Husky Energy

Building Momentum

Annual Report **2012**


Liwan Gas Project plant construction


Sunrise Energy Project construction

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

Financial

Highlights

Financial Highlights[1]

Year ended December 31		2012	2011
(millions of dollars except where indicated)			
Gross revenue		**23,128**	23,082
Revenues, net of royalties		**22,435**	21,957
Cash flow from operations[2]		**5,010**	5,198
Per share *(dollars)*	Basic	**5.13**	5.63
	Diluted	**5.13**	5.58
Net earnings		**2,022**	2,224
Per share *(dollars)*	Basic	**2.06**	2.40
	Diluted	**2.06**	2.34
Dividends			
Per share *(dollars)*	Ordinary	**1.20**	1.20
Capital investment[3]		**4,701**	4,618
Return on capital in use *(%)*[2]		**12.7**	15.6
Return on capital employed *(%)*[2]		**9.5**	11.8
Return on equity *(%)*[2]		**10.9**	13.8
Debt to capital employed *(%)*[2]		**17.0**	18.0
Debt to cash flow *(times)*[2]		**0.8**	0.8

(1) Results are reported in accordance with IFRS.
(2) Non-GAAP measures. Please refer to Section 11.3 of the MD&A on Page 54.
(3) Excludes capitalized costs related to asset retirement obligations incurred during the period.

Operational Highlights

Year ended December 31	2012	2011
Daily production, before royalties		
Light crude oil & NGL *(mbbls/day)*	**72.3**	87.6
Medium crude oil *(mbbls/day)*	**24.1**	24.5
Heavy crude oil and bitumen *(mbbls/day)*	**112.8**	99.2
Total crude oil & NGL *(mbbls/day)*	**209.2**	211.3
Natural gas *(mmcf/day)*	**554**	607
Total *(mboe/day)*	**301.5**	312.5
Total proved reserves,		
before royalties *(mmboe)*[1]	**1,192**	1,172
Upgrader throughput *(mbbls/day)*	**77.4**	69.6
Light oil sales *(million litres/day)*	**9.5**	9.5
Lima Refinery throughput *(mbbls/day)*	**150.0**	144.3
Toledo Refinery throughput *(mbbls/day, 50% w.i.)*	**60.6**	63.9
Lloydminster Refinery throughput *(mbbls/day)*	**28.3**	28.1
Prince George Refinery throughput *(mbbls/day)*	**11.1**	10.6
Ethanol production *(thousand litres/day)*	**721.2**	711.3

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

Consistent Execution

Foundation

Heavy Oil and Western Canada
- More than 95 percent of wells drilled targeted oil
- Heavy oil thermal projects at Pikes Peak South and Paradise Hill executed ahead of schedule and surpassed design production rates
- Increased production from key oil and liquids-rich gas resource developments
- 3,500 bbls/day Sandall thermal project 40% complete
- Sanctioned 10,000 bbls/day Rush Lake thermal project

Downstream
- Focused integration strategy mitigated wide differentials by capturing near-Brent pricing
- Strong refinery and upgrader throughputs

Pillars of Growth

Asia Pacific Region
- Liwan Gas Project nearing completion with first gas in late 2013/early 2014
- Madura Strait developments progressed toward production starting in the 2015 timeframe

Oil Sands
- Sunrise Energy Project on track for first oil in 2014
- More than 85 percent of Phase 1 costs fixed
- Planning advanced for next phase of Sunrise

Atlantic Region
- Executed *SeaRose* Floating Production, Storage and Offloading vessel (FPSO) offstation ahead of schedule
- South White Rose extension advancing to first oil in 2014
- Progressed preliminary engineering on West White Rose
- Advanced exploration program

Report to Shareholders

Lloydminster Upgrader

SeaRose FPSO

Our focus over the past year has been on steady execution. The Company continued the balanced growth strategy it laid out more than two years ago, and has consistently delivered against that blueprint. The strategy has proven to be sound and there is now clear visibility towards the growth part of the balanced growth equation.

This attention on execution is evident throughout the Company's operations. In Heavy Oil, the Company delivered two new thermal projects ahead of schedule and under budget, adding more than 17,000 barrels per day (bbls/day) to production. In Western Canada, the Company more than doubled oil production from resource plays to 7,000 bbls/day as it presses forward with its goal to transform the foundation from conventional to unconventional resource plays. Our focused integration strategy demonstrated its value in mitigating earnings and cash flow volatility as Downstream operations made significant contributions to financial results, capturing margins through reliable and efficient operations. Key milestones were achieved in each of the Company's growth pillars in the Asia Pacific Region, the Oil Sands, and the Atlantic Region, with two major projects moving towards completion.

Momentum continues to build and the Company remains on course.

Performance Highlights

A focused integration strategy and high facility reliability across all business segments contributed to strong financial results in 2012.

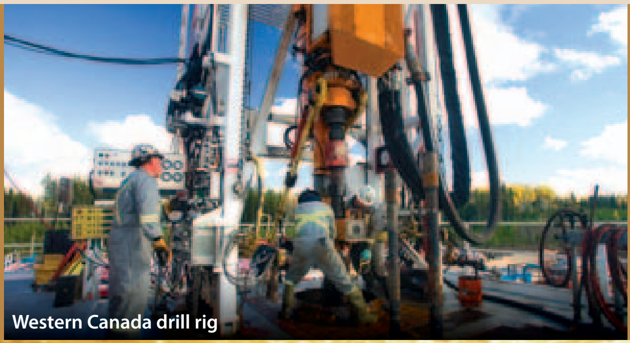
- Net earnings for the year of approximately $2.0 billion were comparable to 2011, excluding after-tax gains on the sale of non-core assets and despite the impact from planned maintenance programs in the Atlantic Region and weak gas prices. Cash flow from operations of $5.0 billion was in line with 2011 results.
- Average annual production in 2012 was within guidance at 301,500 barrels of oil equivalent per day (boe/day), compared to 312,500 boe/day in 2011, reflecting impacts from the two planned offstations in the Atlantic Region.
- Contributions from Downstream operations resulted in the Company being largely unaffected by the wide product and location differentials seen during the year.
- The average proved reserves replacement ratio in 2011-2012 was 175 percent. Including economic revisions, the average proved two-year reserves replacement ratio was 149 percent, ahead of the five-year average target of 140 percent per year.

Foundation

The transformation of the Company's Heavy Oil foundation in Western Canada accelerated with an increased focus on thermal technologies and horizontal wells to tap into the significant resource in place.

Over the past 70 years, Husky has recovered about 800 million barrels of oil from its extensive land base in the Lloydminster region. With proven technologies such as thermal developments, the Company believes it will in time be able to extract that amount again.

An innovative design and construction strategy helped to bring the Pikes Peak South and Paradise Hill thermal projects online ahead of schedule and under budget. Both developments surpassed their nameplate volumes by 40 percent within three months of first production and have laid the groundwork for future growth in Heavy Oil.


Western Canada drill rig


Paradise Hill Thermal Project

The next chapter of Husky's thermal development has begun with the sanctioning of the 10,000 bbls/day Rush Lake project. First oil is targeted for 2015. The 3,500-bbls/day Sandall thermal project is under construction with first oil planned for 2014 and three additional thermal developments are in the planning stages. Heavy oil production from thermal projects is expected to grow to about 55,000 bbls/day by 2017.

To increase oil recovery from the Company's cold heavy oil production with sand (CHOPS) wells, a 250-tonne/day carbon dioxide (CO_2) capture facility became operational during the year. Captured CO_2 from the Lloydminster Ethanol Plant is now being injected into heavy oil reservoirs to increase oil recovery and reduce carbon emissions.

The rejuvenation of our Heavy Oil business is well underway, and we are laying the foundation for the transformation of our business in Western Canada, with its extensive portfolio of approximately two million acres of oil and liquids-rich resource plays. Resource play production reached more than 20,000 boe/day by the end of 2012, an increase of about 70 percent over year-end 2011.

As it advances its established resource plays, the Company is cultivating a number of emerging oil resource developments, including the Rainbow Muskwa in northern Alberta and the Canol at Slater River in the Northwest Territories.

Overall, more than 95 percent of all wells drilled in 2012 targeted oil, a trend expected to continue in 2013. Product mix was about 70 percent oil-weighted. Approximately one-third of gas produced is used in our own facilities, providing an internal hedge against gas prices. Internal natural gas consumption is expected to grow to 50 percent of gas produced by 2015 if gas prices remain in their current range.

Heavy Oil and Western Canadian business performance was underpinned by the integration of our Downstream operations. This strategy demonstrated its ability to mitigate volatility while delivering near-Brent pricing for Western Canada heavy oil, bitumen and light oil production in 2012. Ongoing investments in Downstream operations target three primary objectives: increasing feedstock flexibility to bring the best-priced crude to the Company's refineries; improving product flexibility in the range of products produced to capitalize on opportunities; and enhancing market flexibility for products to achieve the best returns.

Initiatives included the completion of a new 300,000-barrel storage tank at the Company's Hardisty terminal, securing additional storage capacity at Patoka, Illinois and investments at the Lima Refinery to improve feedstock and product options.

Downstream performance reflected consistently high throughputs during 2012. The upgrader and refineries operated at more than 94 percent of their effective capacity, a measurement that reflects actual efficiency rates at the Company's Downstream facilities.

Growth Pillars

Steady progress was made on growth projects in the Asia Pacific Region and Oil Sands during the year. The Atlantic Region business continued to serve as an important part of the Company's foundation while setting the stage for future development.

Asia Pacific Region

Husky and its partner achieved a number of milestones at the Liwan Gas Project in 2012, which was more than 80 percent complete at the end of the year. The shallow water central platform jacket was completed and installed in the South

China Sea, construction of the platform's topsides was advanced in preparation for installation on the jacket in the first half of 2013 and approximately 280 kilometres of pipe was laid from the gas field through to the central platform and on to the onshore gas plant. First gas from the deepwater Liwan development is expected in the late 2013/early 2014 timeframe.

In Indonesia, Husky and its partners made steady progress on the MDA, MBH and BD developments, with first gas expected in the 2015 timeframe from the first two fields and in 2015/2016 for the BD field. Husky holds 40 percent ownership in production from these fields. Four new gas discoveries were made during the year in the Madura Strait and are being evaluated for potential development.

The Company continues to advance towards its target of 50,000 boe/per day from the Asia Pacific Region by 2015.

Oil Sands

The Sunrise Energy Project in northern Alberta is moving forward as planned towards first production in 2014.

Detailed engineering on the in-situ project was finalized and drilling was completed on all 49 steam-assisted gravity drainage (SAGD) horizontal well pairs. Construction was advanced on the central processing facility, which is the biggest building block of the development, and the project was more than 50 percent complete at the end of the year.

The 60,000 bbls/day (30,000 net) first phase of Sunrise achieved considerable cost certainty with the conversion of all significant contracts to lump sum. Planning, design and engineering work continued for the next phase, with regulatory approvals in place for a total of 200,000 (100,000 net) bbls/day.

Pre-work on the Saleski carbonate pilot project began in anticipation of filing a development application in 2013. Industry activity targeting bitumen carbonates, highly porous and permeable sedimentary rock, continued to increase during the year.

Atlantic Region

The White Rose development has now surpassed its original production estimate of 200 million barrels and engineering work is proceeding on projects to further grow and extend the basin's life through satellite developments and a regional exploration program.

A subsea drill centre for the South White Rose extension was excavated in 2012 in preparation for first oil in 2014 and development drilling continued at the North Amethyst satellite field. Work progressed to advance the West White Rose satellite field towards development, including further evaluation of a fixed wellhead platform concept.

A planned maintenance offstation for the *SeaRose* FPSO was successfully executed ahead of schedule and under budget, allowing an earlier than anticipated return to full production at the White Rose field.

The Company was active on several exploration projects in the Atlantic Region, including the completion of pre-drilling work on two potential exploration wells. Husky is also participating in the partner-operated Harpoon well near the Mizzen discovery in the Flemish Pass.

Medium and long-term drilling and exploration plans for this under-explored region were reinforced with the signing of a five-year contract for the new harsh environment semi-submersible rig *West Mira*, which is scheduled for delivery in 2015.

Stage Set for Growth

Husky has been gaining momentum as it positions itself for the next stage of its balanced growth strategy. Fundamental to this growth is the recognition that shareholder value is built on consistent execution and delivery of performance targets.

The Company achieved all of its major milestones in 2012 through safe and reliable operations and prudent financial management. The path forward will reflect these same priorities, and on behalf of the Board of Directors of Husky Energy, we would like to thank our shareholders for their continued support.

Victor T.K. Li
Co-Chairman

Canning K.N. Fok
Co-Chairman

Asim Ghosh
President & Chief Executive Officer

Letter from the CEO

Building Momentum

Achieving a corporation's goals rarely happens with a single step. It requires a constant focus on executing a series of milestones and the balancing of short-term and long-term opportunities. Like the rowers on the cover of this year's annual report, staying on course requires the entire organization to be pulling in unison towards a common destination.

I like that image, because in many ways Husky performed like a practiced rowing team in 2012. We remain on course and are building momentum towards achieving the goals we established in our corporate strategy just over two years ago.

At that time we laid out a blueprint for what we described as a balanced growth strategy. The strategy was built on transforming our foundation in Heavy Oil and Western Canada and underpinned by our Midstream and Downstream assets, which add value to our production. On top of that foundation we are building three growth pillars in the Asia Pacific Region, the Oil Sands, and the Atlantic Region. A key aspect of our balanced growth strategy is a consistent dividend payment to shareholders. The dividend, in my view, is a demonstration of operating discipline and a constant proof point that the Company is operating within the bounds of a sustainable business strategy.

In 2012 we saw steady progress across all business segments towards achieving our goals. The transformation of our Heavy Oil business is well underway and was demonstrated by the delivery of two new heavy oil thermal projects ahead of schedule and under budget. We are setting the stage for the similar transformation of our business in Western Canada and are positioned to advance several emerging plays over the next few years. Our Midstream and Downstream assets once again demonstrated their ability to capture near-Brent pricing during these times of market volatility and steep location and product discounts. Our growth pillars are progressing according to plan with the payoff from two major projects, the Liwan Gas Project and the Sunrise Energy Project, clearly in sight.

We are on target to meet or exceed the goals we set out in 2010, and the strategy is, most importantly, creating value for shareholders.

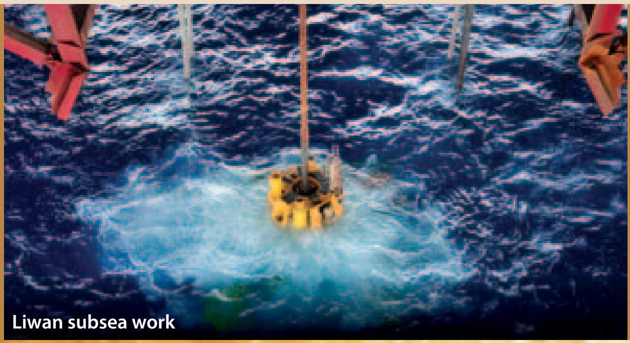
The aim for 2013 is to carry that momentum forward and, in fact, raise the bar. Based on the progress achieved we have increased our five-year target for compound annual production growth from three to five percent through 2015 to the range of five to eight percent from 2012 to 2017. Our capital expenditure budget of $4.8 billion is on par with the prior year and will allow us to progress our major growth projects towards completion while continuing the transformation of our Heavy Oil and Western Canada businesses.

This year Husky is celebrating its 75th anniversary, a remarkable record of achievement that has seen the Company grow from a fledgling heavy oil producer in the Lloydminster region into one of Canada's largest integrated oil and gas companies.

We remain focused on execution and building on our momentum as we carry that torch forward.

Asim Ghosh

Our Business Results


Liwan subsea work


Sunrise steam generators

The five-year business plan Husky put into place in 2010 is delivering the intended results and has been supported by consistent execution across all segments. These results are leading to increased production, throughputs, earnings and cash flow. Midway through the five-year plan, the strategy is standing the test of time.

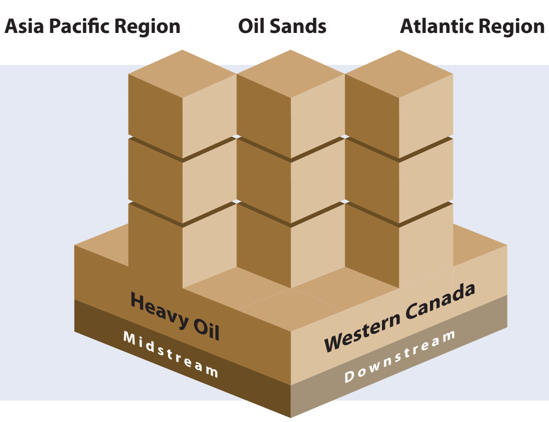
Delivering Production

The business plan the Company laid out in 2010 included a five-year compound annual production growth target of three to five percent. The plan recognized there would be uneven growth as the Company undertook maintenance programs and brought new projects on line. Production has kept pace with the plan, despite the impact of two scheduled offstations in the Atlantic Region, and in 2012 met guidance at 301,500 boe/day.

In Heavy Oil, the Pikes Peak South and Paradise Hill thermal projects came online ahead of schedule and delivered volumes beyond their design rates. The modular projects had a combined design capacity of 11,000 bbls/day but were producing 17,000 bbls/day by the end of the year. Based on production performance of a pilot well at Rush Lake, the Company sanctioned a 10,000 bbls/day thermal project and advanced planning on three additional commercial thermal projects. Overall, with new technologies like thermal development and horizontal wells, the Company expects to grow its total heavy oil production by approximately 36 percent by 2017.

The transformation of the Western Canada foundation towards a greater focus on resource plays picked up steam during the year, with total production from resource plays reaching more than 20,000 boe/day. This included approximately 7,000 barrels of oil per day, compared to 3,000 bbls/day in 2011.

Natural gas production was deliberately reduced to reallocate capital towards higher-return crude oil projects.



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


SeaRose FPSO


Hardisty Pipeline Terminal

The Company has a strong land position in Western Canada with more than two million acres in prospective oil and liquids-rich gas plays. In 2012, the Company was primarily active on the near-term Bakken, Viking and Cardium oil resource plays. Work also continued on longer-term projects in the emerging shale oil plays at the Rainbow Muskwa in northern Alberta and in the Canol at Slater River in the Northwest Territories.

Production guidance for 2013 has been raised to a range of 310,000 to 330,000 barrels per day, reflecting in part the growth in Heavy Oil and the return of the *SeaRose* and *Terra Nova* FPSOs from their respective 2012 offstations.

In anticipation of near-term first production from the Asia Pacific Region and the Oil Sands and a robust pipeline of development projects, the five-year compound annual growth rate target has been increased to five to eight percent for 2012-2017.

Reserves Growth on Target

Reserves growth, an indication of the future potential of the Company, continued to outpace production in 2012 with an average proved reserves replacement ratio over the past two years of 175 percent. Including economic revisions, the average proved two-year reserves replacement ratio was 149 percent, ahead of the five-year average target of 140 percent per year.

The Company added 130 million barrels of oil equivalent of proved reserves during the year.

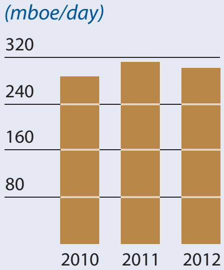
As of the end of 2012, the Company had total proved reserves before royalties of 1.2 billion boe, probable reserves of 1.7 billion boe and best estimate contingent resources of 13.1 billion boe. The Company's oil sands portfolio was responsible for 11.6 billion boe of the best estimate contingent resources total.

Capturing Margins and Increasing Throughputs

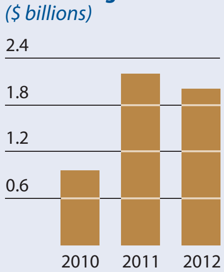
Commodity markets weathered another year of depressed Western Canada pricing in 2012, while product differentials between West Texas Intermediate, Brent-priced crude and heavy-light crude increased along with U.S.-Canada location discounts.

The focused integration of the Company's Downstream operations helped to mitigate differentials by capturing near-Brent pricing over the year for its Heavy Oil and Western Canada production.

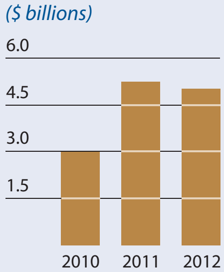
Production
(mboe/day)



Net Earnings
($ billions)



Cash Flow
($ billions)




Lima Refinery


Pikes Peak South Thermal Project

Reliability across all business segments underscored that performance by capturing further margins. Downstream throughputs averaged 327 mbbls/day from 317 mbbls/day in 2011, with record monthly outputs achieved at the Lloydminster Upgrader. At the Lima Refinery, construction was finalized on a new 20,000 barrels per day kerosene hydrotreater to increase on-road diesel and jet fuel production.

The average realized price the Company received for its light, medium, heavy oil, bitumen and natural gas liquids production in 2012 was $75.50 per barrel, compared to the average realized price in 2011 of $83.73 per barrel.

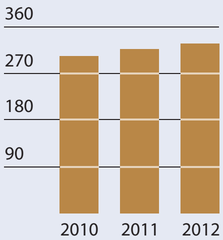
The Company worked to improve netbacks over the year. This included a greater focus on oil plays and a planned reduction in dry gas production. As the Heavy Oil foundation is rejuvenated through more thermal production and horizontal drilling, the Company is realizing value from operating costs of approximately $10-$12 per barrel for horizontal wells compared to approximately $20 per barrel for CHOPS technology. In the Atlantic Region, new satellite developments are underway in the White Rose reservoir to maintain stable, high-netback production while setting the stage for future growth opportunities.

Improving Capital Efficiency

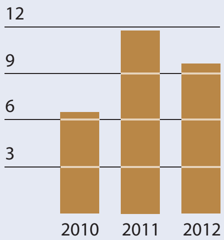
The Company set a target of increasing return on capital employed (ROCE) by five percentage points by the end of its plan period in 2015. It made solid progress against this goal in 2012 with a rate of approximately 9.5 percent, compared to 6.4 percent in 2010. This takes into account the substantial investments being made in the Liwan Gas Project and Sunrise Energy Project as they near completion in the 2013-2014 timeframe.

The ROCE performance metric was further refined in 2012 to include return on capital in use (ROCU), a non-GAAP measure used by the Company to gauge the capital productivity of developments currently in production. This provides a better yardstick to measure and maximize shareholder value in a growing company. In 2012, Husky achieved a 12.7 percent return on capital in use, compared to 8.4 percent in 2010.

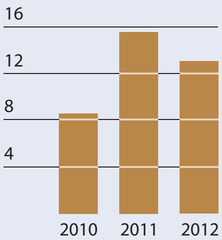
Total Downstream Throughputs *(mbbls/day)*



Return On Capital Employed *(%)*



Return On Capital In Use *(%)*



Slater River Project, N.W.T.

Sunrise construction

The execution of the Pikes Peak South and Paradise Hill thermal projects demonstrated the Company's focus on increasing ROCU through shorter life, high-return projects to balance longer-term developments. Both projects were brought online for about eight percent less than budgeted and six and four months ahead of schedule, respectively.

Improving Safety

The Company's focus on operational integrity is rooted in attention to process and occupational safety throughout all of its operations.

Good safety drives increased reliability and in turn, leads to better results, and this was once again demonstrated in 2012.

A prime example was the *SeaRose* FPSO offstation, which involved approximately half a million person-hours over five weeks. Reflecting strong planning and execution management, the offstation was completed ahead of schedule without a safety incident, allowing the vessel to return to service and ramp up production ahead of schedule.

The commitment to process and occupational safety was further reinforced during planned turnarounds at the Company's upgrader and refineries in 2012, contributing to an effective capacity rate of more than 94 percent for Downstream assets.

A senior management position for process and occupational was created to deliver the Husky Operational Integrity Management System (HOIMS) program, which is designed to identify, eliminate or mitigate potential hazards and risks. With HOIMS, a single set of standards that enables Husky to further improve its safety metrics and share best practices across the organization.

Delivering Value

Two years after the establishment of its balanced growth strategy, Husky is consistently delivering against its performance targets. As the Liwan Gas Project nears completion in late 2013/early 2014 and the Sunrise Energy Project advances according to plan towards first production in 2014, the Company is approaching the growth part of its balanced growth equation.

Husky remains committed to maintaining this execution track record in 2013 and is well positioned to carry through on its objective to increase the value delivered to shareholders.

> **We remain on course and are building momentum towards achieving the goals we established in our corporate strategy two years ago.**
>
> — Asim Ghosh

Management's Discussion and Analysis


Ansell liquids-rich gas production


Safety briefing

February 27, 2013

Contents

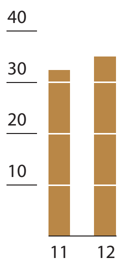
Indonesia exploration

Sunrise drilling

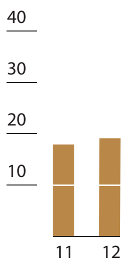
1.0 Financial Summary

1.1 Financial Position

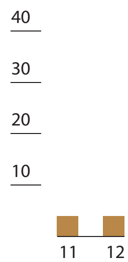
Total Assets
($ billions)



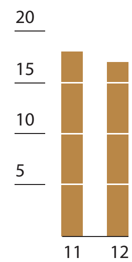
Total Equity
($ billions)



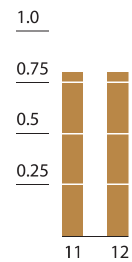
Total Long-term Debt
($ billions)



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

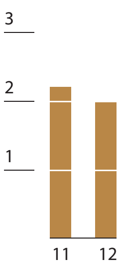


Debt to Cash Flow[(1)]
(times)

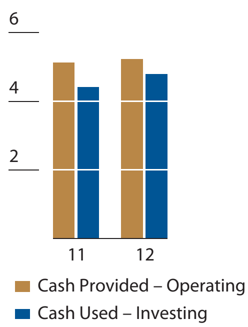


1.2 Financial Performance

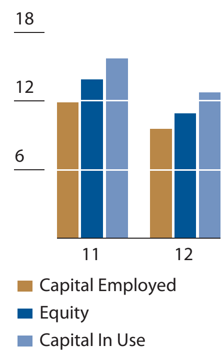
Net Earnings
($ billions)



Cash Flow
($ billions)



Return[(1)]
(%)

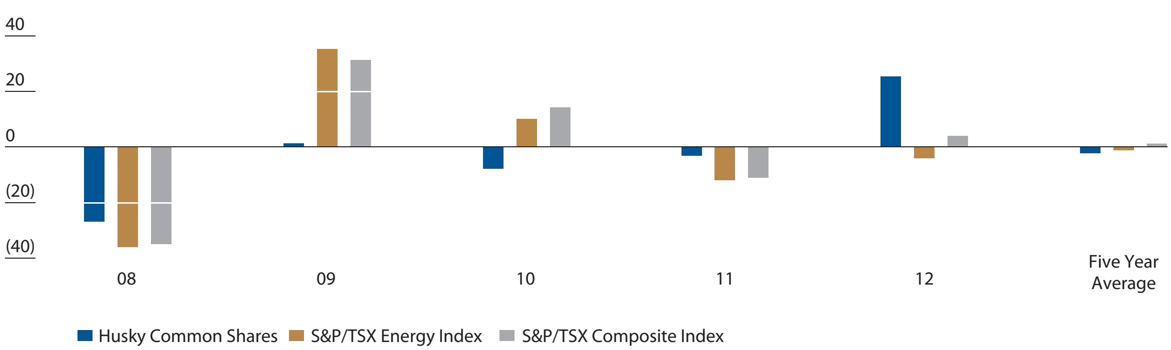


[(1)] *Debt to capital employed, debt to cash flow, return on equity, return on capital employed and return on capital in use constitute non-GAAP measures. (Refer to Section 11.3)*

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)	**2012**	2011	2010
Gross revenues	**23,128**	23,082	18,085
Net earnings by segment[(1)]			
Upstream	**1,320**	1,711	861
Midstream	**–**	–	160
Downstream	**895**	813	160
Corporate	**(193)**	(300)	(187)
Eliminations	**–**	–	(47)
Net earnings	**2,022**	2,224	947
Net earnings per share – basic	**2.06**	2.40	1.11
Net earnings per share – diluted	**2.06**	2.34	1.05
Ordinary dividends per common share	**1.20**	1.20	1.20
Dividends per cumulative redeemable preferred share, series 1	**1.11**	0.87	–
Cash flow from operations[(2)]	**5,010**	5,198	3,072
Total assets	**35,140**	32,426	28,050
Other long-term financial liabilities	**331**	342	102
Long-term debt including current portion	**3,918**	3,911	4,187
Total non-current financial liabilities	**12,886**	11,263	10,907
Cash and cash equivalents	**2,025**	1,841	252
Return on equity *(percent)*[(2)(3)]	**10.9**	13.8	6.7
Return on capital in use (percent)[(2)(4)]	**12.7**	15.6	8.4
Return on capital employed *(percent)*[(2)(5)]	**9.5**	11.8	6.4

(1) During the first quarter of 2012, the Company completed an evaluation of the activities of the former Midstream segment as a service provider to the Upstream and Downstream operations. As a result, the segmented financial information for activities within the previously reported Midstream segment are presented under Upstream or Downstream segments to align with how the Company's results are assessed by management. Prior period information relating to 2011 has been restated to conform with current year presentation. The 2010 information has not been restated.

(2) Cash flow from operations and financial ratios constitute non-GAAP measures. (Refer to Section 11.3)

(3) Return on equity equals net earnings divided by the two-year average shareholder's equity. (Refer to Section 11.3)

(4) Return on capital in use equals net earnings plus after tax interest expense divided by the two-year average of capital employed less any capital invested in assets that are not generating cash flows.(Refer to Section 11.3)

(5) Return on capital employed equals net earnings plus after-tax finance expense divided by the two-year average of long-term debt including long-term debt due within one year plus total shareholders' equity.(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.

During 2012, the Company completed an evaluation of activities of the Company's former Midstream segment as a service provider to the Upstream or Downstream operations. As a result, and consistent with the Company's strategic view of its integrated business, the previously reported Midstream segment activities are aligned and reported within the Company's core exploration and production, or within upgrading and refining businesses. The Company believes this change in segment presentation allows management and third parties to more effectively assess the Company's performance. The current period and 2011 year results have been revised to conform to the new segment presentation.

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 ("ASP") are being field tested and advanced, while techniques that have been in practice for several decades continue to be optimized;
- A large position in Western Canada gas resource plays with approximately 1,000,000 net acres associated with both liquids-rich and dry gas positions;
- Active oil resource play portfolio of approximately 800,000 net acres focusing in the Bakken, Viking, Cardium, Rainbow Muskwa and Canol shale formations;
- 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 first production expected in 2014. Phase 1 is approximately 65% complete and is expected to produce approximately 60,000 bbls/day (30,000 bbls/day net Husky share). Sunrise will use proven steam-assisted gravity drainage ("SAGD") technology, keeping site disturbance to a minimum. Regulatory approval is in place to expand the project to 200,000 bbls/day (100,000 bbls/day net Husky share) and planning has advanced for the 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 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 on Block 29/26 in the South China Sea has been approved by the Chinese Government and is now more than 80% complete and on track to achieve planned first production in late 2013/early 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 natural gas and natural gas liquids fields;
- In 2012, Husky signed a joint venture contract with CPC Corporation, Taiwan for 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 68.9% 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;
- Husky holds ownership interests in the producing oil fields at Terra Nova, White Rose and its satellites and North Amethyst. Husky also has a large portfolio of significant discovery and exploration licences offshore Newfoundland and Labrador and offshore Greenland (collectively referred to as the "Atlantic Region"). The offshore exploration and development program is focused in the Jeanne d'Arc Basin and the Flemish Pass.
- Integrated heavy oil pipeline systems in the Lloydminster producing region;
- The Infrastructure and Marketing business managed third-party commodity trading volumes of approximately 180 mboe/day in 2012 and managed access to capacity on third-party pipelines and storage facilities in both Canada and the United States and natural gas storage in excess of 45 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;
- Refinery at Lima, Ohio and a 50% interest in the BP-Husky Refinery in Toledo, Ohio, each with a gross crude oil throughput capacity of 160 mbbls/day;
- 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 capacity at plants located in Lloydminster, Saskatchewan and Minnedosa, Manitoba; and
- Major regional motor fuel marketer with 512 retail marketing locations as at December 31, 2012 including bulk plants and travel centres with strategic land positions in Western Canada and Ontario.

3.0 The 2012 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 2012, that are anticipated to continue to impact the industry to varying degrees into 2013 and beyond. Business factors impacting Husky's industry during 2012 include but are not limited to the following:

- The proliferation of shale oil plays in the Bakken, the Permian and the Eagle Ford have outpaced EIA production forecasts for the U.S.;
- Key takeaway capacity constraints still exist for Western Canadian crudes in North America causing a widening of differentials of these crudes relative to key benchmarks such as West Texas Intermediate ("WTI");
- Pricing benchmarks for crude oil and natural gas and underlying market supply and demand drivers;
- Political unrest in the Middle East have caused continued unplanned production outages having an impact on crude oil benchmark pricing;
- Expected continued production growth in both U.S. shale oil formations and from the Western Canadian oil sands with approximately 260 bitumen projects in progress at various stages from research to exploration, development and completion;
- Industry advancement in alternate and improved extraction methods have rapidly evolved North American and international on-shore and offshore activity;
- All-time high U.S. natural gas inventories with increased production from shale gas and liquids-rich gas plays have resulted in downward pressure on North American natural gas pricing;
- 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, 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 gas and natural gas and related products. For a discussion on Risks and Risk Management see Section 7.0 and the 2012 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.

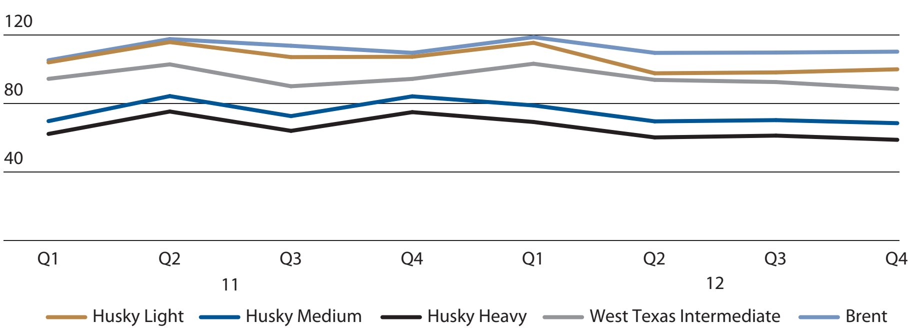
Average Benchmarks		2012	2011
WTI crude oil	*(U.S. $/bbl)*	**94.21**	95.12
Brent crude oil	*(U.S. $/bbl)*	**111.54**	111.27
Canadian light crude 0.3% sulphur	*($/bbl)*	**86.57**	95.32
Western Canada Select @ Hardisty	*(U.S. $/bbl)*	**73.18**	77.97
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**62.89**	67.61
NYMEX natural gas	*(U.S. $/mmbtu)*	**2.79**	4.04
NIT natural gas	*($/GJ)*	**2.28**	3.48
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**21.46**	17.44
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**31.36**	25.26
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**27.63**	24.65
U.S./Canadian dollar exchange rate	*(U.S. $)*	**1.001**	1.011
Canadian Equivalents			
WTI crude oil	*($/bbl)*	**94.12**	94.09
Brent crude oil	*($/bbl)*	**111.43**	110.06
WTI/Lloyd crude blend differential	*($/bbl)*	**21.44**	17.25
NYMEX natural gas	*($/mmbtu)*	**2.79**	4.00

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, including 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 receive 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.

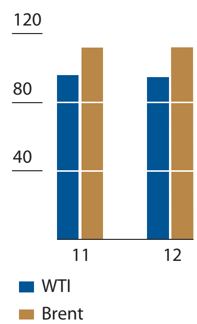
The Downstream segment is heavily impacted by the price of crude oil and natural gas. The largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil. In the upgrading business segment, heavy crude oil feedstock is processed into light synthetic crude oil. Husky's U.S. refining operations process a mix of different types of crude oil from various sources but are 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 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)



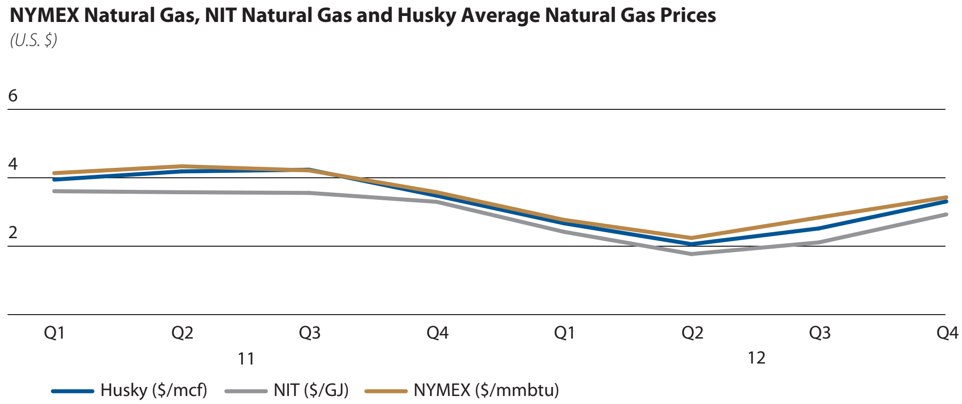
Average WTI and Brent
(U.S. $/bbl)

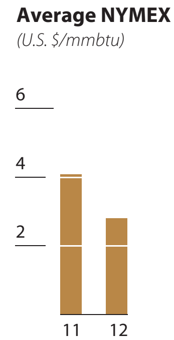


The price Husky receives for production from Western Canada is primarily driven by changes in the price of WTI and discounts or premiums to Western Canadian crude prices while the majority of the Company's production in the Atlantic Region and the Asia Pacific Region is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2012 at U.S. $94.19/bbl compared to U.S. $98.83/bbl on December 31, 2011, and averaged U.S. $94.21/bbl in 2012 compared with U.S. $95.12/bbl in 2011. The price of Canadian light crude ended 2012 at $74.32/bbl compared to $98.19/bbl on December 31, 2011 and averaged $86.57/bbl in 2012 compared with $95.32/bbl in 2011. The price of Brent ended 2012 at U.S. $111.66/bbl, compared to U.S. $106.51/bbl on December 31, 2011, and averaged U.S. $111.54/bbl in 2012 compared with U.S. $111.27/bbl in 2011.

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 2012, 54% of Husky's crude oil production was heavy crude oil or bitumen compared with 47% in 2011. The increase in the 2012 heavy oil to total crude oil production weighting was due to lower light crude oil production from the Atlantic Region where two planned offstation turnarounds for the SeaRose and Terra Nova floating, production, storage and offloading vessels ("FPSO") were completed combined with increased production from new heavy oil thermal projects. The light/heavy crude oil differential averaged U.S. $21.46/bbl or 23% of WTI in 2012 compared to U.S. $17.44/bbl or 18% of WTI in 2011.

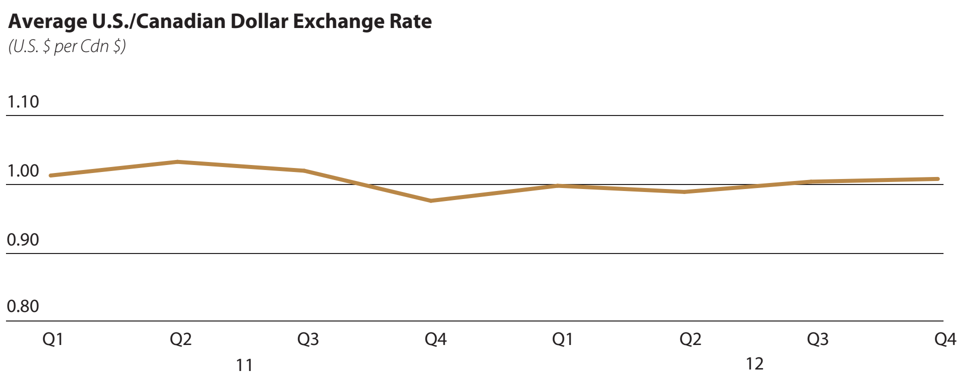
Natural Gas

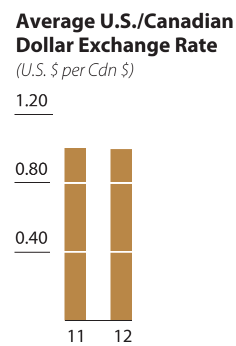




In 2012, 31% of Husky's total oil and gas production was natural gas compared with 32% in 2011. The near-month natural gas price quoted on the NYMEX ended 2012 at U.S. $3.35/mmbtu compared with U.S. $2.99/mmbtu at December 31, 2011. During 2012, the NYMEX near-month contract price of natural gas averaged U.S. $2.79/mmbtu compared with U.S. $4.04/mmbtu in 2011.

Foreign Exchange



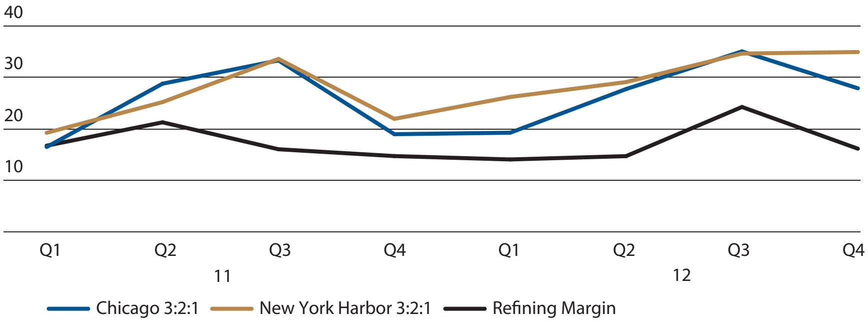


The majority of the Company's revenues from the sale of oil and gas commodities receive prices determined by reference to U.S. benchmark prices. The majority of the Company's expenditures are in Canadian dollars. A decrease in the value of the Canadian dollar relative to the U.S. dollar increases the 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. In addition, changes in foreign exchange rates impact the translation of the foreign operations of the U.S. Downstream segment and the Asia Pacific Region.

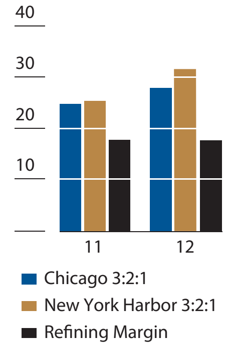
The Canadian dollar ended 2011 at U.S. $0.983 and closed at U.S. $1.005 on December 31, 2012. In 2012, the Canadian dollar averaged U.S. $1.001 weakening by 1% compared with U.S. $1.011 during 2011. In 2012, the price of WTI in U.S. dollars decreased by 1% and nil in Canadian dollars when compared to 2011 with the weakening of the Canadian dollar versus the U.S. dollar offsetting the movement in crude oil prices.

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.

During 2012, the New York Harbor 3:2:1 refining crack spread averaged U.S. $31.36/bbl compared with U.S. $25.26/bbl in 2011 and the Chicago 3:2:1 crack spread averaged U.S. $27.63/bbl in 2012 compared with U.S. $24.65/bbl in 2011.

The following table is indicative of the relative annualized effect on pre-tax earnings and net earnings from changes in certain key variables in 2012. The table below shows what the effect would have been on 2012 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2012. 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	2012 Average	Increase	Effect on Pre-tax Earnings[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	**94.21**	*U.S. $1.00/bbl*	**66**	**0.07**	**49**	**0.05**
NYMEX benchmark natural gas price[5]	**2.79**	*U.S. $0.20/mmbtu*	**24**	**0.02**	**18**	**0.02**
WTI/Lloyd crude blend differential[6]	**62.89**	*U.S. $1.00/bbl*	**(16)**	**(0.02)**	**(12)**	**(0.01)**
Canadian light oil margins	**0.044**	*Cdn $0.005/litre*	**16**	**0.02**	**12**	**0.01**
Asphalt margins	**22.90**	*Cdn $1.00/bbl*	**9**	**0.01**	**7**	**0.01**
New York Harbor 3:2:1 crack spread[7]	**31.36**	*U.S. $1.00/bbl*	**53**	**0.05**	**34**	**0.03**
Exchange rate (U.S. $ per Cdn $)[3][8]	**1.001**	*U.S. $0.01*	**(55)**	**(0.06)**	**(41)**	**(0.04)**

(1) Excludes mark to market accounting impacts.
(2) Based on 982.2 million common shares outstanding as of December 31, 2012.
(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 & 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 resource plays, directing capital into liquids-rich natural gas plays and expanding thermal and horizontal drilling in heavy oil. Approximately two-thirds of Upstream production is oil-weighted. Husky is advancing its oil resource play position with activities in the Bakken, Viking, Cardium, Lower Shaunavon, Muskwa and Canol formations, with approximately 800,000 net acres of oil resource play inventory. Husky also has a large position in Western Canada gas resource plays, with approximately 1,000,000 net acres associated with both liquids-rich and dry gas positions.

Husky has an extensive portfolio of oil sands leases, encompassing 2,500 square kilometers in northern Alberta. Husky has advanced the development of the Sunrise Energy Project, which is a multiple stage, in-situ oil sands development with first phase construction and drilling having commenced in 2011. The first phase, which represents a $2.7 billion investment, is expected to produce approximately 60,000 barrels per day with anticipated first production beginning in 2014. Husky's working interest is 50%. Sunrise will use proven steam-assisted gravity drainage ("SAGD") technology, keeping site disturbance to a minimum.

The Asia Pacific Region consists of the Wenchang oil field, the Liwan Gas Project ("Block 29/26") located offshore China and the Madura Strait block BD, MDA and MBH development fields offshore Indonesia. The Liwan 3-1 field in Block 29/26, located approximately 300 kilometers southeast of Hong Kong, is an important component of the Company's near term production growth strategy and a key step in accessing the burgeoning energy markets in Hong Kong and Mainland China. Husky has partnered with China National Offshore Oil Corporation ("CNOOC") on the development, with first gas production anticipated in late 2013/early 2014. In addition to the producing Wenchang oil field, the natural gas discoveries on Block 29/26 and growth opportunities in Indonesia, including the BD, MDA and MBH developments in the Madura Strait Production Sharing Contract ("PSC"), represent growth areas for Husky in the Asia Pacific Region.

The Atlantic Region continues to be a focus area with current production of approximately 48,000 bbls/day of crude oil. The Company holds interests in eight Production Licences, 17 Exploration Licences and 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. Husky also holds significant exploration acreage in the the Atlantic Region. Work is progressing to identify 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.

4.2 Downstream

Downstream supports heavy oil and oil sands production and makes prudent reinvestments in respect of feedstock, product and market access feasibility. 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. The Company also plans to expand terminal pipeline access and product storage opportunities to enhance market access.

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 foundational 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 of Canada. 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 2012 Capital Program supported the repositioning of 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 at the end of 2012 was approximately 20,000 bbls/day, representing a 70% increase compared to 2011.

Oil Resource Plays
During 2012, the Company continued to advance exploration and development projects on its extensive oil resource land base of approximately 800,000 net acres. A total of 93 horizontal wells and two vertical wells were drilled and 78 horizontal wells were completed in 2012. It is anticipated that up to 88 wells will be drilled during the 2013 oil resource drilling program.

The following table summarizes the oil resource play drilling and completion activity for the year ended December 31, 2012:

Oil Resource Plays[(1)]

Project	Location	Year ended December 31, 2012 Gross Wells Drilled	Gross Wells Completed
Oungre Bakken	S.E. Saskatchewan	22	21
Lower Shaunavon	S.W. Saskatchewan	4	4
Viking [(2)]	Alberta and S.W. Saskatchewan	50	45
N. Cardium	Wapiti, Alberta	5	5
Rainbow Muskwa	Northern Alberta	12	3
Slater River	Northwest Territories	2	–
Total Gross		95	78
Total Net		89	74

(1) *Excludes service/stratigraphic test wells for evaluation purposes. All activity was horizontal except Slater River N.W.T. , vertical wells.*
(2) *Viking is comprised of project activity at Redwater in central Alberta, Alliance in Southeastern Alberta and drilling in Southwestern Saskatchewan.*

At the Rainbow Muskwa play, the first horizontal shale oil well was placed on production to a single well battery and is being monitored.

At the Slater River Project in the Northwest Territories, the Company drilled two vertical wells and a 220 square kilometre three-dimensional ("3-D") seismic survey was completed.

Liquids-Rich Gas Resource Plays

The following table summarizes the liquids-rich gas drilling and completion activity for the year ended December 31, 2012:

Liquids-Rich Gas Resource Plays[(1)]

Project	Location	Year ended December 31, 2012 Gross Wells Drilled	Gross Wells Completed
Ansell	West Central Alberta	18	53
Duvernay	West Central Alberta	4	3
Montney	West Central Alberta	1	2
Total Gross		23	58
Total Net		21	56

(1) Excludes service/stratigraphic test wells for evaluation purposes. Liquids-rich gas drilling activity in 2012 was mainly horizontal wells. Completion activity includes legacy vertical wells. Types of drilling include Wilrich and Cardium horizontals and vertical single and multi-zone wells.

The liquids-rich gas formations at Ansell in west central Alberta continue to be a key area of focus with 55 Cardium and three Wilrich wells on production at the end of 2012.

At the Duvernay play in Kaybob, Alberta, a third horizontal well was completed in 2012 and commenced production in January 2013. In December 2012, the first well on a four well pad of horizontal wells was spud and drilling continues in 2013. A previously completed well is expected to be tied-in during the first quarter of 2013.

Alkaline Surfactant Polymer Floods

Construction was completed on the Fosterton, Saskatchewan Alkaline Surfactant Polymer ("ASP") facility in 2012. Husky is the operator and holds a 62% working interest in this project. Chemical injection has commenced with initial production response expected in the second half of 2013.

Heavy Oil

Production commenced in the second quarter of 2012 ahead of schedule at both the Pikes Peak South and Paradise Hill heavy oil thermal projects and has ramped up to levels exceeding the combined 11,500 bbls/day design rate capacity. Average production levels of approximately 12,000 bbls/day at Pikes Peak South and 5,000 bbls/day at Paradise Hill heavy oil thermal projects were achieved during the fourth quarter of 2012.

Construction is approximately 40% complete at the 3,500 bbls/day Sandall thermal development project and initial drilling has commenced. First production is scheduled in 2014.

Design and initial site work is continuing at the 10,000 bbls/day Rush Lake commercial project with first production anticipated in 2015. Production performance from the first single well pair pilot is in line with expectations and a second well pair pilot is planned to commence production in the second quarter of 2013. Initial planning is ongoing for three additional commercial thermal projects.

The Company advanced its horizontal drilling program in 2012 with the completion of 144 wells. Based on the positive performance of previous horizontal drilling programs, Husky is continuing this program by planning to drill approximately 140 wells in 2013. The Company also drilled 250 gross cold heavy oil production with sand ("CHOPS") wells during 2012. In 2013, 200 CHOPS wells are planned.

A carbon dioxide ("CO_2") capture and liquefaction plant at the Lloydminster Ethanol Plant was commissioned and started producing liquid CO_2 in March 2012. The liquefied CO_2 from this facility is used in the ongoing solvent EOR piloting program.

Asia Pacific Region

China

The Overall Development Plan ("ODP") for the Liwan Gas Project development on Block 29/26 in the South China Sea has been approved by the Chinese Government. The development project is now more than 80% complete and remains on track to achieve planned first production in late 2013/early 2014.

Two further upper completions in the Liwan 3-1 gas field were installed and flow tested successfully at the expected production rates bringing the total of fully ready production wells to seven. All nine subsea production trees have been installed on the wells and eight associated upper completions have also been installed.

At the end of 2012, approximately 90 kilometers of the two 79-kilometer deep water pipelines connecting the gas field to the central platform have been laid and approximately 190 kilometers out of 261 kilometers of shallow water pipeline have been laid from the central platform to the onshore gas plant. Pipe laying activity is planned to resume in 2013.

The completed jacket for the shallow water central platform was transported from the Qingdao construction yard in Eastern China to its final offshore location in the South China Sea and was successfully launched from the transport barge onto the ocean floor on August 30, 2012. Piling to anchor the feet of the jacket to the seabed has also been completed. Fabrication of the platform topsides is progressing and the floatover of the topsides for the central platform is planned for mid-2013.

The 850-tonne Monoethylene Glycol Recovery Unit has been delivered to the Qingdao, Eastern China topsides construction site and the approximately 850 tonne unit has been elevated and set into its final installation position on the upper deck. Generators and compressors have also been positioned on the deck. Construction of control rooms, living areas and other facilities are in their final stages.

The contract for the use of the West Hercules deepwater drilling rig expired in July 2012. The deepwater semi-submersible drilling rig, Hai Yang Shi You 981, has been contracted to continue the deepwater development project.

Construction of the onshore gas plant is also progressing on schedule. Site preparations and foundations are largely complete including the completion of a seawall on the eastern side of the site. Nine of ten spherical liquids storage tanks are in place and the construction of pipe racks for transporting gas through the site is progressing. Construction of control and administrative buildings as well as living areas has commenced.

Development of the single well Liuhua 34-2 field is planned to proceed in parallel with, and be tied into the development of, the Liwan 3-1 field. Front end engineering design (“FEED”) for the development of the Liuhua 29-1 gas field has now been completed, and the ODP is being prepared. Negotiations for the sale of the gas from the Liuhua 34-2 and Liuhua 29-1 fields are ongoing.

On Block 63/05 in the Qiongdongnan Basin, Husky and CNOOC have agreed to the termination of the contract after completion of the first phase of the exploration period. Accordingly, the Company has no further obligation with respect to this block.

Taiwan

In December, Husky signed a joint venture contract with CPC Corporation, Taiwan for an exploration block in the South China Sea. The exploration block is located 100 kilometers southwest of the island of Taiwan and covers approximately 10,000 square kilometers. 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. Under the joint venture contract, Husky has an obligation to carry out 2-D seismic surveys within the first two years, with options to carry out 3-D seismic surveys and to drill at least one exploration well in subsequent exploration periods.

Indonesia

The 2012 exploration drilling program on the Madura Strait Block concluded in October with four new discoveries made as a result of a five well exploration drilling program. These discoveries are now under evaluation for commercial development.

The development plan for a combined MDA and MBH development project was approved in 2013 by SKK Migas, the industry regulator. As agreed with the regulator, a re-tender process for the BD field FPSO was conducted and pre-qualification responses are being evaluated. First gas from the Madura Strait Block is anticipated in the 2015 time frame.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages. During 2012, drilling of the planned SAGD horizontal well pairs for Phase 1 was completed and site construction and equipment installations were substantially advanced. Phase 1 of the 60,000 bbls/day (30,000 bbls/day net) project remains on track for first production in 2014.

Substantial cost certainty on the first phase of the Sunrise Energy Project was achieved in 2012 with the conversion to a lump sum contract for the Central Processing Facility ("CPF"). Over 85% of the costs for Phase 1 are now fixed and incorporate all significant contract conversions and facility and efficiency design improvements. To date, approximately 65% of the project's total cost estimate has been spent.

The CPF is approaching 50% completion with piling substantially completed and foundation work proceeding at the site. Major equipment continues to be delivered and placed into position with approximately half of the modules fabricated and moved to the site. Construction for the field facilities is now more than 80% complete with significant activity currently underway, including pipelining in the field and fabrication in the module shops.

Development work continues on the next phase of the project with the Design Basis Memorandum expected to be completed in 2013. Regulatory approvals are in place for a total of 200,000 bbls/day (100,000 bbls/day net).

Tucker

Production rates at Husky's Tucker Oil Sands Project have remained stable at approximately 10,000 bbls/day in 2012. Production from the Grand Rapids pilot well pair commenced in the first quarter of 2012. Based on positive performance from the pilot, Husky initiated drilling of an additional five Grand Rapids well pairs in November 2012 with production expected in 2013.

Saleski

A regulatory application for the bitumen carbonates pilot is anticipated to be filed in 2013.

McMullen

During 2012, seven evaluation wells were drilled and 32 slant wells were drilled, equipped and placed on production in the cold production development project. At the end of 2012, production from McMullen was 4,600 bbls/day and development activity is continuing.

Atlantic Region

White Rose Field and Satellite Extensions

Development continued at the White Rose field with the addition of an infill production well which was brought online in August 2012. As at the end of 2012, a total of 22 wells, including nine producing wells, ten water injectors, and three gas injectors were in operation. Future infill wells are being evaluated.

The Husky-operated SeaRose FPSO completed its planned maintenance dry-docking in Belfast, Northern Ireland with zero lost-time incidents and ahead of schedule with production resuming on August 13, 2012 approximately three weeks ahead of plan. Production from the White Rose field and satellite extensions returned to expected levels by the end of the third quarter of 2012.

A development plan amendment was filed with the regulator in October 2012 to facilitate development of resources at the South White Rose Extension. This region will be developed via subsea tieback to the SeaRose FPSO, similar to the North Amethyst satellite extension. A new drill centre to support the development was excavated during the third quarter of 2012 and drilling of a gas injection well is scheduled to commence in 2013.

At North Amethyst, development continued in 2012 with the addition of the fourth production well. At the end of 2012, four production and three water injection wells were on-line. An additional water injector well is scheduled to be drilled in 2013. An application to develop the deeper Hibernia formation at North Amethyst is progressing through the regulatory review process.

A water injection well to support the existing producing well for the West White Rose pilot project was completed and brought online during 2012. Evaluation of a wellhead platform to facilitate future development continued during 2012 and supporting regulatory filings were submitted for an environmental assessment of the concept. A decision on a preferred development option is expected in 2013.

Drilling of the Searcher prospect in the southern Jeanne D'Arc Basin did not encounter commercial hydrocarbons and the well was expensed in 2012.

Husky and Seadrill entered into a five-year contract for the use of Seadrill's West Mira rig, a new harsh environment semi-submersible rig currently being built and expected to be completed in 2015.

Atlantic Exploration

The Company was awarded exploration rights to a 208,899 hectare parcel of land offshore Newfoundland during the November 2012 licencing round. The licence is located in the Flemish Pass and is east of and adjacent to existing land holdings in the Jeanne d'Arc Basin. Husky has a 40% working interest and future exploration is currently being evaluated.

The Company plans to participate in a number of operated and non-operated exploratory wells in the Atlantic Region during the 2013/2014 timeframe. The first well in this program is a partner-operated exploration well southeast of the Mizzen discovery located in the Flemish Pass.

Offshore Greenland

A two-year extension was received on the initial phase of the exploration program for two Husky-operated exploration licenses offshore Greenland. Geological and geophysical evaluations continued in 2012 and socio-economic study work is continuing.

Infrastructure and Marketing

Through the Company's continued development of both proprietary infrastructure and contracted pipeline commitments, it is able to access higher priced crude oil markets, partially offset Western Canadian differentials, and provide crude feedstock flexibility for the Lima Refinery, enabling the optimization of the crude slate in terms of quality, location and price.

A new 300,000 barrel tank at the Hardisty terminal was placed in service May 2012. The tank facilitates moving crude oil volumes to U.S. Petroleum Administration for Defense Districts ("PADD") II and III markets.

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 will increase on-road diesel and jet fuel production volumes, is approximately 80% complete and is expected to be operational in the first quarter of 2013.

BP-Husky Toledo Refinery
The Continuous Catalyst Regeneration Reformer Project at the BP-Husky Toledo Refinery is progressing as planned. Mechanical completion was achieved in the fourth quarter of 2012 and start up is expected in the first quarter of 2013. 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

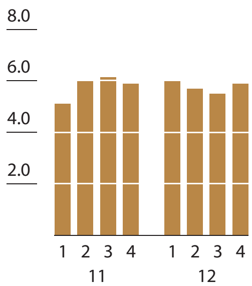
6.1 Segment Earnings

	Earnings (Loss) before Income Taxes		Net Earnings (Loss)		Capital Expenditures[1]	
($ millions)	**2012**	2011	**2012**	2011	**2012**	2011
Upstream[2]						
Exploration and Production	**1,324**	2,137	**979**	1,581	**4,106**	4,131
Infrastructure and Marketing	**457**	174	**341**	130	**54**	43
Downstream[2]						
Upgrading	**306**	202	**226**	150	**47**	55
Canadian Refined Products	**311**	295	**231**	220	**97**	94
U.S. Refining and Marketing	**695**	697	**438**	443	**313**	224
Corporate	**(257)**	(365)	**(193)**	(300)	**84**	71
Total	**2,836**	3,140	**2,022**	2,224	**4,701**	4,618

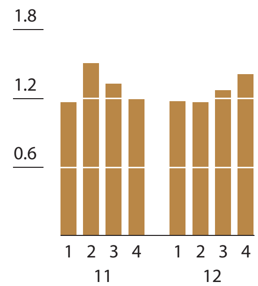
(1) Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.
(2) During the first quarter of 2012, the Company completed an evaluation of the activities of the former Midstream segment as a service provider to the Upstream and Downstream operations. As a result, the segmented financial information for activities within the previously reported Midstream segment are presented under Upstream or Downstream segments to align with how the Company's results are assessed by management. Prior period disclosures have been restated to conform with current year presentation.

6.2 Summary of Quarterly Results

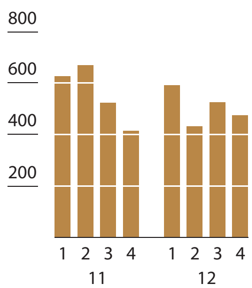
Gross Revenues
($ billions)



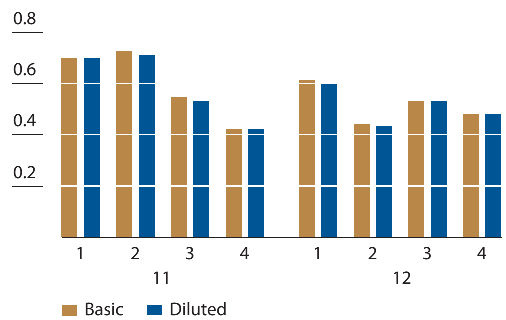
Cash Flow from Operations[(1)]
($ billions)



Net Earnings
($ millions)



Net Earning Per Share
($ per share)

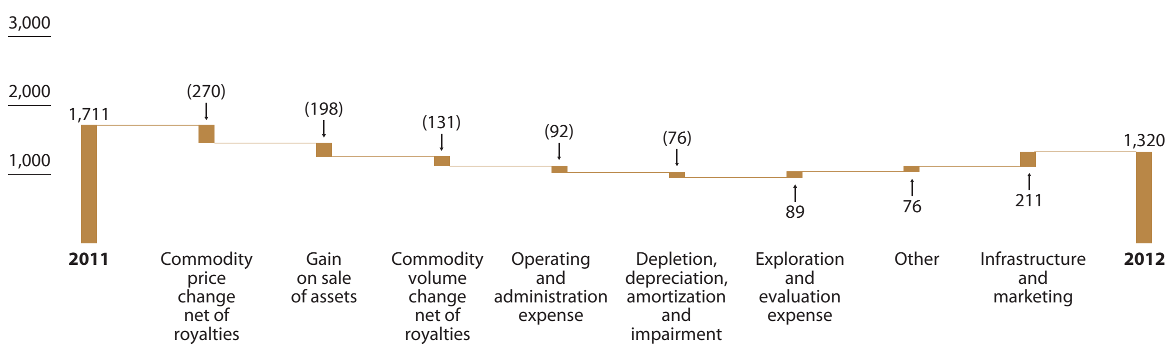


[(1)] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*

6.3 Upstream

2012 Total Upstream Earnings $1,320 million

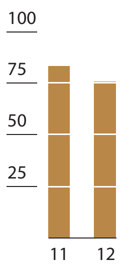
After Tax Earnings Variance Analysis
($ millions)



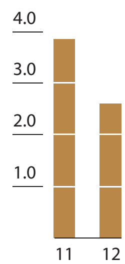
Exploration and Production Earnings Summary *($ millions)*	2012	2011
Gross revenues	**6,547**	7,519
Royalties	**(693)**	(1,125)
Net revenues	**5,854**	6,394
Purchases, operating, transportation and administration expenses	**2,091**	1,966
Depletion, depreciation, amortization and impairment	**2,121**	2,018
Exploration and evaluation expense	**350**	470
Other expenses (income)	**(32)**	(197)
Income taxes	**345**	556
Net earnings	**979**	1,581

Exploration and Production net earnings were $602 million lower in 2012 compared with 2011 primarily due to lower realized crude oil and natural gas prices and lower production in the Atlantic Region as a result of the planned maintenance of the SeaRose and Terra Nova FPSOs, partially offset by increased production in Western Canada from the new heavy oil thermal development projects at Paradise Hill and Pikes Peak South and lower exploration and evaluation expense. In addition, Husky realized after-tax gains on the sale of non-core assets and an asset swap of $198 million in 2011.

Average Price Realized
Crude Oil
($/bbl)



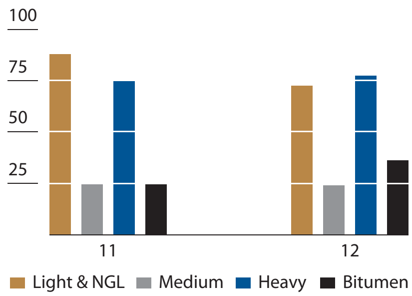
Average Price Realized
Natural Gas
($/mcf)



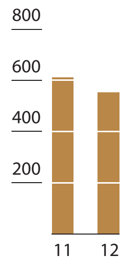
Average Sales Prices Realized	2012	2011
Crude oil *($/bbl)*		
Light crude oil & NGL	**99.22**	104.06
Medium crude oil	**71.51**	76.59
Heavy crude oil	**61.91**	68.13
Bitumen	**59.49**	65.75
Total average	**75.50**	83.73
Natural gas average *($/mcf)*	**2.60**	3.89
Total average *($/boe)*	**57.16**	64.17

During 2012, the average realized price decreased 10% to $75.50/bbl for crude oil, NGL and bitumen compared with $83.73/bbl during 2011 primarily due to lower Brent-based production from the Atlantic Region and wider Western Canada crude oil price differentials to WTI. Realized natural gas prices averaged $2.60/mcf during 2012 compared with $3.89/mcf in 2011, a decline of 33%.

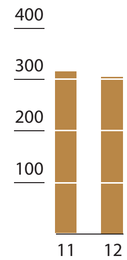
Production
Oil
(mbbls/day)



Production
Natural Gas
(mmcf/day)



Production
Combined
(mboe/day)



Daily Gross Production	2012	2011
Crude oil *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**30.1**	24.8
Medium crude oil	**24.1**	24.5
Heavy crude oil	**76.9**	74.5
Bitumen	**35.9**	24.7
	167.0	148.5
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**30.8**	48.7
Terra Nova – light crude oil	**3.0**	5.6
	33.8	54.3
China		
Wenchang – light crude oil & NGL	**8.4**	8.5
Crude oil *(mbbls/day)*	**209.2**	211.3
Natural gas *(mmcf/day)*	**554.0**	607.0
Total *(mboe/day)*	**301.5**	312.5

Upstream Revenue Mix *(Percentage of Upstream Net Revenues)*	2012	2011
Crude oil		
Light crude oil & NGL	**43%**	44%
Medium crude oil	**10%**	9%
Heavy crude oil	**28%**	26%
Bitumen	**12%**	8%
Crude oil	**93%**	87%
Natural gas	**7%**	13%
Total	**100%**	100%

During 2012, crude oil, bitumen and NGL production decreased by 2.1 boe/day or 1% compared with 2011, primarily due to lower production in the Atlantic Region as a result of the planned maintenance of the SeaRose and Terra Nova FPSOs, largely offset by increased production in Western Canada from the new heavy oil thermal development projects at Paradise Hill and Pikes Peak South.

Production from natural gas decreased by 53.0 mmcf/day or 9% in 2012 compared with 2011 due to natural reservoir declines in mature properties as capital investment is being directed to higher return oil and liquids-rich developments.

2013 Production Guidance and 2012 Actual

Gross Production	Guidance 2013	Year ended December 31, 2012	Guidance 2012
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	85 – 90	**72**	70 – 75
Medium crude oil	25 – 30	**24**	25 – 30
Heavy crude oil & bitumen	110 – 120	**113**	100 – 110
Crude oil & NGL *(mbbls/day)*	220 – 240	**209**	195 – 215
Natural gas *(mmcf/day)*	540 – 580	**554**	560 – 610
Total *(mboe/day)*	310 – 330	**302**	290 – 315

The Company's total production for the year ended December 31, 2012 was within production guidance set by the Company in 2011. Husky expects that production levels in 2013 will be higher compared to 2012 due to a full year of production from the Atlantic Region where the Company and its partners executed two major maintenance turnarounds of the SeaRose and Terra Nova FPSOs. In 2010, the Company set a compound annual production growth target of 3% to 5% through the plan period 2010-2015 and is on track to achieve that goal. In 2012, a new target was set for the plan period of 2012 to 2017 at an increased compound annual production growth rate of 5% to 8%.

Factors that could potentially impact Husky's production performance for 2013 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 11% of gross revenues in 2012 compared with 16% in 2011. Royalty rates in Western Canada averaged 10% in 2012 compared with 14% in 2011 due to lower natural gas prices and royalty credit adjustments. In the Atlantic Region, the average rate was 11% in 2012 compared with 17% in 2011 due to higher eligible costs associated with the SeaRose FPSO offstation and lower Terra Nova production which is subject to higher royalty rates. Royalty rates in the Asia Pacific Region averaged 24% in 2012 compared with 30% in 2011 mainly due to reductions in windfall profit taxes that became effective in November of 2011.

Operating Costs

($ millions)	**2012**	2011
Western Canada	**1,571**	1,485
Atlantic Region	**212**	174
Asia Pacific	**31**	25
Total	**1,814**	1,684
Unit operating costs *($/boe)*	**15.49**	14.01

Total operating costs increased to $1,814 million in 2012 from $1,684 million in 2011. Total Upstream unit operating costs in 2012 averaged $15.49/boe compared with $14.01/boe in 2011.

Operating costs in Western Canada increased to $15.45/boe in 2012 compared with $15.35/boe in 2011 primarily due to higher fuel and labour costs offset by higher heavy oil production, lower treating costs and decreased maintenance costs.

Operating costs in the Atlantic Region averaged $17.12/boe in 2012 compared with $8.75/boe in 2011. The increase was mainly due to higher maintenance costs and lower production as a result of the planned maintenance of the SeaRose and Terra Nova FPSOs.

Operating costs in the Asia Pacific Region averaged $10.08/boe in 2012 compared with $8.08/boe in 2011 due to higher maintenance, fuel, workover and helicopter costs.

Exploration and Evaluation Expenses

($ millions)	**2012**	2011
Seismic, geological and geophysical	**146**	170
Expensed drilling	**188**	245
Expensed land	**16**	55
Total	**350**	470

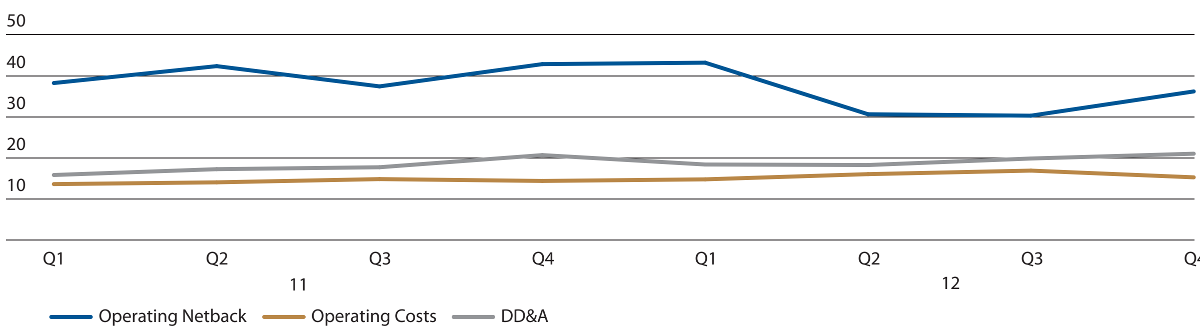
Total exploration and evaluation expenses decreased in 2012 to $350 million from $470 million in 2011. The decrease in seismic, geological and geophysical expense was primarily due to a shift in focus in 2012 to more development activities in Western Canada compared with 2011. Expensed drilling in 2012 primarily consisted of drilling in the Northwest Territories to gain a general understanding of geological formations, and costs related to the Searcher well in the Atlantic Region and the MAQ-1 well in the Madura Strait of Indonesia, neither of which encountered economic quantities of hydrocarbons. Expensed drilling and land costs in 2011 included acquisition and drilling costs expensed for properties in the Columbia River Basin located in the states of Washington and Oregon.

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

During 2012, total unit DD&A was $19.20/boe compared with $17.69/boe during 2011. The higher DD&A rate in 2012 was primarily due to a shift in focus by the Company to higher capital investments in oil and liquids-rich natural gas properties with higher netbacks than natural gas developments.

At December 31, 2012, capital costs in respect of unproved properties and major development projects were $6.1 billion compared with $5.3 billion at the end of 2011. 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 constitutes Husky's average price less royalties and operating costs on a per unit basis. Refer to Section 11.3.

Upstream Capital Expenditures

In 2012, Upstream Exploration and Production capital expenditures were $4,106 million. Capital expenditures were $2,288 million (56%) in Western Canada, $658 million (16%) in Oil Sands, $413 million (10%) in the Atlantic Region and $747 million (18%) in the Asia Pacific Region. Husky's major projects remain on budget and on schedule.

Upstream Capital Expenditures[1] *($ millions)*	2012	2011
Exploration		
Western Canada	**238**	233
Atlantic Region	**13**	2
Asia Pacific	**22**	168
	273	403
Development		
Western Canada	**2,029**	1,787
Oil Sands	**658**	263
Atlantic Region	**400**	258
Asia Pacific	**725**	546
	3,812	2,854
Acquisitions		
Western Canada	**21**	874
	4,106	4,131

(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:

	2012		2011	
Wells Drilled *(wells)*	Gross	Net	Gross	Net
Exploration				
Oil	**47**	**30**	50	40
Gas	**19**	**12**	24	24
Dry	**–**	**–**	3	3
	66	**42**	77	67
Development				
Oil	**775**	**715**	880	765
Gas	**23**	**17**	57	42
Dry	**5**	**4**	4	4
	803	**736**	941	811
Total	**869**	**778**	1,018	878

The Company drilled 778 net wells in the Western Canada, Heavy Oil and Oil Sands business units in 2012 resulting in 745 net oil wells and 29 net natural gas wells compared with 878 net wells resulting in 805 net oil wells and 66 net natural gas wells in 2011.

Capital expenditures for wells drilled in Western Canada increased substantially in 2012 compared with 2011 due to the increased focus on resource play development drilling in areas such as the liquids-rich gas resource play in Ansell, a larger number of horizontal wells drilled and more multi-stage fracture completions performed.

During 2012, Husky invested $2,288 million on exploration, development and acquisitions, including heavy oil, throughout the Western Canada Sedimentary Basin compared with $2,894 million in 2011. Property acquisitions totalling $21 million were completed in 2012 compared with $874 million in 2011. Investment in oil related exploration and development was $538 million and $500 million was invested in natural gas resource plays during 2012 compared with $591 million for oil and $359 million in natural gas in 2011.

In addition, $245 million was spent on production optimization and cost reduction initiatives in 2012. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $398 million.

Capital expenditures on heavy oil thermal projects, CHOPS drilling and horizontal drilling, were $586 million during 2012 compared to $587 million in 2011.

Oil Sands

During 2012, capital expenditures on Oil Sands projects increased to $658 million compared to $263 million in the same period in 2011 as Sunrise Phase 1 progressed and activity at the central processing facility and field facilities accelerated. In addition, the Company drilled 29 gross (15 net) evaluation wells for Phase 2 at the Sunrise Energy Project during 2012.

Atlantic Region

The following table discloses Husky's offshore Atlantic Region drilling activity during 2012:

Atlantic Region Offshore Drilling Activity

White Rose E-18-11	WI 68.875%	Development	Service/injector
North Amethyst G-25 7	WI 68.875%	Development	Production
White Rose B-07 11	WI 72.5%	Development	Production
Searcher C-87	WI 100%	Exploration	Stratigraphic

During 2012, $413 million was invested in Atlantic Region projects primarily on the continued development of the White Rose Extension Project including the West White Rose and North Amethyst satellite fields. A drill center was excavated at the South White Rose Extension and a temporary guide base was installed in 2012. In addition, one infill oil well was drilled in the White Rose field during 2012.

Asia Pacific Region

The following table discloses Husky's offshore China and Indonesia drilling activity completed during 2012:

Asia Pacific Region Offshore Drilling Activity

MBJ-1, Madura Strait Block	WI 40%	Exploration	Stratigraphic test
MDK-1, Madura Strait Block	WI 40%	Exploration	Stratigraphic test
MAC-1, Madura Strait Block	WI 40%	Exploration	Stratigraphic test
MAX-1, Madura Strait Block	WI 40%	Exploration	Stratigraphic test
MAQ-1, Madura Strait Block	WI 40%	Exploration	Stratigraphic test

Total capital expenditures of $747 million were invested in the Asia Pacific Region in 2012 primarily for development of the Liwan Gas Project. Five exploration wells were drilled at the Madura Strait in Indonesia during 2012, resulting in four discoveries under evaluation for commercial development.

2013 Upstream Capital Program

($ millions)

Western Canada	**2,100**
Oil sands	**500**
Atlantic Region	**600**
Asia Pacific Region	**800**
Total Upstream capital expenditures[(1)]	**4,000**

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

The 2013 Capital Program will enable Husky to build on the momentum achieved over the past two 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 $800 million for the Asia Pacific Region in 2013, mainly for the Liwan Gas Project to complete the construction of the shallow water pipeline installations, the onshore gas plant and the topsides portion of the platform with planned first production in late 2013/early 2014. Oil Sands capital for 2013 will primarily be for the continued development of Phase 1 of the Sunrise Energy Project as well as planning, design and engineering for the next phase of the project. Investment in the Atlantic Region of $600 million is for continued development of the White Rose fields and extensions and evaluation of the feasibility of a concrete wellhead and drilling platform for the development of future resources, including the full development of West White Rose.

In addition to advancing mid and long-term growth pillars, the 2013 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 2013. 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 3,500 bbls/day Sandall thermal project with expected first production in 2014 and the 10,000 bbls/day Rush Lake thermal project with expected first production in 2015.

Upstream Turnarounds

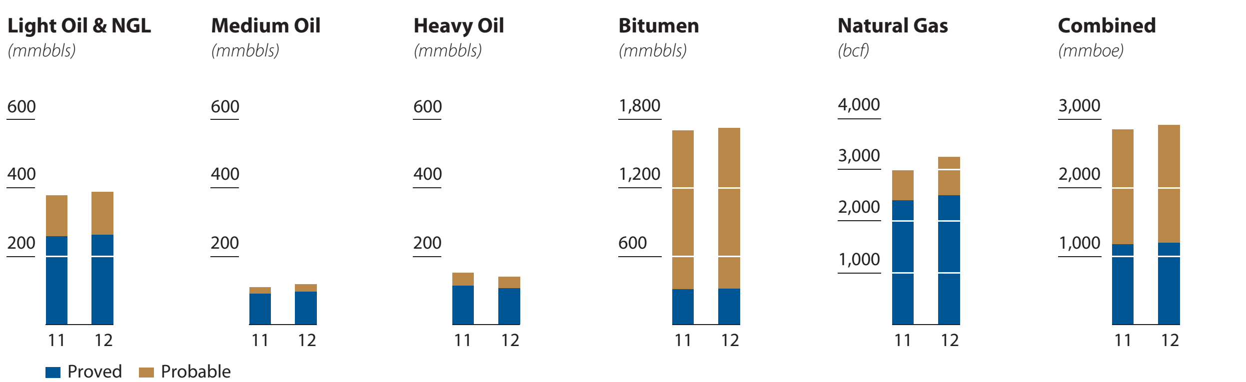
The Husky-operated SeaRose FPSO completed its planned maintenance dry-docking in Belfast, Northern Ireland with zero lost-time incidents and ahead of schedule with production resuming on August 13, 2012, approximately three weeks ahead of plan. Production from the White Rose field and satellite extensions returned to expected levels by the end of the third quarter of 2012.

The non-operated Terra Nova FPSO resumed production in December following a planned 26-week turnaround shutdown and continues to ramp up more slowly than anticipated.

In third quarter of 2013, a one week turnaround is scheduled for the SeaRose FPSO. The Terra Nova FPSO turnaround plans for 2013 are being evaluated.

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, 2012. 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.

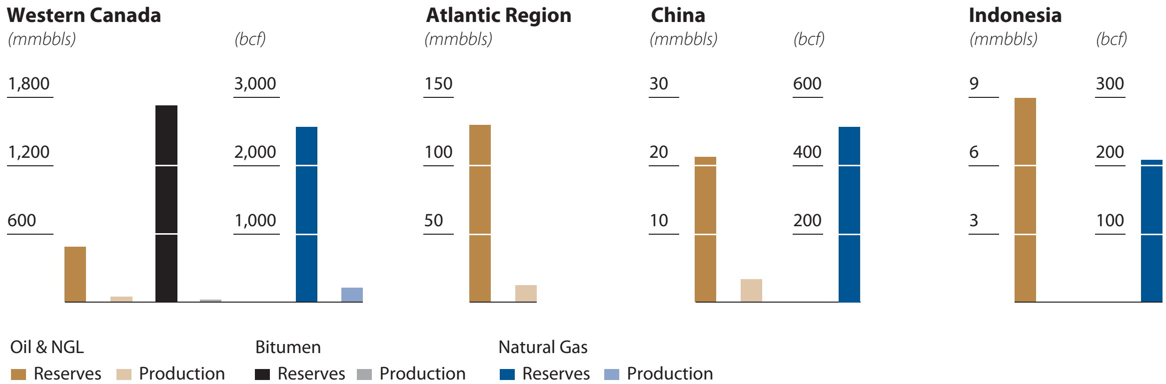


The Company's complete Oil and Gas Reserves Disclosure prepared in accordance with NI 51-101 is contained in Husky's Annual Information Form, which is available at www.sedar.com, or Husky's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com.

McDaniel & Associates Consultants Ltd., 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. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated 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, 2012, Husky's proved oil and gas reserves were 1,192 mmboe, up from 1,172 mmboe at the end of 2011. Addition to proved reserves, including acquisitions and divestitures, represents 140% (118% after economic revisions) of 2012 production. Major additions to proved reserves in 2012 included:

- the initial booking of reserves in the Liwan 3-1 deepwater project that resulted in the addition of 51 mmboe of natural gas and natural gas liquids in proved undeveloped reserves;
- the improved recovery and expansion of heavy oil thermal projects that resulted in the booking of an additional 13 mmboe in proved reserves; and
- the extension through additional drilling locations at the liquids-rich Ansell project that resulted in the booking of an additional 27 mmboe of natural gas and natural gas liquids in proved 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 & NG *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	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, 2011	169	90	113	309	2,253	76	12	167	769	2,420	1,172
Revision of previous estimate	–	8	2	1	14	4	5	–	20	14	22
Purchase of reserves in place	1	–	–	–	–	–	–	–	1	–	1
Sale of reserves in place	–	(1)	–	–	–	–	–	–	(1)	–	(1)
Discoveries, extensions and improved recovery	16	7	18	14	146	–	8	267	63	413	132
Economic revision	(1)	–	–	–	(137)	–	–	–	(1)	(137)	(24)
Production	(12)	(9)	(28)	(13)	(203)	(12)	(3)	–	(77)	(203)	(110)
Proved reserves December 31, 2012	**173**	**95**	**105**	**311**	**2,073**	**68**	**22**	**434**	**774**	**2,507**	**1,192**
Proved and probable reserves December 31, 2012	**229**	**117**	**140**	**1,725**	**2,547**	**130**	**30**	**718**	**2,371**	**3,265**	**2,915**
December 31, 2011	220	109	151	1,709	2,813	141	17	207	2,347	3,020	2,851

Reconciliation of Proved Developed Reserves

	Canada						International		Total		
	Western Canada					Atlantic Region					
(forecast prices and costs before royalties)	Light Crude Oil & NGL *(mmbbls)*	Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Natural Gas *(bcf)*	Light Crude Oil *(mmbbls)*	Light Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Crude Oil & NGL *(mmbbls)*	Natural Gas *(bcf)*	Equivalent Units *(mmboe)*
Proved developed reserves											
December 31, 2011	148	77	86	56	1,916	65	5	–	437	1,916	757
Revision of previous estimate	6	18	16	14	85	3	5	–	62	85	74
Purchase of reserves in place	1	–	–	–	–	–	–	–	1	–	1
Sale of reserves in place	–	(1)	–	–	–	–	–	–	(1)	–	(1)
Discoveries, extensions and improved recovery	7	3	10	2	13	–	1	–	23	13	25
Economic revision	(1)	–	–	–	(97)	–	–	–	(1)	(97)	(17)
Production	(12)	(9)	(28)	(13)	(203)	(12)	(3)	–	(77)	(203)	(110)
Proved developed reserves December 31, 2012	**149**	**88**	**84**	**59**	**1,714**	**56**	**8**	**–**	**444**	**1,714**	**729**

Infrastructure and Marketing

Infrastructure and Marketing Earnings Summary *($ millions, except where indicated)*	2012	2011
Infrastructure gross margin	**162**	169
Marketing and other gross margin	**387**	90
Gross margin	**549**	259
Operating and administrative expenses	**70**	60
Depletion, depreciation and amortization	**22**	24
Other expenses	**–**	1
Income taxes	**116**	44
Net earnings	**341**	130
Commodity trading volumes managed (mboe/day)	**180.1**	181.0

Infrastructure and Marketing net earnings increased by $211 million compared with the same period in 2011 as a result of marketing activities utilizing the Company's access to infrastructure to move crude oil from Canada to the United States to mitigate the impact of wider Western Canadian crude oil differentials on the Exploration and Production business by capturing widening Canadian crude discounts through integration.

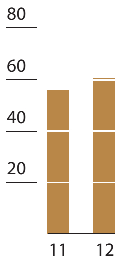
Infrastructure and Marketing capital expenditures totalled $54 million in 2012 compared to $43 million in 2011. The majority of Infrastructure and Marketing capital expenditures during the year related to the completion of the 300,000 barrel tank at the Hardisty terminal and pipeline maintenance and integrity projects.

6.4 Downstream

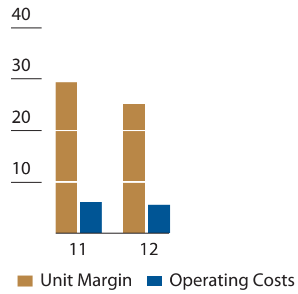
2012 Total Downstream Earnings $895 million

Upgrader

Upgrader
Synthetic Crude Sales
(mbbls/day)



Upgrader
Unit Margin & Operating Costs
($/bbl)



Upgrader Earnings Summary *($ millions, except where indicated)*	2012	2011
Gross revenues	2,191	2,217
Gross margin [(1)]	555	589
Operating and administration expenses[(1)]	153	149
Depreciation and amortization	102	164
Other expenses (income)	(6)	74
Income taxes	80	52
Net earnings	226	150
Upgrader throughput[(2)] *(mbbls/day)*	77.4	69.6
Synthetic crude oil sales *(mbbls/day)*	60.4	55.3
Upgrading differential *($/bbl)*	22.34	27.34
Unit margin[(1)] ($/bbl)	25.17	29.18
Unit operating cost[(3)] ($/bbl)	5.42	5.87

[(1)] *The Company reclassified certain hydrogen feedstock costs from operating and administrative expenses to cost of sales in the third quarter of 2012. Prior periods have been reclassified to conform with current period presentation.*
[(2)] *Throughput includes diluent returned to the field.*
[(3)] *Based on throughput.*

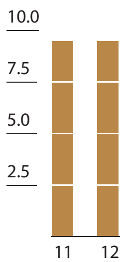
The Upgrading operations add value by processing heavy sour crude oil into high value synthetic crude oil and low sulphur distillates. The Upgrader profitability is primarily dependent on the differential between the cost of heavy crude oil feedstock and the sales price of synthetic crude oil.

Upgrading earnings in 2012 were impacted by lower upgrading differentials resulting from lower synthetic crude oil prices offsetting lower heavy oil feedstock costs. Lower margins were offset by a decrease in the fair value of the remaining upside interest payment obligations included in other income and a decrease in depreciation and amortization as intangible costs were derecognized in the second quarter of 2011.

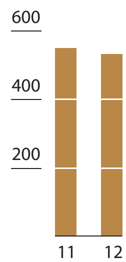
During 2012, the price of Husky's synthetic crude oil averaged $91.90/bbl compared with the average cost of blended heavy crude oil from the Lloydminster area of $69.56/bbl. During 2011, the price of Husky's synthetic crude oil averaged $101.68/bbl compared with an average cost of blended heavy crude oil from the Lloydminster area of $74.34/bbl. This resulted in an average synthetic/heavy crude differential of $22.34/bbl in 2012 compared to $27.34/bbl in 2011 and a gross unit margin of $25.17/bbl in 2012 compared to $29.18/bbl in 2011. The cost of upgrading averaged $5.42/bbl in 2012 compared to $5.87/bbl in 2011, which resulted in a net margin for upgrading heavy crude of $19.75/bbl, down 15% compared with $23.31/bbl in 2011. The decrease in Upgrading differentials, unit margins and net margins in 2012 compared to 2011 was primarily due to Western Canadian synthetic crude oil prices which traded at a discount to WTI in 2012 compared to a premium to WTI in 2011. This new trend is mainly due to export pipeline constraints in Western Canada and new supply in the U.S. which has resulted in a decrease in demand for Western Canadian crude oil.

Canadian Refined Products

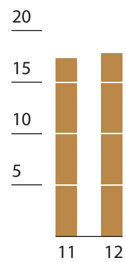
Light Oil Product Marketing
Volume
(millions of litres/day)



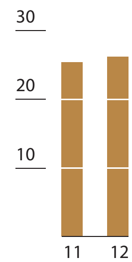
Outlets



Volume per Outlet
(thousands of litres/day)



Asphalt Products
Volume
(mbbls/day)



Canadian Refined Products Earnings Summary *($ millions, except where indicated)*	2012	2011
Gross revenues	**3,848**	3,877
Gross margin [(1)]		
Fuel	**153**	153
Refining	**180**	171
Asphalt	**257**	239
Ancillary	**50**	49
	640	612
Operating and administration expenses	**242**	231
Depreciation and amortization	**83**	80
Other expense	**4**	6
Income taxes	**80**	75
Net earnings	**231**	220
Number of fuel outlets [(2)]	**531**	547
Refined products sales volume		
Light oil products *(million of litres/day)* [(3)]	**9.5**	9.5
Light oil products per outlet *(thousand of litres/day)* [(3)]	**17.8**	17.3
Asphalt products *(mbbls/day)*	**26.2**	25.3
Refinery throughput		
Prince George refinery *(mbbls/day)*	**11.1**	10.6
Lloydminster refinery *(mbbls/day)*	**28.3**	28.1
Ethanol production *(thousand of litres/day)*	**721.2**	711.3

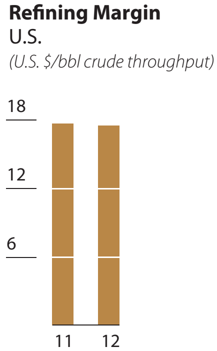
(1) *Gross margin and operating and administrative expenses have been recast for reclassification of certain purchases and operating expenses. Prior periods have been recast to reflect this classification.*
(2) *Average number of fuel outlets for period indicated.*
(3) *Light oil products have been redefined to include ethanol sales. Prior periods have been recast to reflect this change in definition.*

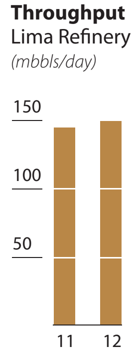
Refining gross margins increased in 2012 primarily due to higher refining market crack spreads and higher throughput and ethanol production compared to 2011. Included in ethanol gross margins in 2012 was $37 million related to government assistance grants compared with $46 million in 2011.

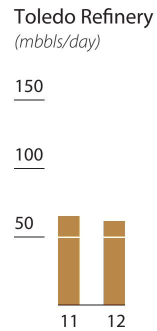
Asphalt gross margins increased compared to the same period in 2011 primarily due to higher realized market prices and increased sales volumes for residuals as a result of strong demand for drilling fluids.

Higher operating and administration expenses were primarily due to increased maintenance activity in 2012 compared to 2011.

U.S. Refining and Marketing







U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*	2012	2011
Gross revenues	**10,038**	9,752
Gross refining margin	**1,314**	1,299
Operating and administration expenses	**398**	403
Depreciation and amortization	**212**	195
Other expenses	**9**	4
Income taxes	**257**	254
Net earnings	**438**	443
Selected operating data:		
Lima Refinery throughput *(mbbls/day)*	**150.0**	144.3
BP-Husky Toledo Refinery throughput *(mbbls/day)*	**60.6**	63.9
Refining margin *(U.S. $/bbl crude throughput)*	**17.51**	17.60
Refinery inventory (feedstocks and refined products) *(mmbbls)*	**11.3**	11.8

U.S. Refining and Marketing net earnings in 2012 were comparable to 2011. Stronger throughput at Lima and higher market crack spreads in 2012 compared to 2011 were offset by the impacts of FIFO accounting on realized margins, lower throughput at the BP-Husky Toledo Refinery due to turnaround activity and higher depreciation and amortization.

The Chicago crack spread market 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 higher. The estimated FIFO impact was a reduction in net earnings of approximately $28 million in 2012 compared to an increase in net earnings of $122 million in 2011.

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 $457 million for 2012 compared to $373 million in 2011. In Canada, capital expenditures were $144 million related to upgrades at the Prince George Refinery, the Upgrader and at retail stations. In the United States, capital expenditures totalled $313 million. At the Lima Refinery, $150 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the BP-Husky Toledo Refinery, capital expenditures totalled $163 million (Husky's 50% share) primarily for engineering work and procurement on the Continuous Catalyst Regeneration Reformer Project, facility upgrades and environmental protection initiatives.

Downstream Planned Turnarounds

The Lloydminster Refinery has a turnaround scheduled in the spring of 2013. The refinery is expected to be shut down for 30 days for inspections and equipment repair.

The Lima Refinery is scheduled to complete a turnaround in 2014 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 2015.

The Upgrader has a turnaround scheduled in the fall of 2013 and is expected to be shut down for 45 days.

6.5 Corporate

2012 Loss $193 million

Corporate Summary *($ millions) income (expense)*	2012	2011
Administration expenses	(128)	(195)
Stock-based compensation	(54)	1
Depreciation and amortization	(40)	(38)
Other income	3	–
Foreign exchange gains	14	10
Interest - net	(52)	(143)
Income taxes	64	65
Net loss	(193)	(300)

The Corporate segment reported a loss in 2012 of $193 million compared with a loss of $300 million in 2011. Administration expenses were lower in 2012 compared to 2011 in which the Company incurred costs related to financing projects and other initiatives. Stock-based compensation expense increased by $55 million in 2012 due to a higher share price at the end of 2012 compared to 2011. Interest - net decreased by $91 million in 2012 compared to 2011 due to increases in amounts of capitalized interest related to projects in the Asia Pacific Region and the Sunrise Energy Project.

Foreign Exchange Summary *($ millions, except exchange rate amounts)*	2012	2011
Gains (losses) on translation of U.S. dollar denominated long-term debt	43	(47)
Gains (losses) on cross currency swaps	2	7
Gains (losses) on contribution receivable	(7)	34
Other foreign exchange gains (losses)	(24)	16
Foreign exchange gains (losses)	14	10
U.S./Canadian dollar exchange rates:		
At beginning of year	U.S. $0.983	U.S. $1.005
At end of year	U.S. $1.005	U.S. $0.983

Consolidated Income Taxes

Consolidated income taxes decreased in 2012 to $814 million from $916 million in 2011 resulting in an effective tax rate of 29% for both 2012 and 2011.

($ millions)	2012	2011
Income taxes as reported	814	916
Cash taxes paid	(575)	(282)

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 will now be payable over a 5-year period commencing in 2013.

Corporate Capital Expenditures

Corporate capital expenditures of $84 million in 2012 were primarily related to computer hardware and software and system upgrades.

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

Husky's businesses are subject to inherent operational risks and hazards in respect of 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 which 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. 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

Husky'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 Husky's financial performance and condition, reduce the value and quantities of Husky's heavier crude oil reserves and delay or cancel projects that involve the development of heavier crude oil resources. There is no guarantee that 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.

Husky'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 Husky's control and accordingly, could have a material adverse effect on the Company's business, financial condition and cash flow. For information on 2012 commodity price sensitivities, refer to Section 3.0 within this Management's Discussion and Analysis.

Reservoir Performance Risk

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

In order to maintain the Company's future production of crude oil, natural gas and 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. In order to mitigate the effects of this, the Company must undertake successful exploration and development programs, increase the recovery factor from existing properties through applied technology, and identify and execute strategic acquisitions of proved developed and undeveloped properties and unproved prospects. Maintaining an inventory of developable projects depends on, among other things, obtaining and renewing rights to explore, develop and produce oil and natural gas, drilling success, completing long-lead time capital intensive projects on budget and on schedule and the application of successful exploitation techniques on mature properties.

Restricted Market Access

Husky's results depend upon the Company's ability to deliver products to the most attractive markets. The Company's results could be impacted by restricted market access resulting from a lack of pipeline or other transportation alternatives to attractive markets as well as regulatory and/or other marketplace barriers. 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.

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, which 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 and PSCs, 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, which may have a material impact on the Company's financial position, 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 Husky's current and future business strategies. However, a tight labour market, an insufficient number of qualified candidates, and an aging workforce are factors that precipitate a human resource risk for the Company. Failure to retain current employees and attract new skilled employees could materially affect the Company's ability to conduct its business.

Major Project Execution

The Company manages a variety of major projects relating to oil and gas exploration, development and production. Risks associated with the execution of Husky'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 Husky 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. Husky is at times dependent upon its partners for the successful execution of various projects. If a dispute with partners were to occur over the development and operation of a project or if partners were unable to fund their contractual share of the capital expenditures, a 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. For those reasons, estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. All reserves estimates involve a degree of ambiguity and, at times, rely on indirect measurement techniques to estimate the size and recoverability of the resource. While new technologies have increased the accuracy and efficacy of these techniques, there remains the potential for human or systemic error in recording and reporting the magnitude of the Company's oil and gas reserves. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets, and could negatively affect the Company's reputation, investor confidence, and the Company's ability to deliver on its growth strategy.

Government Regulation

Given the scope and complexity of Husky'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, reserves access, limitations or increase in costs relating to the exportation of commodities, restrictions on the acquisition of exploration and production rights and land tenure, expropriation or cancellation of PSCs and/or contract rights, limitations on control over the development and abandonment of fields, and loss of licenses to operate.

Environmental Regulation

Husky 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 Husky's financial condition and results of operations.

The 2010 Deepwater Horizon oil spill in the Gulf of Mexico has led to numerous public and governmental expressions of concern about the safety and potential environmental impact of offshore oil and gas operations. Stricter regulation of offshore oil and gas operations has already been implemented by the U.S. 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 Husky'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.

Climate Change Regulation

Husky continues to monitor international efforts to address climate change, including developments on the Kyoto Protocol and the Copenhagen Accord. Canada has withdrawn from participation in the Kyoto Protocol. The effect of these initiatives on the Company's operations cannot be determined with any certainty at this time. The Alberta and BC governments have regulations in place with the Saskatchewan government anticipated to soon follow with similar regulation. These regulations include limiting the intensity limits for large emitters of greenhouse gases in Alberta emitting 100,000 tonnes or more of greenhouse gas in any year. Under the regulations, a 12-15% intensity reduction will be applied to the average of that facility's 2003-2005 baseline emissions intensity for established facilities. New facilities are required to reduce emissions starting with the fourth year of commercial operation by 2%, and then by 2% every year after, until the 12-15% reduction target has been achieved. These regulations impact all of Husky's Upstream operations in BC, the Prince George Refinery, the Ram River gas plant and the Tucker thermal oil facility. In addition, the Federal Government of Canada has announced pending regulations in respect of greenhouse gases and other pollutants. Although the impact of these regulations is uncertain, they may adversely affect the Company's operations and increase costs. These regulations may become more onerous over time as public and political pressures increase to implement initiatives that further reduce the emission of greenhouse gases.

While the U.S. EPA regulations are currently in effect, they have not yet had a material impact on Husky. However, the Company's operations may be materially impacted by future application of these rules or by future U.S. greenhouse gas legislation applying 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 Husky's 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. Husky 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. Husky'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. Husky's competitors comprise all types of energy companies, some of which have greater resources.

Internal Credit Risk

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

General Economic Conditions

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

Cost or Availability of Oil and Gas Field Equipment

The cost or availability of oil and gas field equipment adversely affects 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, which 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 financial losses.

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, Husky 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 2012 audited 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

Husky'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, 2012, the amount that the Company designated was U.S. $2.8 billion (December 31, 2011 - U.S. $1.3 billion). For the year ended December 31, 2012, the unrealized loss arising from the translation of the debt was $15 million (2011 - loss of $18 million), net of tax of $2 million (2011 - $3 million), which was recorded in OCI. At December 31, 2012, the fair value of the hedge was $97 million recorded in long-term debt in the consolidated balance sheets (December 31, 2011 - $80 million).

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)	**December 31, 2012**	December 31, 2011
Derivatives – FVTPL (held-for-trading)		
Accounts receivable	**13**	65
Accounts payable and accrued liabilities	**(5)**	(45)
Other assets, including derivatives	**1**	2
Other – FVTPL (held-for-trading)[(1)]		
Accounts payable and accrued liabilities	**(27)**	(17)
Other long-term liabilities	**(78)**	(112)
Hedging instruments		
Other assets, including derivatives	**1**	–
Accounts payable and accrued liabilities	**–**	(93)
Long-term debt[(2)]	**25**	(13)
	(70)	(213)
Net gains (losses) for the year related to financial instruments held at fair value	**122**	(73)
Included in net earnings	**104**	(55)
Included in OCI	**18**	(18)

[(1)] *Non-derivative items related to contingent consideration recognized as part of a business acquisition.*
[(2)] *Represents the foreign exchange adjustment related to translation of 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 2012, Husky funded its capital programs and dividend payments through cash generated from operating activities and cash on hand. At December 31, 2012, Husky had total debt of $3,918 million partially offset by cash on hand of $2,025 million for $1,893 million of net debt compared to $2,070 million of net debt as at December 31, 2011. At December 31, 2012, the Company had $3.1 billion in unused committed credit facilities, $280 million in unused short-term uncommitted credit facilities, $3.0 billion in unused capacity under its Canadian universal short form base shelf prospectus filed December 31, 2012 and U.S. $1.5 billion in unused capacity under its U.S. universal short form base shelf prospectus filed June 13, 2011. The ability of the Company to utilize the capacity under its shelf prospectuses is subject to market conditions. Refer to Section 8.2.

	2012	2011
Cash flow		
Operating activities *($ millions)*	**5,189**	5,092
Financing activities *($ millions)*	**(162)**	910
Investing activities *($ millions)*	**(4,830)**	(4,420)
Financial Ratios[(1)]		
Debt to capital employed *(percent)*[(2)]	**17**	18
Debt to cash flow *(times)*[(3)(4)]	**0.8**	0.8
Corporate reinvestment ratio *(percent)*[(3)(5)]	**106**	98
Interest coverage on long-term debt only[(3)(6)]		
Earnings	**12.5**	14.5
Cash flow	**24.9**	24.7
Interest coverage on total debt[(3)(7)]		
Earnings	**12.3**	14.1
Cash flow	**24.6**	23.9

(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 $5,189 million in 2012 compared with $5,092 million in 2011. Slightly higher cash flows from operations were mainly due to changes in non-cash working capital, partially offset by higher taxes paid and lower net earnings when compared to 2011.

Cash Flow from Financing Activities

Cash used for financing activities was $162 million in 2012 compared with cash flow from financing activities of $910 million in 2011. Cash flow from financing activities was lower in 2012 compared to 2011 due to a preferred share issuance of $300 million and a common share issuance of $1.2 billion in 2011.

Cash Flow used for Investing Activities

Cash used in investing activities for 2012 was $4,830 million compared with $4,420 million in 2011. Cash invested in both periods was primarily for acquisitions and capital expenditures.

8.2 Working Capital Components

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2012, Husky's working capital was $2,404 million compared with $2,054 million at December 31, 2011.

Movement in Working Capital

($ millions)	**December 31, 2012**	December 31, 2011	Increase/ (Decrease)
Cash and cash equivalents	**2,025**	1,841	184
Accounts receivable	**1,349**	1,235	114
Income taxes receivable	**323**	273	50
Inventories	**1,736**	2,059	(323)
Prepaid expenses	**64**	36	28
Accounts payable and accrued liabilities	**(2,986)**	(2,867)	(119)
Asset retirement obligations	**(107)**	(116)	9
Long-term debt due within one year	**–**	(407)	407
Net working capital	**2,404**	2,054	350

The increase in cash was primarily due to strong cash flow from operations in the year which was in excess of cash flow used for financing and investing activities. Cash flow used for financing and investing activities in 2012 primarily consisted of dividends paid on common and preferred shares, interest paid on long-term debt and Upstream capital expenditures. Increases in accounts receivable and accounts payable were due to the timing of settlements compared to 2011. Inventory levels held at December 31, 2012 decreased from levels held at December 31, 2011 due to comparable production combined with higher throughput in Downstream in the fourth quarter of 2012 compared to the same period in 2011 and the timing of lifts and sales of upstream offshore production. The decrease in long-term debt due within one year was due to the repayment of debt which matured in 2012 compared to no long-term debt maturities in 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, 2012, no production was hedged.

At December 31, 2012 Husky had the following available credit facilities:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[1]	**515**	**280**
Syndicated bank facilities	**3,100**	**3,100**
	3,615	**3,380**

[1] *Consists of demand credit facilities.*

Cash and cash equivalents at December 31, 2012 totalled $2,025 million compared with $1,841 million at the beginning of the year.

At December 31, 2012, Husky had unused short and long-term borrowing credit facilities totalling $3,380 million. A total of $235 million of the Company's short-term borrowing credit facilities was used in support of outstanding letters of credit.

Husky Energy (HK) Limited and Husky Oil China Ltd., subsidiaries of Husky, each have an uncommitted demand revolving facility of U.S. $10 million available for general purposes.

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. A shareholder must deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend confirming they will accept the dividend in common shares. Failure to do so will result in such shareholder receiving the dividend paid in cash. During the year ended December 31, 2012, the Company declared dividends payable of $1.20 per common share, resulting in dividends of $1.2 billion. An aggregate of $557 million was paid in cash during 2012. At December 31, 2012, $295 million, including $293 million in cash and $2 million in common shares, was payable to shareholders on account of dividends declared on November 1, 2012.

On March 18, 2011, Husky issued 12 million Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") at a price of $25.00 per share for aggregate gross proceeds of $300 million under a Canadian universal short form base shelf prospectus (the "Prior Canadian Shelf Prospectus"). Holders of the Series 1 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend payable on the last day of March, June, September and December in each year yielding 4.45% annually for the initial period ending March 31, 2016 as and when declared by Husky'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 will 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 will be entitled to receive cumulative quarterly floating dividends at a rate equal to the three-month Government of Canada Treasury Bill yield plus 1.73%.

On June 13, 2011, the Company 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 that enables 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 up to and including July 12, 2013. At December 31, 2012, approximately $1.5 billion remains available for issuance under the U.S. Shelf Prospectus.

On June 29, 2011, Husky issued 37 million common shares at a price of $27.05 per share for total gross proceeds of approximately $1.0 billion through a public offering, and a total of 7.4 million common shares at a price of $27.05 per share for total gross proceeds of $200 million through a private placement to L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. The Company received total gross proceeds of $1.2 billion from this issuance. The public offering was completed under the U.S. Shelf Prospectus and accompanying prospectus supplement in the United States and under the Prior Canadian Shelf Prospectus and accompanying prospectus supplement in Canada.

On March 22, 2012, the Company issued U.S. $500 million of 3.95% senior unsecured notes due April 15, 2022 pursuant to the U.S. Shelf Prospectus 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.

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 (the "Securities") in Canada up to and including January 30, 2015. As of December 31, 2012, the Company had not issued Securities under the Canadian Shelf Prospectus. This Canadian Shelf Prospectus replaced the Prior Canadian Shelf Prospectus filed in Canada during November 2010 which had remaining unused capacity of $1.4 billion and expired in December 2012. The ability of the Company to raise capital utilizing the U.S. Shelf Prospectus and Canadian Shelf Prospectus is dependent on market conditions at the time of sale.

Capital Structure ($ millions)	December 31, 2012 Outstanding	Available[1]
Total long-term debt	**3,918**	**3,380**
Common shares, retained earnings and other reserves	**19,161**	

(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)*	2013	2014-2015	2016-2017	Thereafter	Total
Long-term debt and interest on fixed rate debt	227	1,428	826	3,125	5,606
Operating leases	130	370	436	556	1,492
Firm transportation agreements	217	561	476	2,652	3,906
Unconditional purchase obligations[1]	3,089	4,347	102	78	7,616
Lease rentals and exploration work agreements	85	174	212	571	1,042
Asset retirement obligations[2]	107	198	211	9,812	10,328
	3,855	7,078	2,263	16,794	29,990

(1) *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases.*
(2) *Asset retirement obligation (ARO) amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets.*

The following additions during the year are included in total non-cancellable contracts and other commercial commitments:

- The Company executed an operating lease agreement with Seadrill for the semi-submersible rig, West Mira. The non-cancellable minimum future payments are approximately $129 million per year commencing 2015 for five years with an option to extend the contract to 2022.
- The Company executed contracts to purchase refined petroleum products in Canada over the next three years totalling approximately $4.5 billion.
- The Company updated its estimates for Asset Retirement Obligations ("ARO") as outlined in Note 16 of the 2012 audited Consolidated Financial Statements. On an undiscounted basis, the ARO increased from $8.5 billion as at December 31, 2011 to $10.3 billion as at December 31, 2012 due to increased cost estimates and asset growth in the Upstream and Downstream segments.

Based on Husky's 2013 commodity price forecast, the Company believes that its non-cancellable contractual obligations, including commercial commitments and the 2013 Capital Program, will be funded by cash flow from operating activities and, to the extent required, by available committed credit facilities and the issuance of long-term debt. In the event of significantly lower cash flow, Husky would be able to defer certain projected capital expenditures without penalty.

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 96 active employees, 110 participants with deferred benefits and 535 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 237 active union represented employees in the United States. A defined benefit pension plan for 207 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 2012 audited Consolidated Financial Statements).

Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery LLC (Refer to Note 8 to the 2012 audited 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, 2012, 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 or financial performance.

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

The Company continues to sell natural gas to and purchase steam from the Meridian cogeneration facility owned by a related party of Husky. These natural gas sales and steam purchases are related party transactions and have been measured at fair value. For the year ended December 31, 2012, the total value of natural gas sales to the Meridian cogeneration facility owned by the related party was $74 million. For the year ended December 31, 2012, the total value of obligated steam purchases from the Meridian cogeneration facility owned by the related party was $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, 2012, the total cost recovery for these services was $19 million.

8.6 Outstanding Share Data

Authorized

unlimited number of common shares

unlimited number of preferred shares

Issued and outstanding: February 27, 2013	
common shares	982,541,821
cumulative redeemable preferred shares, series 1	12,000,000
stock options	28,389,305
stock options exercisable	10,224,925

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 2012 audited 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 instruments 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. Significant estimations are made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where 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 both determine whether a loss is probable based on judgment and interpretation of laws and regulations and determine 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") 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 each reporting date 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, 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.

Functional and Presentation Currency

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

10.0 Recent Accounting Standards

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 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 10 on January 1, 2013. The adoption of the standard is not expected to have a material impact on the Company's 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 arrangement shall be classified as a joint venture and accounted for using the equity method of accounting. Under the existing IFRS standard, the Company has the option to account for any interests it has in joint arrangements using proportionate consolidation or equity accounting. IFRS 11 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 11 on January 1, 2013. The adoption of the standard is not expected to have a material impact on the Company's financial statements.

Disclosure of Interests in Other Entities

In May 2011, the IASB published IFRS 12, "Disclosure of Interests in Other Entities," which contains new 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 financial statements. IFRS 12 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 12 on January 1, 2013. The adoption of the standard is not expected to have a material impact on the Company's 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 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt these amendments on January 1, 2013. The Company does not expect the amendments to IAS 28 to have a material impact on the Company's 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 fair value measurement 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 is effective for the Company on January 1, 2013 with required prospective application and early adoption permitted. The Company intends to adopt IFRS 13 on January 1, 2013. The adoption of the standard is not expected to have a material impact on the Company's 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. The amendments to IAS 19 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt these amendments on January 1, 2013. The adoption of the amended standard is not expected to have a material impact on the Company's financial statements.

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 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. Amendments to IAS 32 are effective for the Company on January 1, 2014 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the IFRS 7 amendments on January 1, 2013 and the IAS 32 amendments on January 1, 2014. The adoption of these amended standards is not expected to have a material impact on the Company's financial statements.

Financial Instruments

In November 2009, the IASB published IFRS 9, "Financial Instruments," which covers the classification and measurement of financial assets as part of its project to replace IAS 39, "Financial Instruments: Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to their own credit risk out of net earnings and recognize the change in OCI. IFRS 9 is effective for the Company on January 1, 2015 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the amendments on January 1, 2015. The adoption of the standard is not expected to have a material impact on the Company's financial statements.

11.0 Reader Advisories

11.1 Forward-Looking Statements

Certain statements in this document are forward looking statements within the meaning of 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, and forward-looking information within the meaning of applicable Canadian securities legislation (collectively "forward-looking statements"). The Company hereby provides cautionary statements identifying important factors that could cause actual results to differ materially from those projected in these forward-looking statements. Any 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," "are expected to," "will continue," "is anticipated," "is targeting," "estimated," "intend," "plan," "projection," "could," "aim," "vision," "goals," "objective," "target," "schedules" and "outlook") are not historical facts, are forward-looking and may involve estimates and assumptions and are subject to risks, uncertainties and other factors some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

In particular, forward-looking statements in this document include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; the Company's general financial plans and goals; target weighting of production among product types; target debt to cash flow ratio and target debt to capital employed ratio; expected sources of cash from the Company's growth projects; the Company's 2013 production guidance; target compound annual production growth for the periods 2010-2015 and 2012-2017, and the Company's ability to achieve such targets; the Company's 2013 capital program; and the funding sources for the Company's non-cancellable contractual obligations and other commercial commitments;
- with respect to the Company's Asia Pacific Region: anticipated timing of first production from the Company's Liwan Gas Project; planned timing of resumption of pipe laying activity at the Company's Liwan Gas Project; planned timing of floatover of the topsides for the central platform at the Company's Liwan Gas Project; planned timing of development of the single well Liuhua 34-2 field; and anticipated timing of first gas from the Company's Madura Strait Block;
- with respect to the Company's Atlantic Region: development and drilling plans for the South White Rose extension project; development and drilling plans for the North Amethyst field; expected timing of a decision on a preferred development option for the West White Rose project; expected timing of completion of the West Mira rig; planned participation in operated and non-operated exploratory wells in the region during 2013 and 2014; and 2013 turnaround plans at the SeaRose and Terra Nova FPSOs;
- with respect to the Company's Oil Sands properties: anticipated timing and volume of production from the Company's Sunrise Energy Project; expected timing of completion of the Design Basis Memorandum for the next phase of the Company's Sunrise Energy Project; expected timing of production from the Company's Tucker Oil Sands Project; and anticipated timing of filing a regulatory application for the bitumen carbonates pilot at the Company's Saleski Oil Sands project;
- with respect to the Company's Heavy Oil properties: scheduled timing of first production from the Company's Sandall thermal development project; anticipated timing of first commercial production at the Company's Rush Lake Project; anticipated timing of production from the second well pair pilot at the Company's Rush Lake project; and the Company's horizontal and CHOPS drilling programs for 2013;
- with respect to the Company's Western Canadian oil and gas resource plays: 2013 drilling plans in the Company's oil and gas resource play portfolio; tie-in plans at the Company's Kaybob property; and expected timing of production response from the Company's Fosterton Alkaline Surfactant Polymer facility;
- with respect to the Company's Infrastructure and Marketing business unit: intended focus of spending with the unit; and
- with respect to the Company's Downstream operating segment: project and expansion plans within the segment for 2013 and beyond; expected timing of operation of a kerosene hydrotreater at the Lima Refinery; expected timing of start up of the Continuous Catalyst Regeneration Reformer Project at the BP-Husky Toledo Refinery; and scheduled timing and anticipated duration of turnarounds at the Lloydminster Refinery, the Lima Refinery and the Lloydminster Upgrader.

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.

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.

Sections 7.2 and 7.3 of this Management's Discussion and Analysis and the Company's Annual Information Form for the year ended December 31, 2012 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 noted in this document, all reserves estimates given have an effective date of December 31, 2012.

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.

11.3 Non-GAAP Measures

Disclosure of non-GAAP Measurements

Husky uses measurements primarily based on IFRS as issued by the International Accounting Standards Board and also certain secondary non-GAAP measurements. The non-GAAP measurements included in this Management's Discussion and Analysis are 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 capital employed and return on capital in use. None of these measurements are used to enhance the Company's reported financial performance or position. With the exception of 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 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 and amortization, future income taxes, foreign exchange 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)	**2012**	2011
GAAP Cash flow – operating activities	**5,189**	5,092
Settlement of asset retirement obligations	**123**	105
Income taxes paid	**575**	282
Interest received	**(34)**	(12)
Change in non-cash working capital	**(843)**	(269)
Non-GAAP Cash flow from operations	**5,010**	5,198
Cash flow from operations – basic	**5.13**	5.63
Cash flow from operations – diluted	**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 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 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 27, 2013. Any events subsequent to that date could conceivably 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 2012, which contain MD&A and Consolidated Financial Statements, and Husky's 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, 2012 and 2011 and Husky's financial position as at December 31, 2012 and at December 31, 2011.

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 the securities of Husky.

Additional Reader Guidance

Unless otherwise indicated:

- Financial information is presented in accordance with IFRS as issued by the International Accounting Standards Board.
- 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.
- Bitumen is solid or semi-solid with a viscosity greater than 10,000 centipoise at original temperature in the deposit and atmospheric pressure.

Terms

Bitumen	*Bitumen is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulphur, metals and other non-hydrocarbons*
Brent Crude Oil	*Prices which are 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*
Coal Bed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Corporate Reinvestment Ratio	*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*
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*
Design Rate Capacity	*Maximum continuous rated output of a plant based on its design*
Embedded Derivative	*Implicit or explicit term(s) in a contract that affects some or all of the cash flows or the value of other exchanges required by the contract*
Feedstock	*Raw materials which 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*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
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 shareholder's 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" 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 exceed the sum of the estimated proved plus probable plus possible reserves.

Abbreviations

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

11.5 Disclosure Controls and Procedures

Disclosure Controls and Procedures

Husky's management, with the participation 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, 2012, and have concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by Husky in reports that it files or submits under the Securities Exchange Act of 1934 and Canadian securities laws is (i) recorded, processed, summarized and reported within the time periods specified in SEC rules and forms and Canadian securities laws and (ii) accumulated and communicated to Husky's management, including its principal executive officer and principal financial officer, to allow for timely decisions regarding required disclosure.

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 is responsible for 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, 2012, management assessed 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, 2012, 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) which 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, 2012, 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

	2012				2011			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream								
Daily production, before royalties								
Light crude oil & NGL *(mbbls/day)*	**86.1**	**55.4**	**56.8**	**91.2**	91.7	83.3	84.5	91.0
Medium crude oil *(mbbls/day)*	**23.2**	**23.9**	**24.1**	**24.9**	24.3	24.6	24.6	24.6
Heavy crude oil *(mbbls/day)*	**76.0**	**77.1**	**78.1**	**76.2**	75.8	75.1	73.6	73.4
Bitumen *(mbbls/day)*	**46.7**	**37.8**	**29.6**	**29.6**	27.4	23.6	23.6	24.2
Total crude oil production (mboe/day)	**232.0**	**194.2**	**188.6**	**221.9**	219.2	206.6	206.3	213.2
Natural gas *(mmcf/day)*	**523.7**	**544.9**	**559.5**	**588.3**	597.9	614.7	631.8	583.3
Total production *(mboe/day)*	**319.3**	**285.0**	**281.9**	**319.9**	318.9	309.1	311.6	310.4
Average sales prices								
Light crude oil & NGL *($/bbl)*	**94.91**	**90.5**	**94.71**	**111.53**	106.61	101.16	108.26	100.21
Medium crude oil *($/bbl)*	**67.55**	**69.59**	**69.92**	**78.63**	85.83	70.81	81.24	68.41
Heavy crude oil *($/bbl)*	**57.9**	**60.58**	**60.42**	**68.93**	76.37	62.35	72.51	61.02
Bitumen *($/bbl)*	**55.74**	**60.1**	**58.09**	**65.83**	74.19	59.60	69.76	58.11
Natural gas *($/mcf)*	**3.25**	**2.48**	**2.05**	**2.64**	3.53	4.12	4.02	3.87
Operating costs *($/boe)*	**15.05**	**16.69**	**15.83**	**14.56**	14.17	14.62	13.83	13.40
Operating netbacks[(1)]								
Lloydminster – Thermal Oil *($/boe)*[(2)]	**45.47**	**48.42**	**43.42**	**50.25**	49.90	39.20	45.61	33.34
Lloydminster – Non-Thermal Oil *($/boe)*[(2)]	**30.09**	**33.35**	**37.07**	**47.94**	47.47	35.75	43.70	35.33
Oil Sands – Bitumen *($/boe)*[(2)]	**19.49**	**33.91**	**30.05**	**35.88**	38.45	27.43	38.66	24.32
Western Canada – Crude Oil *($/boe)*[(2)]	**38.31**	**37.12**	**38.52**	**43.67**	48.12	35.40	45.67	36.81
Western Canada – Natural gas *($/mcf)*[(3)]	**1.49**	**1.16**	**1.11**	**1.52**	2.03	2.51	2.62	2.56
Atlantic – Light Oil *($/boe)*[(2)]	**85.05**	**66.97**	**70.99**	**94.34**	82.26	82.03	86.00	80.15
Asia Pacific – Light Oil & NGL *($/boe)*[(2)]	**69.28**	**72.97**	**73.54**	**88.16**	70.04	67.07	67.30	73.42
Total *($/boe)*[(2)]	**35.99**	**30.08**	**30.43**	**43.00**	42.65	37.22	42.16	38.04
Net wells drilled[(4)]								
Exploration Oil	**8**	**1**	**3**	**18**	19	8	4	9
Gas	**–**	**2**	**–**	**10**	11	3	1	9
Dry	**–**	**–**	**–**	**–**	–	–	–	3
	8	**3**	**3**	**28**	30	11	5	21
Development Oil	**217**	**245**	**56**	**197**	196	286	93	190
Gas	**6**	**1**	**2**	**8**	4	8	3	27
Dry	**3**	**–**	**–**	**1**	1	2	1	–
	226	**246**	**58**	**206**	201	296	97	217
	234	**249**	**61**	**234**	231	307	102	238
Success ratio *(percent)*	**99**	**100**	**100**	**100**	100	99	99	99
Upgrader								
Synthetic crude oil sales *(mbbls/day)*	**63.4**	**64.1**	**53.1**	**61.1**	58.2	60.7	61.0	41.0
Upgrading differential *($/bbl)*	**24.27**	**22.04**	**22.64**	**20.38**	22.32	29.87	33.09	24.00
Canadian Refined Products								
Refined products sales volumes								
Light oil products *(million litres/day)*	**9.6**	**9.9**	**8.4**	**9.1**	9.4	9.9	8.3	8.4
Asphalt products *(mbbls/day)*	**24.1**	**34**	**26.2**	**20.4**	20.1	36.4	20.2	19.9
Refinery throughput								
Lloydminster refinery *(mbbls/day)*	**28.3**	**28.7**	**29.1**	**27.2**	29.0	28.5	26.2	28.9
Prince George refinery *(mbbls/day)*	**11.4**	**11.3**	**10.4**	**11.1**	11.1	7.9	9.1	11.0
Refinery utilization *(percent)*	**97**	**97**	**96**	**93**	97	88	85	96
U.S. Refining and Marketing								
Refinery throughput								
Lima refinery (mbbls/day)	**155.9**	**153.9**	**150.7**	**139.4**	142.9	136.8	148.6	148.9
BP-Husky Toledo refinery (mbbls/day)	**58.1**	**52.7**	**64.9**	**67.3**	64.4	60.8	62.6	67.9

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

Segmented Capital Expenditures[1]

($ millions)	2012 Q4	2012 Q3	2012 Q2	2012 Q1	2011 Q4	2011 Q3	2011 Q2	2011 Q1
Upstream								
Exploration								
Western Canada	**79**	**43**	**29**	**87**	87	19	5	122
Asia Pacific	**(28)**	**17**	**–**	**–**	37	79	–	–
Atlantic Region	**5**	**35**	**6**	**–**	–	2	–	–
	56	**95**	**35**	**87**	124	100	5	122
Development								
Western Canada	**662**	**497**	**293**	**577**	653	472	254	404
Oil Sands	**220**	**152**	**132**	**154**	81	69	82	35
Asia Pacific	**91**	**175**	**203**	**134**	226	150	175	47
Atlantic Region	**213**	**150**	**101**	**58**	61	62	73	62
	1,186	**974**	**729**	**923**	1,021	753	584	548
Acquisitions								
Western Canada	**–**	**16**	**–**	**5**	14	0	18	842
Total Exploration and Production	**1,242**	**1,085**	**764**	**1,015**	1,159	853	607	1,512
Infrastructure and Marketing	**19**	**14**	**11**	**10**	14	13	10	6
Total Upstream	**1,261**	**1,099**	**775**	**1,025**	1,173	866	617	1,518
Downstream								
Upgrader	**17**	**13**	**9**	**8**	20	19	6	10
Canadian Refined Products	**33**	**32**	**19**	**13**	33	28	18	15
U.S. Refining and Marketing	**113**	**92**	**65**	**43**	72	68	62	22
	163	**137**	**93**	**64**	125	115	86	47
Corporate	**49**	**16**	**14**	**5**	34	22	12	3
	1,473	**1,252**	**882**	**1,094**	1,332	1,003	715	1,568

[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			
2012 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues	**1,764**	**1,430**	**1,382**	**1,971**	**796**	**377**	**633**	**614**	**562**	**576**	**472**	**581**
Royalties	**(189)**	**(145)**	**(140)**	**(219)**	–	–	–		–	–	–	–
Marketing and other	–	–	–	–	**76**	**120**	**120**	**71**	–	–	–	–
Revenues, net of royalties	**1,575**	**1,285**	**1,242**	**1,752**	**872**	**497**	**753**	**685**	**562**	**576**	**472**	**581**
Expenses												
Purchases of crude oil and products[2]	**20**	**15**	**13**	**25**	**741**	**335**	**591**	**591**	**417**	**423**	**339**	**447**
Production and operating expenses	**508**	**446**	**431**	**455**	**7**	**16**	**14**	**12**	**40**	**33**	**47**	**40**
Selling, general and administrative expenses	**21**	**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	**163**	**59**	**53**	**75**	–	–	–	–	–	–	–	–
Other – net	**(72)**	**28**	**(60)**	**(1)**	–	–	**1**	**(1)**	**(17)**	–	–	–
Earnings from operating activities	**321**	**167**	**276**	**633**	**112**	**136**	**135**	**74**	**94**	**95**	**60**	**68**
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	**302**	**151**	**257**	**614**	**112**	**136**	**135**	**74**	**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)	**224**	**110**	**190**	**455**	**84**	**101**	**100**	**56**	**68**	**68**	**42**	**48**
Capital expenditures[3]	**1,242**	**1,085**	**764**	**1,015**	**19**	**14**	**11**	**10**	**17**	**13**	**9**	**8**
Total assets	**22,753**	**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 the Infrastructure and Marketing segment as these assets provide a service to the Exploration and Production segment.*

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

(3) *Certain hydrogen feedstock costs from production and operating expenses have been reclassified to purchases of crude oil and products in 2012. Prior periods have been reclassified to conform with current period presentation.*

Downstream (continued)								Corporate and Eliminations[1]				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	2,412	2,477	2,657	2,492	(598)	(596)	(484)	(625)	5,869	5,331	5,628	5,913
–	–	–	–	–	–	–	–	–	–	–	–	(189)	(145)	(140)	(219)
–	–	–	–	–	–	–	–	–	–	–	–	76	120	120	71
933	1,067	968	880	2,412	2,477	2,657	2,492	(598)	(596)	(484)	(625)	5,756	5,306	5,608	5,765
794	849	802	763	2,102	2,021	2,368	2,233	(598)	(596)	(484)	(625)	3,476	3,047	3,629	3,434
49	45	50	40	102	91	100	92	(1)	1	1	3	705	632	643	642
15	14	15	14	3	4	3	3	63	34	40	41	109	112	131	99
21	21	21	20	57	52	52	51	13	11	9	7	738	629	576	637
–	–	–	–	–	–	–	–	–	–	–	–	163	59	53	75
–	(2)	–	–	4	–	–	–	(19)	4	7	5	(104)	30	(52)	3
54	140	80	43	144	309	134	113	(56)	(50)	(57)	(56)	669	797	628	875
–	–	–	–	–	–	–	–	(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	143	308	132	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	88	195	84	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	35,140	33,466	32,842	33,286

2011 *($ millions)*	Upstream								Downstream			
	Exploration and Production				Infrastructure and Marketing				Upgrading			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues[2]	2,051	1,797	1,920	1,751	619	537	336	495	615	586	648	368
Royalties	(331)	(247)	(289)	(258)	–	–	–	–	–	–	–	–
Marketing and other	–	–	–	–	32	21	2	35	–	–	–	–
Revenues, net of royalties	1,720	1,550	1,631	1,493	651	558	338	530	615	586	648	368
Expenses												
Purchases of crude oil and products[2]	60	11	(12)	40	579	506	285	448	462	400	474	269
Production and operating expenses	477	429	408	400	3	2	21	17	29	36	46	58
Selling, general and administrative expenses	25	34	51	43	4	4	5	4	7	(1)	(3)	–
Depletion, depreciation, amortization and impairment	601	498	483	436	5	7	6	6	25	26	88	25
Exploration and evaluation expenses	194	95	88	93	–	–	–	–	–	–	–	–
Other – net	2	(1)	(73)	(189)	1	–	–	–	24	18	15	10
Earnings from operating activities	361	484	686	670	59	39	21	55	68	107	28	6
Net foreign exchange gains (losses)	–	–	–	–	–	–	–	–	–	–	–	–
Finance income	1	1	1	1	–	–	–	–	–	–	–	–
Finance expenses	(19)	(16)	(18)	(15)	–	–	–	–	(2)	(2)	(1)	(2)
	(18)	(15)	(17)	(14)	–	–	–	–	(2)	(2)	(1)	(2)
Earnings (loss) before income taxes	343	469	669	656	59	39	21	55	66	105	27	4
Provisions for (recovery of) income taxes												
Current	(25)	9	32	25	18	22	13	11	2	(2)	(3)	1
Deferred	115	96	150	154	(3)	(13)	(7)	3	15	29	10	–
	90	105	182	179	15	9	6	14	17	27	7	1
Net earnings (loss)	253	364	487	477	44	30	15	41	49	78	20	3
Capital expenditures[3]	1,159	853	607	1,512	14	13	10	6	20	19	6	10
Total assets	20,141	19,669	18,916	18,708	1,509	1,206	1,353	1,628	1,316	1,266	1,302	1,335

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

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

(3) *Certain hydrogen feedstock costs from production and operating expenses have been reclassified to purchases of crude oil and products in 2012. Prior periods have been reclassified to conform with current period presentation.*

Downstream (continued)								Corporate and Eliminations[(1)]				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
928	1,177	945	827	2,381	2,527	2,600	2,244	(738)	(566)	(408)	(648)	5,856	6,058	6,041	5,037
–	–	–	–	–	–	–	–	–	–	–	–	(331)	(247)	(289)	(258)
–	–	–	–	–	–	–	–	–	–	–	–	32	21	2	35
928	1,177	945	827	2,381	2,527	2,600	2,244	(738)	(566)	(408)	(648)	5,557	5,832	5,754	4,814
786	974	798	707	2,097	2,239	2,202	1,915	(738)	(566)	(408)	(648)	3,246	3,564	3,339	2,731
44	47	49	42	101	108	90	92	–	–	–	–	654	622	614	609
13	11	12	13	4	2	3	3	55	46	70	23	108	96	138	86
20	23	19	18	52	48	45	50	13	9	9	7	716	611	650	542
–	–	–	–	–	–	–	–	–	–	–	–	194	95	88	93
–	–	–	–	–	–	–	–	(5)	6	1	(2)	22	23	(57)	(181)
65	122	67	47	127	130	260	184	(63)	(61)	(80)	(28)	617	821	982	934
–	–	–	–	–	–	–	–	(15)	6	17	2	(15)	6	17	2
–	–	–	–	–	–	–	–	25	20	17	20	26	21	18	21
(2)	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(47)	(50)	(62)	(66)	(71)	(70)	(84)	(85)
(2)	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(37)	(24)	(28)	(44)	(60)	(43)	(49)	(62)
63	121	65	46	126	129	259	183	(100)	(85)	(108)	(72)	557	778	933	872
14	3	4	4	21	55	–	–	123	(28)	26	29	153	59	72	70
2	28	12	8	25	(8)	94	67	(158)	66	(67)	(56)	(4)	198	192	176
16	31	16	12	46	47	94	67	(35)	38	(41)	(27)	149	257	264	246
47	90	49	34	80	82	165	116	(65)	(123)	(67)	(45)	408	521	669	626
33	28	18	15	72	68	62	22	34	22	12	3	1,332	1,003	715	1,568
1,632	1,630	1,625	1,581	5,476	5,459	5,043	5,034	2,352	2,456	1,852	507	32,426	31,686	30,091	28,793

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, 2012. 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 and Chief Executive Officer

Alister Cowan

Chief Financial Officer

Calgary, Canada

February 27, 2013

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, 2012 and December 31, 2011, 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, 2012 and December 31, 2011, 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 27, 2013

Consolidated Financial Statements

Consolidated Balance Sheets

(millions of Canadian dollars)	**December 31, 2012**	December 31, 2011
Assets		
Current assets		
Cash and cash equivalents *(note 9)*	**2,025**	1,841
Accounts receivable *(note 4)*	**1,349**	1,235
Income taxes receivable	**323**	273
Inventories *(note 5)*	**1,736**	2,059
Prepaid expenses	**64**	36
	5,497	5,444
Exploration and evaluation assets *(note 6)*	**810**	746
Property, plant and equipment, net *(note 7)*	**27,399**	24,279
Goodwill *(note 10)*	**663**	674
Contribution receivable *(note 8)*	**607**	1,147
Other assets	**164**	136
Total Assets	**35,140**	32,426
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities *(note 12)*	**2,986**	2,867
Asset retirement obligations *(note 16)*	**107**	116
Long-term debt due within one year *(note 13)*	**–**	407
	3,093	3,390
Long-term debt *(note 13)*	**3,918**	3,504
Other long-term liabilities *(note 15)*	**331**	342
Contribution payable *(note 8, 22)*	**1,336**	1,437
Deferred tax liabilities *(note 17)*	**4,615**	4,329
Asset retirement obligations *(note 16)*	**2,686**	1,651
Commitments and contingencies *(note 20)*		
Total Liabilities	**15,979**	14,653
Shareholders' equity		
Common shares *(note 18)*	**6,939**	6,327
Preferred shares *(note 18)*	**291**	291
Retained earnings	**11,950**	11,097
Other reserves	**(19)**	58
Total Shareholders' Equity	**19,161**	17,773
Total Liabilities and Shareholders' Equity	**35,140**	32,426

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, 2012	2011
Gross revenues *(note 3)*	**22,741**	22,992
Royalties	**(693)**	(1,125)
Marketing and other *(note 3)*	**387**	90
Revenues, net of royalties	**22,435**	21,957
Expenses		
Purchases of crude oil and products *(note 3)*	**13,596**	12,903
Production and operating expenses	**2,612**	2,476
Selling, general and administrative expenses	**451**	428
Depletion, depreciation, amortization and impairment *(note 7)*	**2,580**	2,519
Exploration and evaluation expenses *(note 6)*	**350**	470
Other – net *(note 3)*	**(123)**	(193)
	19,466	18,603
Earnings from operating activities	**2,969**	3,354
Financial items *(note 14)*		
Net foreign exchange gains	**14**	10
Finance income	**93**	86
Finance expenses	**(240)**	(310)
	(133)	(214)
Earnings before income taxes	**2,836**	3,140
Provisions for income taxes *(note 17)*		
Current	**536**	354
Deferred	**278**	562
	814	916
Net earnings	**2,022**	2,224
Earnings per share *(note 18)*		
Basic	**2.06**	2.40
Diluted	**2.06**	2.34
Weighted average number of common shares outstanding *(note 18)*		
Basic *(millions)*	**975.8**	923.8
Diluted *(millions)*	**975.9**	932.0

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, 2012	2011
Net earnings	**2,022**	2,224
Other comprehensive income (loss)		
Items that will not be reclassified into earnings, net of tax:		
Actuarial gains (losses) on pension plans *(note 19)*	**15**	(20)
Items that may be reclassified into earnings, net of tax:		
Derivatives designated as cash flow hedges *(note 22)*	**3**	–
Exchange differences on translation of foreign operations	**(95)**	88
Hedge of net investment *(note 22)*	**15**	(18)
Other comprehensive income (loss)	**(62)**	50
Comprehensive income	**1,960**	2,274

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

Consolidated Statements of Changes in Shareholders' Equity

(millions of Canadian dollars)	Common Shares (note 18)	Preferred Shares (note 18)	Retained Earnings	Other Reserves: Foreign Currency Translation	Other Reserves: Hedging (note 22)	Total Shareholders' Equity
	Attributable to Equity Holders					
Balance as at December 31, 2010	4,574	–	10,012	(10)	(2)	14,574
Net earnings	–	–	2,224	–	–	2,224
Other comprehensive income						
Actuarial losses on pension plans (net of tax of $8 million)	–	–	(20)	–	–	(20)
Exchange differences on translation of foreign operations (net of tax of $14 million)	–	–	–	88	–	88
Hedge of net investment (net of tax of $3 million) *(note 22)*	–	–	–	(18)	–	(18)
Total comprehensive income	–	–	2,204	70	–	2,274
Transactions with owners recognized directly in equity:						
Issue of common shares	1,200	–	–	–	–	1,200
Share issue costs	(27)	–	–	–	–	(27)
Issue of preferred shares	–	300	–	–	–	300
Share issue costs	–	(9)	–	–	–	(9)
Stock dividends paid	580	–	–	–	–	580
Dividends declared on common shares *(note 18)*	–	–	(1,109)	–	–	(1,109)
Dividends declared on preferred shares *(note 18)*	–	–	(10)	–	–	(10)
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)						
Actuarial gains on pension plans (net of tax of $5 million)	**–**	**–**	**15**	**–**	**–**	**15**
Derivatives designated as cash flow hedges (net of tax of $1 million)	**–**	**–**	**–**	**–**	**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	**607**	**–**	**–**	**–**	**–**	**607**
Stock options exercised	**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**

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, **2012**	2011
Operating activities		
Net earnings	**2,022**	2,224
Items not affecting cash:		
Accretion *(note 14)*	**97**	79
Depletion, depreciation, amortization and impairment *(note 7)*	**2,580**	2,519
Exploration and evaluation expenses	**60**	68
Deferred income taxes *(note 17)*	**278**	562
Foreign exchange	**(20)**	14
Stock-based compensation *(note 18)*	**54**	(1)
Loss (gain) on sale of assets	**1**	(261)
Other	**(62)**	(6)
Settlement of asset retirement obligations *(note 16)*	**(123)**	(105)
Income taxes paid	**(575)**	(282)
Interest received	**34**	12
Change in non-cash working capital *(note 9)*	**843**	269
Cash flow – operating activities	**5,189**	5,092
Financing activities		
Long-term debt issuance *(note 13)*	**500**	5,054
Long-term debt repayment *(note 13)*	**(410)**	(5,434)
Settlement of cross currency swaps	**(89)**	–
Debt issue costs	**(9)**	(5)
Proceeds from common share issuance, net of share issue costs *(note 18)*	**–**	1,173
Proceeds from preferred share issuance, net of share issue costs *(note 18)*	**–**	291
Proceeds from exercise of stock options *(note 18)*	**5**	–
Dividends on common shares *(note 18)*	**(557)**	(495)
Dividends on preferred shares *(note 18)*	**(17)**	(7)
Interest paid	**(252)**	(229)
Contribution receivable payment *(note 8)*	**563**	234
Other	**25**	90
Change in non-cash working capital *(note 9)*	**79**	238
Cash flow – financing activities	**(162)**	910
Investing activities		
Capital expenditures	**(4,701)**	(4,800)
Proceeds from asset sales	**24**	179
Contribution payable payment *(note 8)*	**(152)**	(103)
Other	**(57)**	(12)
Change in non-cash working capital *(note 9)*	**56**	316
Cash flow – investing activities	**(4,830)**	(4,420)
Increase in cash and cash equivalents	**197**	1,582
Effect of exchange rates on cash and cash equivalents	**(13)**	7
Cash and cash equivalents at beginning of year	**1,841**	252
Cash and cash equivalents at end of year	**2,025**	1,841

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.

During the first quarter of 2012, the Company completed an evaluation of activities of the Company's former Midstream segment as a service provider to the Upstream or Downstream operations. As a result, and consistent with the Company's strategic view of its integrated business, the previously reported Midstream segment activities are now aligned and reported within the Company's core exploration and production, or in its upgrading and refining businesses. The Company believes this change in segment presentation allows management and third parties to more effectively assess the Company's performance.

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 and blending of crude oil and natural gas and storage of crude oil, diluent and natural gas (Infrastructure and Marketing). The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada, offshore Greenland, offshore China and offshore Indonesia.

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

Comparative periods have been reclassified to conform to the revised segment presentation.

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2012**	2011	**2012**	2011	**2012**	2011
Gross revenues	**6,547**	7,519	**2,420**	1,987	**8,967**	9,506
Royalties	**(693)**	(1,125)	**–**	–	**(693)**	(1,125)
Marketing and other	**–**	–	**387**	90	**387**	90
Revenues, net of royalties	**5,854**	6,394	**2,807**	2,077	**8,661**	8,471
Expenses						
Purchases of crude oil and products	**73**	99	**2,258**	1,818	**2,331**	1,917
Production and operating expenses	**1,840**	1,714	**49**	43	**1,889**	1,757
Selling, general and administrative expenses	**178**	153	**21**	17	**199**	170
Depletion, depreciation, amortization and impairment	**2,121**	2,018	**22**	24	**2,143**	2,042
Exploration and evaluation expenses	**350**	470	**–**	–	**350**	470
Other – net	**(105)**	(261)	**–**	1	**(105)**	(260)
Earnings (loss) from operating activities	**1,397**	2,201	**457**	174	**1,854**	2,375
Financial items						
Net foreign exchange gains	**–**	–	**–**	–	**–**	–
Finance income	**5**	4	**–**	–	**5**	4
Finance expenses	**(78)**	(68)	**–**	–	**(78)**	(68)
Earnings (loss) before income taxes	**1,324**	2,137	**457**	174	**1,781**	2,311
Provisions for (recovery of) income taxes						
Current	**134**	41	**171**	64	**305**	105
Deferred	**211**	515	**(55)**	(20)	**156**	495
Total income tax provision (recovery)	**345**	556	**116**	44	**461**	600
Net earnings (loss)	**979**	1,581	**341**	130	**1,320**	1,711
Intersegment revenues	**2,003**	2,072	**–**	–	**2,003**	2,072
Other material non-cash items						
Gain (loss) on sale of assets	**1**	261	**–**	–	**1**	261

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

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

(3) *Certain hydrogen feedstock costs from production and operating expenses have been reclassified to purchases of crude oil and products in 2012. Prior periods have been reclassified to conform with current period presentation.*

Downstream								Corporate and Eliminations[2]		Total	
Upgrading[3]		Canadian Refined Products		U.S. Refining and Marketing		Total					
2012	2011	2012	2011	2012	2011	2012	2011	2012	2011	2012	2011
2,191	2,217	3,848	3,877	10,038	9,752	16,077	15,846	(2,303)	(2,360)	22,741	22,992
–	–	–	–	–	–	–	–	–	–	(693)	(1,125)
–	–	–	–	–	–	–	–	–	–	387	90
2,191	2,217	3,848	3,877	10,038	9,752	16,077	15,846	(2,303)	(2,360)	22,435	21,957
1,636	1,628	3,208	3,265	8,724	8,453	13,568	13,346	(2,303)	(2,360)	13,596	12,903
150	146	184	182	385	391	719	719	4	–	2,612	2,476
3	3	58	49	13	12	74	64	178	194	451	428
102	164	83	80	212	195	397	439	40	38	2,580	2,519
–	–	–	–	–	–	–	–	–	–	350	470
(17)	67	(2)	–	4	–	(15)	67	(3)	–	(123)	(193)
317	209	317	301	700	701	1,334	1,211	(219)	(232)	2,969	3,354
–	–	–	–	–	–	–	–	14	10	14	10
–	–	–	–	–	–	–	–	88	82	93	86
(11)	(7)	(6)	(6)	(5)	(4)	(22)	(17)	(140)	(225)	(240)	(310)
306	202	311	295	695	697	1,312	1,194	(257)	(365)	2,836	3,140
31	(2)	89	25	(1)	76	119	99	112	150	536	354
49	54	(9)	50	258	178	298	282	(176)	(215)	278	562
80	52	80	75	257	254	417	381	(64)	(65)	814	916
226	150	231	220	438	443	895	813	(193)	(300)	2,022	2,224
134	120	166	168	–	–	300	288	–	–	2,303	2,360
–	–	(2)	–	–	–	(2)	–	–	–	(1)	261

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2012**	2011	**2012**	2011	**2012**	2011
Expenditures on exploration and evaluation assets[3]	**273**	403	**–**	–	**273**	403
Expenditures on property, plant and equipment[3]	**3,833**	3,728	**54**	43	**3,887**	3,771
As at December 31,						
Exploration and evaluation assets	**810**	746	**–**	–	**810**	746
Developing and producing assets at cost	**38,826**	33,640	**–**	–	**38,826**	33,640
Accumulated depletion, depreciation, amortization and impairment	**(17,947)**	(15,900)	**–**	–	**(17,947)**	(15,900)
Other property, plant and equipment at cost	**47**	48	**934**	882	**981**	930
Accumulated depletion, depreciation and amortization	**(29)**	(27)	**(414)**	(380)	**(443)**	(407)
Total exploration and evaluation assets and property, plant and equipment, net	**21,707**	18,507	**520**	502	**22,227**	19,009
Total assets	**22,753**	20,141	**1,506**	1,509	**24,259**	21,650

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

(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. Includes assets acquired through acquisitions.*

Geographical Financial Information

($ millions)	Canada	
Year ended December 31,	**2012**	2011
Gross revenues	**11,365**	11,481
Royalties	**(611)**	(1,024)
Marketing and other	**386**	89
Revenue, net of royalties[1]	**11,140**	10,546
As at December 31,		
Exploration and evaluation assets	**496**	421
Property, plant and equipment, net	**21,718**	19,481
Goodwill	**160**	160
Total non-current assets	**23,090**	21,315

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

Downstream								Corporate and Eliminations[2]		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2012	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011	**2012**	2011
–	–	**–**	–	**–**	–	**–**	–	**–**	–	**273**	403
47	55	**97**	94	**313**	224	**457**	373	**84**	71	**4,428**	4,215
–	–	**–**	–	**–**	–	**–**	–	**–**	–	**810**	746
–	–	**–**	–	**–**	–	**–**	–	**–**	–	**38,826**	33,640
–	–	**–**	–	**–**	–	**–**	–	**–**	–	**(17,947)**	(15,900)
2,006	1,972	**2,189**	2,208	**4,487**	4,325	**8,682**	8,505	**643**	557	**10,306**	9,992
(950)	(848)	**(967)**	(1,007)	**(951)**	(759)	**(2,868)**	(2,614)	**(475)**	(432)	**(3,786)**	(3,453)
1,056	1,124	**1,222**	1,201	**3,536**	3,566	**5,814**	5,891	**168**	125	**28,209**	25,025
1,242	1,316	**1,646**	1,632	**5,326**	5,476	**8,214**	8,424	**2,667**	2,352	**35,140**	32,426

United States		Other International		Total	
2012	2011	**2012**	2011	**2012**	2011
11,004	11,201	**372**	310	**22,741**	22,992
–	–	**(82)**	(101)	**(693)**	(1,125)
1	1	**–**	–	**387**	90
11,005	11,202	**290**	209	**22,435**	21,957
–	–	**314**	325	**810**	746
3,535	3,572	**2,146**	1,226	**27,399**	24,279
503	514	**–**	–	**663**	674
4,055	4,103	**2,498**	1,564	**29,643**	26,982

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 Chief Executive Officer on February 27, 2013, having been duly authorized to do so by the Board of Directors.

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, 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") 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. 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 which 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 and 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 next scheduled turnaround.

v) Depletion, Depreciation and Amortization

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

Oil and gas reserves are evaluated internally and audited by independent qualified reserves 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. 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.

f) 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. 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.

g) 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.

h) 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 which 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, probable and unproved volumes, which are risk-weighted utilizing geological, production, recovery 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.

i) 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 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.

j) 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.

k) Share Capital

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

l) 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 other comprehensive income ("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.

m) 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 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.

i) Derivative Instruments

All derivative instruments, other than those designated as effective hedging instruments, are classified as FVTPL – held for trading and are recorded on the balance sheet 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 to offset fixed or floating price contracts entered into with customers and suppliers to retain market prices while meeting customer or supplier pricing requirements. The estimation of the fair value of commodity derivatives and the related inventory incorporates forward prices and adjustments for quality or location. Gains and losses from these 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 and are recorded on the balance sheet as set forth below under "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, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between the hedged items and the hedging items, and the method for testing the effectiveness of the hedge, which must be reasonably assured over the term of the derivative transaction. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions.

The Company formally assesses, both at the inception of the hedge and at each reporting date, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of the hedged items. For fair value hedges, the gains or losses arising from adjusting the derivative to its fair value are recognized immediately in net earnings along with the offsetting gain or loss on the hedged item. For cash flow hedges, the effective portion of the gains and losses is recorded in OCI until the hedged transaction is recognized in net earnings. Any hedge ineffectiveness is immediately recognized in net earnings. When the hedged transaction is recognized in net earnings, the fair value of the associated cash flow hedging item is reclassified from other reserves into net earnings. Hedge accounting is discontinued on a prospective basis when the hedging relationship no longer qualifies for hedge accounting.

When a fair value hedging relationship is discontinued as a result of discontinuing the hedging instrument, any gain or loss on the hedging instrument is deferred and amortized to net earnings over the remaining maturity of the hedged item. Any gain or loss on the hedging instrument resulting from the discontinuation of a cash flow hedging relationship 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.

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.

The Company may enter into interest rate swap agreements to hedge its fixed and floating interest rate mix on long-term debt. The estimated fair value of interest rate hedges is determined primarily through forward market prices and compared with quotes from financial institutions. Gains and losses from these contracts are recognized as an adjustment to finance expense on the hedged debt instrument.

The Company may also enter into interest rate swap agreements to fix interest rates on a highly probable forecasted issuance of long-term debt. The estimated fair value of forward starting swaps is determined primarily using forward market prices. The effective portion of gains and losses on these instruments is recorded in OCI and is adjusted for changes in the fair value of the instrument until the forecasted transaction occurs.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. The estimated fair value of forward purchases of U.S. dollars is determined primarily using forward market prices. Gains and losses on these instruments related to foreign exchange are recorded in foreign exchange gains or losses in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The remaining portion of the gain or loss is recorded in OCI and is adjusted for changes in the fair value of the instrument over the life of the debt.

The Company may enter into foreign exchange forwards and foreign exchange collars to hedge anticipated U.S. dollar denominated crude oil and natural gas sales. The estimate of fair value for foreign currency hedges is determined primarily through forward market prices and compared with quotes from financial institutions. Gains and losses on these instruments are recognized in Upstream oil and gas revenues when the sale is recorded.

n) 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.

o) 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. An impairment loss 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 requires 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.

p) 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.

Past service costs are recognized in the benefit cost on a straight-line basis over the average period until the benefits become vested. The past service costs are recognized as an expense immediately following the introduction of, or changes to, the pension plans.

The defined benefit asset or liability is comprised of the present value of the defined benefit obligation, less past service costs 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 who is 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.

q) 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. Significant estimations are also made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where 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.

r) 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.

s) 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 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.

t) 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 date of the transaction. 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 date of the transactions.

u) 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 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 is contingent on the Company's total shareholder return relative to a peer group of companies. 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.

v) 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 share 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.

w) 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.

x) Recent Accounting Standards

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 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 10 on January 1, 2013. The adoption of the standard is not expected to have a material impact on the Company's 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 arrangement shall be classified as a joint venture and accounted for using the equity method of accounting. Under the existing IFRS standard, the Company has the option to account for any interests it has in joint arrangements using proportionate consolidation or equity accounting. IFRS 11 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 11 on January 1, 2013. The adoption of the standard is not expected to have a material impact on the Company's financial statements.

iii) Disclosure of Interests in Other Entities

In May 2011, the IASB published IFRS 12, "Disclosure of Interests in Other Entities," which contains new 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 financial statements. IFRS 12 is effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 12 on January 1, 2013. The adoption of the standard is not expected to have a material impact on the Company's 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 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt these amendments on January 1, 2013. The Company does not expect the amendments to IAS 28 to have a material impact on the Company's financial statements.

i) 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 fair value measurement 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 is effective for the Company on January 1, 2013 with required prospective application and early adoption permitted. The Company intends to adopt IFRS 13 on January 1, 2013. The adoption of the standard is not expected to 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 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt these amendments on January 1, 2013. The adoption of the amended standard is not expected to have a material impact on the Company's financial statements.

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 are effective for the Company on January 1, 2013 with required retrospective application and early adoption permitted. Amendments to IAS 32 are effective for the Company on January 1, 2014 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the IFRS 7 amendments on January 1, 2013 and the IAS 32 amendments on January 1, 2014. The adoption of these amended standards is not expected to have a material impact on the Company's financial statements.

viii) Financial Instruments

In November 2009, the IASB published IFRS 9, "Financial Instruments," which covers the classification and measurement of financial assets as part of its project to replace IAS 39, "Financial Instruments: Recognition and Measurement." In October 2010, the requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to their own credit risk out of net earnings and recognize the change in OCI. IFRS 9 is effective for the Company on January 1, 2015 with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the amendments on January 1, 2015. The adoption of the standard is not expected to have a material impact on the Company's financial statements.

y) Change in Presentation of Trading Activities

During the first quarter of 2012, the Company completed a review of the trading activities within its Infrastructure and Marketing segment and determined that the realized and the unrealized gains and losses previously presented on a gross basis in gross revenues, purchases of crude oil and products and other – net, would be more appropriately presented on a net basis to reflect the nature of trading activities. As a result, these realized and unrealized gains and losses, and the underlying settlement of these contracts, have been recognized and recorded on a net basis in marketing and other in the consolidated statements of income.

Prior periods have been reclassified to reflect this change in presentation and there was no impact on net earnings:

Earnings Impact

($ millions)	2011
Gross revenues	(1,497)
Marketing and other	90
Purchases of crude oil and products	1,399
Other net	8
Net earnings	–

z) Change in Accounting Policy

In June 2011, the International Accounting Standards Board ("IASB") issued IAS 1, "Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements." The amendments stipulate the presentation of net earnings and OCI and also require the Company to group items within OCI based on whether the items may be subsequently reclassified to profit or loss. Amendments to IAS 1 were effective for the Company on January 1, 2012 with required retrospective application and early adoption permitted. The Company retrospectively adopted the amendments on January 1, 2012. The adoption of the amendments to this standard did not have a material impact on the Company's financial statements.

Note 4 Accounts Receivable

Accounts Receivable

($ millions)	**December 31, 2012**	December 31, 2011
Trade receivables	**1,291**	1,071
Allowance for doubtful accounts	**(23)**	(23)
Derivatives due within one year	**14**	66
Other	**67**	121
	1,349	1,235

Note 5 Inventories

Inventories

($ millions)	**December 31, 2012**	December 31, 2011
Crude oil, natural gas and sulphur	**1,113**	1,476
Refined petroleum products	**157**	176
Trading inventories measured at fair value	**328**	284
Materials, supplies and other	**138**	123
	1,736	2,059

Impairment of inventory to net realizable value as at December 31, 2012 was $1 million (December 31, 2011 – $3 million) primarily due to a reduction in market prices for asphalt and ethanol products.

Note 6 Exploration and Evaluation Costs

Exploration and Evaluation Assets

($ millions)	2012	2011
Beginning of year	**746**	472
Additions	**291**	331
Acquisitions	**16**	116
Transfers to oil and gas properties *(note 7)*	**(198)**	(92)
Expensed exploration expenditures previously capitalized	**(42)**	(68)
Disposals	**–**	(19)
Exchange adjustments	**(3)**	6
End of year	**810**	746

The following exploration and evaluation expenses for the years ended December 31, 2012 and 2011 relate to activities associated with the exploration for and evaluation of oil and natural gas resources and are recorded in Exploration and Production in the Upstream segment:

Exploration and Evaluation Expense Summary

($ millions)	2012	2011
Seismic, geological and geophysical	**146**	170
Expensed drilling	**188**	245
Expensed land	**16**	55
	350	470

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, 2010	29,144	1,069	1,974	4,545	2,028	38,760
Additions	3,028	43	58	269	119	3,517
Acquisitions	848	–	–	–	–	848
Transfers from exploration and evaluation *(note 6)*	92	–	–	–	–	92
Intersegment transfers	84	(84)	–	–	–	–
Changes in asset retirement obligations	542	5	3	30	27	607
Disposals and derecognition	(113)	(103)	(63)	(22)	2	(299)
Exchange adjustments	15	–	–	94	–	109
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)**
December 31, 2012	**38,826**	**981**	**2,006**	**5,094**	**2,225**	**49,132**
Accumulated depletion, depreciation, amortization and impairment						
December 31, 2010	(13,919)	(449)	(742)	(818)	(1,062)	(16,990)
Depletion, depreciation, amortization and impairment[1]	(1,990)	(48)	(169)	(220)	(92)	(2,519)
Intersegment transfers	(46)	46	–	–	–	–
Disposals and derecognition	58	44	63	3	–	168
Exchange adjustments	(3)	–	–	(11)	–	(14)
December 31, 2011	(15,900)	(407)	(848)	(1,046)	(1,154)	(19,355)
Depletion, depreciation and amortization[1]	**(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)**
Net book value						
December 31, 2011	17,740	523	1,124	3,870	1,022	24,279
December 31, 2012	**20,879**	**538**	**1,056**	**3,834**	**1,092**	**27,399**

(1) *Depletion, depreciation and amortization for the year ended December 31, 2012 does not include amortization of research and development assets of $5 million (2011 – $10 million), offset by exchange adjustments of $8 million (2011 – $10 million).*

Costs of property, plant and equipment, including major development projects, excluded from costs subject to depletion, depreciation and amortization as at December 31, 2012 were $6.1 billion (December 31, 2011 – $5.3 billion).

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, 2011	1,913
December 31, 2012	**3,051**

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, 2011	2,200
December 31, 2012	**1,796**

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, 2011	32
December 31, 2012	**30**

In 2012, as a result of declines in future natural gas prices, an impairment test was performed on two heavily gas-weighted CGUs located in East Central Alberta. No impairment indicators were identified for Husky's remaining CGUs. The Company estimated the recoverable amount based on a VIU methodology using estimated cash flows based on both proved plus probable reserves and near-term development plans, discounted using an average pre-tax discount rate of 8% (2011 – 8%). At December 31, 2012, no impairment has been recognized in relation to these CGUs (December 31, 2011 – $70 million); however, the VIU calculation continues to be sensitive to factors such as development plans and, in particular, future natural gas prices, as a U.S. $0.10/mmbtu decrease represents an approximate effect on an annual undiscounted pre-tax earnings of $12 million.

Note 8 Joint Ventures

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)	**2012**	2011
Beginning of year	**1,437**	1,427
Accretion	**81**	83
Paid	**(152)**	(103)
Foreign exchange	**(30)**	30
End of year	**1,336**	1,437

The contribution payable accretes at a rate of 6% and is payable between December 31, 2012 and December 31, 2015 with the final balance due 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. 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)	**2012**	2011
Revenues	**2,574**	2,632
Expenses	**(2,319)**	(2,389)
Proportionate share of net earnings	**255**	243

Balance Sheets

($ millions)	**December 31, 2012**	December 31, 2011
Current assets	**416**	487
Non-current assets	**1,864**	1,859
Current liabilities	**(210)**	(223)
Non-current liabilities	**(492)**	(534)
Proportionate share of net assets	**1,578**	1,589

Other Joint Ventures

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, 2012 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 from BP included in the consolidated balance sheets is as follows:

Contribution Receivable

($ millions)	**2012**	2011
Beginning of year	**1,147**	1,284
Accretion	**53**	71
Received	**(563)**	(234)
Foreign exchange	**(30)**	26
End of year	**607**	1,147

The Company also holds a 40% interest in Husky-CNOOC Madura Limited, which is engaged in exploring for oil and gas resources in Indonesia. Results of the Husky-CNOOC Madura Limited and Sunrise Oil Sands Partnership joint ventures are included in Exploration and Production in the Upstream segment.

Summarized below is the Company's proportionate share of operating results and financial position in the Sunrise Oil Sands Partnership and Husky-CNOOC Madura Limited that have been included in the consolidated statements of income and the consolidated balance sheets:

Results of Operations

($ millions)	2012	2011
Revenues	–	–
Expenses	(13)	(9)
Financial items	30	97
Proportionate share of net earnings	17	88

Balance Sheets

($ millions)	December 31, 2012	December 31, 2011
Current assets	17	8
Non-current assets	1,960	1,778
Current liabilities	(117)	(38)
Non-current liabilities	(51)	(21)
Proportionate share of net assets	1,809	1,727

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

Non-cash Working Capital

($ millions)	2012	2011
Decrease (increase) in non-cash working capital		
Accounts receivable	314	553
Inventories	329	(77)
Prepaid expenses	(29)	(8)
Accounts payable and accrued liabilities	364	355
Change in non-cash working capital	978	823
Relating to:		
Operating activities	843	269
Financing activities	79	238
Investing activities	56	316

Cash and cash equivalents at December 31, 2012 included $127 million of cash (December 31, 2011 – $2 million) and $1,898 million of short-term investments with original maturities less than three months at the time of purchase (December 31, 2011 – $1,839 million).

Note 10 Goodwill

Goodwill

($ millions)	2012	2011
Beginning of year	**674**	663
Exchange adjustments	**(11)**	11
End of year	**663**	674

As at December 31, 2012, 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 10% (2011 – 10%). 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% (2011 – 2%). At December 31, 2012, 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.

Note 11 Bank Operating Loans

At December 31, 2012, the Company had unsecured short-term borrowing lines of credit with banks totalling $515 million (December 31, 2011– $465 million) and letters of credit under these lines of credit totalling $235 million (December 31, 2011 – $250 million). As at December 31, 2012, bank operating loans were nil (December 31, 2011 – nil). Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates. During 2012, the Company's weighted average interest rate on short-term borrowings was approximately 1.2% (2011 – 1.2%).

Husky Energy (HK) Limited and Husky Oil China Ltd., subsidiaries of the Company, each have an uncommitted demand revolving facility of U.S. $10 million available for general purposes. As at December 31, 2012, there was no balance outstanding under these facilities (December 31, 2011 – nil). 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, 2012, there was no balance outstanding under this credit facility (December 31, 2011 – nil).

Note 12 Accounts Payable and Accrued Liabilities

Accounts Payable and Accrued Liabilities

($ millions)	December 31, 2012	December 31, 2011
Trade payables	**152**	74
Accrued liabilities	**2,292**	2,178
Dividend payable *(note 18)*	**295**	291
Stock-based compensation	**47**	9
Derivatives due within one year	**5**	138
Contingent consideration	**27**	17
Other	**168**	160
	2,986	2,867

Note 13 Long-term Debt

Long-term Debt ($ millions)	Maturity	Canadian $ Amount December 31, 2012	Canadian $ Amount December 31, 2011	U.S. $ Denominated December 31, 2012	U.S. $ Denominated December 31, 2011
Long-term debt					
5.90% notes(1)(2)	2014	**746**	763	**750**	750
3.75% medium-term notes(1)	2015	**300**	300	**–**	–
7.55% debentures(1)	2016	**199**	203	**200**	200
6.20% notes(1)(2)	2017	**298**	305	**300**	300
6.15% notes(2)	2019	**298**	305	**300**	300
7.25% notes(2)	2019	**746**	763	**750**	750
5.00% medium-term notes	2020	**400**	400	**–**	–
3.95% notes(2)	2022	**498**	–	**500**	–
6.80% notes(2)	2037	**385**	393	**387**	387
Debt issue costs(3)		**(24)**	(21)	**–**	–
Unwound interest rate swaps		**72**	93	**–**	–
Long-term debt		**3,918**	3,504	**3,187**	2,687
Long-term debt due within one year					
6.25% notes(4)		**–**	407	**–**	400

(1) A portion of the Company's debt was designated in a fair value hedging relationship for interest rate risk management and the gains or losses arising from adjusting the derivative to its fair value were recognized immediately in net earnings along with the offsetting gain or loss on the hedged item recorded at fair value until discontinuation of the hedging relationship in 2011. Refer to Note 22.

(2) A portion of the Company's U.S. denominated debt is designated as a hedge of the Company's net investment in its U.S. refining operations. Refer to Note 22.

(3) Calculated using the effective interest rate method.

(4) A portion of the Company's debt was designated in a cash flow hedging relationship for foreign currency risk management, with the use of cross currency swaps, until expiration of the hedging relationship in the second quarter of 2012 with the repayment of the related U.S. $400 million of 6.25% notes which matured on June 15, 2012 and the settlement of the cross currency swaps on the same day. Refer to Note 22.

Credit Facilities

The Company's revolving syndicated credit facility, which was entered into on November 15, 2011 and amended and restated on December 14, 2012, allows the Company to borrow up to $1.5 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a four-year committed revolving credit facility with a maturity date of December 14, 2016.

The Company also has a second revolving syndicated credit facility, which was entered into on August 31, 2010 and amended and restated on December 14, 2012. The facility allows the Company to borrow up to $1.6 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a four-year committed revolving credit with a maturity date of August 31, 2014.

These facilities, except for their maturity dates, have the same terms. 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, 2012, the Company had no borrowings under either revolving syndicated credit facility (December 31, 2011 – no borrowings under the prior $1.6 billion revolving syndicated credit facility, the prior $1.7 billion revolving syndicated credit facility or the $100 million bilateral credit facility which was cancelled effective February 3, 2012).

Notes and Debentures

The 7.55% debentures represent unsecured securities under a trust indenture dated October 31, 1996.

The 6.15% notes represent unsecured securities under a trust indenture dated June 14, 2002.

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.

The 3.75% and the 5.00% medium-term notes represent unsecured securities under a trust indenture dated December 21, 2009.

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.

At December 31, 2012, 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, which is the Company's forecasted debt issuance on the same date. Refer to Note 22.

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 enables 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 up to and including July 12, 2013. At December 31, 2012, approximately $1.5 billion remains available for issuance under the U.S. Base Prospectus.

On December 31, 2012, the Company filed a universal short form base shelf prospectus (the "Canadian Base 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 (the "Securities") in Canada up to and including January 30, 2015. As of December 31, 2012, the Company had not issued Securities under the Canadian Base Prospectus. This Canadian Base 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.

The ability of the Company to raise capital utilizing the U.S. Base Prospectus or the Canadian Base 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.

The unamortized portion of the gain on previously unwound interest rate swaps that were designated as a fair value hedge is included in the carrying value of long-term debt. Refer to Note 22.

Note 14 Financial Items

Financial Items

($ millions)	2012	2011
Foreign exchange		
Gains (losses) on translation of U.S. dollar denominated long-term debt	**43**	(47)
Gains on cross currency swaps	**2**	7
Gains (losses) on contribution receivable	**(7)**	34
Other foreign exchange gains (losses)	**(24)**	16
Net foreign exchange gains	**14**	10
Finance income		
Contribution receivable	**53**	71
Interest income	**34**	–
Other	**6**	15
Finance income	**93**	86
Finance expenses		
Long-term debt	**(232)**	(226)
Contribution payable	**(81)**	(82)
Short-term debt	**(3)**	(9)
	(316)	(317)
Interest capitalized[1]	**173**	86
	(143)	(231)
Accretion of asset retirement obligations *(note 16)*	**(87)**	(73)
Accretion of other long-term liabilities	**(10)**	(6)
Finance expenses	**(240)**	(310)
	(133)	(214)

[1] *Interest capitalized on project costs in 2012 is calculated using the Company's annualized effective interest rate of 6% (2011 – 6%).*

Other foreign exchange gains and losses primarily include realized and unrealized foreign exchange gains and losses on property, plant and equipment, and working capital.

Note 15 Other Long-term Liabilities

Other Long-term Liabilities

($ millions)	December 31, 2012	December 31, 2011
Employee future benefits *(note 19)*	**147**	166
Finance lease obligations	**31**	33
Stock-based compensation	**21**	8
Contingent consideration *(note 22)*	**78**	112
Other	**54**	23
	331	342

Note 16 Asset Retirement Obligations

At December 31, 2012, the estimated total undiscounted inflation adjusted amount required to settle the Company's ARO was $10.3 billion (December 31, 2011 – $8.5 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 45 years into the future. This amount has been discounted using credit-adjusted risk-free rates of 3% to 5% (December 31, 2011 – 3% to 5%). Obligations related to environmental remediation and cleanup of oil and gas producing assets are included in the estimated ARO.

The change in estimates in 2012 primarily related to increased cost estimates for the retirement of assets in the Asia Pacific Region, the Atlantic Region and in Western Canada, and a revision of the timing of future ARO cash flows for Western Canadian and Downstream assets.

Asset Retirement Obligations

($ millions)	**2012**	2011
Beginning of year	**1,767**	1,198
Additions	**154**	188
Liabilities settled	**(123)**	(105)
Liabilities disposed	**(1)**	(6)
Change in discount rate	**174**	387
Change in estimates	**737**	32
Exchange adjustment	**(2)**	–
Accretion[1]	**87**	73
End of year	**2,793**	1,767
Expected to be incurred within 1 year	**107**	116
Expected to be incurred beyond 1 year	**2,686**	1,651

(1) Accretion is included in finance expenses. Refer to Note 14.

Note 17 Income Taxes

The major components of income tax expense for the years ended December 31, 2012 and 2011 were as follows:

Income Tax Expense

($ millions)	**2012**	2011
Current income tax		
Current income tax charge	**529**	334
Adjustments in respect of current income tax of previous years	**7**	20
	536	354
Deferred income tax		
Relating to origination and reversal of temporary differences	**221**	511
Adjustments in respect of deferred income tax of previous years	**57**	51
	278	562

Deferred Tax Items in OCI

($ millions)	**2012**	2011
Deferred tax items expensed (recovered) directly in OCI		
Derivatives designated as cash flow hedges	**1**	–
Actuarial gains (losses) on pension plans	**5**	(8)
Exchange differences on translation of foreign operations	**(12)**	14
Hedge of net investment	**2**	(3)
	(4)	3

Deferred Tax Items in Equity

($ millions)	**2012**	2011
Deferred tax items expensed (recovered) directly in equity		
Share issue costs	**–**	(9)

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, 2012 and 2011 were accounted for as follows:

Reconciliation of Effective Tax Rate

($ millions)	**2012**	2011
Earnings before income taxes		
Canada	**2,097**	2,556
United States	**575**	508
Other foreign jurisdictions	**164**	76
	2,836	3,140
Statutory income tax rate (percent)	**25.8**	27.3
Expected income tax	**732**	857
Effect on income tax resulting from:		
Rate benefit on partnership earnings	**–**	(56)
Capital gains and losses	**(10)**	2
Foreign jurisdictions	**37**	46
Non-taxable items	**12**	(5)
Adjustments in respect of previous years	**64**	71
Other – net	**(21)**	1
Income tax expense	**814**	916

The statutory tax rate was 25.8% in 2012 (2011 – 27.3%). The decrease from 2011 to 2012 is due to a reduction in the 2012 Canadian corporate tax rates as part of a series of corporate tax rate reductions previously enacted by the Canadian federal government.

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

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	(4,914)	**(487)**	**13**	**(12)**	**(5,400)**
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**
	(4,329)	**(278)**	**4**	**(12)**	**(4,615)**

Deferred Tax Liabilities and Assets ($ millions)	January 1,2011	Recognized in Earnings	Recognized in OCI	Other	December 31, 2011
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(4,371)	(519)	(18)	(6)	(4,914)
Foreign exchange gains taxable on realization	(74)	(13)	3	–	(84)
Other temporary differences	22	(34)	–	9	(3)
Deferred tax assets					
Pension plans	38	–	8	–	46
Asset retirement obligations	308	180	1	–	489
Financial assets at fair value	3	3	–	–	6
Loss carry-forwards	310	(192)	3	–	121
Debt issue costs	(3)	13	–	–	10
	(3,767)	(562)	(3)	3	(4,329)

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At December 31, 2012, the Company has no deferred tax liabilities in respect of these temporary differences (December 31, 2011 – nil).

At December 31, 2012, the Company had $86 million (December 31, 2011 – $443 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, 2010	890,708,795	4,574
Common shares issued, net of share issue costs	44,362,214	1,173
Stock dividends	22,461,089	580
Options exercised	5,000	–
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**

On June 29, 2011, the Company issued approximately 37 million common shares at a price of $27.05 per share for total gross proceeds of approximately $1.0 billion through a public offering, and a total of approximately 7.4 million common shares at a price of $27.05 per share for total gross proceeds of $200 million through a private placement to L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. The public offering was conducted under the Company's universal base shelf prospectus filed November 26, 2010 with the securities regulatory authorities in all provinces of Canada, the Company's universal base shelf prospectus filed June 13, 2011 with the Alberta Securities Commission and the U.S. Securities and Exchange Commission and the respective accompanying prospectus supplements.

Shareholders have the option to receive dividends in common shares or in cash. 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, 2012, the Company declared dividends payable of $1.20 per common share (2011 – $1.20 per common share), resulting in dividends of $1.2 billion (2011 – $1.1 billion). An aggregate of $557 million was paid in cash during 2012 (2011 – $495 million). At December 31, 2012, $295 million, including $293 million in cash and $2 million in common shares, was payable to shareholders on account of dividends declared on November 1, 2012 (December 31, 2011 – $287 million, including $87 million in cash and $200 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, 2010	–	–
Cumulative Redeemable Preferred Shares, Series 1 issued, net of share issue costs	12,000,000	291
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**

On March 18, 2011, the Company issued 12 million Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") at a price of $25.00 per share for aggregate gross proceeds of $300 million. Net proceeds after share issue costs were $291 million. The Series 1 Preferred Shares were offered by way of a prospectus supplement under the short form base shelf prospectus filed November 26, 2010 with the securities regulatory authorities in all provinces of Canada.

Holders of the Series 1 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.45% annually for the 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, 2012, the Company declared dividends payable of $13 million on the Series 1 Preferred Shares (2011 – $10 million) representing approximately $1.11 per Series 1 Preferred Share (2011 – $0.87 per Series 1 Preferred Share). At December 31, 2012, there were no amounts payable as dividends on the Series 1 Preferred Shares (December 31, 2011 – $3 million). A total of $17 million was paid during 2012 (2011 – $7 million), representing approximately $0.28 per Series 1 Preferred Share (2011 – $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. For options granted up to 2009, when the option is surrendered for cash, the cash payment is the difference between the weighted average trading price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option. For options granted after 2009, when the option is surrendered for cash, the cash payment is the difference between the weighted average trading price of the Company's common shares for the five trading days following the surrender date and the exercise price of the option.

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, 2012 was $57 million (December 31, 2011 – $16 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, 2012 was $42 million (2011 – recovery of $2 million). At December 31, 2012, stock options exercisable for cash had an intrinsic value of $31 million (December 31, 2011 – nil).

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

Outstanding and Exercisable Options	2012		2011	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of year	**33,337**	**34.62**	29,541	37.04
Granted[(1)]	**11,137**	**25.61**	9,618	28.80
Exercised for common shares	**(177)**	**27.61**	(5)	28.19
Expired or forfeited	**(15,276)**	**39.09**	(5,817)	37.30
Outstanding, end of year	**29,021**	**28.85**	33,337	34.62
Exercisable, end of year	**10,796**	**32.19**	18,486	39.50

(1) *Options granted during the year ended December 31, 2012 were attributed a fair value of $3.94 per option (2011 – $4.41) 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	25,765	27.32	3	7,540	28.40
$30.00 – $34.99	661	31.24	1	661	31.24
$35.00 – $39.99	201	39.97	–	201	39.97
$40.00 – $42.99	748	40.91	–	748	40.91
$43.00 – $45.02	1,646	45.02	1	1,646	45.02
December 31, 2012	**29,021**	**28.85**	**3**	**10,796**	**32.19**

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 two plans:

Black-Scholes Assumptions	December 31, 2012		December 31, 2011	
	Tandem Options	Tandem Performance Options	Tandem Options	Tandem Performance Options
Dividend per option	**1.31**	**1.31**	1.33	1.33
Range of expected volatilities used *(percent)*	**13.5 – 33.2**	**13.5 – 24.8**	21.3 – 35.9	21.3 – 32.0
Range of risk-free interest rates used *(percent)*	**0.9 – 1.4**	**0.9 –1.1**	0.7 – 1.3	0.7 – 1.0
Expected life of share options from vesting date *(years)*	**1.82**	**1.82**	1.75	1.75
Expected forfeiture rate *(percent)*	**11.0**	**11.0**	11.5	11.5
Weighted average exercise price	**29.16**	**41.36**	34.59	41.51
Weighted average fair value	**2.84**	**0.28**	0.82	0.03

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 Board of Directors based on the Company reaching certain shareholder return 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, 2012, the carrying amount of the liability relating to PSUs was $11 million (December 31, 2011 – $1 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, 2012 was $12 million (2011 – expense of $1 million). The weighted average contractual life of the PSUs at December 31, 2012 was 2 years.

The number of PSUs outstanding was as follows:

Performance Share Units	2012	2011
Beginning of year	500,000	220,000
Granted	539,500	295,000
Exercised	(82,000)	–
Forfeited	(93,000)	(15,000)
Outstanding, end of year	864,500	500,000
Vested, end of year	429,835	121,190

Earnings per Share

Earnings per share *($ millions)*	2012	2011
Net earnings	2,022	2,224
Effect of dividends declared on preferred shares in the year	(13)	(10)
Net earnings – basic	2,009	2,214
Dilutive effect of accounting for share options as equity-settled[(1)]	–	(30)
Net earnings – diluted	2,009	2,184
(millions)		
Weighted average common shares outstanding – basic	975.8	923.8
Effect of stock dividends declared in the year	0.1	8.2
Weighted average common shares outstanding – diluted	975.9	932.0
Earnings per share – basic ($/share)	2.06	2.40
Earnings per share – diluted ($/share)	2.06	2.34

(1) Stock-based compensation expense was $42 million based on cash-settlement for the year ended December 31, 2012 (2011 – recovery of $2 million). Stock-based compensation expense was $33 million based on equity-settlement for the year ended December 31, 2012 (2011 – expense of $28 million). For the year ended December 31, 2012, 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, 2012, 29 million tandem options and 1 million tandem performance options (2011 – 26 million tandem options and 7 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, 2012. The most recent actuarial valuation of the plans was December 31, 2011 for the Canadian defined benefit plan and the other post-employment benefit plan. The most recent actuarial valuation of the U.S. plans was January 1, 2012.

Defined Contribution Pension Plan

During the year ended December 31, 2012, the Company recognized a $33 million expense (2011 – $28 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, 2012**	December 31, 2011	December 31, 2010
Fair value of plan assets	**156**	147	142
Defined benefit obligation	**(189)**	(183)	(170)
Funded status	**(33)**	(36)	(28)
Unrecognized past service costs	**–**	–	–
Net Liability	**(33)**	(36)	(28)
Non-current liability	**(33)**	(36)	(28)

OPEB Plan

($ millions)	**December 31, 2012**	December 31, 2011	December 31, 2010
Fair value of plan assets	**–**	–	–
Defined benefit obligation	**(105)**	(120)	(100)
Funded status	**(105)**	(120)	(100)
Unrecognized past service costs	**(9)**	(10)	(12)
Net Liability	**(114)**	(130)	(112)
Non-current liability	**(114)**	(130)	(112)

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

DB Pension Plan

($ millions)	**2012**	2011	2010
Experience adjustments arising on plan liabilities	**(0.5)**	0.2	1.8

OPEB Plan

($ millions)	**2012**	2011	2010
Experience adjustments arising on plan liabilities	**1.6**	(1.2)	(0.6)

The following table summarizes the experience adjustments arising on the DP Pension Plan assets:

DB Pension Plan

($ millions)	**2012**	2011	2010
Experience adjustments arising on plan assets	**(2.2)**	5.3	(4.0)

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, 2012 and 2011:

DB Pension Plan and OPEB Plan Net Asset (Liability)

($ millions)	DB Pension Plan 2012	DB Pension Plan 2011	OPEB Plan 2012	OPEB Plan 2011
Beginning of year	**(36)**	(28)	**(130)**	(112)
Employer contributions	**8**	10	**1**	1
Benefit cost	**–**	–	**(10)**	(9)
Actuarial loss (gain)	**(5)**	(18)	**25**	(10)
End of year	**(33)**	(36)	**(114)**	(130)

DB Pension Plan and OPEB Plan

($ millions)	DB Pension Plan 2012	DB Pension Plan 2011	OPEB Plan 2012	OPEB Plan 2011
Amounts recognized in net earnings				
Current service cost	**2**	3	**7**	6
Interest cost	**7**	8	**4**	5
Expected return on plan assets	**(9)**	(10)	**–**	–
Past service cost (credit)	**–**	–	**(2)**	(2)
Curtailment gain	**–**	(1)	**–**	–
Benefit cost	**–**	–	**9**	9
Amounts recognized in retained earnings				
Actuarial loss (gain) recognized	**5**	18	**(25)**	10
Cumulative actuarial loss (gain), end of year	**32**	27	**(4)**	21

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

Defined Benefit Obligation

($ millions)	DB Pension Plan 2012	DB Pension Plan 2011	OPEB Plan 2012	OPEB Plan 2011
Beginning of year	**183**	170	**120**	100
Current service cost	**2**	3	**7**	6
Interest cost	**7**	8	**4**	5
Benefits paid	**(10)**	(10)	**(1)**	(1)
Actuarial loss (gain)	**7**	13	**(25)**	10
Curtailment gain	**–**	(1)	**–**	–
End of year	**189**	183	**105**	120

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

Fair Value of Plan Assets

($ millions)	2012	2011
Beginning of year	**147**	142
Contributions by employer	**8**	10
Benefits paid	**(10)**	(10)
Expected return on plan assets	**9**	10
Actuarial gain (loss)	**2**	(5)
End of year	**156**	147

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

(percent)	Canada – DB Pension Plan		U.S. – DB Pension Plan	
	2012	2011	**2012**	2011
Discount rate for benefit expense	**4.1**	5.0	**3.9**	4.7
Discount rate for benefit obligation	**3.8**	4.1	**3.2**	3.9
Rate of compensation expense	**3.5**	4.0	**4.5**	4.5
Expected rate of return on plan assets	**6.5**	6.5	**5.3**	6.0

OPEB Plan Long-term Assumptions

(percent)	OPEB Plan	
	2012	2011
Discount rate for benefit expense	**4.1 – 4.3**	4.9 – 5.2
Discount rate for benefit obligation	**3.3 – 4.0**	4.1 – 4.3
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 2012, 2013 and 2014, grading 0.5% per year for four 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 2012, 2013 and 2014, grading 0.5% per year for four 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 2012 and 2013, and 7.0% for 2014, grading 0.5% per year for four 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 8.0% for 2012 and 2013, and 7.0% for 2014, grading 0.5% per year for four years to 5.0% in 2018 and thereafter.

The medical cost trend rate assumption has a significant effect on amounts reported for the OPEB plan. A one percent 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	(2)
Effect on defined benefit obligation	18	(15)

The expected rate of return on the plan assets was determined based on management's best estimate and the historical rates of return, adjusted periodically by asset category. The actual rate of return on plan assets for 2012 was 8% and 6% (2011 – 3% and 1%) for the Canadian and U.S. DB Pension Plans, respectively.

During 2012, the Company contributed $8 million (2011 – $10 million) to the defined benefit pension plan assets and is expecting to contribute $8 million in 2013. Benefits of $12 million are expected to be paid in 2013.

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, 2012 and 2011 was as follows:

DB Pension Plan Assets

(percent)	Target allocation range	2012	2011
Money market type funds	0 – 7	–	6.8
Equity securities	50 – 80	**59.8**	56.1
Debt securities	30 – 50	**39.6**	36.7
Real estate	0 – 5	–	–
Other	0 – 15	**0.6**	0.4

Note 20 Commitments and Contingencies

At December 31, 2012, 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	130	806	556	1,492
Firm transportation agreements	217	1,037	2,652	3,906
Unconditional purchase obligations	3,089	4,449	78	7,616
Lease rentals and exploration work agreements	85	386	571	1,042
	3,521	6,678	3,857	14,056

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, 2012 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
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, 2012, the senior notes are included in long-term debt in the Company's consolidated balance sheet.

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, 2012, the amount of natural gas sales to Meridian and other cogeneration facilities owned by the related party totalled $74 million (2011 – $108 million). For the year ended December 31, 2012, the amount of steam purchases by the Company from Meridian totalled $13 million (2011 – $19 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, 2012, the total cost recovery for these services was $19 million (2011 – $16 million).

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 via private placement to its principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

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, 2012 was $673 million (2011 – $588 million) as follows:

Compensation of Employees

($ millions)	**2012**	2011
Short-term employee benefits	**661**	615
Post-employment benefits	**42**	37
Stock-based compensation	**54**	(1)
	757	651
Less: capitalized portion	**(84)**	(63)
	673	588

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

Compensation of Key Management Personnel

($ millions)	**2012**	2011
Short-term employee benefits	**11**	11
Post-employment benefits	**–**	–
Stock-based compensation	**4**	(2)
	15	9

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 in the consolidated statements of income.

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). 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, 2012	December 31, 2011
Derivatives – FVTPL (held-for-trading)		
Accounts receivable	**13**	65
Accounts payable and accrued liabilities	**(5)**	(45)
Other assets, including derivatives	**1**	2
Other – FVTPL (held-for-trading)[1]		
Accounts payable and accrued liabilities	**(27)**	(17)
Other long-term liabilities	**(78)**	(112)
Hedging instruments		
Other assets, including derivatives	**1**	–
Accounts payable and accrued liabilities	**–**	(93)
Long-term debt[2]	**25**	(13)
	(70)	(213)
Net gains (losses) for the year related to financial instruments held at fair value	**122**	(73)
Included in net earnings	**104**	(55)
Included in OCI	**18**	(18)

(1) *Non-derivative items related to contingent consideration recognized as part of a business acquisition.*

(2) *Represents the foreign exchange adjustment related to translation of 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 and cash and cash equivalents 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, 2012 was $4.6 billion (December 31, 2011 – $4.4 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 following table summarizes the Company's assets and liabilities recorded at fair value on a recurring basis:

Fair Value Hierarchy

($ millions)	**December 31, 2012**	December 31, 2011
Financial assets		
Level 2	**15**	67
Financial liabilities		
Level 2	**20**	(151)
Level 3	**(105)**	(129)
	(70)	(213)

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)	**2012**	2011
Beginning of year	**129**	53
Accretion	**11**	6
Upside interest payment	**(17)**	–
Increase (decrease) on revaluation[1]	**(18)**	70
End of year	**105**	129
Expected to be incurred within 1 year	**27**	17
Expected to be incurred beyond 1 year	**78**	112

[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 market risks related to the volatility of commodity prices, foreign exchange 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. 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 which has a U.S. dollar functional currency. The unrealized foreign exchange gain related to this hedge is recorded in OCI.

At December 31, 2012, the Company had designated U.S. $2.8 billion of its U.S. denominated debt as a hedge of the Company's net investment in its U.S. refining operations (December 31, 2011 – U.S. $1.3 billion). Of this amount, U.S. $700 million was designated in the first quarter of 2012 and included the U.S. $500 million of the 3.95% senior unsecured notes issued on March 22, 2012. During the third quarter of 2012, U.S. $800 million was designated, including U.S. $50 million of the 7.25% notes and U.S. $750 million of the 5.90% notes issued in 2009. For the year ended December 31, 2012, the unrealized loss arising from the translation of the debt was $15 million (2011 – loss of $18 million), net of tax of $2 million (2011 – $3 million), which was recorded in OCI. At December 31, 2012, the fair value of the hedge was $97 million recorded in long-term debt in the consolidated balance sheets (December 31, 2011 – $80 million).

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, 2012, the balance in long-term debt related to deferred gains resulting from unwound interest rate swaps that were designated as a fair value hedge was $72 million (December 31, 2011 – $93 million). The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $21 million for the year ended December 31, 2012 (2011 – offset of $9 million).

Cash flow hedges may also be used to mitigate risk related to interest rates. At December 31, 2012, 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, which is the Company's forecasted debt issuance on the same date. The effective portion of these contracts has been recorded at fair value in other assets; there was no ineffective portion at December 31, 2012. The forward starting swaps have the following terms and fair value as at December 31, 2012:

		December 31, 2012	
Forward Starting Swaps *($ millions)*	Swap Rate[(1)]	Notional Amount *(U.S. $ millions)*	Fair Value
Swap Maturity			
June 15, 2024	2.24%	**105**	**–**
June 16, 2024	2.25%	**310**	**1**
June 17, 2024	2.24%	**85**	**–**
		500	**1**

(1) *Weighted average rate.*

iv) Financial Position of Market Risk Management Contracts

The Company has the following risk management contracts and related inventory recognized at fair value in the consolidated balance sheets at December 31, 2012 and 2011:

Financial Position	December 31, 2012			December 31, 2011		
($ millions)	Asset	Liability	Net	Asset	Liability	Net
Commodity Price						
Natural gas contracts	**3**	**(2)**	**1**	2	(2)	–
Natural gas storage contracts	**10**	**–**	**10**	32	(8)	24
Natural gas storage inventory[1]	**6**	**–**	**6**	(9)	–	(9)
Crude oil contracts[2]	**–**	**–**	**–**	–	(8)	(8)
Crude oil inventory[3]	**–**	**–**	**–**	2	–	2
Crude oil contracts	**–**	**(3)**	**(3)**	–	(4)	(4)
Crude oil inventory[4]	**53**	**–**	**53**	6	–	6
Foreign Currency						
Cross currency swaps[5]	**–**	**–**	**–**	–	(2)	(2)
Foreign currency forwards	**–**	**–**	**–**	1	–	1
Interest Rates						
Forward starting swaps	**1**	**–**	**1**	–	–	–
	73	**(5)**	**68**	34	(24)	10

(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 $107 million at December 31, 2012 (December 31, 2011 – $121 million).

(2) Certain crude oil physical purchase contracts were designated as a fair value hedge against changes in the fair value of the related inventory held in storage. During 2012, the fair value hedging relationship was discontinued and only fair value changes related to the derivative contracts continued to be recorded in the consolidated balance sheets.

(3) Represents the fair value adjustment to inventory recognized in the consolidated balance sheets related to the crude oil physical purchase contracts designated as a fair value hedge. During 2012, the fair value hedging relationship was discontinued and the total fair value adjustment of the related crude oil inventory was nil at December 31, 2012 (December 31, 2011 – $16 million).

(4) 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 $221 million at December 31, 2012 (December 31, 2011 – $147 million).

(5) Represents the fair value adjustment to cross currency swaps related to a portion of the Company's U.S. denominated debt designated in a cash flow hedging relationship for foreign currency risk management. The hedging relationship expired in the second quarter of 2012 with the repayment of the related U.S. $400 million of 6.25% notes which matured on June 15, 2012 and the settlement of the cross currency swaps on the same day. Refer to Note 13.

v) Earnings Impact of Market Risk Management Contracts

The gains (losses) recognized on risk management positions for the years ended December 31, 2012 and 2011 are set out below. All gains (losses) are unrealized, unless otherwise noted.

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

Earnings Impact ($ millions)	2011 Marketing and Other	2011 Purchases of Crude Oil and Products	2011 Other – Net	2011 Net Foreign Exchange Gains (Losses)	2011 Finance Expenses
Commodity Price					
Natural gas	(11)	–	–	–	–
Crude oil(1)	4	(6)	–	–	–
	(7)	(6)	–	–	–
Foreign Currency					
Cross currency swaps	–	–	2	7	–
Foreign currency forwards(3)	–	–	1	(5)	–
	–	–	3	2	–
Interest Rates					
Interest rate swaps(4)	–	–	–	–	13
	(7)	(6)	3	2	13

(1) *Certain crude oil physical purchase contracts were designated as a fair value hedge with fair value changes recognized in purchases of crude oil and products in the consolidated statements of income. During 2012, the fair value hedging relationship was discontinued and only fair value changes related to the derivative contracts continued to be recorded in purchases of crude oil and products.*

(2) *A portion of the Company's U.S. denominated debt was designated in a cash flow hedging relationship for foreign currency risk management, with the use of cross currency swaps, until expiration of the hedging relationship in the second quarter of 2012 with the repayment of the related U.S. $400 million of 6.25% notes which matured on June 15, 2012 and the settlement of the cross currency swaps on the same day. Refer to Note 13. The balance of $2 million included in other reserves was reclassified into net earnings upon the repayment of the debt and concurrent settlement of the cross currency swaps.*

(3) *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.*

(4) *A portion of the Company's debt was designated in a fair value hedging relationship for interest rate risk management and recorded at fair value until discontinuation of the hedging relationship in 2011. Amortization of the accrued gain recognized upon termination of the interest rate swaps is not included in this table and is discussed in the Interest Rate Swaps section below.*

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 and related inventories 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	36	(36)
Natural gas price	–	–

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	44	(50)

(1) *Based on average crude oil and natural gas market prices as at December 31, 2012.*
(2) *Based on the U.S./Canadian dollar exchange rate as at December 31, 2012.*
(3) *Based on U.S. LIBOR as at December 31, 2012.*

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 availability 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, 2012:

Credit Facilities

($ millions)	Available	Unused
Operating facilities(1)	**515**	**280**
Syndicated bank facilities	**3,100**	**3,100**
	3,615	**3,380**

(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. $1.5 billion. The unused capacity of two Canadian shelf prospectuses expired in 2012. The unused capacity of $300 million under the debt shelf prospectus filed in Canada in December 2009 expired in January 2012 and the unused capacity of $1.4 billion under the debt shelf prospectus filed in Canada in November 2010 expired in December 2012. 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, 2012:

Contractual Maturities of Financial Liabilities

($ millions)	2013	2014	2015	2016	2017	Thereafter
Accounts payable and accrued liabilities	2,986	–	–	–	–	–
Other long-term liabilities	3	52	38	3	3	29
Long-term debt	227	951	477	371	455	3,125

The Company's contribution payable pursuant to the joint arrangement with BP is payable between December 31, 2012 and December 31, 2015, with the final balance due and payable by December 31, 2015. Refer to Note 8 and 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, 2012 and December 31, 2011, 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, 2012:

Accounts Receivable Aging

($ millions)	**December 31, 2012**
Current	**1,245**
Past due (1 – 30 days)	**95**
Past due (31 – 60 days)	**10**
Past due (61 – 90 days)	**6**
Past due (more than 90 days)	**16**
Allowance for doubtful accounts	**(23)**
	1,349

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, 2012, the Company impaired $4 million (2011 – $3 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 at December 31, 2012 was $23.1 billion (December 31, 2011 – $21.7 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, 2012, debt to capital employed was 17% (December 31, 2011 – 18%) 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, 2012, debt to cash flow was 0.8 times (December 31, 2011 – 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 fully compliant with these covenants at December 31, 2012.

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 2012, the Company received $40 million (2011 – $38 million) under these programs. The grants accrued for operational purposes have been recorded as revenues in the consolidated statements of income.

Supplemental Financial and Operating Information

Segmented Financial Information

	Upstream				Downstream	
	Exploration and Production		Infrastructure and Marketing		Upgrading	
($ millions)	**2012**	2011	**2012**	2011	**2012**	2011
Year ended December 31						
Gross revenues	**6,547**	7,519	**2,420**	1,987	**2,191**	2,217
Royalties	**(693)**	(1,125)	**–**	–	**–**	–
Marketing – Other	**–**	–	**387**	90	**–**	–
Revenues, net of royalties	**5,854**	6,394	**2,807**	2,077	**2,191**	2,217
Expenses						
Purchase of crude oil and products	**73**	99	**2,258**	1,818	**1,636**	1,628
Production and Operating expenses	**1,840**	1,714	**49**	43	**150**	146
Selling, general and administrative expenses	**178**	153	**21**	17	**3**	3
Depletion, depreciation, amortization and impairment	**2,121**	2,018	**22**	24	**102**	164
Exploration and evaluation expenses	**350**	470	**–**	–	**–**	–
Other – net	**(105)**	(261)	**–**	1	**(17)**	67
Total Expenses	**4,457**	4,193	**2,350**	1,903	**1,874**	2,008
Earnings from Operating Activities	**1,397**	2,201	**457**	174	**317**	209
Net Foreign exchange gains/(loses)	**–**	–	**–**	–	**–**	–
Finance Income	**5**	4	**–**	–	**–**	–
Finance Expenses	**(78)**	(68)	**–**	–	**(11)**	(7)
Net Financial Items	**(73)**	(64)	**–**	–	**(11)**	(7)
Earnings (loss) before income tax	**1,324**	2,137	**457**	174	**306**	202
Current income taxes	**134**	41	**171**	64	**31**	(2)
Deferred income taxes	**211**	515	**(55)**	(20)	**49**	54
Total income tax provision	**345**	556	**116**	44	**80**	52
Net earnings (loss)	**979**	1,581	**341**	130	**226**	150
Total assets As at December 31	**22,753**	20,141	**1,506**	1,509	**1,242**	1,316

(1) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment net earnings in inventories.*

Downstream				Corporate and Eliminations[1]		Total	
Canadian Refined Products		U.S. Refining and Marketing					
2012	2011	**2012**	2011	**2012**	2011	**2012**	2011
3,848	3,877	**10,038**	9,752	**(2,303)**	(2,360)	**22,741**	22,992
–	–	**–**	–	**–**	–	**(693)**	(1,125)
–	–	**–**	–	**–**	–	**387**	90
3,848	3,877	**10,038**	9,752	**(2,303)**	(2,360)	**22,435**	21,957
3,208	3,265	**8,724**	8,453	**(2,303)**	(2,360)	**13,596**	12,903
184	182	**385**	391	**4**	–	**2,612**	2,476
58	49	**13**	12	**178**	194	**451**	428
83	80	**212**	195	**40**	38	**2,580**	2,519
–	–	**–**	–	**–**	–	**350**	470
(2)	–	**4**	–	**(3)**	–	**(123)**	(193)
3,531	3,576	**9,338**	9,051	**(2,084)**	(2,128)	**19,466**	18,603
317	301	**700**	701	**(219)**	(232)	**2,969**	3,354
–	–	**–**	–	**14**	10	**14**	10
–	–	**–**	–	**88**	82	**93**	86
(6)	(6)	**(5)**	(4)	**(140)**	(225)	**(240)**	(310)
(6)	(6)	**(5)**	(4)	**(38)**	(133)	**(133)**	(214)
311	295	**695**	697	**(257)**	(365)	**2,836**	3,140
89	25	**(1)**	76	**112**	150	**536**	354
(9)	50	**258**	178	**(176)**	(215)	**278**	562
80	75	**257**	254	**(64)**	(65)	**814**	916
231	220	**438**	443	**(193)**	(300)	**2,022**	2,224
1,646	1,632	**5,326**	5,476	**2,667**	2,352	**35,140**	32,426

Segmented Financial Information

($ millions)	Upstream Exploration and Production 2010(1)	2009(1)	2008(1)	Midstream Infrastructure and Marketing 2010(1)	2009(1)	2008(1)	Downstream Upgrading 2010(1)	2009(1)	2008(1)
Year ended December 31									
Gross revenues	5,744	5,313	9,932	7,002	6,984	13,544	1,570	1,572	2,435
Royalties	(978)	(861)	(2,043)	–	–	–	–	–	–
Revenues, net of royalties	4,766	4,452	7,889	7,002	6,984	13,544	1,570	1,572	2,435
Expenses									
Purchases of crude oil and products(2)	1,403	1,425	1,561	6,684	6,655	13,177	1,439	1,461	2,053
Selling, general and administrative expenses	152	70	66	22	14	15	–	–	–
Depletion, depreciation, amortization and impairment	1,521	1,397	1,505	43	36	31	74	34	31
Exploration and evaluation expenses	438	–	–	–	–	–	–	–	–
Other – net	1	–	–	34	–	–	(41)	–	–
Net financial items	40	–	–	–	–	–	9	–	–
	3,555	2,892	3,132	6,783	6,705	13,223	1,481	1,495	2,084
Earnings (loss) before income taxes	1,211	1,560	4,757	219	279	321	89	77	351
Current income taxes (recoveries)	(23)	909	585	62	101	126	1	111	84
Future income taxes (reductions)	373	(462)	795	(3)	(22)	(29)	25	(88)	21
Net earnings (loss)	861	1,113	3,377	160	200	224	63	54	246
Total assets As at December 31	17,354	16,338	15,653	1,325	1,712	1,486	1,987	1,427	1,322

(1) Results are reported in accordance with previous Canadian GAAP and have not been restated for the change in presentation of the former Midstream segment.
(2) Purchases of crude oil and products includes purchases of crude oil, products, production and operating expenses.
(3) Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment net earnings in inventories

Downstream						Corporate and Eliminations[3]			Total		
Canadian Refined Products			U.S. Refining and Marketing								
2010[1]	2009[1]	2008[1]	2010[1]	2009[1]	2008[1]	2010[1]	2009[1]	2008[1]	2010[1]	2009[1]	2008[1]
2,975	2,495	3,564	7,107	5,349	7,802	(6,313)	(5,778)	(10,533)	18,085	15,935	26,744
–	–	–	–	–	–	–	–	–	(978)	(861)	(2,043)
2,975	2,495	3,564	7,107	5,349	7,802	(6,313)	(5,778)	(10,533)	17,107	15,074	24,701
2,679	2,174	3,308	6,935	4,955	8,278	(6,251)	(5,821)	(10,757)	12,889	10,849	17,620
49	30	32	7	2	2	61	158	177	291	274	292
88	93	81	191	194	154	75	51	30	1,992	1,805	1,832
–	–	–	–	–	–	–	–	–	438	–	–
(2)	–	–	–	–	–	(7)	–	–	(15)	–	–
2	–	–	6	3	3	238	186	(191)	295	189	(188)
2,816	2,297	3,421	7,139	5,154	8,437	(5,884)	(5,426)	(10,741)	15,890	13,117	19,556
159	198	143	(32)	195	(635)	(429)	(352)	208	1,217	1,957	5,145
56	38	28	–	3	(24)	92	100	102	188	1,262	901
(14)	19	11	(12)	68	(208)	(287)	(236)	(97)	82	(721)	493
117	141	104	(20)	124	(403)	(234)	(216)	203	947	1,416	3,751
1,517	1,430	1,375	5,092	4,771	5,380	775	617	1,270	28,050	26,295	26,486

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	**2012**	2011	2010	2009[(1)]	2008[(1)]	2007[(1)]	2006[(1)]	2005[(1)]	2004[(1)]	2003[(1)]
Financial Highlights										
Gross Revenues[(2)]	**23,128**	23,082	18,085	15,935	26,744	16,583	13,478	11,085	9,151	8,242
Net earnings	**2,022**	2,224	947	1,416	3,751	3,201	2,734	1,996	1,001	1,374
Earnings per share										
Basic	**2.06**	2.40	1.11	1.67	4.42	3.77	3.21	2.35	1.18	1.64
Diluted	**2.06**	2.34	1.05	1.67	4.42	3.77	3.21	2.35	1.18	1.63
Expenditures on PP&E[(3)]	**4,701**	4,618	3,571	2,797	4,108	2,974	3,201	3,099	2,379	1,902
Total debt	**3,918**	3,911	4,187	3,229	1,957	2,814	1,611	1,886	2,204	2,094
Debt to capital employed *(percent)*[(4)]	**17**	18	22	18	12	19	14	20	26	27
Corporate reinvestment ratio *(percent)*[(4)]	**106**	98	134	111	66	86	71	80	112	92
Return on capital employed *(percent)*[(4)]	**9.5**	11.8	6.4	9.1	25.1	25.6	27.1	22.7	13.0	18.9
Return on equity *(percent)*[(4)]	**10.9**	13.8	6.7	9.8	28.9	30.1	31.9	29.2	17.0	26.5
Upstream										
Daily production, before royalties										
Light crude oil & NGL *(mbbls/day)*	**72.3**	87.6	80.4	89.1	122.9	138.7	111.0	64.6	66.2	71.6
Medium crude oil *(mbbls/day)*	**24.1**	24.5	25.4	25.4	26.9	27.1	28.5	31.1	35.0	39.2
Heavy crude oil *(mbbls/day)*	**76.9**	74.5	74.5	78.6	84.3	86.5	88.5	88.0	90.2	85.1
Bitumen *(mbbls/day)*	**35.9**	24.7	22.3	23.1	22.7	20.4	19.6	18.0	18.7	14.8
	209.2	211.3	202.6	216.2	256.8	272.7	247.6	201.7	210.1	210.7
Natural gas *(mmcf/day)*	**554**	607	507	542	594	623	672	680	689	611
Total production *(mboe/day)*	**301.5**	312.5	287.1	306.5	355.9	376.6	359.7	315.0	325.0	312.5
Total proved reserves, before royalties *(mmboe)*[(5)]	**1,192**	1,172	1,081	933	896	1,014	1,004	985	791	887
Downstream										
Upgrading										
Synthetic crude oil sales *(mbbls/day)*	**60.4**	55.3	54.1	61.8	58.7	53.1	62.5	57.5	53.7	63.6
Upgrading differential *($/bbl)*	**22.34**	27.34	14.52	11.89	28.77	30.73	26.16	30.70	17.79	12.88
Canadian Refined Products										
Light oil products sales *(million litres/day)*	**9.5**	9.5	8.2	7.6	7.9	8.7	8.7	8.9	8.4	8.2
Asphalt products sales *(mbbls/day)*	**26.2**	25.3	24.1	22.6	24.0	21.8	23.4	22.5	22.8	22.0
Refinery throughput										
Prince George refinery *(mbbls/day)*	**11.1**	10.6	10.0	10.3	10.1	10.5	9.0	9.7	9.8	10.3
Lloydminster refinery *(mbbls/day)*	**28.3**	28.1	27.8	24.1	26.1	25.3	27.1	25.5	25.3	25.7
Refinery utilization *(percent)*[(6)]	**96**	92	92	86	91	90	90	101	100	103
U.S. Refining and Marketing										
Refinery throughput										
Lima Refinery *(mbbls/day)*	**150.0**	144.3	136.6	114.6	136.6	143.8	–	–	–	–
Toledo Refinery *(mbbls/day)*	**60.6**	63.9	64.4	64.9	60.6	–	–	–	–	–
Refining Margin *(U.S. $/bbl crude throughput)*	**17.51**	17.60	7.29	11.37	(0.86)	12.42	–	–	–	–

(1) Results are reported in accordance with previous Canadian GAAP. Certain reclassifications have been made to conform with current presentation.
(2) Results reported for 2010 and previous years have not been adjusted for the change in presentation of the former Midstream.
(3) Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.
(4) 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.
(5) Total proved reserves, before royalties for 2012 and 2011 were prepared in accordance with the Canadian Securities Administrators' National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Years including 2009 and prior 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.
(6) Refinery utilization averages Prince George and Lloydminster utilization percentages.

Upstream Operating Information

	2012	2011	2010[4]	2009[4]	2008[4]
Daily Production, before royalties					
Light crude oil & NGL *(mmbls/day)*	**72.3**	87.6	80.4	89.1	122.9
Medium crude oil *(mmbls/day)*	**24.1**	24.5	25.4	25.4	26.9
Heavy crude oil *(mmbls/day)*	**76.9**	74.5	74.5	78.6	84.3
Bitumen *(mmbls/day)*	**35.9**	24.7	22.3	23.1	22.7
	209.2	211.3	202.6	216.2	256.8
Natural gas *(mmcf/day)*	**554**	607.0	506.8	541.7	594.4
Total production *(mboe/day)*	**301.5**	312.5	287.1	306.5	355.9
Average sales prices					
Light crude oil & NGL *($/bbl)*	**99.22**	104.06	76.90	62.70	97.28
Medium crude oil *($/bbl)*	**71.51**	76.59	64.92	56.37	81.79
Heavy crude oil *($/bbl)*	**61.91**	68.13	58.91	52.54	71.98
Bitumen *($/bbl)*	**59.49**	65.75	57.84	51.90	70.24
Natural gas *($/mcf)*	**2.60**	3.89	3.86	3.83	7.94
Operating costs *($/bbl)*	**15.49**	14.01	13.35	11.82	10.93
Operating netbacks[1][5]					
Light crude oil[2]	**66.13**	70.86	47.58	37.54	65.03
Medium crude oil[2]	**38.22**	42.41	36.88	32.08	50.40
Heavy crude oil[2]	**38.31**	41.72	34.51	31.58	47.22
Bitumen *($/boe)*[2]	**42.32**	39.34	28.96	28.46	36.89
Natural gas *($/mcfge)*[3]	**0.77**	1.96	1.93	2.08	5.02

(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) *Results are reported in accordance with previous Canadian GAAP. Results prior to 2011 have not been adjusted for the reclassification of the Midstream operating segment.*
(5) *The Upstream netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing.*

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

		2012		2011		2010		2009		2008	
		Gross	**Net**	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	**47**	**30**	50	40	60	51	18	9	80	70
	Gas	**19**	**12**	24	24	37	31	37	22	102	79
	Dry	**–**	**–**	3	3	8	8	7	6	27	23
		66	**42**	77	67	105	90	62	37	209	172
Development	Oil	**775**	**715**	880	765	815	722	315	278	685	578
	Gas	**23**	**17**	57	42	73	53	122	61	435	270
	Dry	**5**	**4**	4	4	10	9	7	7	36	36
		803	**736**	941	811	898	784	444	346	1,156	884
		869	**778**	1,018	878	1,003	874	506	383	1,365	1,056
Success Ratio *(Percent)*		**99**	**99**	99	99	98	98	97	97	95	94

(1) *Excludes service/stratigraphic test wells for evaluation purposes. All activity was horizontal except Slater River N.W.T. vertical wells.*

Supplemental Upstream Operating Statistics

The following table summarizes Husky's netback analysis by product and area. During the first quarter of 2012, the Company completed an evaluation of activities of the Midstream segment as a service provider to the Upstream or Downstream operations. As a result, and consistent with the Company's strategic view of its integrated business, the previously reported Midstream segment activities are aligned and reported within the Company's core exploration and production, or in upgrading and refining businesses. The netback analysis has been revised to align with the change in segment presentation and 2011 has been restated to reflect the current presentation.

Netback Analysis

	2012	2011	2010 (8)
Total Upstream (1)			
Crude oil equivalent *($/boe)* (2)			
Sales volume *(mboe/day)*	**301.5**	312.5	287.1
Price received *($/boe)*	**57.16**	64.17	54.25
Royalties *($/boe)*	**6.29**	9.86	9.33
Operating costs *($/boe)* (3)	**15.49**	14.01	13.55
Offshore transportation *($/boe)* (4)	**0.24**	0.26	0.25
Netback *($/boe)*	**35.14**	40.04	31.32
Depletion, depreciation and amortization *($/boe)*	**19.20**	17.69	14.52
Administration expenses and other *($/boe)* (3)	**1.75**	1.34	0.48
Earnings before taxes	**14.19**	21.01	16.32
Lloydminster Heavy Oil			
Thermal Oil			
Bitumen			
Sales volumes *(mbbls/day)*	**26.3**	17.4	18.3
Price received *($/bbl)*	**61.03**	67.43	58.34
Royalties *($/bbl)*	**3.82**	10.78	9.84
Operating costs *($/bbl)* (3)	**10.34**	14.59	14.15
Netback *($/bbl)*	**46.87**	42.06	34.35
Non Thermal Oil			
Medium Oil			
Sales volumes *(mbbls/day)*	**2.1**	2.3	2.3
Price received *($/bbl)*	**70.22**	75.19	65.49
Royalties *($/bbl)*	**5.13**	5.10	4.64
Heavy Oil			
Sales volumes *(mbbls/day)*	**61.1**	60.3	59.8
Price received *($/bbl)*	**62.35**	68.44	58.70
Royalties *($/bbl)* (5)	**4.88**	7.81	7.50
Natural Gas			
Sales volumes *(mmcf/day)*	**25.4**	29.3	34.4
Price received *($/mcf)*	**2.25**	3.44	3.74
Royalties *($/mcf)*	**0.16**	0.27	0.31
Non Thermal Oil Total (2)			
Sales volumes *(boe/day)*	**67.4**	67.5	67.8
Price received *($/boe)*	**59.53**	65.20	55.86
Royalties *($/boe)*	**4.64**	7.27	6.93
Operating costs *($/boe)* (3)	**17.75**	17.34	16.07
Netback *($/boe)*	**37.14**	40.59	32.86

Netback Analysis (continued)

	2012	2011	2010(8)
Oil Sands			
Bitumen			
Total sales volumes *(mbbls/day)*	**9.6**	7.3	4.0
Price received *($/boe)*	**55.29**	61.77	55.56
Royalties *($/boe)*	**3.76**	3.75	2.46
Operating costs *($/boe)*(3)	**21.61**	25.13	48.75
Netback *($/bbl)*	**29.92**	32.89	4.35
Western Canada Conventional			
Crude Oil			
Light Oil			
Sales volumes *(mbbls/day)*	**21.3**	16.5	15.0
Price received *($/bbl)*	**80.98**	88.23	74.02
Royalties *($/bbl)*	**10.56**	14.61	12.57
Medium Oil			
Sales volumes *(mbbls/day)*	**22.0**	22.2	23.1
Price received *($/bbl)*	**71.63**	76.73	64.87
Royalties *($/bbl)*	**13.48**	15.05	12.28
Heavy Oil			
Sales volumes *(mbbls/day)*	**15.8**	14.2	14.7
Price received *($/bbl)*	**60.21**	66.81	59.76
Royalties *($/bbl)*	**10.55**	13.16	13.21
Western Canada Crude Oil Total			
Total sales volumes *(boe/day)*	**59.0**	53.0	52.8
Price received *($/boe)*	**71.96**	77.66	66.05
Royalties *($/boe)*	**11.64**	14.41	12.70
Operating costs *($/boe)*(3)	**20.93**	21.69	16.79
Netback *($/bbl)*	**39.39**	41.56	36.56
Natural Gas & NGLs			
Natural Gas Liquids			
Sales volumes *(mbbls/day)*	**8.8**	8.3	8.0
Price received *($/bbl)*	**66.92**	75.62	52.13
Royalties *($/bbl)*	**18.69**	21.87	18.07
Natural Gas			
Sales volumes *(mmcf/day)*	**528.6**	577.7	472.4
Price received *($/mcf)*(6)	**2.61**	3.91	3.93
Royalties *($/mcf)*(6)(7)	**(0.10)**	0.18	0.22
Western Canada Natural Gas & NGLs Total(2)			
Total sales volumes *(mmcf/day)*	**581.8**	627.4	520.4
Price received *($/mcf)*	**3.39**	4.60	4.37
Royalties *($/mcf)*	**0.19**	0.46	0.48
Operating costs *($/mcf)*(3)	**1.88**	1.71	1.70
Netback *($/bbl)*	**1.32**	2.43	2.19

Netback Analysis (continued)

	2012	2011	2010(8)
Atlantic Region			
Light Oil			
Sales volumes *(mbbls/day)*	**33.8**	54.3	46.7
Price received *($/boe)*	**115.78**	112.21	82.16
Royalties *($/boe)*	**12.36**	19.36	19.25
Operating costs *($/boe)*(3)	**17.12**	8.76	10.33
Transportation *($/boe)*(4)	**2.14**	1.50	1.55
Netback *($/boe)*	**84.16**	82.59	51.03
Asia Pacific Region			
Light Oil & NGL(2)			
Sales volumes *(mboe/day)*	**8.4**	8.5	10.7
Price received *($/boe)*	**113.01**	110.54	83.38
Royalties *($/boe)*	**26.89**	32.75	19.11
Operating costs *($/boe)*(3)	**10.08**	8.17	6.06
Netback *($/boe)*	**76.04**	69.62	58.21

(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 second quarter.*
(6) *Includes sulphur sales revenues/royalties.*
(7) *Alberta Gas Cost Allowance reported exclusively as gas royalties.*
(8) *Results are reported in accordance with previous Canadian GAAP. Results prior to 2011 have not been adjusted for the reclassification of the Midstream operating segment.*

Advisories

Forward-Looking Statements

Certain statements in this document are forward-looking statements within the meaning of 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, and forward-looking information within the meaning of applicable Canadian securities legislation (collectively "forward-looking statements").

The Company hereby provides cautionary statements identifying important factors that could cause actual results to differ materially from those projected in these forward-looking statements.

Any 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," "are expected to," "will continue," "is anticipated," "is targeting," "estimated," "intend," "plan," "projection," "could," "aim," "vision," "goals," "objective," "target," "schedules" and "outlook") are not historical facts, are forward looking and may involve estimates and assumptions and are subject to risks, uncertainties and other factors some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements.

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 and associated timelines; target five-year average reserves replacement ratio; anticipated growth of internal gas consumption by 2015; target five-year compound annual production growth for the periods ending 2015 and 2017; the Company's capital expenditure budget for 2013; production guidance for 2013; target five-year compound annual growth rate; and target increase on return on capital employed by 2015;

- with respect to the Company's Asia Pacific Region: anticipated timing of production of first gas at the Liwan Gas Project; anticipated timing of first production at the Madura Straits developments; anticipated timing of installation of the platform topsides on the jacket at the Liwan Gas Project; and target production from the region by 2015;

- with respect to the Company's Atlantic Region: anticipated timing of first production from the South White Rose extension project; and scheduled timing of delivery of the semi-submersible rig West Mira;

- with respect to the Company's Oil Sands properties: anticipated timing of first production at the Sunrise Energy Project; and anticipated timing of filing a development application for the Saleski carbonate project; and

- with respect to the Company's Heavy Oil properties: the Company's belief that it will be able to extract another 800 million barrels of oil from the Lloydminster region; targeted timing of first oil from the Rush Lake project; planned timing of first oil from the Sandall thermal project; anticipated growth of heavy oil production, including production from thermal projects, by 2017; and anticipated percentage of wells targeting oil to be drilled in 2013.

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.

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, 2012, 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.

Disclosure of non-GAAP Measurements

Husky uses measurements primarily based on IFRS and also on secondary non-GAAP measurements. The non-GAAP measurements included in this Annual Report are: cash flow from operations, return on capital in use, return on capital employed, return on equity, debt to capital employed and debt to cash flow. For further details on these non-GAAP measurements, please refer to Non-GAAP Measures and Additional Reader Advisories contained in sections 11.3 and 11.4, respectively, of the Company's Management's Discussion and Analysis for the year ended December 31, 2012, which sections are incorporated by reference herein.

Disclosure of Oil and Gas Information

Unless otherwise specified, reserves and resources estimates represent Husky's share and are given with an effective date of December 31, 2012.

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 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.

The Company has disclosed best estimate contingent resources of 13.1 billion boe, which is comprised of 12.0 billion bbls of crude oil and 6.6 tcf of natural gas. Of the total, 10.8 billion boe is economic at year-end 2012.

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, East Coast offshore and Asia Pacific 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 and/or new technology for unrisked contingent resources; (ii) regulatory approvals; and (iii) Company 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.

Reserves replacement ratio is determined by taking the Company's yearly incremental proved reserve additions divided by the yearly upstream gross production. The two-year average reserves replacement ratio for 2011 and 2012 was determined based on the sum of the Company's 2011 and 2012 incremental proved reserves additions divided by the sum of the Company's 2011 and 2012 upstream gross production.

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 document, 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 noted.

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		2012	2011	2010
Share price *(dollars)*	High	**29.50**	30.58	30.88
	Low	**22.04**	20.63	24.21
	Close at December 31	**29.40**	24.55	26.55
Average daily trading volumes *(thousands)*		**956**	1,183	1,173
Number of common shares outstanding *(thousands)*		**982,229**	957,537	890,709
Weighted average number of common shares outstanding *(thousands)*				
	Basic	**975,808**	923,821	852,670
	Diluted	**975,883**	931,978	852,670

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, 2012 was 982,229,220.

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

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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 Tuesday, May 7, 2013, at TELUS Spark, the New Science Centre, 220 St. George's Drive N.E., Calgary, Alberta.

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

Pikes Peak South Thermal Project

SeaRose FPSO

Dividends

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

Declaration Date	Quarter Dividend
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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