target allocation range	**2013**	2012
Money market type funds	0 – 15	**0.5**	–
Equity securities	35 – 80	**64.5**	59.8
Debt securities	30 – 65	**34.5**	39.6
Real estate	0 – 5	**–**	–
Other	–	**0.5**	0.6

Note 20 Commitments and Contingencies

At December 31, 2013, the Company had commitments that require the following minimum future payments which are not accrued for 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	155	958	367	1,480
Firm transportation agreements	289	1,073	2,702	4,064
Unconditional purchase obligations	2,287	2,028	71	4,386
Lease rentals and exploration work agreements	107	431	1,208	1,746
	2,838	4,490	4,348	11,676

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, 2013 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. 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, 2013, the senior notes are included in long-term debt in the Company's consolidated balance sheets.

In April 2011, the Company sold its 50% interest in the Meridian cogeneration facility ("Meridian") at Lloydminster to a related party. The consideration for the Company's share of Meridian was $61 million, resulting in no net gain or loss on the transaction.

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, 2013, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $55 million (2012 – $74 million). For the year ended December 31, 2013, the amount of steam purchases by the Company from Meridian totalled $17 million (2012 – $13 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, 2013, the total cost recovery for these services was $9 million (2012 – $19 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)	**2013**	2012
Short-term employee benefits[(1)]	**13**	11
Post-employment benefits[(2)]	–	–
Stock-based compensation[(3)]	**10**	4
	23	15

(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, 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, 2013**	December 31, 2012
Derivatives – fair value through profit or loss ("FVTPL")		
Accounts receivable	**18**	13
Accounts payable and accrued liabilities	**(19)**	(5)
Other assets, including derivatives	**2**	1
Other – FVTPL[1]		
Accounts payable and accrued liabilities	**(29)**	(27)
Other long-term liabilities	**(31)**	(78)
Hedging instruments[2]		
Derivatives designated as a cash flow hedge	**37**	1
Hedge of net investment[3]	**(93)**	88
	(115)	(7)

(1) Non-derivative items related to contingent consideration recognized as part of a business acquisition.
(2) Hedging instruments are presented net of tax.
(3) 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, 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, 2013 was $4.6 billion (December 31, 2012 – $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, 2013, 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 until 2014, 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 fair value of financial liabilities classified in Level 3 is provided below:

Level 3 Valuations

($ millions)	2013	2012
Beginning of year	**105**	129
Accretion	**7**	11
Upside interest payment	**(25)**	(17)
Increase (decrease) on revaluation[1]	**(27)**	(18)
End of year	**60**	105
Expected to be incurred within 1 year	**29**	27
Expected to be incurred beyond 1 year	**31**	78

(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, 2013, the Company had designated all of its U.S. $3.2 billion denominated debt as a hedge of the Company's net investment in its U.S. refining operations (December 31, 2012 – U.S. $2.8 billion). Of this amount, U.S. $400 million was designated in the third quarter of 2013. For the year ended December 31, 2013, the unrealized loss arising from the translation of the debt was $180 million (2012 – unrealized gain of $15 million), net of tax of $27 million (2012 – $2 million), which was recorded in net investment hedge 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, 2013, 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 $50 million (December 31, 2012 – $72 million). The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $22 million for the year ended December 31, 2013 (2012 – $21 million).

Cash flow hedges may also be used to mitigate risk related to interest rates. At December 31, 2013, the Company had entered into a cash flow hedge using forward starting interest rate swap arrangements, whereby the Company fixed the underlying U.S. 10-year Treasury Bond rate on U.S. $500 million to June 16, 2014. The effective portion of these contracts has been recorded at fair value in other assets; there was no ineffective portion at December 31, 2013. For the year ended December 31, 2013, the Company incurred an unrealized gain of $36 million (2012 – $3 million), arising from the revaluation of the forward starting swaps, net of tax of $13 million (2012 – $1 million), which was recorded in cash flow hedge within OCI.

The forward starting swaps had the following terms and fair value as at December 31, 2013:

Forward Starting Swaps ($ millions)	Swap Rate[1]	December 31, 2013 Notional Amount (U.S. $ millions)	December 31, 2013 Fair Value
Swap Maturity			
June 15, 2024	2.24%	**105**	**10**
June 16, 2024	2.25%	**310**	**31**
June 17, 2024	2.24%	**85**	**9**
		500	**50**

(1) *Weighted average rate.*

iv) Financial Position of Market Risk Management Contracts

The following represents the cumulative fair value adjustments on the Company's other risk management contracts as at December 31, 2013 and 2012:

Risk Management ($ millions)	December 31, 2013 Asset	December 31, 2013 Liability	December 31, 2013 Net	December 31, 2012 Asset	December 31, 2012 Liability	December 31, 2012 Net
Commodity Price						
Natural gas contracts	**15**	**(7)**	**8**	3	(2)	1
Natural gas storage contracts	**2**	**(2)**	**–**	10	–	10
Natural gas storage inventory[1]	**27**	**–**	**27**	6	–	6
Crude oil contracts	**2**	**(10)**	**(8)**	–	(3)	(3)
Crude oil inventory[2]	**49**	**–**	**49**	53	–	53
Foreign Currency						
Foreign currency forwards	**–**	**–**	**–**	–	–	–
	95	**(19)**	**76**	72	(5)	67

(1) *Represents the fair value adjustment to 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 was $124 million at December 31, 2013 (December 31, 2012 – $107 million).*

(2) *Represents the fair value adjustment to inventory recognized in the consolidated balance sheets related to third-party crude oil physical purchase and sale contracts. Total fair value adjustment of the related crude oil inventory was $297 million at December 31, 2013 (December 31, 2012 – $221 million).*

v) Earnings Impact of Market Risk Management Contracts

The gains (losses) recognized on risk management positions for the years ended December 31, 2013 and 2012 are set out below:

	2013			
Earnings Impact *($ millions)*	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)**

	2012			
Earnings Impact *($ millions)*	Marketing and Other	Purchases of Crude Oil and Products	Other – Net	Net Foreign Exchange Gains (Losses)
Commodity Price				
Natural gas	2	–	–	–
Crude oil	48	(2)	–	–
	50	(2)	–	–
Foreign Currency				
Cross currency swaps	–	–	(2)	2
Foreign currency forwards(1)	–	–	(1)	(5)
	50	(2)	(3)	(3)

(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:

	As at December 31, 2013		
Offsetting Financial Assets and Liabilities *($ millions)*	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)**

Offsetting Financial Assets and Liabilities ($ millions)	As at December 31, 2012 Gross Amount	Amount Offset	Net Amount
Financial Assets			
Financial derivatives	36	(5)	31
Normal purchase and sale agreements	595	(116)	479
	631	(121)	510
Financial Liabilities			
Financial derivatives	(141)	138	(3)
Normal purchase and sale agreements	(687)	260	(427)
	(828)	398	(430)

vi) 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	22	(22)
Natural gas price	(12)	12

Foreign Exchange Rate[2] ($ millions)	Canadian dollar $0.01 increase	Canadian dollar $0.01 decrease
U.S. dollar per Canadian dollar	1	(1)

Interest Rate[3] ($ millions)	100 basis point increase	100 basis points decrease
LIBOR	41	(46)

(1) *Based on average crude oil and natural gas market prices as at December 31, 2013.*
(2) *Based on the U.S./Canadian dollar exchange rate as at December 31, 2013.*
(3) *Based on U.S. LIBOR as at December 31, 2013.*

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, 2013:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[1] *(note 11)*	**595**	**371**
Syndicated bank facilities *(note 13)*	**3,200**	**3,200**
	3,795	**3,571**

[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 $3.0 billion and unused capacity under the universal short form base shelf prospectus filed in the United States of U.S. $3.0 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, 2013:

Contractual Maturities of Financial Liabilities

($ millions)	2014	2015	2016	2017	2018	Thereafter
Accounts payable and accrued liabilities	3,155	–	–	–	–	–
Other long-term liabilities	3	38	3	3	3	26
Long-term debt	1,015	487	395	486	146	3,163

The Company's contribution payable pursuant to the joint arrangement with BP is payable between December 31, 2013 and December 31, 2015, with the final balance due and payable by December 31, 2015. 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, 2013 or December 31, 2012, 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, 2013:

Accounts Receivable Aging

($ millions)	December 31, 2013
Current	**1,353**
Past due (1 – 30 days)	**74**
Past due (31 – 60 days)	**25**
Past due (61 – 90 days)	**10**
Past due (more than 90 days)	**23**
Allowance for doubtful accounts	**(27)**
	1,458

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, 2013, the Company impaired $1 million (2012 – $4 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 $24.2 billion as at December 31, 2013 (December 31, 2012 – $23.1 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, 2013, debt to capital employed was 17% (December 31, 2012 – 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, 2013, debt to cash flow was 0.8 times (December 31, 2012 – 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, 2013.

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. The programs expire in 2015 and applications for funding are submitted quarterly. During 2013, the Company received $26 million (2012 – $40 million) under these programs. The grants are accrued for operational purposes and have been recorded as revenues in the consolidated statements of income.

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, 2013 was $778 million (2012 – $673 million) as follows:

Compensation of Employees

($ millions)	**2013**	2012
Short-term employee benefits[(1)]	**711**	661
Post-employment benefits[(2)]	**48**	42
Stock-based compensation[(3)]	**105**	54
	864	757
Less: capitalized portion	**(86)**	(84)
	778	673

(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.*

Supplemental Financial and Operating Information

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	**2013**	2012[1]	2011[1]	2010[2]	2009[2][3]	2008[2][3]	2007[2][3]	2006[2][3]	2005[2][3]	2004[2][3]
Financial Highlights										
Gross Revenues	**24,181**	22,948	22,829	18,085	15,935	26,744	16,583	13,478	11,085	9,151
Net earnings	**1,829**	2,022	2,224	947	1,416	3,751	3,201	2,734	1,996	1,001
Earnings per share										
Basic	**1.85**	2.06	2.40	1.11	1.67	4.42	3.77	3.21	2.35	1.18
Diluted	**1.85**	2.06	2.34	1.05	1.67	4.42	3.77	3.21	2.35	1.18
Expenditures on PP&E[4]	**5,028**	4,701	4,618	3,571	2,797	4,108	2,974	3,201	3,099	2,379
Total debt	**4,119**	3,918	3,911	4,187	3,229	1,957	2,814	1,611	1,886	2,204
Debt to capital employed *(percent)*[5]	**17**	17	18	22	18	12	19	14	20	26
Corporate reinvestment ratio *(percent)*[5]	**108**	106	98	134	111	66	86	71	80	112
Return on capital employed *(percent)*[5]	**8.7**	9.5	12.1	6.4	9.1	25.1	25.6	27.1	22.7	13.0
Return on equity *(percent)*[5]	**9.3**	10.9	13.8	6.7	9.8	28.9	30.1	31.9	29.2	17.0
Upstream										
Daily production, before royalties										
Light crude oil and NGL *(mbbls/day)*	**81.1**	72.3	87.6	80.4	89.1	122.9	138.7	111.0	64.6	66.2
Medium crude oil *(mbbls/day)*	**23.2**	24.1	24.5	25.4	25.4	26.9	27.1	28.5	31.1	35.0
Heavy crude oil *(mbbls/day)*	**74.5**	76.9	74.5	74.5	78.6	84.3	86.5	88.5	88.0	90.2
Bitumen *(mbbls/day)*	**47.7**	35.9	24.7	22.3	23.1	22.7	20.4	19.6	18.0	18.7
	226.5	209.2	211.3	202.6	216.2	256.8	272.7	247.6	201.7	210.1
Natural gas *(mmcf/day)*	**512.7**	554.0	607.0	506.8	541.7	594.4	623.3	672.3	680.0	689.2
Total production *(mboe/day)*	**312.0**	301.5	312.5	287.1	306.5	355.9	376.6	359.7	315.0	325.0
Total proved reserves, before royalties *(mmboe)*[6]	**1,265**	1,192	1,172	1081	933	896	1,014	1,004	985	791
Downstream										
Upgrading										
Synthetic crude oil sales *(mbbls/day)*	**50.5**	60.4	55.3	54.1	61.8	58.7	53.1	62.5	57.5	53.7
Upgrading differential *($/bbl)*	**29.14**	22.34	27.34	14.52	11.89	28.77	30.73	26.16	30.70	17.79
Canadian Refined Products										
Fuel sales *(million of litres/day)*[7]	**8.1**	8.7	9.5	8.2	7.6	7.9	8.7	8.7	8.9	8.4
Refinery throughput										
Prince George refinery *(mbbls/day)*	**10.3**	11.1	10.6	10.0	10.3	10.1	10.5	9.0	9.7	9.8
Lloydminster refinery *(mbbls/day)*	**26.4**	28.3	28.1	27.8	24.1	26.1	25.3	27.1	25.5	25.3
Refinery utilization *(percent)*[8]	**89**	96	92	92	86	91	90	90	101	100
US Refining and Marketing										
Refinery throughput										
Lima Refinery *(mbbls/day)*	**149.4**	150.0	144.3	136.6	114.6	136.6	143.8	–	–	–
Toledo Refinery *(mbbls/day)*	**65.0**	60.6	63.9	64.4	64.9	60.6	–	–	–	–
Refining Margin *(U.S. $/bbl crude throughput)*	**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 7.3 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.*

Segmented Financial Information

($ millions)	Upstream						Downstream		
	Exploration and Production			Infrastructure and Marketing			Upgrading		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Year ended December 31									
Gross revenues[2][3]	**7,333**	6,581	7,556	**2,134**	2,377	1,945	**2,023**	2,191	2,217
Royalties	**(864)**	(693)	(1,125)	**–**	–	–	**–**	–	–
Marketing - other[2][3]	**–**	–	–	**312**	398	94	**–**	–	–
Revenues, net of royalties	**6,469**	5,888	6,431	**2,446**	2,775	2,039	**2,023**	2,191	2,217
Expenses									
Purchase of crude oil and products[2]	**91**	73	99	**2,004**	2,258	1,818	**1,378**	1,636	1,628
Production and operating expenses[3]	**2,016**	1,875	1,751	**14**	12	6	**161**	150	146
Selling, general and administrative expenses	**240**	175	153	**19**	21	17	**7**	3	3
Depletion, depreciation, amortization and impairment	**2,515**	2,121	2,018	**20**	22	24	**96**	102	164
Exploration and evaluation expenses	**246**	344	470	**–**	–	–	**–**	–	–
Other – net	**(35)**	(105)	(261)	**(3)**	–	1	**(27)**	(17)	67
Total Expenses	**5,073**	4,483	4,230	**2,054**	2,313	1,866	**1,615**	1,874	2,008
Earnings from operating activities	**1,396**	1,405	2,201	**392**	462	173	**408**	317	209
Share of equity investment	**(10)**	(11)	–	**–**	–	–	**–**	–	–
Net financial items	**(103)**	(73)	(64)	**–**	–	–	**(7)**	(11)	(7)
Earnings (loss) before income tax	**1,283**	1,321	2,137	**392**	462	173	**401**	306	202
Current income taxes	**162**	134	41	**222**	171	64	**19**	31	(2)
Deferred income taxes	**169**	211	515	**(122)**	(55)	(20)	**85**	49	54
Total income tax provision (recovery)	**331**	345	556	**100**	116	44	**104**	80	52
Net earnings (loss)	**952**	976	1,581	**292**	346	129	**297**	226	150
Total assets - as at December 31	**24,653**	22,774	20,141	**1,670**	1,506	1,509	**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								
2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
3,737	3,848	3,877	**10,728**	9,856	9,500	**(2,086)**	(2,303)	(2,360)	**23,869**	22,550	22,735
–	–	–	**–**	–	–	**–**	–	–	**(864)**	(693)	(1,125)
–	–	–	**–**	–	–	**–**	–	–	**312**	398	94
3,737	3,848	3,877	**10,728**	9,856	9,500	**(2,086)**	(2,303)	(2,360)	**23,317**	22,255	21,704
3,134	3,208	3,265	**9,546**	8,544	8,200	**(2,086)**	(2,303)	(2,360)	**14,067**	13,416	12,650
193	184	182	**409**	385	391	**–**	4	–	**2,793**	2,610	2,476
60	58	49	**15**	13	12	**217**	178	194	**558**	448	428
90	83	80	**233**	212	195	**51**	40	38	**3,005**	2,580	2,519
–	–	–	**–**	–	–	**–**	–	–	**246**	344	470
(5)	(2)	–	**–**	4	–	**(17)**	(3)	–	**(87)**	(123)	(193)
3,472	3,531	3,576	**10,203**	9,158	8,798	**(1,835)**	(2,084)	(2,128)	**20,582**	19,275	18,350
265	317	301	**525**	698	702	**(251)**	(219)	(232)	**2,735**	2,980	3,354
–	–	–	**–**	–	–	**–**	–	–	**(10)**	(11)	–
(5)	(6)	(6)	**(3)**	(5)	(4)	**21**	(38)	(133)	**(97)**	(133)	(214)
260	311	295	**522**	693	698	**(230)**	(257)	(365)	**2,628**	2,836	3,140
65	89	25	**18**	(1)	76	**103**	112	150	**589**	536	354
1	(9)	50	**165**	258	178	**(88)**	(176)	(215)	**210**	278	562
66	80	75	**183**	257	254	**15**	(64)	(65)	**799**	814	916
194	231	220	**339**	436	444	**(245)**	(193)	(300)	**1,829**	2,022	2,224
1,788	1,646	1,632	**5,537**	5,326	5,476	**1,901**	2,667	2,352	**36,904**	35,161	32,426

Segmented Financial Information

	Upstream				Downstream	
	Exploration and Production		Infrastructure and Marketing		Upgrading	
($ millions)	2010	2009[2]	2010	2009[2]	2010	2009[2]
Year ended December 31						
Gross revenues[3]	5,744	5,313	7,002	6,984	1,570	1,572
Royalties	(978)	(861)	–	–	–	–
Revenues, net of royalties	4,766	4,452	7,002	6,984	1,570	1,572
Expenses						
Purchase of crude oil and products and production and operating expenses[3]	1,403	1,425	6,684	6,655	1,439	1,461
Selling, general and administrative expenses	152	70	22	14	–	–
Depletion, depreciation, amortization and impairment	1,521	1,397	43	36	74	34
Exploration and evaluation expenses	438	–	–	–	–	–
Other – net	1	–	34	–	(41)	–
Total expenses	3,515	2,892	6,783	6,705	1,472	1,495
Earnings from operating activities	1,251	1,560	219	279	98	77
Net financial items	40	–	–	–	9	–
Earnings (loss) before income tax	1,211	1,560	219	279	89	77
Current income taxes	(23)	909	62	101	1	111
Deferred income taxes	373	(462)	(3)	(22)	25	(88)
Total income tax provision	350	447	59	79	26	23
Net earnings (loss)	861	1,113	160	200	63	54
Total assets - as at December 31	17,354	16,338	1,325	1,712	1,987	1,427

(1) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices.
(2) 2009 results are reported in accordance with previous Canadian GAAP.
(3) 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.

Downstream				Corporate and Eliminations[1]		Total	
Canadian Refined Products		U.S. Refining and Marketing					
2010	2009[2]	2010	2009[2]	2010	2009[2]	2010	2009[2]
2,975	2,495	7,107	5,349	(6,313)	(5,778)	18,085	15,935
–	–	–	–	–	–	(978)	(861)
2,975	2,495	7,107	5,349	(6,313)	(5,778)	17,107	15,074
2,679	2,174	6,935	4,955	(6,251)	(5,821)	12,889	10,849
49	30	7	2	61	158	291	274
88	93	191	194	75	51	1,992	1,805
–	–	–	–	–	–	438	–
(2)	–	–	–	(7)	–	(15)	–
2,814	2,297	7,133	5,151	(6,122)	(5,612)	15,595	12,928
161	198	(26)	198	(191)	(166)	1,512	2,146
2	–	6	3	238	186	295	189
159	198	(32)	195	(429)	(352)	1,217	1,957
56	38	–	3	92	100	188	1,262
(14)	19	(12)	68	(287)	(236)	82	(721)
42	57	(12)	71	(195)	(136)	270	541
117	141	(20)	124	(234)	(216)	947	1,416
1,517	1,430	5,092	4,771	775	617	28,050	26,295

Upstream Operating Information

	2013	2012	2011	2010[1]	2009[1]
Daily Production, before royalties					
Light crude oil and NGL *(mmbls/day)*	**81.1**	72.3	87.6	80.4	89.1
Medium crude oil *(mmbls/day)*	**23.2**	24.1	24.5	25.4	25.4
Heavy crude oil *(mmbls/day)*	**74.5**	76.9	74.5	74.5	78.6
Bitumen *(mmbls/day)*	**47.7**	35.9	24.7	22.3	23.1
	226.5	209.2	211.3	202.6	216.2
Natural gas *(mmcf/day)*	**512.7**	554.0	607.0	506.8	541.7
Total production *(mboe/day)*	**312.0**	301.5	312.5	287.1	306.5
Average sales prices					
Light crude oil and NGL *($/bbl)*	**102.35**	99.22	104.06	76.90	62.70
Medium crude oil *($/bbl)*	**74.29**	71.51	76.59	64.92	56.37
Heavy crude oil *($/bbl)*	**63.44**	61.91	68.13	58.91	52.54
Bitumen *($/bbl)*	**61.68**	59.49	65.75	57.84	51.90
Natural gas *($/mcf)*	**3.19**	2.60	3.89	3.86	3.83
Operating costs *($/boe)*	**16.28**	15.49	14.01	13.35	11.82
Operating netbacks[2][3]					
Light crude oil[4]	**69.42**	66.13	70.86	47.58	37.54
Medium crude oil[4]	**41.53**	38.22	42.41	36.88	32.08
Heavy crude oil[2]	**34.61**	38.31	41.72	34.51	31.58
Bitumen *($/boe)*	**43.92**	42.32	39.34	28.96	28.46
Natural gas *($/mcfge)*[5]	**1.06**	0.77	1.96	1.93	2.08

(1) *Results have not been adjusted for the reclassification of the Midstream operating segment.*
(2) *Operating netbacks are Husky's average prices less royalties and operating costs on a per unit basis.*
(3) *The Upstream netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing.*
(4) *Includes associated co-products converted to boe.*
(5) *Includes associated co-products converted to mcfge.*

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

		2013		2012		2011		2010		2009	
		Gross	**Net**	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	**39**	**24**	47	30	50	40	60	51	18	9
	Gas	**19**	**14**	19	12	24	24	37	31	37	22
	Dry	**–**	**–**	–	–	3	3	8	8	7	6
		58	**38**	66	42	77	67	105	90	62	37
Development	Oil	**768**	**709**	775	715	880	765	815	722	315	278
	Gas	**68**	**41**	23	17	57	42	73	53	122	61
	Dry	**1**	**–**	5	4	4	4	10	9	7	7
		837	**750**	803	736	941	811	898	784	444	346
		895	**788**	869	778	1,018	878	1,003	874	506	383
Success Ratio *(percent)*		**100**	**100**	99	99	99	99	98	98	97	97

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

Supplemental Upstream Operating Statistics

Netback Analysis	2013	2012	2011
Total Upstream [1]			
Crude Oil Equivalent *($/boe)*[2]			
Sales volume *(mboe/day)*	**312.0**	301.5	312.5
Price received *($/boe)*	**61.96**	57.16	64.17
Royalties *($/boe)*	**7.59**	6.29	9.86
Operating costs *($/boe)*[3]	**16.28**	15.49	14.01
Offshore transportation *($/boe)*[4]	**0.37**	0.24	0.26
Netback *($/boe)*	**37.72**	35.14	40.04
Depletion, depreciation, amortization and impairment *($/boe)*	**22.09**	19.20	17.69
Administration expenses and other ($/boe)[3]	**2.51**	1.75	1.34
Earnings before taxes	**13.12**	14.19	21.01
Lloydminster Heavy Oil			
Thermal Oil			
Bitumen			
Sales volumes *(mbbls/day)*	**37.4**	26.3	17.4
Price received *($/bbl)*	**63.36**	61.03	67.43
Royalties *($/bbl)*	**5.69**	3.82	10.78
Operating costs *($/bbl)*[3]	**9.90**	10.34	14.59
Netback *($/bbl)*	**47.77**	46.87	42.06
Non Thermal Oil			
Medium Oil			
Sales volumes *(mbbls/day)*	**1.9**	2.1	2.3
Price received *($/bbl)*	**71.41**	70.22	75.19
Royalties *($/bbl)*	**4.90**	5.13	5.10
Heavy Oil			
Sales volumes *(mbbls/day)*	**58.6**	61.1	60.2
Price received *($/bbl)*	**64.26**	62.35	68.44
Royalties *($/bbl)*[5]	**7.67**	4.88	7.81
Natural Gas			
Sales volumes *(mmcf/day)*	**19.6**	25.4	29.3
Price received *($/mcf)*	**2.89**	2.25	3.44
Royalties *($/mcf)*	**0.34**	0.16	0.27
Non Thermal Oil Total[2]			
Sales volumes *(mboe/day)*	**63.8**	67.4	67.4
Price received *($/boe)*	**62.07**	59.53	65.20
Royalties *($/boe)*	**7.30**	4.64	7.27
Operating costs *($/boe)*[3]	**21.17**	17.75	17.34
Netback *($/boe)*	**33.60**	37.14	40.59
Oil Sands			
Bitumen			
Total sales volumes *(mbbls/day)*	**10.3**	9.6	7.3
Price received *($/bbl)*	**55.60**	55.29	61.77
Royalties *($/boe)*	**4.18**	3.76	3.75
Operating costs *($/boe)*[3]	**21.44**	21.61	25.13
Netback *($/boe)*	**29.98**	29.92	32.89
Western Canada Conventional			
Crude Oil			
Light Oil			
Sales volumes *(mbbls/day)*	**20.5**	21.3	16.5
Price received *($/bbl)*	**88.27**	80.98	88.23
Royalties *($/bbl)*	**10.38**	10.56	14.61

Netback Analysis (continued)	2013	2012	2011
Medium Oil			
Sales volumes *(mbbls/day)*	**21.3**	22.0	22.2
Price received *($/bbl)*	**74.56**	71.63	76.73
Royalties *($/bbl)*	**12.89**	13.48	15.05
Heavy Oil			
Sales volumes *(mbbls/day)*	**15.9**	15.8	14.3
Price received *($/bbl)*	**60.41**	60.21	66.81
Royalties *($/bbl)*	**10.12**	10.55	13.16
Western Canada Crude Oil Total			
Total sales volumes *(mboe/day)*	**57.7**	59.1	53.0
Price received *($/boe)*	**75.54**	71.96	77.66
Royalties *($/boe)*	**11.23**	11.64	14.41
Operating costs *($/boe)*[3]	**23.58**	20.93	21.69
Netback *($/bbl)*	**40.73**	39.39	41.56
Natural Gas and NGL			
Natural Gas Liquids			
Sales volumes *(mbbls/day)*	**9.2**	8.8	8.3
Price received *($/bbl)*	**70.34**	66.92	75.62
Royalties *($/bbl)*	**18.45**	18.69	21.87
Natural Gas			
Sales volumes *(mmcf/day)*	**493.1**	528.6	577.7
Price received *($/mcf)*[6]	**3.20**	2.61	3.91
Royalties *($/mcf)*[6][7]	**(0.02)**	(0.10)	0.18
Western Canada Natural Gas and NGL Total[2]			
Total sales volumes *(mmcf/day)*	**548.3**	581.4	627.5
Price received *($/mcf)*	**4.05**	3.39	4.60
Royalties *($/mcf)*	**0.29**	0.19	0.46
Operating costs *($/mcf)*[3]	**2.08**	1.88	1.71
Netback *($/mcf)*	**1.68**	1.32	2.43
Atlantic Region			
Light Oil			
Sales volumes *(mbbls/day)*	**44.1**	33.8	54.3
Price received *($/boe)*	**114.60**	115.78	112.21
Royalties *($/boe)*	**14.65**	12.36	19.36
Operating costs *($/boe)*[3]	**12.47**	17.12	8.76
Transportation *($/boe)*[4]	**2.62**	2.14	1.50
Netback *($/boe)*	**84.86**	84.16	82.59
Asia Pacific Region			
Light Oil and NGL[2]			
Sales volumes *(mboe/day)*	**7.3**	8.4	8.5
Price received *($/boe)*	**107.95**	113.01	110.54
Royalties *($/boe)*	**26.23**	26.89	32.75
Operating costs *($/boe)*[3]	**11.39**	10.08	8.17
Netback *($/boe)*	**70.33**	76.04	69.62

(1) *The Upstream netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing.*
(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

Forward-Looking Statements and Information

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, including its targets for compound annual growth and reserves replacement ratios; the Company's target volumes of thermal production by 2016; the Company's production guidance for 2014; the Company's capital spending program for 2014; ability of the Company's projects to put the Company in a free cash-flow position, after capital expenditures, by 2014; and the ability of the Company to achieve its five-year CAGR target by 2017;

- with respect to the Company's Asia Pacific Region: potential for sales from the onshore gas terminal at the Liwan Gas Project to the Hong Kong SAR; anticipated timing and duration of tie-in of the Liuhua 34-2 well to the Company's Liwan 3-1 infrastructure; anticipated timing of the Company's Liuhua 29-1 development coming onstream; anticipated gross volume of natural gas sales from the Liwan Gas Project following tie-in of the Liuhua 34-2 and Liuhua 29-1 wells; and the expected volumes of production from the Company's Liwan project;

- with respect to the Company's Atlantic Region: planned timing of commencement of oil production from the Company's South White Rose extension project; planned timing of first oil production from the Company's West White Rose extension project; expected commercial viability of the Company's discoveries at Bay du Nord, Harpoon and Mizzen; and the Company's exploration and delineation plans in the Atlantic Region for 2014 and beyond;

- with respect to the Company's Oil Sands properties: anticipated timing of startup and first oil at the Company's Sunrise Energy Project; scheduled timing of completion work on two trains at the Central Plant Facility at the Company's Sunrise Energy Project; and development plans and anticipated production capacity from the next phase of the Company's Sunrise Energy Project;

- with respect to the Company's Heavy Oil properties: the Company's expected steady growth in crude oil volumes in 2014 and beyond; scheduled timing of first production at the Company's Rush Lake thermal project; scheduled timing of construction and production, and anticipated volumes of daily production from, the Company's Edam East and Vawn thermal projects; the Company's 2014 drilling program in its heavy oil portfolio; and target production from thermal projects by 2016;

- with respect to the Company's Western Canadian oil and gas resource plays: anticipated volumes of production from the Company's Ansell liquids-rich gas play project; and the Company's levels of consumption of its own gas production by 2015; and

- with respect to the Company's Downstream operating segment: anticipated outcome of a feedstock optimization project at the BP-Husky Refinery in Toledo, Ohio; expected timing of completion and additional processing capacity to be added by the Company's feedstock flexibility project at its Lima Refinery.

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, 2013 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.

Non-GAAP Measures

Husky uses measurements primarily based on IFRS, as issued by the IASB, and also on secondary non-GAAP measurements. The non-GAAP measurements included in this Annual Report are: return on capital employed, return on capital in use, cash flow from operations and net operating earnings. 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, 2013, 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, 2013 and represent Husky's share. Unless otherwise noted, historical production numbers given represent Husky's share.

The Company uses the terms barrels of oil equivalent ("boe"), which is 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. Forecast reserve replacement ratios for a given period are calculated by taking the forecast proved reserve additions for those periods divided by the forecast gross production for the same periods.

The Company has disclosed possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10 percent probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

The Company has disclosed best-estimate contingent resources of 13.2 billion boe, which is comprised of 12.0 billion bbls of crude oil and 6.5 tcf of natural gas. Of the total, 11.0 billion boe is economic at year-end 2013.

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 varies in the properties. The properties assigned contingent resources are Western Canada gas resource plays and EOR projects, Lloydminster thermal 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. Estimates of contingent resources have not been adjusted for risk based on the chance of development.

There is no certainty as to the timing of such development. For movement of resources to reserves categories, all projects must have an economic depletion plan and may require, among other things: (i) additional delineation drilling for unrisked contingent resources; (ii) regulatory approvals; and (iii) Company and partner approvals to proceed with development.

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 SAGD and/or Cyclic Steam Stimulation (CSS) technology in carbonate reservoirs at Saleski, which is currently under active development. 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.

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 news release, such as "possible reserves" and "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.

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 (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

Alister Cowan
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

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

Robert Hinkel
Chief Operating Officer, Asia Pacific

Terry Manning
Senior Vice President, Safety, Engineering & Procurement

Malcolm Maclean
Senior Vice President, Atlantic Region

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		2013	2012	2011
Share price *(dollars)*	High	**33.85**	29.50	30.58
	Low	**26.97**	22.04	20.63
	Close at December 31	**33.70**	29.40	24.55
Average daily trading volumes *(thousands)*		**1,533**	1,496	1,351
Number of common shares outstanding *(thousands)*		**983,379**	982,229	957,537
Weighted average number of common shares outstanding *(thousands)*				
	Basic	**983,028**	975,808	923,821
	Diluted	**983,618**	975,883	931,978

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 Canadian Energy Sector and in the S&P/TSX 60 indices.

Toronto Stock Exchange Listing: HSE and HSE.PR.A

Outstanding Shares

The number of common shares outstanding at December 31, 2013 was 983,379,074.

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).

Corporate Office

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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

Auditors

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

Annual Meeting

The Annual Meeting of Shareholders will be held at 10:30 a.m. on Wednesday, May 7, 2014 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

Liwan gas terminal

Dividends

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

Declaration Date	Quarter Dividend
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
October 2009	0.300
July 2009	0.300
April 2009	0.300
February 2009	0.300
October 2008	0.500
July 2008	0.500
April 2008	0.400
February 2008	0.330

Husky Energy

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