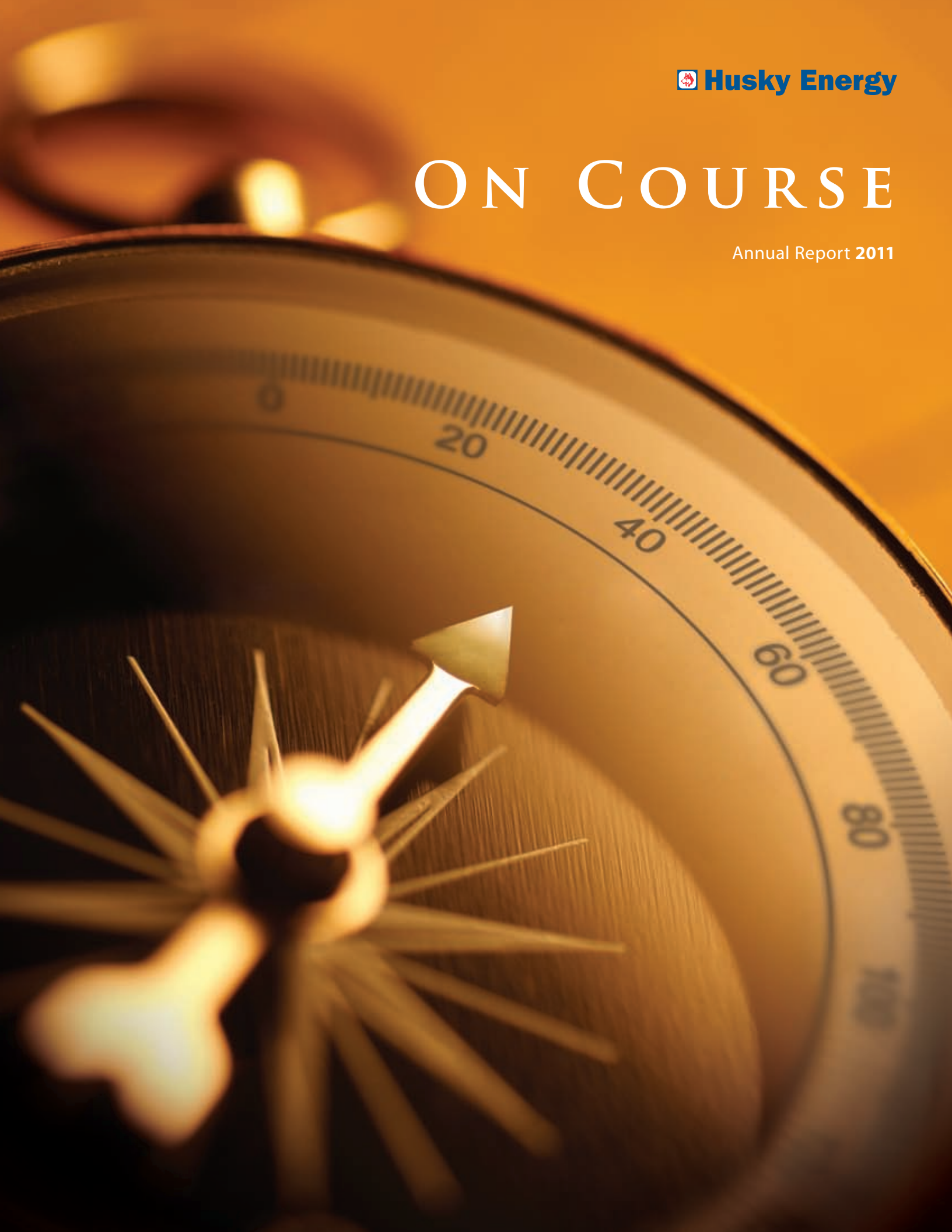
Husky Energy

On Course

Annual Report **2011**



Corporate Profile

Husky Energy is one of Canada's largest integrated energy companies. It is headquartered in Calgary, Alberta, and is publicly traded on the Toronto Stock Exchange under the symbols HSE and HSE.PR.A. The Company operates worldwide with Upstream, Midstream and Downstream business segments. Husky uses a combination of technological innovation, prudent investment, sound project management and responsible resource development to deliver a consistent return to shareholders.

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2011 Highlights

Financial Highlights[1]

Year ended December 31		2011	2010
(millions of dollars except where indicated)			
Revenues, net of royalties		**23,364**	17,107
Cash flow from operations[2]		**5,198**	3,072
Per share *(dollars)*	Basic	**5.63**	3.60
	Diluted	**5.58**	3.60
Net earnings		**2,224**	947
Per share *(dollars)*	Basic	**2.40**	1.11
	Diluted	**2.34**	1.05
Dividends			
Per share *(dollars)*	Ordinary	**1.20**	1.20
Capital expenditures[3]		**4,618**	3,571
Return on average capital employed *(%)*		**11.8**	6.4
Return on equity *(%)*		**13.8**	6.7
Debt to capital employed *(%)*		**18.0**	22.3
Debt to cash flow *(times)*		**0.8**	1.4

(1) Results are reported in accordance with IFRS.
(2) Non-GAAP
(3) Excludes capitalized costs related to asset retirement obligations incurred during the period.

Operational Highlights

Year ended December 31	2011	2010
Daily production, before royalties		
Light crude oil & NGL *(mbbls/day)*	**87.6**	80.4
Medium crude oil *(mbbls/day)*	**24.5**	25.4
Heavy crude oil *(mbbls/day)*	**74.5**	74.5
Bitumen *(mbbls/day)*	**24.7**	22.3
Total crude oil & NGL *(mbbls/day)*	**211.3**	202.6
Natural gas *(mmcf/day)*	**607.0**	506.8
Total *(mboe/day)*	**312.5**	287.1
Proved reserves, before royalties[1]		
Light crude oil & NGL *(mmbbls)*	**257**	237
Medium crude oil *(mmbbls)*	**90**	88
Heavy crude oil *(mmbbls)*	**113**	110
Bitumen *(mmbbls)*	**309**	247
Natural gas *(bcf)*	**2,420**	2,395
Total *(mmboe)*	**1,172**	1,081
Upgrader throughput *(mbbls/day)*	**69.6**	65.4
Commodity volumes marketed *(mmboe/day)*	**1.0**	1.0
Pipeline throughput *(mbbls/day)*	**559**	512
Light oil sales *(million litres/day)*	**9.5**	8.2
Lima Refinery throughput *(mbbls/day)*	**144.3**	136.6
Toledo Refinery throughput *(mbbls/day, 50% w.i.)*	**63.9**	64.4
Lloydminster Refinery throughput *(mbbls/day)*	**28.1**	27.8
Prince George Refinery throughput *(mbbls/day)*	**10.6**	10.0
Ethanol production *(thousand litres/day)*	**711.3**	619.7

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

Select Achievements for 2011

Foundation

Western Canada and Heavy Oil

- Production approximately 250,000 boe/day
- Advanced heavy oil thermal projects – Pikes Peak South and Paradise Hill – first oil expected in 2012
- Developments in oil resource plays – Bakken, Viking, Cardium, Shaunavon, Muskwa and Canol
- Developments in gas resource plays – Ansell capacity expanded
- Select acquisitions in core areas

Pillars of Growth

Asia Pacific Region

- Liwan sanctioned and construction underway
- Madura PSC extended and work progressing offshore Indonesia
- Building a material business ~ 50,000 boe/d by 2015

Oil Sands

- Sunrise Energy Project construction accelerates with base camp and central plant facility underway
- Advanced drilling program at Sunrise
- Progressed engineering for Sunrise Phase 2

Atlantic Region

- Positive production contributed to foundation
- North Amethyst achieved design target of 37,000 bbls/day (gross)
- First oil from West White Rose pilot
- *SeaRose* facility uptime 98 percent

Safety

- HOIMS delivering operational integrity across the Company
- Commitment to process and occupational safety

2011 Report to Shareholders

This has been a year in which Husky as an organization rolled up its sleeves and focused on executing its business strategy. The actions achieved to date have taken root. Strong performance, aided by improved crude oil prices, contributed to four consecutive quarters of improved results. The Company is on course and the strategy is creating value for shareholders, positioning the Company to capitalize on our growth opportunities.

The initiatives executed over the past year are a direct outcome of a comprehensive review the Company undertook to refine its business strategy and set clear financial and operational targets. The resulting five-year plan leverages the Company's strong foundation in Western Canada where investments are being made to transform and regenerate the oil and natural gas business to resource plays and transition a greater percentage of the Company's heavy oil production to long-life thermal. That foundation, along with strong cash flow from the Atlantic Region, provides the stable base on which the Company is building its three pillars of growth in the Asia Pacific Region, the Oil Sands, and the Atlantic Region.

Performance Highlights

Husky delivered strong financial results in 2011, reflecting solid performance across all business segments, increased production and higher crude prices. The Company's integration strategy in heavy oil and oil sands also provided substantial value as market refining crack spreads increased and a wider spread between West Texas Intermediate and Brent-priced crude oil presented opportunities to capitalize on differentials.

Net earnings for the year increased by 135 percent to $2.2 billion compared to $947 million in 2010. Cash flow from operations increased 69 percent to $5.2 billion, compared to $3.1 billion in 2010. Increased production was a key contributor to the improved results, with production averaging 312,500 boe/day for the year, a nine percent increase over the average of 287,100 boe/day in 2010. The Midstream and Downstream segments also performed well with strong throughputs, contributing $1.1 billion in net earnings, compared to $320 million a year earlier. Total sales and operating revenues, net of royalties, were $23.4 billion, compared to $17.1 billion in 2010.

Husky's balance sheet remains strong, with a debt to cash flow ratio of 0.8 times, well below the target of 1.5 to 2.5. Actions undertaken in early 2011 to enhance the Company's financial position have provided increased flexibility to carry out the balanced growth strategy through periods of economic and commodity price volatility.

Near-Term Growth Highlights (2011 – 2013)

A primary goal the Company set for the near term is to stabilize production levels in Western Canada and return the overall production profile to a path of measured growth. The target for the plan period is to achieve a compound annual growth rate of three to five percent.

In the Atlantic Region, first oil was achieved from a pilot at the West White Rose satellite, the next White Rose field targeted for development. The additional West White Rose volume, combined with strong performance from the North Amethyst



satellite field, which reached its production design target of 37,000 bbls/day (26,000 net to Husky), were key contributors to production gains.

The Company successfully completed acquisitions of oil and natural gas properties in northwest Alberta and northeast British Columbia in early 2011. The acquisitions added production in regions with established Husky infrastructure.

In 2012, production guidance has been set for 290,000 to 315,000 boe/day reflecting the impact of planned offstations in the Atlantic Region for the *SeaRose* Floating Production, Storage and Offloading vessel (FPSO) and the *Terra Nova* FPSO.

New volumes from the Pikes Peak South and Paradise Hill heavy oil thermal projects, which are expected to add a combined 11,000 bbls/day to production when at full operation, are anticipated to partially offset impacts from the Atlantic Region.

During the year, Husky added 205 million barrels of oil equivalent of proved reserves for a replacement rate of 180 percent, exceeding the target of 140 percent average annual growth through to 2015.

Mid-Term Growth Highlights (2014 – 2016)

This has been a year of significant progress in achieving the milestones set out for the Company's mid-term growth opportunities.

Following sanction of the Sunrise Energy Project, a premier in-situ oil sands development in northern Alberta, crews commenced major construction activity on a 1,500-person camp building, the central plant facility and other infrastructure components. By the end of 2011, drilling was completed on more than half of the 49 steam-assisted gravity drainage (SAGD) horizontal well pairs planned for Phase 1. The full drilling program is expected to be completed in the second half of 2012. Sunrise Phase 1, which is expected to produce 60,000 bbls/day (30,000 net to Husky), is proceeding on budget and on schedule towards first production in 2014.

Another significant milestone was the sanctioning of development of the principal fields of the Liwan Gas Project in the South China Sea. The project, which is being jointly developed with China National Offshore Oil Corporation (CNOOC), aims to bring to market three significant natural gas discoveries on Block 29/26. Project sanction followed the filing of an Overall Development Plan with Chinese government authorities and the signing of a gas sales agreement for volumes from the Liwan 3-1 field. Construction is well underway on subsea equipment, the production jacket, topsides and onshore gas plant. The Liwan Gas Project is proceeding towards first production in 2013/2014.

Activities are accelerating at the Madura block offshore Indonesia, following the receipt of a 20-year extension to the Madura Straits Production Sharing Contract. Tendering of equipment and services for the Madura BD field development is underway and the project is advancing towards first production in 2014. An exploration well in the MDA field confirmed additional commercial gas resources. An exploration well in the MBH field was also successful, encountering significant gas shows and testing at an equipment-restricted rate of 18.1 mmcf/day. The MBH field may be combined with MDA in a cluster development. A Plan of Development for the MDA field is expected to be filed in 2012. Husky has a 40 percent ownership interest in production.

The Liwan and Madura developments represent a significant opportunity for the Company in a region with high energy growth demands. By 2015, the Company anticipates it will have established a 50,000 boe/day business in the Asia Pacific Region.

In Western Canada, Husky increased its production from liquids-rich gas and oil resource plays and expanded its land holding targeting these plays.

Long-Term Growth Highlights (2017 – 2021)

Important milestones were achieved in 2011 to positively impact our business in the long term.

A contract was awarded to initiate design basis engineering for the next development stages of the Sunrise Energy Project. Front-end engineering and design (FEED) is expected to be completed in 2013. Regulatory approvals are in place for up to 200,000 bbls/day (100,000 bbls/day net to Husky). The design and engineering process will determine the most efficient method to advance the project towards this approved production capacity.

Engineering was initiated during the year for the development of a fixed wellhead and drilling platform for the White Rose development in the Atlantic Region. The concept would allow more efficient drilling and development of known resources, and has the potential to extend the life of the White Rose project.

The Company was successful in acquiring two exploration licences in the Central Mackenzie Valley region of the Northwest Territories. After extensive consultations, access and benefits agreements were signed with stakeholders in the region, establishing terms for proceeding with exploration and development activity. In early 2012, the Company initiated a winter evaluation program on the licences which includes the drilling of two vertical wells and a 220-square kilometre 3-D seismic program. The winter program is designed to further the Company's understanding of the potential resource.

An evaluation of the Company's emerging oil sands portfolio was completed during the year, which added approximately 10 billion barrels of best-estimate contingent resources (bitumen). The majority of the additions are attributed to the Saleski oil sands lease, a 1,000-square kilometre holding in the Grosmont carbonate formation, located west of Fort McMurray. The evaluation further supports the future development potential of the Saleski lease as enhancements to technologies such as SAGD are being tested for their ability to optimize recovery of the oil resource in the carbonate formation. The Company is initiating plans to conduct a pilot which will test multiple thermal development methods, including SAGD.

Focused on Execution

Husky's success is founded on its core principles, which include an unwavering commitment to process and occupational safety, strict financial discipline, investing in the communities where we operate, and creating value for shareholders through responsible and sustainable growth. The Company's strategic plan ensures those principles are maintained and enhanced, while providing a sound course to accelerate the value delivered to shareholders.

The capital expenditure program approved for 2012 builds on the momentum established over the past year to increase near-term production and supports the continued execution of the Company's mid and long-term growth initiatives.

The achievements of the past year begin and end with the commitment and expertise of our talented team of employees. On behalf of Husky's Board of Directors, we would like to offer our sincere gratitude for their efforts and extend our appreciation to shareholders for their continued support.

Victor T.K. Li
Co-Chairman

Canning K.N. Fok
Co-Chairman

Asim Ghosh
President & Chief Executive Officer

March 8, 2012

Letter from the CEO

On Course

The closing of 2011 marked the end of my first full calendar year as CEO of Husky Energy. Much has been achieved in that relatively short period of time and the overwhelming sense is that this is a company in motion, focused on execution.

Last year we established and communicated our business strategy and instituted a five-year plan which would accelerate the value delivered to shareholders. The plan contains definitive milestones for achieving our near-term, mid-term and long-term growth targets and well-defined safety, operational and financial metrics.

I am pleased to report that in the first full year of executing the plan, we have achieved our milestones and, aided by improved crude prices, met or exceeded our performance targets.

The average annual production rate of 312,500 boe/day represented a nine percent increase over 2010, and was well above our compound annual growth target of three to five percent through 2015. We reported a 180 percent reserves replacement ratio for 2011, a solid performance against our target of a 140 percent annual reserves replacement ratio. Our goal to increase the return on capital employed (ROCE) by five percentage points over the plan period is solidly on track with ROCE increasing five percentage points over 2010. Efforts to control finding and development (F&D) and operating costs, combined with strong crude oil prices, resulted in a 23 percent increase in netbacks for the year.

The strategy is set, the Company is on course, we are meeting our targets, and value is being delivered to shareholders.

The goal for 2012 is to build on the established momentum from the past year and to continue to execute against the plan. A capital expenditure program of $4.7 billion is planned for 2012. It is worth noting that the program requires a cash outlay by the Company of $4.1 billion due to commitments from our partners on various projects, including the Sunrise Energy Project. Approximately 60 percent of the Upstream capital expenditure program is directed towards the Company's growth pillars. Investment in Sunrise more than doubles to $610 million as construction activity ramps up. Just over $1 billion is budgeted for the Asia Pacific Region as fabrication of deepwater and shallow water facilities for the Liwan Gas Project accelerates. Substantial investment is provided for repositioning the foundation in Western Canada, where we are accelerating oil and liquids-rich natural gas plays and transitioning a greater percentage of our heavy oil production to thermal.

It has been a rewarding year and as a result of the actions executed in 2011, we are well positioned to realize our potential.

Asim Ghosh

Focused on Execution

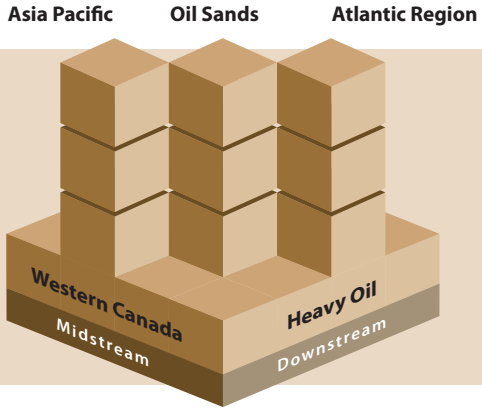
The Company's strategic business plan is underpinned by a clearly defined set of performance metrics designed to ensure value is delivered to shareholders. Actions undertaken in 2011 to execute the plan across the organization have taken root, with the Company meeting or exceeding its targets.

Our Targets and How We Delivered in 2011

The progress the Company made in delivering against its plan in 2011 was the result of solid execution across the business. Improved results were underpinned by increased production, strong throughputs in Midstream and Downstream, and overall high reliability in operations and process safety. Strengthening crude oil prices and higher market refinery crack spreads were also positive contributors.

The Company's balanced growth strategy begins with its solid foundation in Western Canada and Heavy Oil. That foundation is being sustained and regenerated, and serves as the base on which the Company is building its three pillars of growth in the Asia Pacific Region, the Oil Sands, and the Atlantic Region. The Company's focused integration strategy supports the very specific Upstream needs in Heavy Oil and the Oil Sands, ensuring the greatest value is captured from production.

In conjunction with the business strategy, the Company has set clear, realistic performance targets to gauge its progress and ensure value is being delivered to shareholders. Among those performance metrics are targets set for production, reserves replacement, netbacks and return on capital employed.



The Company's business strategy begins with its foundation in Western Canada and Heavy Oil, supported by a focused integration strategy. On that solid base, three pillars of growth are being built – the Asia Pacific Region, the Oil Sands, and the Atlantic Region.

Delivering on Production

The Company established a target to grow production three to five percent on a compound annual growth basis through the five-year plan period, recognizing that actual annual growth may be variable. That target was surpassed in 2011, with average annual production reaching 312,500 boe/day, a nine percent increase over 2010.

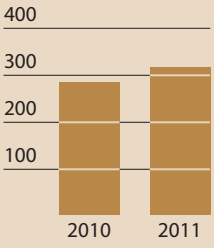
Strong performance from the Atlantic Region was a key contributor to the increase, with North Amethyst reaching its design target of 37,000 bbls/day (gross) and new production coming on stream from the West White Rose pilot. Acquisitions in Alberta and northeast British Columbia in early 2011 were additional contributors, adding immediate production and value in core producing areas. The gains in production were achieved despite disruptions associated with a fire in the Slave Lake region of Alberta and a prolonged outage to a third-party pipeline servicing the Rainbow region.

The strategy for Western Canada and Heavy Oil is focused on sustaining production at finding and development (F&D) and operating costs that are comparable to current levels. In order to compensate for natural declines associated with conventional production in the Western Canadian Sedimentary Basin, the Company is regenerating its base by transitioning to a greater percentage of unconventional production and long-life thermal. Advances in technology are breathing new life into the Basin, and by leveraging these technologies, the Company expects to maintain production levels through the plan period.

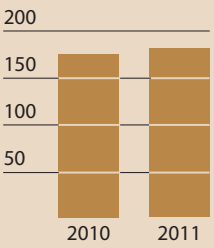
Delivering on Netbacks

While growing production is a primary target, increasing netbacks from the oil and natural gas the Company produces is an equally important goal. Netbacks represent the operating cash margin received for each barrel or equivalent barrel sold, after royalties and operating costs are deducted. In 2011, netbacks increased to approximately $39 per barrel, from approximately $31 per barrel in 2010, a 23 percent increase.

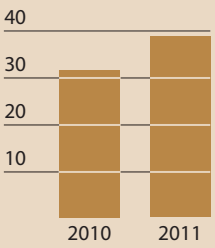
Production
(mboe/day)



Reserve Replacement Ratio *(%)*



Netbacks
($/boe)



Stronger crude oil prices were a significant factor in the improved performance. Increased production from offshore facilities, discipline in controlling operating costs, and solid execution allowed the Company to capture the full value of improved pricing conditions.

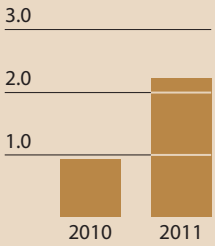
Throughput at the Company's refineries and upgrader increased four percent in 2011 to an average of 317 mbbls/day. Minor turnarounds were completed at the Lloydminster Upgrader, the Lima Refinery and the Toledo Refinery during the year, underscoring their solid execution and performance. The U.S. Downstream business contributed $440 million to net earnings in 2011, compared to a loss of $20 million in 2010. The Canadian Refined Products and Upgrading segments contributed $373 million to net earnings, a 107 percent increase from the $180 million contribution to net earnings in 2010. Midstream also had a strong performance, contributing $246 million to net earnings, compared to $160 million in 2010. Construction of a 300,000-barrel storage tank at the Company's Hardisty terminal, which will facilitate the movement of volumes onto the Keystone pipeline system, is on track to be completed by mid-2012.

Delivering on ROCE

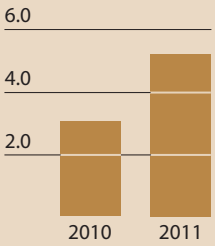
ROCE, which is return on capital employed, is the fourth key performance metric. ROCE is a gauge of how well a company puts its capital to work. Husky has set a target of increasing ROCE by five percentage points over the plan period. Strong progress was achieved on this front, with ROCE increasing from 6.4 percent in 2010 to 11.8 percent in 2011.

Contributing to this improvement was the crude oil pricing environment. The average realized price the Company received for its light, medium and heavy oil, bitumen and natural gas liquids production in 2011 was $82.72 per barrel. This compares to the average realized price in 2010 of $66.70. A supporting factor was strong operational performance from the Atlantic Region, where the light oil produced garnered a substantial premium to West Texas Intermediate (WTI) pricing in 2011. This was achieved as the Company ramped up production at the North Amethyst field to its design target of 37,000 bbls/day (gross).

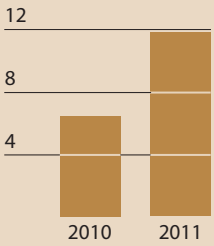
Net Income
($ billions)



Cash Flow
($ billions)



Return on Average Capital Employed *(%)*





Further gains in ROCE were achieved in the Company's Downstream business. The average realized refining margin in 2011 more than doubled on improved crack spreads to US $17.60 per barrel from US $7.29 per barrel in 2010. The Company was able to capitalize on this improved environment through strong operational performance at its refineries. In addition to higher crack spreads, the BP-Husky Toledo Refinery was able to capitalize on wider margins between heavy and light crude oil. Approximately 50 percent of the feedstock at the Toledo Refinery is heavy oil.

Delivering on Safety

Husky considers its commitment to safety and operational integrity of paramount importance. Considerable progress was made in 2011 in rolling out the Husky Operational Integrity Management System (HOIMS) at the operational level. HOIMS introduces a single set of rigorous standards and processes company-wide in Upstream, Midstream and Downstream. By ensuring all business units speak the same language, the Company is able to share best practices and make improvements at a faster pace.

In 2011, six company-wide standards were rolled out covering Leadership, Risk Management, Competency, Incident Management, Documentation and Continuous Improvement.

Result: Value Delivered

Husky made considerable progress in executing against its targets in 2011. The end result is increased value delivered to shareholders. Net earnings for the year more than doubled to $2.2 billion compared to $0.9 billion in 2010. Cash flow from operations increased 69 percent to $5.2 billion, compared to $3.1 billion in 2010.

As a result of activities undertaken early in 2011 to strengthen the balance sheet, the Company has considerable financial flexibility to fund its growth strategy in the face of ongoing economic uncertainty and commodity pricing volatility.

The strategy has taken root and the path ahead is clear. The focus for 2012 remains on achieving predictable and reliable top-tier performance.

The strategy is set, the Company is on course, we are meeting our targets, and value is being delivered to shareholders.

— Asim Ghosh

Management's Discussion and Analysis

March 8, 2012

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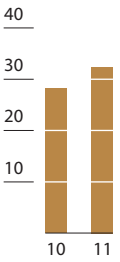
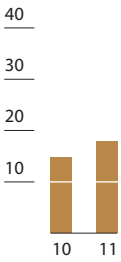
1.0 Financial Summary

1.1 Financial Position

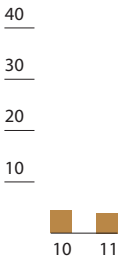
Total Assets
($ billions)



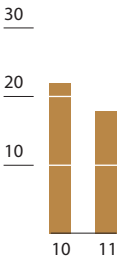
Total Equity
($ billions)



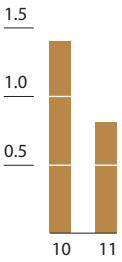
Total Long-term Debt
($ billions)



Debt to Capital Employed[1]
(%)

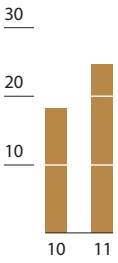


Debt to Cash Flow[1]
(times)

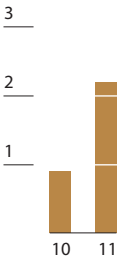


1.2 Financial Performance

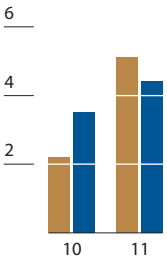
Gross Revenues
($ billions)



Net Earnings
($ billions)

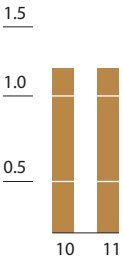


Cash Flow
($ billions)

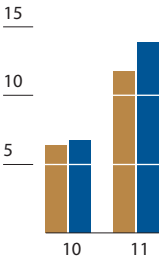


Cash Provided – Operating
Cash Used – Investing

Dividends
($ per share)



Return[1]
(%)



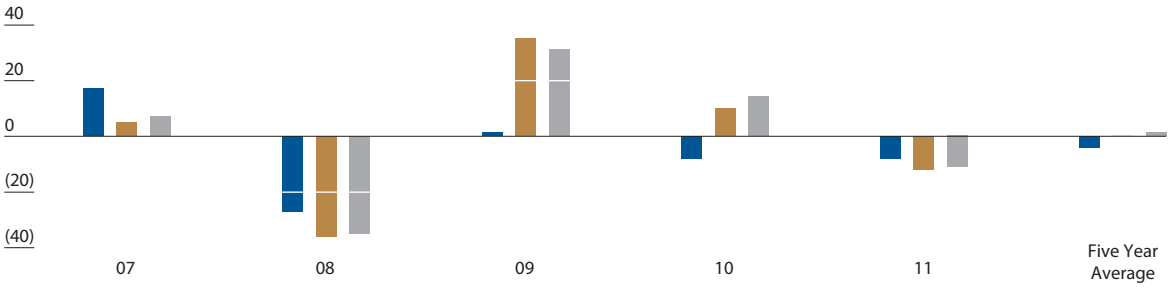
Capital Employed
Equity

[1] *Debt to capital employed, debt to cash flow, return on equity and return on capital employed 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
(%)



Husky Common Shares
S&P/TSX Energy Index
S&P/TSX Composite Index

1.4 Selected Annual Information

($ millions, except where indicated)	2011	2010	2009[1]
Gross revenues[2]	**24,489**	18,085	15,935
Net earnings by sector			
Upstream	**1,502**	861	1,113
Midstream	**246**	160	200
Downstream	**813**	160	319
Corporate	**(286)**	(187)	(172)
Eliminations	**(51)**	(47)	(44)
Net earnings	**2,224**	947	1,416
Net earnings per share – basic	**2.40**	1.11	1.67
Net earnings per share – diluted	**2.34**	1.05	1.67
Ordinary dividends per common share	**1.20**	1.20	1.20
Cash flow from operations[3]	**5,198**	3,072	2,507
Total assets	**32,426**	28,050	26,295
Other long-term financial liabilities	**–**	102	96
Long-term debt including current portion	**3,911**	4,187	3,229
Cash and cash equivalents	**1,841**	252	392
Return on equity *(percent)*[3][4]	**13.8**	6.7	9.8
Return on average capital employed *(percent)*[3][5]	**11.8**	6.4	9.1

(1) *Results are reported in accordance with previous Canadian GAAP. The results for 2009 are not incorporated into Sections 1.1 and 1.2 as IFRS comparative information is not available.*
(2) *In 2011, the Company changed its treatment of certain intersegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for 2010. The recasting reduced each of gross revenues and purchases of crude oil and products by $217 million and did not impact net earnings.*
(3) *Cash flow from operations and financial ratios constitute non-GAAP measures. (Refer to Section 11.3)*
(4) *Return on equity equals net earnings divided by the two-year average shareholder's equity.*
(5) *Return on average 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.*

2.0 Husky Business Overview

Husky Energy Inc. ("Husky" or the "Company") is an international integrated energy company headquartered in Calgary, Alberta, and is publicly traded on the TSX under the symbols HSE and HSE.PR.A. The Company operates worldwide in the Upstream, Midstream and Downstream business segments. Husky uses a combination of technological innovation, prudent investment, sound project management and responsible resource development to deliver consistent shareholder returns.

- In the Upstream segment, the Company explores for, develops and produces crude oil, bitumen, natural gas and natural gas liquids.
- In the Midstream segment, the Company markets and operates storage facilities for crude oil and natural gas and processes and transports heavy crude oil through pipelines (infrastructure and marketing).
- In the Downstream segment, the Company upgrades heavy crude oil feedstock into synthetic oil (upgrading), distributes motor fuel and ancillary and convenience products, manufactures and markets asphalt products, produces ethanol and operates two regional refineries in Canada (Canadian refined products), refines crude oil through interests in two refineries in Ohio and markets refined products in the U.S. Midwest (U.S. refining and marketing).

In 2012, the Company commenced evaluating and reporting activities of the Midstream reporting segment as a service provider to the Upstream and Downstream operations. As a result, the Company will reclassify and report its Midstream activities into the Upstream and Downstream reportable business segments commencing the first quarter of 2012 (Refer to Note 25 to the Consolidated Financial Statements).

3.0 The 2011 Business Environment

3.1 Business Risk Factors

Husky's results of operations are significantly influenced by the global and domestic business environment. Some risk factors are entirely beyond the Company's control and others, to some extent, can be strategically managed. Husky has implemented risk management processes that are intended to manage these risks. Salient factors include:

Financial and Economic Risks

An adverse change in any of the following conditions could affect the Company's ability to realize the value and quantity of its oil and natural gas reserves, achieve expected cash flow and financial performance, optimize project economics and sanction capital projects, and could negatively impact the Company's results of operations, liquidity and financial condition:

- the demand for the Company's products and the prices the Company receives for crude oil, bitumen and natural gas production and refined petroleum products;
- the economic conditions of the markets in which Husky conducts business;
- the exchange rate between the Canadian and U.S. dollar;
- the cost and availability of capital, including access to capital markets at acceptable rates; and
- other financial risks as described in Section 8.6.

Operational Risks

An adverse change in any of the following conditions could affect the Company's ability to gain access to the resources required to increase oil and natural gas reserves and production, retain adequate markets for its products and services and complete development projects:

- the ability to replace reserves of oil and gas, whether sourced from exploration, improved recovery or acquisitions;
- the availability of prospective drilling rights;
- the costs to acquire exploration rights and undertake geological studies, appraisal drilling and project development;
- the availability and cost of labour, material and equipment to efficiently, effectively and safely undertake capital projects;
- the ability and costs to operate properties, plants and equipment in an efficient, reliable and safe manner;
- access to supporting infrastructure and crude oil feedstock;
- prevailing climatic conditions in the Company's operating locations;
- the competitive actions of other companies, including increased competition from other oil and gas companies;
- the ability to access different geographic markets for products;
- business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures, unplanned and extended pipeline shutdowns and other similar events affecting the Company or other parties whose operations or assets directly or indirectly affect the Company;
- the inability to reach the Company's estimated production levels from existing and future oil and gas development projects as a result of technological or commercial difficulties; and
- changes in workforce demographics.

Legislative Risks

An adverse change in any of the following conditions could affect the Company's ability to access markets, utilize its financial resources in an efficient manner and undertake exploration, development and construction projects and could impact the Company's interests in its foreign operations and future profitability:

- potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations;
- changes to taxes and royalty regimes;
- regulations intended to deal with climate change issues;
- changes to government fiscal, monetary and other financial policies; and
- the ability to obtain regulatory approvals to operate existing properties or develop significant growth projects.

3.2 Economic Sensitivities

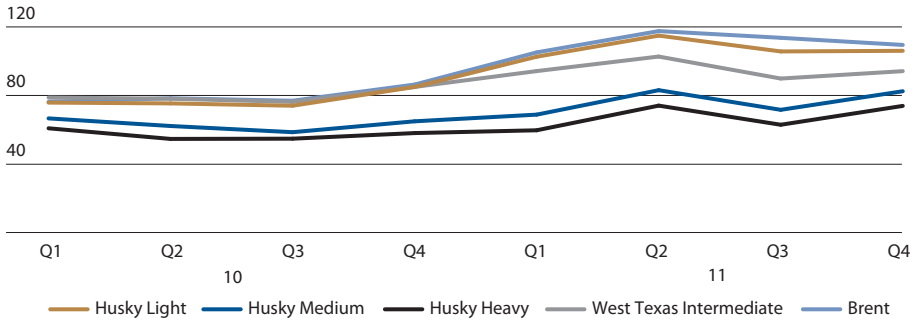
Average Benchmarks		2011	2010
WTI crude oil	*(U.S. $/bbl)*	**95.12**	79.46
Brent crude oil	*(U.S. $/bbl)*	**111.27**	79.42
Canadian light crude 0.3% sulphur	*($/bbl)*	**95.32**	77.75
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**67.61**	59.87
NYMEX natural gas	*(U.S. $/mmbtu)*	**4.04**	4.39
NIT natural gas	*($/GJ)*	**3.48**	3.91
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**17.44**	14.48
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**25.26**	9.64
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**24.65**	9.20
U.S./Canadian dollar exchange rate	*(U.S. $)*	**1.011**	0.971
Canadian Equivalents			
WTI crude oil	*($/bbl)*	**94.09**	81.83
Brent crude oil	*($/bbl)*	**110.06**	81.79
WTI/Lloyd crude blend differential	*($/bbl)*	**17.25**	14.91
NYMEX natural gas	*($/mmbtu)*	**4.00**	4.52

As an integrated producer, Husky's profitability is largely determined by realized prices for crude oil and natural gas 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 global factors and is beyond the Company's control. The price for natural gas is determined more by the North America 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 dramatic effect on short-term supply and demand.

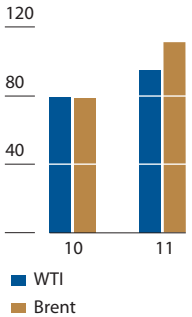
The Downstream segment is heavily impacted by the price of crude oil and natural gas. The largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil. In the upgrading business segment, heavy crude oil feedstock is processed into light synthetic crude oil. 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, Ohio Refinery and approximately 50% heavy crude oil feedstock at the Toledo, Ohio 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
(US $/bbl)



Average WTI and Brent
(US $/bbl)

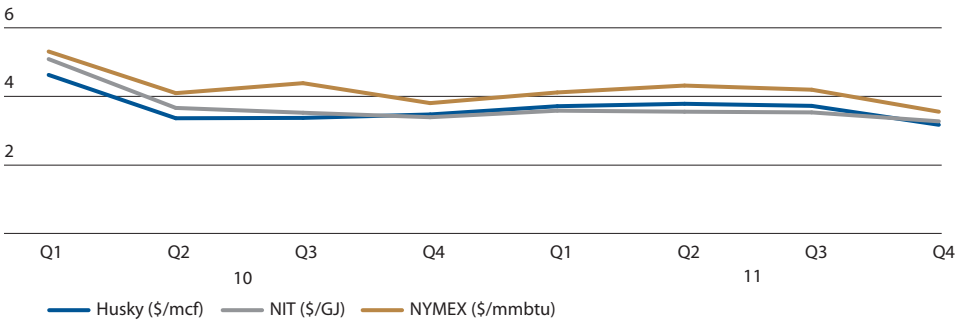


The price Husky receives for production from Western Canada is primarily driven by changes in the price of West Texas Intermediate ("WTI") while the majority of the Company's production in the Atlantic Region and the Asia Pacific Region is referenced to the price of Brent, an imported light sweet benchmark crude oil produced in the North Sea. The price of WTI ended 2011 at U.S. $98.83/bbl compared to U.S. $91.38/bbl on December 31, 2010, and averaged U.S. $95.12/bbl in 2011 compared with U.S. $79.46/bbl in 2010. The price of Brent ended 2011 at U.S. $106.51/bbl, compared to U.S. $92.55/bbl on December 31, 2010, and averaged U.S. $111.27/bbl in 2011 compared with U.S. $79.42/bbl in 2010.

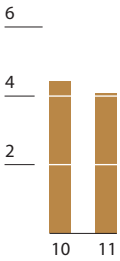
A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2011, 47% of Husky's crude oil production was heavy crude oil or bitumen compared with 48% in 2010. The light/heavy crude oil differential averaged U.S. $17.44/bbl or 18% of WTI in 2011 compared to U.S. $14.48/bbl or 18% of WTI in 2010.

Natural Gas

NYMEX Natural Gas, NIT Natural Gas and Husky Average Natural Gas Prices
(US $)



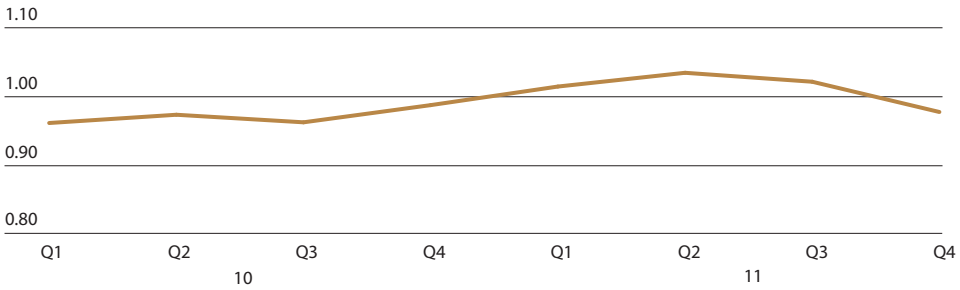
Average NYMEX
(US $/mmbtu)



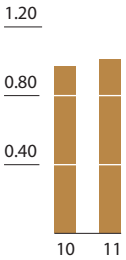
In 2011, 32% of Husky's total oil and gas production was natural gas compared with 29% in 2010. The near-month natural gas price quoted on the NYMEX ended 2011 at U.S. $2.99/mmbtu compared with U.S. $4.41/mmbtu at December 31, 2010. During 2011, the NYMEX near-month contract price of natural gas averaged U.S. $4.04/mmbtu compared with U.S. $4.39/mmbtu in 2010.

Foreign Exchange

Average US/Canadian Dollar Exchange Rate
(US $ per Cdn $)



Average US/Canadian Dollar Exchange Rate
(US $ per Cdn $)



The majority of the Company's revenues from the sale of oil and gas commodities receive prices determined by reference to U.S. benchmark prices. 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 of the 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 2010 at U.S. $1.005 and closed at U.S. $0.983 at December 31, 2011. In 2011, the Canadian dollar averaged U.S. $1.011 strengthening by 4% compared with U.S. $0.971 during 2010.

Increased U.S. crude oil prices were partially offset by the strengthening of the Canadian dollar against the U.S. dollar in 2011. The price of WTI in 2011 in U.S. dollars increased 20% compared with an increase of 15% in Canadian dollars when compared to 2010.

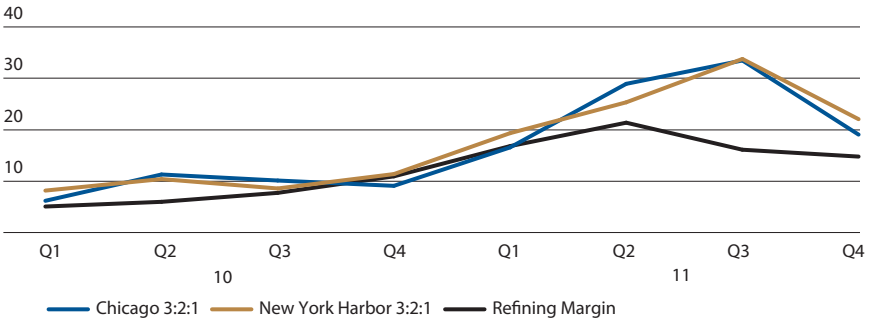
Refining Crack Spreads

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").

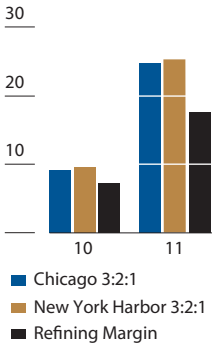
The New York Harbor 3:2:1 refining crack spread benchmark is calculated as the difference between the price of a barrel of WTI crude oil and the sum of the price of two-thirds of a barrel of reformulated gasoline and the price of one-third of a barrel of heating oil. The Chicago 3:2:1 refining crack spread benchmark is calculated based on WTI, regular unleaded gasoline and ultra low sulphur diesel. During 2011, the New York Harbor 3:2:1 refining crack spread averaged U.S. $25.26/bbl compared with U.S. $9.64/bbl in 2010. During 2011, the Chicago 3:2:1 crack spread averaged U.S. $24.65/bbl compared with U.S. $9.20/bbl in 2010.

During 2011, the 3:2:1 crack spreads were higher than 2010 reflecting the change in WTI relative to Brent crude oil pricing.

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



Average Crack Spread
(US $/bbl)



Global Economic and Financial Environment

The EIA Short-Term Energy Outlook[1], published on February 7, 2012, provided the following insights to the near-term energy environment. World energy demand is expected to continue to increase in 2012 and 2013, mostly in countries outside of the Organization for Economic Cooperation and Development ("OECD"). World liquid fuels consumption grew by 0.8 mmbbls/day to reach 87.9 mmbbls/day in 2011 and is expected to reach 89.3 mmbbls/day in 2012 and 90.7 mmbbls/day in 2013. Modest growth in consumption in the United States and Japan is expected to be more than offset by lower consumption in Europe over the next two years. The Organization of Petroleum Exporting Countries ("OPEC") spare capacity is expected to rise from 2.2 mmbbls/day in December 2011 to 3.9 mmbbls/day by the end of 2013.

During 2011, natural gas production in Canada continued to decline while production in the United States increased by an estimated 4.8 bcf/day over the previous year. Ample natural gas supply and high storage levels have resulted in continued low prices. Although the natural gas rig count has declined, natural gas markets are expected to remain well supplied in the near-term as a backlog of shale natural gas wells near markets in the U.S. Gulf Coast, mid-continent and eastern states continue to be completed and tied-in. As a result, investment in Canadian natural gas exploration and development is expected to be focused on resource plays that utilize new technology and are in natural gas liquid prone areas[2]. Conventional natural gas exploration is expected to be focused on the traditionally less accessible areas along the eastern slope of the Rocky Mountains.

Notes:

(1) *"Short-Term Energy Outlook," February 7, 2012, Energy Information Administration U.S. Department of Energy.*

(2) *"Winter Energy Outlook 2011 – 2012 Adjusting to Economic Uncertainty", November 2011, National Energy Board.*

3.3 Sensitivities for 2011 Results

The following table is indicative of the relative annualized effect on pre-tax cash flow and net earnings from changes in certain key variables in 2011. The table below shows what the effect would have been on 2011 financial results had the indicated variable increased by the notional amount. The analysis is based on business conditions and production volumes during 2011. 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	2011 Average	Increase	Effect on Pre-tax Cash Flow[1]		Effect on Net Earnings[1]	
			($ millions)	*($/share)*[2]	*($ millions)*	*($/share)*[2]
WTI benchmark crude oil price[3][4]	$ 95.12	*U.S. $1.00/bbl*	66	0.07	49	0.05
NYMEX benchmark natural gas price[5]	$ 4.04	*U.S. $0.20/mmbtu*	28	0.03	20	0.02
WTI/Lloyd crude blend differential[6]	$ 17.44	*U.S. $1.00/bbl*	(9)	(0.01)	(7)	(0.01)
Canadian light oil margins	$ 0.043	*Cdn $0.005/litre*	16	0.02	12	0.01
Asphalt margins	$ 22.13	*Cdn $1.00/bbl*	9	0.01	7	0.01
New York Harbor 3:2:1 crack spread[7]	$ 25.26	*U.S. $1.00/bbl*	73	0.08	46	0.05
Exchange rate (U.S. $ per Cdn $)[3][8]	$ 1.011	*U.S. $0.01*	(48)	(0.05)	(36)	(0.04)
Interest rate		*100 basis points*	(7)	(0.01)	(5)	(0.01)

(1) *Excludes mark to market accounting impacts.*
(2) *Based on 957.5 million common shares outstanding as of December 31, 2011.*
(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 Capability to Deliver Results

Husky's results are dependent on a number of factors including commodity prices, foreign exchange rates, interest rates, the Company's continued success in exploring for oil and natural gas, efficient and safe execution of capital projects and operations, effective marketing of crude oil and natural gas, retention of expertise, and continued access to the financial markets. Husky is engaged in several key projects within each operating segment to maximize the potential for achieving targets.

4.1 Upstream

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 exploitation 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 stabilize decline rates of light and heavy crude oil. Emerging EOR techniques are being field tested, while techniques that have been in practice for several decades continue to be optimized;
- A growing position in Western Canada gas resource plays with approximately 850,000 acres associated with both liquids-rich and dry gas positions;
- A growing oil resource play position with existing activities in the Viking, Bakken, Lower Shaunavon, and Cardium formations;
- Expertise and experience exploring and developing the high-impact natural gas potential in the Alberta Deep Basin, Foothills, and northwest plains of Alberta and British Columbia;
- Substantial position in the Alberta oil sands. The initial stages of the development of these assets include the Sunrise Energy Project that is in the development phase and the Tucker oil sands project that is currently on production. The Sunrise Energy Project is proceeding as a joint 50/50 partnership with BP and is an integral part of a North American oil sands business which includes the BP-Husky Toledo Refinery. Husky holds approximately 550,000 acres in 13 undeveloped oil sands leases;
- 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;
- Husky has a 40% interest in approximately 690,400 acres (2,800 square kilometers) of the Madura Strait block, located offshore East Java, south of Madura Island, Indonesia. Offshore Indonesia is focused on the development of the Madura BD, MDA and MBH natural gas and natural gas liquids fields; and
- Husky has a large portfolio of significant discovery and exploration licences offshore Newfoundland and Labrador and offshore Greenland (collectively referred to as the "Atlantic Region"). Husky's offshore East Coast exploration and development program is

focused in the Jeanne d'Arc Basin on the Grand Banks, which contains the Hibernia, Terra Nova, White Rose and North Amethyst oil fields. Husky holds ownership interests in the Terra Nova, White Rose and North Amethyst oil fields as well as in a number of smaller undeveloped fields in the central part of the basin. Husky also holds significant exploration acreage in the area.

4.2 Midstream

Highlights of the Midstream segment include:

- Integrated heavy oil pipeline systems in the Lloydminster producing region;
- Natural gas storage in excess of 45 bcf, owned and leased;
- Petroleum marketer balancing the needs of both customers and suppliers; and
- Supplier of crude oil, natural gas, petroleum coke, sulphur and electrical power for the Company's plants and facilities.

4.3 Downstream

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 549 retail marketing locations as at December 31, 2011 including bulk plants and travel centres with strategic land positions in Western Canada and Ontario. Retail outlets include, in many cases, convenience stores, restaurants, service bays and car washes.

5.0 Strategic Plan

Husky's strategy is to maintain production in its foundation of Western Canada and Heavy Oil and reposition these areas to resource play and thermal development, while advancing its three major growth pillars in the Asia Pacific Region, the Atlantic Region and the Oil Sands. The Company is not integrated on a barrel-for-barrel basis and seeks to operate and maintain Midstream and Downstream assets which provide specialized support and value to its Upstream heavy oil and bitumen assets. The Company's strategy is to maximize the efficiency of its Midstream and Downstream operations and extract the greatest value from production.

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

5.1 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 on resource play and thermal development by growing oil resource plays, directing capital into liquids-rich gas plays and increasing horizontal drilling for heavy oil production. Approximately two-thirds of Upstream production is oil-weighted with the objective of maintaining this weighting. Husky is advancing its oil resource play position with activities in the Muskwa, Canol, Viking, Bakken, Lower Shaunavon and Cardium formations, with approximately 800,000 net acres of oil resource play inventory. Husky also has a growing position in Western Canada gas resource plays, with approximately 850,000 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 commencing in 2011. The first phase, which represents a $2.5 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 BD, MDA and MBH field developments in 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 mid-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. Combined with the producing Wenchang oil field, further 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"), the Asia Pacific Region represents a growth area for Husky.

The Atlantic Region stretches from Greenland to the Sydney Basin, south of Newfoundland and Labrador. The Atlantic Region continues to be a focus area, with the Company holding 18 Exploration Licences and interests in eight Production Licences and 23 Significant Discovery Areas. Work is well underway to identify new and innovative ways to further develop the significant resources in the basin.

5.2 Midstream

Midstream is focused on supporting Upstream production and making prudent reinvestments. The Company's spending will be focused on maintenance and optimization of existing infrastructure.

5.3 Downstream

Downstream is focused on supporting heavy oil and oil sands production and making prudent reinvestments. Husky plans to continue to pursue projects to optimize, integrate and reconfigure the Lima, Ohio Refinery for additional crude oil feedstock flexibility and reconfigure and increase capacity at the BP-Husky Toledo, Ohio Refinery to accommodate Sunrise production as its primary feedstock. The Company also plans to expand terminalling and product storage opportunities.

5.4 Financial

Husky is committed to ensuring adequate liquidity and financial flexibility to fund the Company's growth and support dividend payments. Over the business cycle, the Company's objective is to maintain a debt to cash flow ratio of 1.5 to 2.5 times and a debt to capital employed target of 25% to 35%.

The Company also aims to retain investment grade credit ratings by continuing to focus on financial discipline around costs and the efficiency of Husky's operations and, at the same time, emphasizing the Company's focus on its return on capital.

6.0 Key Growth Highlights

The 2011 capital program was established with focus on projects offering the highest potential for returns and mid to long-term growth. Husky's 2011 capital program was built on the momentum achieved in 2010 with respect to accelerating near-term production growth as well as continuing to advance its three major growth pillars in the Asia Pacific Region, the Atlantic Region and the Oil Sands.

6.1 Upstream

Western Canada (excluding Heavy Oil and Oil Sands)

Gas Resource Plays

The liquids-rich formations at Ansell in west central Alberta continues to be a key area of focus. During 2011, Husky drilled 34 Cardium formation wells and seven multi-zone wells, and commenced a Cardium horizontal well at Ansell. Completion operations continued and offload capacity expansion construction progressed during 2011.

The evaluation of the Duvernay liquids-rich gas play in Kaybob continued in 2011 with the drilling, coring and logging of two vertical wells. A program of horizontal wells to establish the productive capacity of this zone commenced in late 2011 with the first well rig released and the second being drilled at year end. Completion of these horizontal wells is expected to occur in 2012.

In 2011, three wells in the multi-zone program were drilled at Kakwa and placed on production.

Oil Resource Plays

In the Viking oil resource project, 16 wells were drilled in the Dodsland/Elrose area of southwest Saskatchewan. The horizontal program conducted in Redwater, Alberta resulted in 22 gross Viking horizontal wells drilled. Approximately 50 wells are planned for the Redwater and Saskatchewan Viking projects in 2012.

During 2011, Husky was successful in acquiring approximately 11,500 acres of high potential Bakken Formation acreage adjacent to its Oungre Oil Resource Project lands in south central Saskatchewan. Husky holds a total of approximately 18,700 net acres in this play. Husky drilled a total of 12 wells in 2011 and acquired additional three-dimensional ("3-D") seismic in 2011 in order to obtain full coverage over all landholdings at Oungre.

Husky drilled five gross wells in the lower Shaunavon zone in early 2011 with four wells currently producing and one well abandoned due to surface casing issues. Five additional wells are planned in the Shaunavon resource play for 2012.

Husky drilled three vertical pilot wells and two horizontal wells at the Rainbow Muskwa project during 2011. It is anticipated that these wells will provide information for resource and reservoir characterization across the Rainbow area. One of the horizontal wells was completed in late 2011 and is undergoing post fracture clean up. Husky holds a significant acreage position in this emerging oil resource play which compliments its wholly owned infrastructure at Rainbow Lake.

Husky currently holds approximately 29,000 net acres in the Northern Cardium oil resource trend at Wapiti and Kakwa. In 2011, four horizontal wells were drilled with two wells completed at Wapiti. During the year, a four-well pilot program was drilled at Kakwa. Completion operations are planned throughout 2012 with two wells already completed in early 2012.

In mid-2011, Husky was granted the rights to two exploration blocks in the Mackenzie Valley area of the Northwest Territories covering approximately 437,000 acres for a work commitment bid of $188 million per license. The rights have a primary term of five years with a term extension to nine years when a well is drilled. The project received regulatory approvals for the construction and drilling operations of two vertical pilot wells and a 220 square kilometer 3-D seismic program. Husky drilled one vertical pilot well to total depth in early 2012 with the second vertical well planned for late 2012.

Heavy Oil

In 2011, construction of the 8,000 bbls/day Pikes Peak South thermal project progressed according to plan with production expected to commence in mid-2012. Husky also continued construction of its 3,000 bbls/day Paradise Hill development. The project is on schedule and is anticipated to become operational by late 2012. In addition, the Rush Lake single well pair thermal pilot achieved first oil in October 2011.

Husky advanced its horizontal drilling program in 2011 with the completion of an expanded 130 well program. Based on the positive performance of the past horizontal drilling programs, Husky is expanding the drilling program to approximately 140 to 150 wells in 2012. Husky also drilled 332 gross cold heavy oil production with sand ("CHOPS") wells during 2011. In addition, Husky is operating four solvent EOR pilots, two of which became operational in 2011. A CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant is under construction and is expected to be commissioned in early 2012. The liquefied CO_2 from this facility will be used in the ongoing solvent EOR piloting program.

Oil Sands

Sunrise Energy Project

Husky and BP continue to advance the development of the Sunrise Energy Project in multiple stages. To date, Husky has drilled more than half of the planned 49 SAGD horizontal well pairs for Phase I and is on track for the full drilling program to be completed by the second half of 2012, with first production anticipated in 2014.

Detailed engineering activities for the facilities and supporting infrastructure continued in 2011. The field facilities engineering contractor has mobilized on site to begin construction on the first well pad. The Central Processing Facility contractor has also mobilized on site and commenced foundation installation for facilities. The first major equipment delivery was completed in January 2012. Major construction of the camp building is also underway and is expected to be available for use in early 2012.

A contract for the Design Basis Memorandum and front end engineering design ("FEED") of the next development stage of the Sunrise Energy Project was awarded in October 2011 with FEED expected to be completed in 2013.

Tucker Oil Sands Project

Based on a greater understanding of the Tucker reservoir, Husky has addressed production challenges by remediating mature wells with new stimulation techniques, drilling new wells, and initiating new start up procedures.

Husky completed its 16 well pair A Pad development in 2011. Production was phased in during the year with all 16 wells on production by year end. One well pair was drilled in the Grand Rapids pilot with production expected in early 2012. Several applications to the Energy Resources Conservation Board have been approved or are proceeding for additional drilling and field development through to 2015. Daily production rates reached 10,000 boe/day in December 2011 and have been sustained at 10,000 boe/day for the first two months of 2012.

McMullen

Husky's development of the McMullen property, which is located in the west central region of the Athabasca oil sands of northern Alberta, involves a cold production development project and an air injection pilot project. Alberta Environment approval for the McMullen air injection pilot was achieved in early 2011 and was the final regulatory approval required for the project. In 2011, six observation wells and one horizontal production well were drilled as per plan. Facility construction commenced in May 2011 and was completed on schedule in August 2011. Steam injection was successfully initiated at the end of September, with first air injection initiated in December 2011. During 2011, 83 slant development wells were drilled with a total of 41 slant development wells equipped and put on production in the cold production project. The remaining wells are expected to be equipped, completed and placed on production at the end of first quarter of 2012.

Saleski

In 2011, Husky acquired approximately 100 kilometers of two-dimensional ("2-D") seismic data as part of a continuing assessment program. In addition, survey work has been completed for the applications for 30 vertical stratigraphic wells and 144 kilometers of 2-D seismic data for the upcoming 2012 winter program.

Asia Pacific Region

Offshore China Exploration, Delineation and Development

Husky sanctioned the development of the principal fields of the Liwan Gas Project, Liwan 3-1 and Liuhua 34-2, following the finalization of the gas sales agreement for production for Liwan 3-1 and submission of the Overall Development Plan to the Chinese government authorities for regulatory approval. Production will supply the Guangdong Province. The price mechanism will be in line with the anticipated Guangdong market price which, as published by the Chinese government in December 2011, was a maximum current Guangdong gate station price of 2.74 RMB/m^3, which equates approximately to U.S. $12.20/mcf. In December 2011, the Original Gas In-Place report for the Liuhua 29-1 gas field was approved by the Chinese government. FEED for the development of this field is scheduled to commence in March 2012. Regulatory approvals in relation to environmental matters and civil construction were received for the Liwan Gas Project in late 2011.

The project is proceeding on schedule towards planned first gas delivery in late 2013/early 2014. The Liwan 3-1 and Liuhua 34-2 fields are expected to ramp up through 2014 with expected gross production rates above 300 mmcf/day. Development of the Liuhua 34-2 field is planned to proceed in parallel with and be tied into the development of the Liwan 3-1 field. The Liuhua 29-1 field is intended to be developed in an overlapping sequence to the development of the Liwan 3-1 and Liuhua 34-2 fields. The total project is expected to reach gross production of approximately 500 mmcf/day in the 2015 timeframe.

In the first half of 2011, Husky successfully completed the development well drilling program for the field. In addition, Husky successfully drilled two appraisal wells on the Liuhua 29-1 field. The wells encountered commercial quantities of gas and will be completed as production wells. The Company also drilled three exploration wells in the second half of 2011. One well encountered hydrocarbons and well results are being evaluated. Two wells encountered hydrocarbons in non-commercial quantities and were abandoned without testing. Husky completed an exploration well on Block 63/05 in the shallow water of the Qiongdongnan Basin located 50 kilometers south of Hainan Island. The exploration well was drilled to a total depth of 3,620 meters however, commercial hydrocarbons were not encountered and the well was plugged and abandoned. Husky has a 49% ownership interest in the net production after expenses, taxes and royalties of the Liwan Gas Project.

Indonesia Exploration and Development

Both Husky and CNOOC completed the sale of 10% equity stakes in Husky-CNOOC Madura Ltd. to Samudra Energy Ltd. through its affiliate SMS Development Ltd in January 2011. As a result of the sale, Husky and CNOOC each hold a 40% interest in Husky-CNOOC Madura Ltd. with the remaining 20% held by SMS Development Ltd. During 2011, CNOOC as the operator for the Madura Strait Block commenced the tendering of equipment and services for the Madura BD field development. Two exploration wells were drilled in 2011 which confirmed additional gas resources in the MDA and MBH fields. A Plan of Development is expected to be filed in 2012 with first gas production from the Madura Straits Block expected in 2014.

Husky currently holds a 100% working interest in the North Sumbawa II Exploration Block, comprised of 5,000 square kilometers in the East Java Sea, where interpretation of 1,020 kilometers of new 2-D seismic data is under review.

Atlantic Region

White Rose Extension Projects

Development continued at the North Amethyst satellite extension in 2011. At the end of 2011, the North Amethyst field had three production and three water injection wells on stream with one production well brought on stream in June 2011. While further wells are expected to be drilled to sustain production, the field has now fully met its target production rate of 37,000 bbls/day. During 2011, Husky filed an application to amend the development plan for North Amethyst to include the Hibernia reservoir. In 2012, Husky plans to continue development drilling at North Amethyst and to drill an infill well at the main White Rose field to facilitate incremental oil recovery.

First production from a two-well pilot project at the West White Rose field was achieved in September 2011 with completion of a production well. A supporting water injection well was drilled to total depth during the fourth quarter and is expected to be completed in 2012. The pilot program will assist in refining the development plan for the full West White Rose resource.

The Company continues to evaluate the feasibility of a concrete wellhead and drilling platform for development of future resources in the White Rose region including the full development of West White Rose. Pre-FEED and FEED contracts to support this work are expected to be awarded at the end of the first quarter of 2012.

Atlantic Region Exploration

Husky participated in a non-operated Mizzen well which was completed in September 2011. Husky holds a 35% working interest in the field which is located in the Flemish Pass Basin.

Husky commenced drilling of an exploration well in late 2011 to test the non-operated Fiddlehead prospect located south of the Terra Nova field. Husky holds a 50% working interest in the well.

Husky plans to participate in two to three exploratory wells in the Atlantic Region in 2012.

Offshore Greenland

Husky has a significant position in three blocks off the west coast of Greenland. Geological and geophysical work continues in order to define potential well locations.

6.2 Midstream

Husky's project to construct a 300,000 barrel tank at the Hardisty terminal is on target to be in service in mid-2012. The tank will facilitate moving volumes to U.S. Petroleum Administration for Defense Districts ("PADD") II and PADD III markets.

6.3 Downstream

Lima, Ohio Refinery

The refinery continues to implement short term reliability and profitability improvement projects. Ordering of equipment and site construction has commenced on a 20 mbbls/day kerosene hydrotreater which is expected to increase jet fuel production volume. The kerosene hydrotreater is expected to be operational in the first quarter of 2013.

Toledo, Ohio Refinery

The Continuous Catalyst Regeneration Reformer Project at the Toledo, Ohio Refinery is progressing as planned. Overall detailed engineering and procurement is complete and construction activities are progressing. All major construction contracts have been awarded including mechanical, electrical and instrumentation contracts. All heavy haul transports were completed and equipment continues to be installed at the site. The refinery continues to advance a multi-year program to improve operational integrity and plant performance while reducing operating costs and environmental impacts.

7.0 Results of Operations

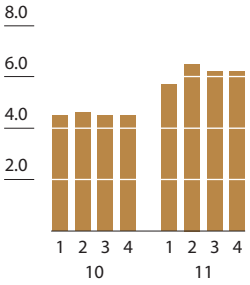
7.1 Segment Earnings

($ millions)	Earnings (Loss) before Income Taxes 2011	2010	Net Earnings (Loss) 2011	2010	Capital Expenditures[1] 2011	2010
Upstream	**2,032**	1,211	**1,502**	861	**4,131**	2,812
Midstream	**328**	219	**246**	160	**43**	40
Downstream						
Upgrading	**207**	89	**153**	63	**55**	182
Canadian Refined Products	**295**	159	**220**	117	**94**	244
U.S. Refining and Marketing	**693**	(32)	**440**	(20)	**224**	256
Corporate and Eliminations	**(415)**	(429)	**(337)**	(234)	**71**	37
Total	**3,140**	1,217	**2,224**	947	**4,618**	3,571

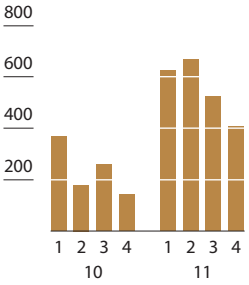
[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

7.2 Summary of Quarterly Results

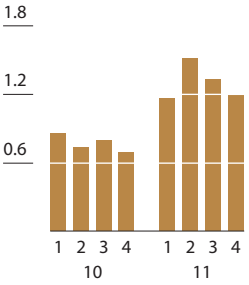
Gross Revenues
($ billions)



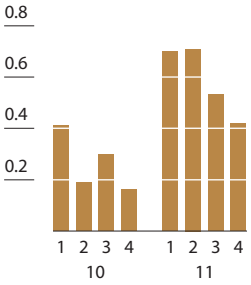
Net Earnings
($ millions)



Cash Flow from Operations[1]
($ billions)



Net Earning Per Share[2]
($ per share)

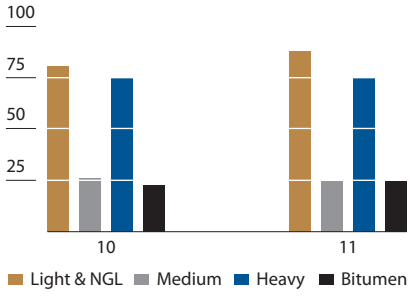


[1] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*
[2] *Reported figure represents net earnings per share – diluted*

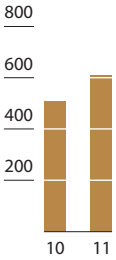
7.3 Upstream

2011 Earnings $1,502 million

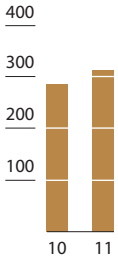
Production
Oil
(mbbls/day)



Production
Natural Gas
(mmcf/day)

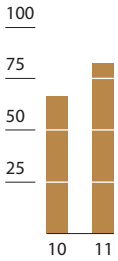


Production
Combined
(mboe/day)

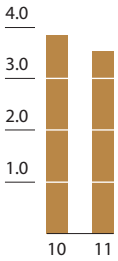


Upstream Earnings Summary *($ millions)*	2011	2010
Gross revenues	**7,250**	5,744
Royalties	**1,125**	978
Net revenues	**6,125**	4,766
Operating, transportation and administration expenses	**1,890**	1,595
Exploration and evaluation expense	**470**	438
Depletion, depreciation, amortization and impairment	**1,996**	1,521
Other expenses (income)	**(263)**	1
Income taxes	**530**	350
Net earnings	**1,502**	861

Average Price Realized
Crude Oil
($/bbl)



Average Price Realized
Natural Gas
($/mcf)

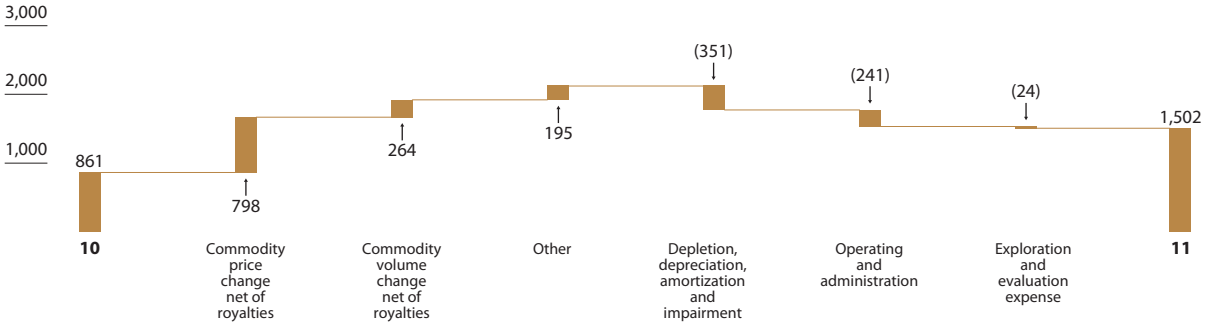


Average Sales Prices Realized	2011	2010
Crude oil *($/bbl)*		
Light crude oil & NGL	**103.25**	76.90
Medium crude oil	**75.65**	64.92
Heavy crude oil	**66.99**	58.91
Bitumen	**64.34**	57.84
Total average	**82.72**	66.70
Natural gas average *($/mcf)*	**3.55**	3.86
Total average *($/boe)*	**63.23**	54.25

Upstream net earnings were $641 million higher in 2011 compared with 2010 primarily due to increased crude oil and natural gas production, higher realized crude oil prices and realized gains on the sale of assets, partially offset by lower realized natural gas prices and higher depletion, depreciation, amortization and impairment, operating expenses and exploration and evaluation expenses.

During 2011, the average realized price increased 24% to $82.72/bbl for crude oil, NGL and bitumen compared with $66.70/bbl during 2010. Realized natural gas prices averaged $3.55/mcf during 2011 compared with $3.86/mcf in 2010. Production in the Atlantic Region and Asia Pacific Region benefited from higher realized prices as the price of Brent increased by approximately 40% compared with 2010, while WTI increased by approximately 20%. Higher U.S. dollar crude oil pricing was partially offset by the strengthening of the Canadian dollar against the U.S. dollar throughout the majority of the year.

After Tax Earnings Variance Analysis
($ millions)



Daily Gross Production	2011	2010
Crude oil *(mbbls/day)*		
Western Canada		
Light crude oil & NGL	**24.8**	23.0
Medium crude oil	**24.5**	25.4
Heavy crude oil	**74.5**	74.5
Bitumen	**24.7**	22.3
	148.5	145.2
Atlantic Region		
White Rose and Satellite Fields – light crude oil	**48.7**	38.2
Terra Nova – light crude oil	**5.6**	8.5
	54.3	46.7
China		
Wenchang – light crude oil & NGL	**8.5**	10.7
	211.3	202.6
Natural gas *(mmcf/day)*	**607.0**	506.8
Total *(mboe/day)*	**312.5**	287.1

Upstream Revenue Mix *Percentage of Upstream Net Revenues*	2011	2010
Crude oil		
Light crude oil & NGL	**44%**	36%
Medium crude oil	**9%**	11%
Heavy crude oil	**26%**	29%
Bitumen	**8%**	8%
	87%	84%
Natural gas	**13%**	16%
Total	**100%**	100%

During 2011, crude oil, bitumen and NGL production increased by 8.7 mbbls/day or 4% compared with 2010, primarily due to higher production from North Amethyst and the impact of acquisitions in the fourth quarter of 2010 and the first quarter of 2011, partially offset by the impacts of the Plains Rainbow pipeline outages and operational issues at Terra Nova.

Production from natural gas increased by 100.2 mmcf/day or 20% in 2011 compared with 2010 due to the impact of acquisitions of properties in Western Canada during the fourth quarter of 2010 and the first quarter of 2011, partially offset by natural reservoir declines in mature properties as capital investment has been focused on higher return projects.

2012 Production Guidance and 2011 Actual

Gross Production	Guidance 2012	Year ended December 31 2011	Guidance 2011
Crude oil & NGL *(mbbls/day)*			
Light crude oil & NGL	70 – 75	**88**	75 – 80
Medium crude oil	25 – 30	**24**	25 – 30
Heavy crude oil & bitumen	100 – 110	**99**	95 – 105
	195 – 215	**211**	195 – 215
Natural gas *(mmcf/day)*	560 – 610	**607**	560 – 610
Total *(mboe/day)*	290 – 315	**312**	290 – 315

The Company's total production for the year ended December 31, 2011 was at the high end of the production guidance set by the Company in 2010 due to strong performance from the Atlantic Region. Husky expects that production levels will be marginally lower in 2012 as compared to 2011 due to a decrease in production from the Atlantic Region as a result of a maintenance offstation of the SeaRose floating, production, and storage offloading vessel ("FPSO") and a maintenance offstation for the Terra Nova FPSO. Although the Company does not expect production growth in fiscal 2012, it expects to meet its long-term compound annual growth target of three to five percent over the term of the five-year plan ending 2015.

Factors that could potentially impact Husky's production performance for 2012 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 facilities, offstations at the SeaRose and Terra Nova FPSO, 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 16% of gross revenue in 2011 compared with 17% in 2010. Royalty rates in Western Canada averaged 14% compared with 15% in 2010. In the Atlantic Region, the average rate was 17% in 2011 compared with 24% in 2010. The lower royalty rate is attributable to the North Amethyst field which is subject to a basic royalty rate of 1%, while Terra Nova and White Rose, being mature fields, are subject to higher rates. Royalty rates at North Amethyst will increase and reach levels similar to Terra Nova and White Rose after certain project payouts as prescribed in the royalty regulations are met. Royalty rates in the Asia Pacific Region averaged 30% compared with 23% in 2010 due to the sliding scale Chinese government's "Special Oil Gain Levy" that applies higher rates in a higher commodity price environment.

Operating Costs

($ millions)	2011	2010
Western Canada	**1,462**	1,199
Atlantic Region	**174**	176
Asia Pacific	**25**	24
Total	**1,661**	1,399
Unit operating costs *($/boe)*	**14.56**	13.35

Total Upstream operating costs increased to $1,661 million in 2011 from $1,399 million in 2010. Total Upstream unit operating costs in 2011 averaged $14.56/boe compared with $13.35/boe in 2010 due to increased fuel and electrical costs combined with treating, servicing, maintenance and labour costs that were impacted by acquisitions in the fourth quarter of 2010 and the first quarter of 2011.

Operating costs in Western Canada increased to $16.04/boe in 2011 compared with $14.44/boe in 2010 primarily as a result of increased costs associated with fuel, electrical, servicing, treating and maintenance, transportation, disposal of water and emulsion production, partially offset by higher production in 2011 compared with 2010. The increase was also due to maturing fields in Western Canada which require more extensive infrastructure servicing and maintenance, the impact of additional wells and facilities acquired through acquisitions, facilities associated with enhanced recovery schemes, extensive gathering systems, and complex natural gas compression systems.

Operating costs in the Atlantic Region averaged $8.75/boe in 2011 compared with $10.33/boe in 2010 primarily as a result of higher production from North Amethyst in 2011.

Operating costs in the Asia Pacific Region averaged $8.17/boe in 2011 compared with $6.06/boe in 2010 primarily as a result of increased workover activity at Wenchang combined with declining production.

Exploration and Evaluation Expenses

($ millions)	**2011**	2010
Seismic, geological and geophysical	**170**	186
Expensed drilling	**245**	252
Expensed land	**55**	–
Total	**470**	438

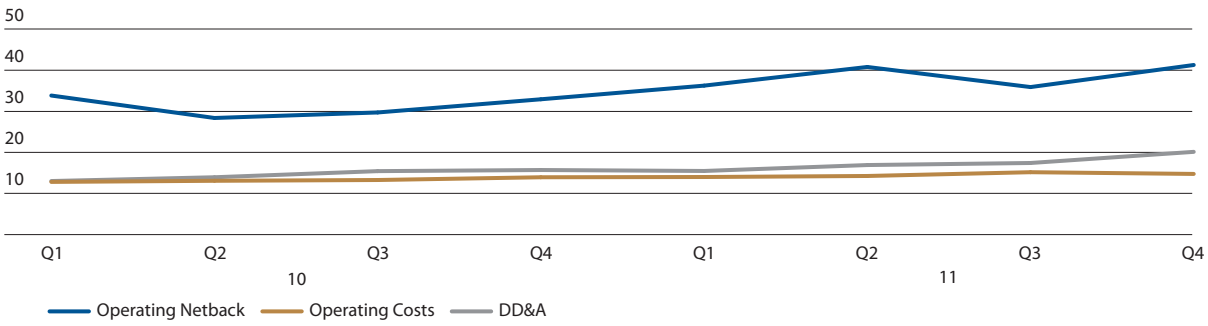
Total exploration and evaluation expenses increased in 2011 to $470 million from $438 million in 2010 due to land costs of $43 million relating to the Columbia River Basin located in the states of Washington and Oregon that were expensed in 2011.

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

During 2011, total unit DD&A was $17.51/boe compared with $14.52/boe during 2010. The higher DD&A rate in 2011 was primarily due to higher production from the North Amethyst offshore project and a pre-tax impairment charge of $70 million on conventional natural gas properties located in east central Alberta.

At December 31, 2011, capital costs in respect of unproved properties and major development projects were $5.3 billion compared with $4.1 billion at the end of 2010. These costs are excluded from the Company's DD&A calculation until the unproved properties are evaluated and proved reserves are attributed to the project that commences production or the project is deemed to be impaired.

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



[1] *Operating netbacks are Husky's average price less royalties and operating costs on a per unit basis.*

Upstream Capital Expenditures

In 2011, Upstream capital expenditures were $4,131 million compared to the 2011 capital expenditure program of $4,395 million. Upstream capital expenditures were $714 million (17%) in the Asia Pacific Region, $260 million (6%) in the Atlantic Region and $3,157 million (77%) in Western Canada which included $874 million for acquisitions. Husky's major projects remain on budget and on schedule.

Upstream Capital Expenditures[1] *($ millions)*	2011	2010
Exploration		
Western Canada	233	344
Atlantic Region	2	68
Asia Pacific	168	229
	403	641
Development		
Western Canada	2,050	1,334
Atlantic Region	258	375
Asia Pacific	546	62
	2,854	1,771
Acquisitions		
Western Canada	874	400
	4,131	2,812

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

Asia Pacific Region

The following table discloses Husky's offshore China and Indonesia drilling activity completed during 2011:

Asia Pacific Region Offshore Drilling Activity

China			
Liuhua 29-1-4 Block 29/26	WI 100%[1]	Stratigraphic test	Delineation
Liuhua 29-1-5 Block 29/26	WI 100%[1]	Stratigraphic test	Delineation
Liuhua 32-1-1 Block 29/26	WI 100%[1]	Stratigraphic test	Exploratory
Liwan 5-1-1 Block 29/26	WI 100%[1]	Stratigraphic test	Exploratory
Liwan 4-3-1 Block 29/26	WI 100%[1]	Stratigraphic test	Exploratory
Yacheng 5-1-1 Block 63/05	WI 100%[1]	Stratigraphic test	Exploratory
Liwan 3-1-5 Block 29/26	WI 49%	Production	Development
Liwan 3-1-6 Block 29/26	WI 49%	Production	Development
Liwan 3-1-7 Block 29/26	WI 49%	Production	Development
Liwan 3-1-8 Block 29/26	WI 49%	Production	Development
Wenchang 13-2-A4h1 side track	WI 40%	Production	Development
Indonesia			
MDA-4 Madura Strait	WI 40%	Stratigraphic test	Exploratory
MBH-1 Madura Strait	WI 40%	Stratigraphic test	Exploratory

[1] *CNOOC has the right to participate in development of discoveries up to 51%.*

During 2011, $700 million of capital expenditures was spent in China primarily on the construction of the Liwan Gas Project and the drilling of four exploration, two delineation and five development wells on Block 29/26 in the South China Sea. In Indonesia, $14 million was spent on two exploratory wells in the Madura Strait.

Atlantic Region

The following table discloses Husky's offshore Atlantic Region drilling activity during 2011:

Offshore Atlantic Region Drilling Activity

North Amethyst G-25-5	WI 68.875%	Water injection	Development
North Amethyst G-25-6	WI 68.875%	Production	Development
White Rose E-18-10 (West pilot)	WI 68.875%	Production	Development
Mizzen F-09	WI 35%	Exploratory	Exploratory
Fiddlehead D-83	WI 50%	Exploratory	Exploratory

During 2011, $260 million was invested in Atlantic Region development projects, primarily for the drilling of water injection and production wells in North Amethyst. Two exploration wells were drilled in the Atlantic Region in 2011 including one well in the Flemish Pass Basin and one well located south of the Terra Nova field.

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:

	2011		2010	
Wells Drilled *(wells)*	Gross	Net	Gross	Net
Exploration				
Oil	**50**	**40**	60	51
Gas	**24**	**24**	37	31
Dry	**3**	**3**	8	8
	77	**67**	105	90
Development				
Oil	**880**	**765**	815	722
Gas	**57**	**42**	73	53
Dry	**4**	**4**	10	9
	941	**811**	898	784
Total	**1,018**	**878**	1,003	874

The Company drilled 878 net wells in the Western Canada Sedimentary Basin in 2011 resulting in 805 net oil wells and 66 net natural gas wells compared with 874 net wells resulting in 773 net oil wells and 84 net natural gas wells in 2010. Capital expenditures for wells drilled in Western Canada increased substantially in 2011 compared with 2010 due to the increased focus on resource development drilling in areas such as the Ansell liquids rich gas resource play. In addition, a larger number of horizontal wells were drilled and more multi-stage fracture completions were performed in 2011.

During 2011, Husky invested $3,157 million on exploration, development and acquisitions throughout the Western Canada Sedimentary Basin compared with $2,078 million in 2010. Property acquisitions of $874 million were completed during 2011, primarily in the Rainbow Lake area of northwestern Alberta, the Foothills and Deep Basin areas of Alberta and in northeastern British Columbia.

In 2011, $591 million was invested in oil related exploration and development and $359 million was invested in natural gas related exploration and development compared with $410 million for oil related exploration and development and $163 million for natural gas related exploration and development in 2010.

Capital expenditures include $176 million spent on production optimization and cost reduction initiatives in 2011. Capital expenditures on facilities, land acquisition and retention and environmental protection totalled $307 million.

During 2011, capital expenditures on heavy oil projects including thermal projects, CHOPS drilling and horizontal drilling were $587 million compared with $469 million in 2010.

During 2011, capital expenditures on Oil Sands projects were $263 million compared with $171 million in 2010 as Sunrise Phase I progressed.

2012 Upstream Capital Program

($ millions)	
Western Canada	
Oil and gas	**1,800**
Oil sands	**640**
Atlantic Region	**500**
Asia Pacific Region	**1,100**
Total Upstream capital expenditures[1]	**4,040**

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

The 2012 Capital Program will enable Husky to build on the continuous momentum in accelerating near-term production and support the continued execution of the Company's mid and long-term growth initiatives.

Investment in the Sunrise Energy Project is expected to more than double to $610 million as construction activity ramps up and the project advances towards planned first production in 2014. Over $1 billion is budgeted for the Asia Pacific Region as fabrication of deep water and shallow water facilities for the Liwan Gas Project accelerates. Investment in the Atlantic Region of $500 million will be directed at continued development of the White Rose fields and extensions, a scheduled turnaround of the SeaRose FPSO and continued evaluation of the feasibility of a concrete wellhead and drilling platform for the development of future resources in the White Rose region including the full development of West White Rose.

In addition to advancing mid and long-term growth pillars, the 2012 Capital Program provides support to the Company's efforts to reinvigorate and transform its foundation in Western Canada. A substantial oil and liquids-rich natural gas resource play portfolio has been acquired and drilling is scheduled to take place across the portfolio in 2012. The Company is making progress in its strategy to transition a greater percentage of its heavy oil production to long-life thermal. The 8,000 bbls/day Pikes Peak South thermal project is expected to become operational in mid-2012 and the 3,000 bbls/day Paradise Hill thermal project is on target to become operational in late 2012.

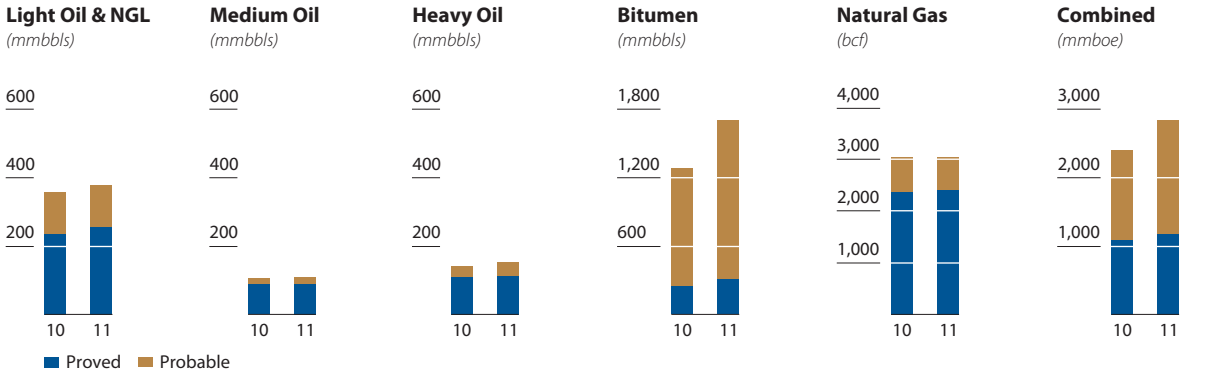
Upstream Planned Turnarounds

Husky intends to proceed with an offstation for the SeaRose FPSO propulsion system in the second and third quarters of 2012 which is expected to result in production shut-in for approximately 125 days. Production from the White Rose, North Amethyst, and West White Rose fields will be shut-in during the offstation maintenance. The impact to Husky's production, averaged over the entire year, is forecasted to be approximately 12,000 bbls/day.

A 21-week dockside maintenance for the non-operated Terra Nova FPSO is scheduled to be completed during the second half of 2012. The impact to annual production is estimated to be approximately 4,000 bbls/day. The program anticipates a return to the field and reinstatement of production by the end of 2012.

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, 2011. Prior to 2010, Husky applied for and was granted an exemption from certain of the provisions of NI 51-101, which permitted the Company to present oil and gas reserves disclosures in accordance with the rules of the United States Securities and Exchange Commission and the United States Financial Accounting Standards Board (the "U.S. Rules"). This is no longer available for the Company's reserves reporting in Canada, although the Company 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. Rules 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 .

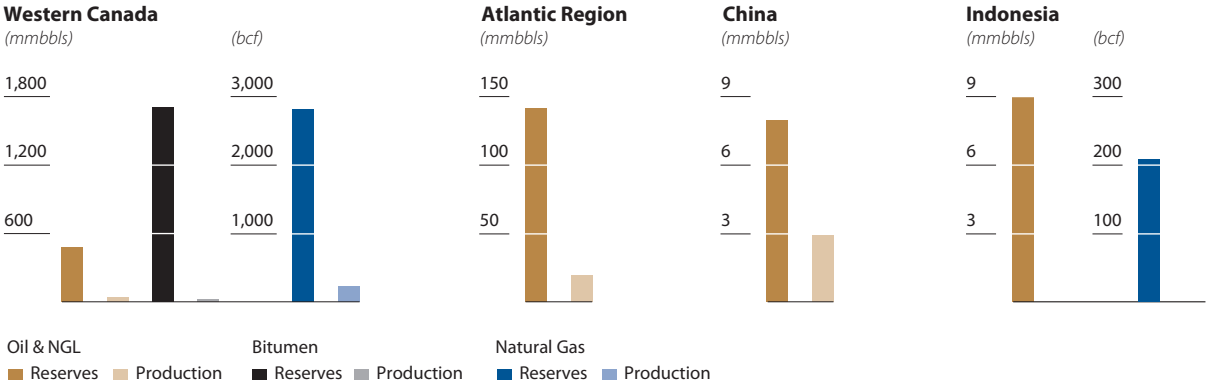


The Company's complete Oil and Gas Reserves Disclosure prepared in accordance with NI 51-101 is contained in Husky's Annual Information Form available at www.sedar.com or Husky's Form 40-F available at www.sec.gov or on the Company's website at www.huskyenergy.com.

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, 2011, Husky's proved oil and gas reserves were 1,172 mmboe, up from 1,081 mmboe at the end of 2010. The net addition to proved reserves, including acquisitions and divestitures, represents 180% of 2011 production. Major additions to proved reserves in 2011 included:

- the extension through additional drilling and seismic interpretation of the Sunrise Energy Project that resulted in booking an additional 60 mmbbls of bitumen to proved undeveloped reserves;
- the acquisitions of properties in the first quarter of 2011 that resulted in the booking of an additional 108 mmboe in proved reserves; and
- the extension through additional drilling locations at Ansell in the Alberta Deep Basin area that resulted in the booking of an additional 12 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 & 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)*	Equiva-lent Units *(mmboe)*
Proved reserves											
December 31, 2010	133	88	110	247	2,186	88	16	209	682	2,395	1,081
Revision of previous estimate	(4)	1	7	2	–	3	1	–	10	–	10
Purchase of reserves in place	41	–	5	–	398	–	–	–	46	398	112
Sale of reserves in place	–	–	(3)	–	(1)	–	(2)	(42)	(5)	(43)	(12)
Discoveries, extensions and improved recovery	10	10	21	69	77	5	–	–	115	77	128
Economic revision	(2)	–	–	–	(185)	–	–	–	(2)	(185)	(33)
Production	(9)	(9)	(27)	(9)	(222)	(20)	(3)	–	(77)	(222)	(114)
Proved reserves December 31, 2011	**169**	**90**	**113**	**309**	**2,253**	**76**	**12**	**167**	**769**	**2,420**	**1,172**
Proved and probable reserves December 31, 2011	**220**	**109**	**151**	**1,709**	**2,813**	**141**	**17**	**207**	**2,347**	**3,020**	**2,851**
December 31, 2010	176	108	143	1,287	2,766	159	22	258	1,895	3,024	2,399

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, 2010	111	79	82	51	1,721	64	7	–	394	1,721	681
Revision of previous estimate	(2)	3	19	14	21	19	1	–	54	21	58
Purchase of reserves in place	41	–	3	–	393	–	–		44	393	109
Sale of reserves in place	–	–	(3)	–	(1)	–	–	–	(3)	(1)	(3)
Discoveries, extensions and improved recovery	7	4	12	–	48	2	–		25	48	33
Economic revision	–	–	–	–	(44)	–	–	–	–	(44)	(7)
Production	(9)	(9)	(27)	(9)	(222)	(20)	(3)	–	(77)	(222)	(114)
Proved developed reserves December 31, 2011	**148**	**77**	**86**	**56**	**1,916**	**65**	**5**	**–**	**437**	**1,916**	**757**

7.4 Midstream

2011 Earnings $246 million

Infrastructure and Marketing Earnings Summary *($ millions, except where indicated)*	2011	2010
Gross revenues	**9,446**	7,002
Gross margin		
Pipeline	**150**	124
Other infrastructure and marketing	**255**	193
	405	317
Operating and administration expenses	**25**	21
Depreciation and amortization	**46**	43
Other expenses	**6**	34
Income taxes	**82**	59
Net earnings	**246**	160
Commodity volumes managed *(mboe/day)*	**1,028**	952
Aggregate pipeline throughput *(mbbls/day)*	**559**	512

Infrastructure and marketing net earnings in 2011 increased by $86 million compared with 2010 due primarily to higher pipeline throughput and marketed volumes and trading gains captured on light and synthetic crude oil moving from Canada to the U.S. as a result of the widening WTI to Brent differential, partially offset by lower natural gas storage earnings. Other expenses, which include the fair value impact of the Company's commodity price risk management activities, decreased by $28 million in 2011 as compared to 2010 due to the timing of realized gains on natural gas storage contracts.

Midstream Capital Expenditures

Midstream capital expenditures totalled $43 million in 2011 compared to $40 million in 2010. The majority of midstream capital expenditures during the year related to the construction of the 300,000 barrel tank at the Hardisty terminal.

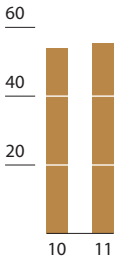
7.5 Downstream

Effective 2011, Husky commenced evaluating and reporting its Upgrading activities as part of Downstream operations. As a result, Upgrading was moved from the Midstream segment to the Downstream segment. All prior periods have been reclassified to conform to these segment definitions.

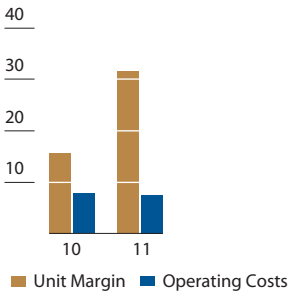
2011 Earnings $813 million

Total downstream earnings in 2011 were $813 million, up from $160 million in 2010. The increase was primarily due to higher realized refining margins in the U.S. as a result of higher market crack spreads, higher fuel and asphalt margins for Canadian refined products and higher throughput at the Lloydminster Upgrader.

Upgrader
Synthetic Crude Sales
(mbbls/day)



Upgrader
Unit Margin & Operating Costs
($/bbl)



Upgrader

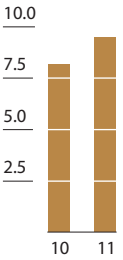
Upgrader Earnings Summary *($ millions, except where indicated)*		2011	2010
Gross revenues		**2,217**	1,570
Gross margin		**636**	311
Operating and administration expenses		**191**	185
Depreciation and amortization		**164**	74
Other expenses (income)		**74**	(37)
Income taxes		**54**	26
Net earnings		**153**	63
Upgrader throughput[1]	*(mbbls/day)*	**69.6**	65.4
Synthetic crude oil sales	*(mbbls/day)*	**55.3**	54.1
Upgrading differential	*($/bbl)*	**27.34**	14.52
Unit margin	*($/bbl)*	**31.51**	15.73
Unit operating cost[2]	*($/bbl)*	**7.40**	7.76

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

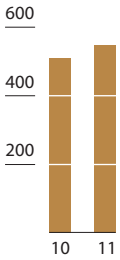
Upgrading earnings in 2011 increased by $90 million compared with 2010 primarily due to higher realized differentials and higher production as a result of improved reliability which more than offset the impact of a fire in early February that resulted in a reduction in average throughput at the Upgrader to 53.2 mbbls/day in the first quarter. In addition, increased earnings were offset by higher depreciation and amortization and the derecognition of certain intangible costs.

During 2011, the price of Husky's synthetic crude oil averaged $101.68/bbl compared with the average cost of blended heavy crude oil from the Lloydminster area of $74.34/bbl. During 2010, the price of Husky's synthetic crude oil averaged $80.97/bbl compared with the average cost of blended heavy crude oil from the Lloydminster area of $66.45/bbl. This resulted in an average synthetic/heavy crude differential of $27.34/bbl in 2011 compared to $14.52/bbl in 2010 and a gross unit margin of $31.51/bbl in 2011 compared to $15.73/bbl in 2010. The cost of upgrading averaged $7.40/bbl compared with $7.76/bbl in 2010, which results in a net margin for upgrading heavy crude of $24.11/bbl, up 203% compared with $7.97/bbl in 2010. The increase in other expenses is due to the increase in the fair value of the remaining upside interest payment obligation to Natural Resources Canada and the Alberta Department of Energy through 2014 as a result of higher upgrading differentials throughout the year.

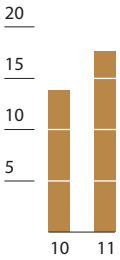
Light Oil Product Marketing
Volume
(millions of litres/day)



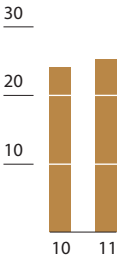
Outlets



Volume per Outlet
(thousands of litres/day)



Asphalt Products
Volume
(mbbls/day)



Canadian Refined Products

Canadian Refined Products Earnings Summary *($ millions, except where indicated)*		2011	2010
Gross revenues		**3,860**	2,975
Gross margin			
Fuel		**149**	87
Refining		**90**	64
Asphalt		**204**	160
Ancillary		**49**	46
		492	357
Operating and administration expenses		**117**	110
Depreciation and amortization		**80**	88
Income taxes		**75**	42
Net earnings		**220**	117
Number of fuel outlets[1]		**547**	508
Refined products sales volume			
Light oil products	*(million of litres/day)*	**9.5**	8.2
Light oil products per outlet	*(thousand of litres/day)*	**17.3**	13.8
Asphalt products	*(mbbls/day)*	**25.3**	24.1
Refinery throughput			
Prince George refinery	*(mbbls/day)*	**10.6**	10.0
Lloydminster refinery	*(mbbls/day)*	**28.1**	27.8
Ethanol production	*(thousand of litres/day)*	**711.3**	619.7

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

During 2011, fuel gross margins were higher than in 2010 primarily due to higher retail and wholesale market prices combined with increased volumes due to the purchase of 97 retail stations in 2010.

Refining gross margins increased in 2011 primarily due to higher market crack spreads, higher total ethanol production from a successful recycle thermal oxidiser installation at the Lloydminster Ethanol Plant and higher realized prices for gasoline, diesel and ethanol partially offset by lower production at the Prince George Refinery and Minnedosa Ethanol Plant due to turnaround activity. Included in ethanol gross margins in 2011 was $46 million related to government assistance grants compared with $50 million in 2010.

Asphalt gross margins increased compared to the same period in 2010 primarily due to higher realized market prices and increased sales volumes for residuals as a result of strong demand for drilling fluids.

U.S. Refining and Marketing

U.S. Refining and Marketing Earnings Summary *($ millions, except where indicated)*		2011	2010
Gross revenues		9,593	7,107
Gross refining margin		1,290	547
Operating and administration expenses		400	386
Interest – net		2	2
Depreciation and amortization		195	191
Income taxes (recoveries)		253	(12)
Net earnings (loss)		440	(20)
Selected operating data:			
Lima Refinery throughput	*(mbbls/day)*	144.3	136.6
Toledo Refinery throughput	*(mbbls/day)*	63.9	64.4
Refining margin	*(U.S. $/bbl crude throughput)*	17.60	7.29
Refinery inventory (feedstocks and refined products)	*(mmbbls)*	11.8	11.9

U.S. refining and marketing net earnings increased in 2011 compared with 2010 as a result of higher realized refining margins including FIFO inventory gains. In addition to increased market crack spreads, feedstock at the Toledo Refinery was approximately half heavy crude oil which added to increased margins as differentials between heavy and light crude oil were higher in 2011 compared with 2010. The increase in net earnings was partially offset at the Lima Refinery where over half of the feedstock in 2011 was based on the price of Brent which traded at a significant premium to WTI and at the Toledo Refinery where there was crude oil supply constraints due to the Enbridge pipeline curtailment and planned maintenance.

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 year when crude oil prices were lower.

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.

The overall strengthening of the Canadian dollar against the U.S. dollar compared with 2010 had a negative impact on the translation of U.S. dollar financial results into Canadian dollars.

Downstream Capital Expenditures

Downstream capital expenditures totalled $373 million for 2011 compared to $682 million in 2010. In Canada, capital expenditures were $149 million related to upgrades at the Prince George Refinery, the Upgrader and retail stations. In the United States, capital expenditures totalled $224 million. At the Lima Refinery, $124 million was spent on various debottleneck projects, optimizations and environmental initiatives. At the Toledo Refinery, capital expenditures totalled $100 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

An outage is scheduled for approximately three weeks in the first half of 2012 at the Upgrader to expedite hydrogen plant repairs and catalyst change out. The next major turnaround is scheduled to commence in the fall of 2013.

The Lloydminster Refinery will have a major turnaround in the spring of 2013. The refinery will be shut down during the turnaround for inspections and equipment repair. The turnaround is scheduled to last approximately 21 days.

The next minor turnaround at the Toledo Refinery is expected to occur in mid-2012 with the partial outage expected to last approximately 21 days.

The Lima Refinery is scheduled to have a 15-day Diesel Hydrotreater outage in late 2012 to replace the catalyst. In addition, a 29-day aromatics turnaround is expected in late 2012. Neither of the planned outages are expected to have a material impact on crude throughputs. The Lima Refinery is scheduled to complete a major turnaround in 2014 on 70 percent of its operating units. The refinery is expected to be shut down for 45 days during the turnaround. The remaining 30 percent of operating units will be addressed in a major turnaround currently planned for 2015.

7.6 Corporate

2011 Loss $337 million

Corporate Earnings Summary *($ millions) income (expense)*	2011	2010
Intersegment eliminations – net	(51)	(47)
Administration expenses	(199)	(88)
Other income	3	3
Stock-based compensation	1	13
Depreciation and amortization	(38)	(75)
Interest – net	(141)	(186)
Foreign exchange gains (losses)	10	(49)
Income taxes	78	195
Net loss	(337)	(234)

The Corporate segment reported a loss in 2011 of $337 million compared with a loss of $234 million in 2010. Administration expenses increased by $111 million as compared to 2010 primarily due to increased administration costs on financing projects and other initiatives. Interest – net decreased by $45 million as compared to 2010 due to increased amounts capitalized related to projects in the Asia Pacific Region. Intersegment eliminations are profit earned on inventory that has not been sold to third parties at the end of the period.

Foreign Exchange Summary *($ millions)*	2011	2010
Gains (losses) on translation of U.S. dollar denominated long-term debt	(47)	108
Gains (losses) on cross currency swaps	7	(18)
Gains (losses) on contribution receivable	34	(67)
Other gains (losses)	16	(72)
Foreign exchange gains (losses)	10	(49)
U.S./Canadian dollar exchange rates:		
At beginning of year	U.S. $1.005	U.S. $0.956
At end of year	U.S. $0.983	U.S. $1.005

Consolidated Income Taxes

Consolidated income taxes increased in 2011 to $916 million from $270 million in 2010 resulting in an effective tax rate of 29% for 2011 and 22% for 2010.

($ millions)	2011	2010
Income taxes as reported	916	270
Cash taxes paid	282	784

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 due over the 5-year period ending in 2016.

In 2012, cash tax instalments of $730 million are estimated to be payable in respect of a combination of 2012 reported earnings and a portion of 2011 earnings which were previously deferred.

Corporate Capital Expenditures

Corporate capital expenditures of $71 million in 2011 were primarily for construction of a new building in Lloydminster, computer hardware and software, office furniture, renovations and equipment and system upgrades.

8.0 Liquidity and Capital Resources

8.1 Summary of Cash Flow

In 2011, Husky funded its capital programs, including acquisitions and dividend payments, by cash generated from operating activities, equity issuances and cash on hand. At December 31, 2011, Husky had total debt of $3,911 million partially offset by cash on hand of $1,841 million for $2,070 million of net debt compared to $3,935 million of net debt at December 31, 2010 consisting of $4,187 million of total debt and $252 million of cash on hand. At December 31, 2011, the Company had $3.5 billion in unused committed credit facilities, $110 million in unused short-term uncommitted credit facilities, unused capacity under the debt shelf prospectus filed in Canada of $300 million, which expired in January 2012, unused capacity under the November 2010 universal short form base shelf prospectus filed in Canada of $1.4 billion, and unused capacity under the June 2011 U.S. base shelf prospectus of U.S. $2.0 billion. The ability of the Company to utilize the capacity under its prospectuses is subject to market conditions (Refer to Section 8.2).

	2011	2010
Cash flow		
Operating activities *($ millions)*	**5,092**	2,222
Financing activities *($ millions)*	**910**	1,085
Investing activities *($ millions)*	**(4,420)**	(3,453)
Financial Ratios[1]		
Debt to capital employed *(percent)*[2]	**18.0**	22.3
Debt to cash flow *(times)*[3][4]	**0.8**	1.4
Corporate reinvestment ratio *(percent)*[3][5]	**98**	134
Interest coverage ratios on long-term debt only[3][6]		
Earnings	**14.5**	6.2
Cash flow	**24.7**	11.4
Interest coverage on ratios of total debt[3][7]		
Earnings	**14.1**	6.0
Cash flow	**23.9**	11.2

(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 $5,092 million in 2011 compared with $2,222 million in 2010. Higher cash flow from operating activities was primarily due to higher production, higher crude oil prices in Upstream and higher realized margins in Canadian and U.S. Downstream.

Cash Flow from Financing Activities

Cash generated from financing activities was $910 million in 2011 compared with $1,085 million in 2010. The decrease in cash provided by financing activities was due to a decrease in long-term debt issuances, net of repayments, partially offset by an increase in proceeds from common and preferred share issuances and the adoption of a stock dividend plan in the second quarter of 2011.

Cash Flow used for Investing Activities

Cash used in investing activities for 2011 was $4,420 million compared with $3,453 million in 2010. 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, 2011, Husky's working capital was $2,054 million compared with $1,181 million at December 31, 2010.

Movement in Working Capital

($ millions)	**December 31, 2011**	December 31, 2010	Increase/ (Decrease)
Cash and cash equivalents	**1,841**	252	1,589
Accounts receivable	**1,235**	1,183	52
Income taxes receivable	**273**	346	(73)
Inventories	**2,059**	1,935	124
Prepaid expenses	**36**	34	2
Accounts payable and accrued liabilities	**(2,867)**	(2,506)	(361)
Asset retirement obligations	**(116)**	(63)	(53)
Long-term debt due within one year	**(407)**	–	(407)
Net working capital	**2,054**	1,181	873

The increase in cash was primarily due to increased production, higher crude oil prices in Upstream and higher realized margins in Canadian and U.S. Downstream. The increase in accounts receivable was primarily as a result of increased crude oil sales. The increase in accounts payable and accrued liabilities was mainly due to higher capital expenditures. The increase in long-term debt due within one year is due to certain debt maturing in 2012.

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 upstream capital programs principally by cash generated from operating activities, cash on hand, issuances of equity, the issuance of long-term debt and 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, 2011, no production was hedged.

At December 31, 2011 Husky had the following available credit facilities:

($ millions)	Available[1]	Unused
Operating facilities[2]	465	215
Syndicated bank facilities	3,300	3,300
Bilateral credit facility[3]	100	100
Total	3,865	3,615

[1] *Available short and long-term debt includes committed and uncommitted credit facilities.*
[2] *The operating facilities included $265 million of demand credit facilities and $200 million of committed credit facilities. The $200 million of committed credit facilities were increased to $250 million and converted to demand credit facilities in 2012.*
[3] *The $100 million bilateral credit facility was cancelled effective February 3, 2012.*

Cash and cash equivalents at December 31, 2011 totalled $1,841 million compared with $252 million at the beginning of the year.

At December 31, 2011, Husky had unused committed short and long-term borrowing credit facilities of $3.5 billion and uncommitted short-term borrowing facilities of $110 million. A total of $250 million of the Company's short-term borrowing credit facilities were used in support of outstanding letters of credit.

On December 21, 2009, Husky filed a debt shelf prospectus with the applicable securities regulators in each of the provinces of Canada that enabled Husky to offer up to $1.0 billion of medium-term notes in Canada until January 21, 2012. As of December 31, 2011, $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020 had been issued under this shelf prospectus (Refer to Note 14 to the Consolidated Financial Statements).

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. As of December 31, 2011, there was no balance outstanding under these facilities.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility available of $10 million for general purposes. Husky's proportionate share is $5 million. As of December 31, 2011, there was no balance outstanding under this facility.

On November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada that enables Husky to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 26, 2012 (the "Canadian Shelf Prospectus"). During the 25-month period that the Canadian Shelf Prospectus is effective, Securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement.

On December 7, 2010, Husky issued 11.9 million common shares at a price of $24.50 per share for total gross proceeds of $293 million under the Canadian Shelf Prospectus. Husky also issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of approximately $707 million to principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. The common shares issued under the private placements were not issued under the Canadian Shelf Prospectus. The Company received total net proceeds of $988 million from this issuance.

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 would be 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. Quarterly dividends of $0.30 ($1.20 annually) per common share were declared during 2011 totalling $1.1 billion in 2011 of which $328 million was accepted in cash and $781 million was accepted in common shares. The declaration of dividends is at the discretion of the Board of Directors, which will consider earnings, capital requirements, the Company's financial condition and other relevant factors.

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 the 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, Husky filed a universal short form base shelf prospectus with the Alberta Securities Commission and the U.S. Securities and Exchange Commission that enables Husky 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 until July 13, 2013 (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 Canadian Shelf Prospectus and accompanying prospectus supplement in Canada.

Capital Structure

	December 31, 2011	
($ millions)	Outstanding	Available[1]
Total short-term and long-term debt	3,911	3,615
Common shares, retained earnings and accumulated other comprehensive income	17,773	

[1] *Available short and 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)	2012	2013–2014	2015–2016	Thereafter	Total
Long-term debt and interest on fixed rate debt	631	1,163	819	3,030	5,643
Operating leases	108	165	123	119	515
Firm transportation agreements	187	400	367	3,291	4,245
Unconditional purchase obligations[1]	2,926	1,352	309	89	4,676
Lease rentals and exploration work agreements	77	240	524	519	1,360
Asset retirement obligations[2]	116	231	248	7,905	8,500
	4,045	3,551	2,390	14,953	24,939

(1) *Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling rig services and natural gas purchases.*

(2) *Asset retirement obligation amounts represent the undiscounted future payments for the estimated cost of abandonment, removal and remediation associated with retiring the Company's assets.*

Based on Husky's 2012 commodity price forecast, the Company believes that its non-cancellable contractual obligations, other commercial commitments and the 2012 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

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 Consolidated Financial Statements).

Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery LLC (Refer to Note 8 to the 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, 2011, Husky's share of this obligation was U.S. $1.4 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 asset retirement obligations ("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

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 and Major Customers

On May 11, 2009, the Company issued 5 and 10-year senior notes of U.S. $251 million and U.S. $107 million, respectively, to certain management, shareholders, affiliates and directors as part of the U.S. $750 million 5-year and U.S. $750 million 10-year senior notes issued through a base shelf prospectus, which was filed with the Alberta Securities Commission and U.S. Securities and Exchange Commission in February 2009. The coupon rates offered were 5.90% and 7.25% for the 5 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. At December 31, 2011, the U.S. $1.5 billion senior notes are included in long-term debt on the Company's balance sheet.

On December 7, 2010, the Company issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million via a private placement to its principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

In April 2011, Husky and TransAlta Cogeneration, L.P., which was the Company's 50% joint venture partner for the Meridian cogeneration facility at Lloydminster, sold the Meridian cogeneration facility to a related party. The consideration for Husky's share of the cogeneration facility was $61 million, resulting in no net gain or loss on the transaction.

The Company continues to sell natural gas to and purchase steam from the Meridian cogeneration facility 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, 2011, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by the related party was $108 million. For the year ended December 31, 2011, the total value of obligated steam purchases from the Meridian and other cogeneration facilities owned by the related party was $13 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 a private placement to its principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

All debt and equity issuance transactions with related parties have been measured at the exchange amount, which was equivalent to the fair market value at the date of the transaction and have been carried out on the same terms as would apply with unrelated parties.

8.6 Financial Risk and Risk Management

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates, interest rates, credit risk and changes in fiscal, monetary and other financial policies related to royalties, taxes and others (Refer to Section 3.0). On occasion, the Company will use derivative instruments to manage its exposure to these risks.

Political Risk

Husky is exposed to risks associated with operating in developed and developing countries, including risks associated with political and regulatory instability. The Company monitors the changes to regulations and government policies in the areas within which it operates.

Environmental Risk

Husky's business operations are subject to numerous laws and regulations regarding environmental, health and safety matters, including those relating to emissions to air, discharges to water and the storage and disposal of regulated materials. The nature of Husky's business is exposed to risks of liabilities under such laws and regulations due to the production, storage, use, transportation and disposal of materials that can cause contamination or personal injury if released into the environment.

Husky's offshore operations are subject to the risk of blowouts and other catastrophic events, resulting from actions of the Company or its contractors or agents, or those of third parties, that could result in suspension of operations, damage to equipment and harm to personnel, and damage to the natural environment. The consequences of such catastrophic events occurring in deep water operations, in particular, can be more costly and time-consuming to remedy. The remedy may be made more difficult or uncertain by the extreme pressures and cold temperatures encountered in deep water operations, shortages of equipment and specialist personnel required to work in these conditions, or the absence of appropriate and proven means to effectively remedy such consequences. The costs associated with such events could be material and Husky may not maintain sufficient insurance to cover such costs. Husky currently has a working interest in non-operated offshore deepwater drilling operations in Canada and a development program in China includes deep water drilling.

The 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 United States 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.

The United States Environmental Protection Agency ("EPA") is implementing regulations pertaining to greenhouse gas emissions, which could increase costs of doing business. In particular, the so-called 'Tailoring Rule' now requires sources emitting greater than 100,000 tons per year of greenhouse gases to obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. The Tailoring Rule also can require the installation and operation of expensive pollution control technology as a part of any project that results in a significant greenhouse gas emissions increase. The EPA has promulgated regulations requiring greenhouse gas emissions reporting from certain U.S. operations. The EPA also is required to issue greenhouse gas emission guidelines for existing refineries and new source performance standards for new refineries or modifications to existing refineries by November 10, 2012. These and other EPA regulations regarding greenhouse gas emissions are subject to legislative and judicial challenges, including current Congressional proposals to block or delay the EPA's authority to regulate greenhouse gas emissions. It is not possible to predict the ultimate outcome of these challenges. While these EPA regulations are currently in effect, they have not yet had a material impact on Husky. Husky's operations may, however, be materially impacted by future application of these rules or by future United States 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.

Financial Risk

Husky's financial risks are largely related to commodity prices, refinery crack spreads, foreign exchange rates, interest rates, credit risk, changes in fiscal policy related to royalties and taxes and others. From time to time, Husky uses financial and derivative instruments to manage its exposure to these risks.

Commodity Price Risk Management

Husky uses derivative commodity instruments from time to time 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.

At December 31, 2011, the Company had third-party physical natural gas purchase and sale derivative contracts and natural gas storage contracts. These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized loss of $8 million has been recorded in other expenses in the Consolidated Statements of Income for the year ended December 31, 2011. Natural gas inventory held in storage relating to the natural gas storage contracts is recorded at fair value. At December 31, 2011, the fair value of the inventory was $121 million, resulting in an unrealized loss of $3 million recorded in other expenses in the Consolidated Statements of Income for the year ended December 31, 2011.

At December 31, 2011, the Company had third-party crude oil purchase and sale derivative contracts, which have been designated as a fair value hedge. These contracts have been recorded at their fair value in accrued liabilities and the resulting unrealized loss of $8 million has been recorded in purchases of crude oil and products in the Consolidated Statements of Income for the year ended December 31, 2011. The crude oil inventory held in storage is recorded at fair value. At December 31, 2011, the fair value of the inventory was $16 million, resulting in an unrealized gain of $2 million recorded in purchases of crude oil and products in the Consolidated Statements of Income for the year ended December 31, 2011.

The Company also enters into derivative contracts for future crude oil purchases, whereby there is a requirement to pay the market difference of the inventory price paid at delivery and the current market price at the settlement date in the future. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. As at December 31, 2011, a loss related to these contracts of $7 million was recorded in purchases of crude oil and products in the Consolidated Statements of Income for the year ended December 31, 2011.

The Company enters into certain crude oil purchase and sale derivative contracts to minimize its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. These contracts meet the definition of a derivative instrument and have been recorded at their fair value in accounts receivable and accrued liabilities. At December 31, 2011, the Company had 1.1 mmbbls of purchase and sale contracts resulting in an unrealized gain of $4 million recorded in other expenses in the Consolidated Statements of Income for the year ended December 31, 2011. A portion of the crude oil inventory is sold to third parties. This inventory is measured at fair value. At December 31, 2011, the fair value of the inventory was $147 million, resulting in an unrealized gain of less than $1 million in other expenses in the Consolidated Statements of Income for the year ended December 31, 2011.

During 2011, the Company entered into third party commodity swaps based on the price of butane and crude oil. These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain of less than $1 million for the year ended December 31, 2011 has been recorded in other expenses in the Consolidated Statements of Income.

Interest Rate Risk Management

The Company had entered into a fair value hedge using interest rate swap arrangements whereby the fixed interest rate coupon on the long-term debt was swapped to floating rates. These interest rate swap arrangements have been sold and derecognized during the year. Accordingly, the accrued gains on these interest rate swaps will be amortized over the remaining life of the underlying long-term debt to which the hedging relationship was originally designated.

During 2011, these swaps resulted in a reduction of finance expenses of $13 million. The amortization of terminated interest rate swaps resulted in additional finance expenses of $8 million for the year ended December 31, 2011. The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $9 million for the year ended December 31, 2011.

Foreign Currency Risk Management

Husky's results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of Husky's expenditures are in Canadian dollars. 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.

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, as expressed in Canadian dollars, as well as in the related interest expense. At December 31, 2011, 82% or $3.1 billion of Husky's outstanding debt was denominated in U.S. dollars (74% or $3.1 billion at December 31, 2010). The percentage of the Company's debt exposed to the Canadian/U.S. exchange rate decreases to 73% when cross currency swaps are considered (2010 – 67%).

At December 31, 2011, Husky had the following cross currency swaps in place:

- U.S. $50 million at 6.25% swapped at $1.17 to $59 million at 5.67% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.19 to $89 million at 5.65% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.17 to $88 million at 5.61% until June 15, 2012.
- U.S. $150 million at 6.25% swapped at $1.41 to $211 million at 7.41% until June 15, 2012.

At December 31, 2011, the cost of a U.S. dollar in Canadian currency was $1.017.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars in order to hedge against the foreign exchange exposures from oil and natural gas revenues. Aside from offsetting unrealized gains or losses from oil and natural gas sales, these contracts have a resulting unrealized gain of $1 million based on changes in fair value recorded in other expenses for the year ended December 31, 2011. For the year ended December 31, 2011, the impact of these contracts was a realized loss of $5 million recorded in net foreign exchange gains or losses.

At December 31, 2011, the Company had designated U.S. $1.3 billion of its U.S. debt as a hedge of the Company's net investment in the U.S. refining operations, which are considered foreign functional currency. In 2011, the unrealized foreign exchange loss arising from the translation of the debt was $18 million, net of tax of $3 million, which was recorded in other comprehensive income ("OCI").

Including cross-currency swaps and the debt that has been designated as a hedge of a net investment, 27% of long-term debt is exposed to changes in the Canadian/U.S. exchange rate (2010 – 42%).

Husky holds 50% of a contribution receivable which represents BP's obligation to fund capital expenditures of the Sunrise Oil Sands Partnership and this receivable is denominated in U.S. dollars. Related gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in net foreign exchange gains or losses in current period net earnings. At December 31, 2011, Husky's share of this receivable was U.S. $1.1 billion (2010 – U.S. $1.3 billion) including accrued interest. Husky has an obligation to fund capital expenditures of the BP-Husky Toledo Refinery and this contribution payable is denominated in U.S. dollars. Gains and losses from the translation of this obligation are recorded in OCI as this item relates to a foreign functional currency entity. At December 31, 2011 Husky's share of this obligation was U.S. $1.4 billion (2010 – U.S. $1.4 billion) including accrued interest.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meets its liabilities when they become due. The Company prepares annual capital expenditure budgets, which are monitored and are updated as required. In addition, the Company requires authorizations for expenditures on projects to assist with the management of capital.

The following are the contractual maturities of the Company's financial liabilities as at December 31, 2011:

	2012	2013	2014	2015	2016	Thereafter
Accounts payable and accrued liabilities	2,867	–	–	–	–	–
Other long-term liabilities	20	43	43	30	1	25
Long-term debt	407	–	779	306	208	2,211

The Company's contribution payable to the joint arrangement with BP of U.S. $1.4 billion is payable between December 31, 2011 and December 31, 2015, with the final balance due by December 31, 2015 (Refer to Section 8.3 for additional contractual obligations).

Credit and Contract Risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial instrument, in owing an amount to the Company, fail to meet or discharge their obligation to the Company. Husky actively manages its exposure to credit and contract execution risk from both a customer and a supplier perspective.

The Company's debt instruments are rated by various credit rating agencies. These ratings affect the Company's ability to gain access to debt financing at attractive terms. If any of the Company's credit rating agencies downgrade the Company's debt instruments, it may restrict the Company's ability to issue debt and may also increase the cost of borrowing, including under existing credit facilities.

Fair Value of Financial Instruments

The derivative portion of cash flow hedges, fair value hedges, and freestanding derivatives that are recorded at fair value on a recurring basis have been categorized into one of three categories based upon the fair value hierarchy that reflects the significance of the inputs used in determining fair value. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. 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 valuations are based on inputs that are unobservable and significant to the overall fair value measurement.

8.7 Outstanding Share Data

Authorized:
- unlimited number of common shares
- unlimited number of preferred shares

Issued and outstanding: February 29, 2012

• common shares	965,757,608
• cumulative redeemable preferred shares, series 1	12,000,000
• stock options	32,792,775
• stock options exercisable	18,341,697

8.8 Liquidity Summary

The following information relating to Husky's credit ratings is provided as it relates to Husky's financing costs, liquidity and operations. Specifically, 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 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. In addition, changes in credit ratings may affect Husky's ability to enter, and the associated costs of entering, (i) into ordinary course derivative or hedging transactions, which may require Husky to post additional collateral under certain of its contracts, and (ii) into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

	Rating	Last Review	Last Rating Change
Moody's:			
Outlook	Stable	August 17, 2011	August 17, 2011
Senior Unsecured Debt	Baa2	August 17, 2011	April 25, 2001
Standard and Poor's:			
Outlook	Stable	December 9, 2011	July 27, 2006
Senior Unsecured Debt	BBB+	December 9, 2011	July 27, 2006
Series 1 Preferred Shares	P-2 (low)	March 11, 2011	March 11, 2011
Dominion Bond Rating Service:			
Trend	Stable	March 10, 2011	March 31, 2008
Senior Unsecured Debt	A (low)	March 10, 2011	March 31, 2008
Series 1 Preferred Shares	Pfd-2 (low)	March 10, 2011	March 10, 2011

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 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.

9.0 Application of Critical Accounting Estimates

Husky's Consolidated Financial Statements have been prepared in accordance with IFRS. Significant accounting policies are disclosed in Note 3 to the Consolidated Financial Statements. Certain of the Company's accounting policies require subjective judgment about uncertain circumstances. The following discussion highlights the nature and potential effect of these estimates. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

Depletion Expense

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 reserves using the unit of production method.

Withheld Costs

Costs related to exploration and evaluation activities and major development projects 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.

Impairment of Long-Lived Assets

Impairment is indicated if the carrying value of the long-lived asset or oil and gas cash generating unit exceeds its recoverable amount. 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 judgments 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.

Fair Value of Derivative Instruments

Periodically Husky utilizes financial derivatives and hedge accounting to manage market risk.

The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through forward market prices and compared with quotes from financial institutions. The estimation of fair value of forward purchases of U.S. dollars is determined using forward market prices.

Asset Retirement Obligations ("ARO")

Husky has significant obligations to remove tangible assets and restore land after operations cease and Husky retires or relinquishes the asset. The Company's ARO primarily relates to the Upstream business. The retirement of Upstream assets consists primarily of plugging and abandoning wells, removing and disposing of surface and subsea equipment and facilities and restoring land to a state required by regulation or contract. Estimating the 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 the ARO are numerous assumptions and judgments 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.

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 assumptions that affect expected future benefit payments. These assumptions 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.

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.

Income Tax Accounting

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. 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.

Business Combinations

Under the acquisition method, the acquiring company includes the fair value of the various assets and liabilities of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. In some circumstances the fair value of an asset is determined by estimating the amount and timing of future cash flows associated with that asset. The actual amounts and timing of cash flow may differ materially and may possibly lead to an impairment charged to net earnings. Contingent consideration associated with a business combination is based on the satisfaction of future conditions which requires Husky to make certain judgments of the probability of such conditions being fulfilled to estimate the contingent consideration to be paid in future years. The actual consideration paid may differ materially from amounts estimated in the provision recorded.

10.0 Recent Accounting Standards

International Financial Reporting Standards ("IFRS")

Husky has completed its adoption of IFRS for the year beginning on January 1, 2011. As a result, the Company's financial results for the year ended December 31, 2011 and comparative periods are reported under IFRS while selected historical data continues to be reported under previous Canadian GAAP (Refer to Note 26 of the Consolidated Financial Statements for the Company's assessment of impacts of the transition to IFRS).

Presentation of Financial Statements

In June 2011, the 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 net earnings. Amendments to IAS 1 were effective for the Company beginning 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.

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 linkage 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 in its financial statements for the annual period beginning January 1, 2013. The adoption of the standard is not expected to have a significant 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 are 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 retrospective application and early adoption permitted. The Company intends to retrospectively adopt IFRS 11 in its financial statements for the annual period beginning January 1, 2013 and is currently reviewing the classification of its joint arrangements. The extent of the impact of adoption of IFRS 11 has not yet been determined.

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 in its financial statements for the annual period beginning January 1, 2013. It is expected that IFRS 12 will increase the current level of disclosure related to the Company's interests in other entities upon adoption.

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 will be 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 in its financial statements for the annual period beginning on January 1, 2013. The Company does not expect the amendments to IAS 28 to have a material impact on the 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. The standard also provides a framework for recurring valuations that are subject to measurement uncertainty and 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 prospectively in its financial statements for the annual period beginning January 1, 2013. The extent of the impact of adoption of IFRS 13 has not yet been determined.

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 in its financial statements for the annual period beginning 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 in its financial statements for the annual period beginning January 1, 2013 and the IAS 32 amendments for the

annual period beginning 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 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 significant 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 2012 Capital Program; the Company's financial strategy; the Company's 2012 production guidance; and the timing of adoption and anticipated impact of recent accounting standards;
- with respect to the Company's Asia Pacific Region: the timetable for project execution, development plans, timing of FEED, anticipated rates of production and anticipated timing of first gas for the Company's Liwan Gas Project; planned timing of regulatory submissions and anticipated timing of first gas at the Company's Madura Straits block, offshore Indonesia; and exploration plans for the Company's North Sumbawa II block, offshore Indonesia;
- with respect to the Company's Atlantic Region: timing of well completions and expected effect of the pilot program at the Company's West White Rose field; drilling plans at the Company's North Amethyst and White Rose fields; exploration plans for offshore Canada's East Coast and Greenland; continued evaluation of a concrete wellhead and drilling platform in the White Rose region; and the timing, duration and expected impact of the planned offstation of the SeaRose and Terra Nova FPSOs;
- with respect to the Company's Oil Sands properties: project schedule, anticipated costs and anticipated timing and rates of first production at Phase I of the Company's Sunrise Energy Project; expected timing of availability for use of the construction camp building at the Sunrise Energy Project; expected timing of completion of FEED for the next development stage of the Sunrise Energy Project; drilling and development plans and timetable for the Company's Tucker project; expected timing of well completion and production at the Company's McMullen property; and 2012 evaluation plans at the Company's Saleski property;
- with respect to the Company's Heavy Oil properties: anticipated timing of when the Company's Pikes Peak South and Paradise Hill thermal projects are expected to become operational; the expected timing of commissioning of the CO_2 capture and liquefaction plant project at the Lloydminster Ethanol Plant, and planned use of CO_2 from the plant; and 2012 drilling plans for the Company's horizontal drilling program;
- with respect to the Company's Western Canadian oil and gas resource plays: 2012 drilling plans at the Company's Kaybob property, Redwater project, Saskatchewan Viking project, Shaunavon oil resource play, Wapiti project and Kakwa project; and timing of the pilot drilling program at the Company's Mackenzie Valley properties;
- with respect to the Company's Midstream operating segment: the expected timing and outcome of construction of a 300,000 barrel tank at the Hardisty terminal; and
- with respect to the Company's Downstream operating segment: bitumen processing and capacity expansion plans for the Toledo Refinery; continued reconfiguration of the Lima Refinery for heavy crude oil feedstock; anticipated timing and expected outcomes of the construction of the kerosene hydrotreater at the Lima Refinery; advancement of the Company's Continuous Catalyst Regeneration Reformer Project; the timing of planned turnarounds at the Upgrader, Lloydminster Refinery, Toledo Refinery and Lima Refinery; and the timing and expected impact of planned outages at the Lima Refinery.

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

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, 2011 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 Reserve 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, 2011.

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 and also on secondary non-GAAP measurements. The non-GAAP measurements included in this report are cash flow from operations, operating netback, return on equity, return on average capital employed, debt to capital employed, debt to cash flow, corporate reinvestment ratio, interest coverage on long-term debt and interest coverage on total debt. 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 in accordance with IFRS. These are useful 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 to similar measures presented by other users. They are common in the reports of other companies but may differ by definition and application. 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 from operations to cash flow – operating activities for the years ended December 31:

($ millions)		2011	2010
Non-GAAP	Cash flow from operations	**5,198**	3,072
	Settlement of asset retirement obligations	**(105)**	(60)
	Income taxes paid	**(282)**	(784)
	Interest received	**12**	1
	Change in non-cash working capital	**269**	(7)
GAAP	Cash flow – operating activities	**5,092**	2,222

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 2011 netback was determined by taking 2011 upstream netback (gross revenues less operating costs less royalties) divided by 2011 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 March 1, 2012. 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 2011, 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, 2011 and 2010 and Husky's financial position as at December 31, 2011 and at December 31, 2010.

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

11.5 Disclosure Controls and Procedures

Disclosure Controls and Procedures

Husky's management, 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, 2011, 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, 2011, management assessed the effectiveness of Husky's internal control over financial reporting and concluded that such internal control over financial reporting is effective and that there are no material weaknesses in Husky's internal control over financial reporting that have been identified by management.
4) KPMG LLP, who has audited the Consolidated Financial Statements of Husky for the year ended December 31, 2011, 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, 2011, 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

		2011				2010			
		Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream									
Daily production, before royalties									
Light crude oil & NGL *(mbbls/day)*		91.7	83.3	84.5	91.0	75.1	84.4	78.7	84.3
Medium crude oil *(mbbls/day)*		24.3	24.6	24.6	24.6	25.3	25.7	25.1	25.3
Heavy crude oil *(mbbls/day)*		75.8	75.1	73.6	73.4	74.6	72.4	74.6	76.4
Bitumen *(mbbls/day)*		27.4	23.6	23.6	24.2	23.1	21.9	21.5	22.6
		219.2	206.6	206.3	213.2	198.1	204.4	199.9	208.6
Natural gas *(mmcf/day)*		597.9	614.7	631.8	583.3	494.2	505.5	503.9	523.7
Total production *(mboe/day)*		318.9	309.1	311.6	310.4	280.5	288.7	283.9	295.9
Average sales prices									
Light crude oil & NGL *($/bbl)*		105.97	100.44	107.29	99.29	82.90	73.88	75.61	76.72
Medium crude oil *($/bbl)*		84.32	70.11	80.27	67.83	65.75	60.88	63.90	69.30
Heavy crude oil *($/bbl)*		75.60	61.61	71.59	58.86	58.82	56.96	56.18	63.31
Bitumen *($/bbl)*		73.24	58.70	68.62	55.41	59.14	55.41	52.58	61.82
Natural gas *($/mcf)*		3.24	3.64	3.66	3.66	3.52	3.50	3.45	4.81
Operating costs *($/boe)*		14.75	15.17	14.25	14.00	13.94	13.27	13.08	12.81
Operating netbacks[1]									
Lloydminster – Thermal Oil *($/boe)*[2]		47.67	37.04	43.34	29.10	37.77	32.05	31.06	36.51
Lloydminster – Non-Thermal Oil *($/boe)*[2]		45.42	33.78	41.63	31.48	32.12	31.31	30.30	37.51
Oil Sands – Bitumen *($/boe)*[2]		36.23	25.28	36.39	20.07	(0.03)	11.14	(4.76)	9.18
Western Canada – Crude Oil *($/boe)*[2]		46.21	33.77	44.39	35.00	40.57	36.70	33.23	35.42
Western Canada – Natural gas *($/mcf)*[3]		1.82	2.29	2.36	2.36	2.08	1.53	1.95	3.26
Atlantic – Light Oil *($/boe)*[2]		82.17	81.94	85.91	80.25	60.55	51.14	44.68	48.65
Asia Pacific – Light Oil & NGL *($/boe)*[2]		69.98	67.01	67.25	73.37	61.48	54.66	59.46	56.93
Total *($/boe)*[2]		41.25	35.88	40.77	36.23	32.91	29.70	28.36	33.82
Net wells drilled[4]									
Exploration	Oil	19	8	4	9	12	17	3	19
	Gas	11	3	1	9	9	6	1	15
	Dry	–	–	–	3	–	1	–	7
		30	11	5	21	21	24	4	41
Development	Oil	196	286	93	190	257	235	52	179
	Gas	4	8	3	27	38	6	–	9
	Dry	–	2	1	–	2	2	–	5
		200	296	97	217	297	243	52	193
		230	307	102	238	318	267	56	234
Success ratio *(percent)*		100	99	99	99	99	99	100	95
Midstream									
Pipeline throughput *(mbbls/day)*		548	534	568	580	501	489	537	524
Upgrader									
Synthetic crude oil sales *(mbbls/day)*		58.2	60.7	61.0	41.0	45.1	21.0	58.0	68.6
Upgrading differential *($/bbl)*		22.32	29.87	33.09	24.00	16.39	13.80	15.44	12.54
Canadian Refined Products									
Refined products sales volumes									
Light oil products *(million litres/day)*		9.4	9.9	8.3	8.4	8.7	8.5	7.8	7.6
Asphalt products *(mbbls/day)*		20.1	36.4	20.2	19.9	27.5	30.9	19.2	18.7
Refinery throughput									
Lloydminster refinery *(mbbls/day)*		29.0	28.5	26.2	28.9	29.0	28.9	26.1	27.0
Prince George refinery *(mbbls/day)*		11.1	7.9	9.1	11.0	11.5	11.9	6.9	9.7
Refinery utilization *(percent)*		97	88	85	96	99	100	80	90

(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 Financial Information

	Upstream				Midstream				Downstream			
					Infrastructure and Marketing				Upgrading			
2011 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues[2]	1,984	1,715	1,880	1,671	2,436	2,228	2,414	2,368	615	585	649	368
Royalties	(331)	(247)	(289)	(258)	–	–	–	–	–	–	–	–
Revenues, net of royalties	1,653	1,468	1,591	1,413	2,436	2,228	2,414	2,368	615	585	649	368
Expenses												
Purchases of crude oil and products[2]	–	–	–	–	2,295	2,131	2,317	2,203	463	390	459	269
Production and operating expenses	426	437	416	393	26	22	13	34	37	47	46	58
Selling, general and administrative expenses	24	33	51	42	6	7	6	6	3	–	–	–
Depletion, depreciation, amortization and impairment	590	494	480	432	17	9	10	10	25	27	87	25
Exploration and evaluation expenses	194	95	88	93	–	–	–	–	–	–	–	–
Other – net	3	(1)	(72)	(189)	2	(16)	10	10	24	18	15	10
Earnings from operating activities	416	410	628	642	90	75	58	105	63	103	42	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	398	395	611	628	90	75	58	105	61	101	41	4
Provisions for (recovery of) income taxes												
Current	–	(29)	11	20	26	45	30	20	–	(2)	1	1
Deferred	105	114	157	152	(4)	(26)	(15)	6	16	28	10	–
	105	85	168	172	22	19	15	26	16	26	11	1
Net earnings (loss)	293	310	443	456	68	56	43	79	45	75	30	3
Capital expenditures[3]	1,159	853	607	1,512	14	13	10	6	20	19	6	10
Total assets	20,117	19,343	18,869	18,631	1,543	1,532	1,410	1,717	1,315	1,266	1,301	1,335

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

(2) *In 2011, the Company changed its treatment of certain intersegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast by approximately $250 million per quarter and did not impact net earnings.*

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

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
938	1,162	927	833	2,371	2,413	2,585	2,224	(2,190)	(1,884)	(2,001)	(1,802)	6,154	6,219	6,454	5,662
–	–	–	–	–	–	–	–	–	–	–	–	(331)	(247)	(289)	(258)
938	1,162	927	833	2,371	2,413	2,585	2,224	(2,190)	(1,884)	(2,001)	(1,802)	5,823	5,972	6,165	5,404
795	957	783	713	2,091	2,127	2,189	1,896	(2,111)	(1,924)	(2,008)	(1,771)	3,533	3,681	3,740	3,310
44	48	48	42	102	107	90	92	(1)	–	1	(10)	634	661	614	609
13	11	12	13	2	2	1	2	60	43	68	23	108	96	138	86
20	23	19	18	52	48	45	50	12	10	9	7	716	611	650	542
–	–	–	–	–	–	–	–	–	–	–	–	194	95	88	93
–	–	–	–	–	–	–	–	(8)	6	–	(1)	21	7	(47)	(170)
66	123	65	47	124	129	260	184	(142)	(19)	(71)	(50)	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)
64	122	63	46	123	128	259	183	(179)	(43)	(99)	(94)	557	778	933	872
14	4	3	4	20	54	–	–	93	(13)	27	25	153	59	72	70
2	28	12	8	25	(7)	94	67	(148)	61	(66)	(57)	(4)	198	192	176
16	32	15	12	45	47	94	67	(55)	48	(39)	(32)	149	257	264	246
48	90	48	34	78	81	165	116	(124)	(91)	(60)	(62)	408	521	669	626
33	28	18	15	72	68	62	22	34	22	12	3	1,332	1,003	715	1,568
1,623	1,630	1,616	1,569	5,476	5,459	5,043	5,034	2,352	2,456	1,852	507	32,426	31,686	30,091	28,793

	Upstream				Midstream				Downstream			
					Infrastructure and Marketing				Upgrading			
2010 *($ millions)*	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenues[2]	1,487	1,385	1,334	1,538	1,700	1,704	1,772	1,826	366	291	405	508
Royalties	(211)	(233)	(248)	(286)	–	–	–	–	–	–	–	–
Revenues, net of royalties	1,276	1,152	1,086	1,252	1,700	1,704	1,772	1,826	366	291	405	508
Expenses												
Purchases of crude oil and products[2]	–	–	–	–	1,555	1,627	1,672	1,667	288	241	311	418
Production and operating expenses	364	352	344	343	42	35	40	46	46	43	43	49
Selling, general and administrative expenses	46	35	42	29	7	5	5	5	–	–	–	–
Depletion, depreciation, amortization and impairment	406	408	361	346	13	10	10	10	35	26	10	3
Exploration and evaluation expenses	233	25	131	49	–	–	–	–	–	–	–	–
Other – net	(2)	(1)	3	1	20	(8)	(9)	31	(32)	(2)	–	(7)
Earnings from operating activities	229	333	205	484	63	35	54	67	29	(17)	41	45
Net foreign exchange gains (losses)	–	–	–	–	–	–	–	–	–	–	–	–
Finance income	–	–	–	–	–	–	–	–	–	–	–	–
Finance expenses	(9)	(11)	(10)	(10)	–	–	–	–	(2)	(2)	(2)	(3)
	(9)	(11)	(10)	(10)	–	–	–	–	(2)	(2)	(2)	(3)
Earnings (loss) before income taxes	220	322	195	474	63	35	54	67	27	(19)	39	42
Provisions for (recovery of) income taxes												
Current	(68)	13	16	16	15	16	16	15	(20)	(4)	15	10
Deferred	131	80	41	121	2	(6)	(2)	3	28	(1)	(4)	2
	63	93	57	137	17	10	14	18	8	(5)	11	12
Net earnings (loss)	157	229	138	337	46	25	40	49	19	(14)	28	30
Capital expenditures[3]	1,152	595	439	626	15	10	12	3	49	108	16	9
Total assets	17,354	16,307	16,072	16,016	1,325	1,680	1,694	1,551	1,987	1,233	1,290	1,325

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

(2) *In 2011, the Company changed its treatment of certain intersegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for 2010. The recast reduced gross revenues and purchases of crude oil and products by $217 million which did not impact net earnings.*

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

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
835	834	700	606	1,824	1.683	1,881	1,719	(1,722)	(1,425)	(1,462)	(1,704)	4,490	4.472	4,630	4.493
–	–	–	–	–	–	–	–	–	–	–	–	(211)	(233)	(248)	(286)
835	834	700	606	1,824	1,683	1,881	1,719	(1,722)	(1,425)	(1,462)	(1,704)	4,279	4,239	4,382	4,207
701	683	598	516	1,640	1,537	1,758	1,623	(1,643)	(1,432)	(1,500)	(1,680)	2,541	2,656	2,839	2,544
45	45	51	40	94	94	97	92	(8)	9	1	2	583	578	576	572
12	12	12	13	2	2	2	1	38	16	8	(1)	105	70	69	47
17	22	24	25	51	47	47	46	19	19	18	19	541	532	470	449
–	–	–	–	–	–	–	–	(3)	–	–	3	230	25	131	52
–	–	(2)	–	–	–	(2)	2	1	(8)	–	–	(13)	(19)	(10)	27
60	72	17	12	37	3	(21)	(45)	(126)	(29)	11	(47)	292	397	307	516
–	–	–	–	–	–	–	–	(76)	11	(14)	30	(76)	11	(14)	30
–	–	–	–	–	–	–	–	17	19	20	23	17	19	20	23
–	(1)	–	(1)	(3)	(1)	(1)	(1)	(75)	(63)	(67)	(63)	(89)	(78)	(80)	(78)
–	(1)	–	(1)	(3)	(1)	(1)	(1)	(134)	(33)	(61)	(10)	(148)	(48)	(74)	(25)
60	71	17	11	34	2	(22)	(46)	(260)	(62)	(50)	(57)	144	349	233	491
12	14	15	15	–	–	–	–	24	24	22	22	(37)	63	84	78
4	4	(10)	(12)	12	1	(8)	(17)	(135)	(53)	(47)	(52)	42	25	(30)	45
16	18	5	3	12	1	(8)	(17)	(111)	(29)	(25)	(30)	5	88	54	123
44	53	12	8	22	1	(14)	(29)	(149)	(33)	(25)	(27)	139	261	179	368
79	83	66	16	118	67	50	21	20	11	4	2	1,433	874	587	677
1,517	1,403	1,403	1,370	5,092	5,102	5,144	4,940	775	556	633	938	28,050	26,281	26,236	26,140

Segmented Capital Expenditures[1]

	2011				2010			
($ millions)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Upstream								
Exploration								
Western Canada	**87**	**19**	**5**	**122**	63	134	64	83
Atlantic Region	**–**	**2**	**–**	**–**	7	–	5	56
Asia Pacific	**37**	**79**	**52**	**–**	65	7	63	94
	124	**100**	**57**	**122**	135	141	132	233
Development								
Western Canada	**734**	**541**	**336**	**439**	562	275	205	292
Atlantic Region	**61**	**62**	**73**	**62**	71	115	98	91
Asia Pacific	**226**	**150**	**123**	**47**	59	2	–	1
	1,021	**753**	**532**	**548**	692	392	303	384
Acquisitions								
Western Canada	**14**	**–**	**18**	**842**	325	62	4	9
Total Upstream	**1,159**	**853**	**607**	**1,512**	1,152	595	439	626
Midstream								
Infrastructure and Marketing	**14**	**13**	**10**	**6**	15	10	12	3
	14	**13**	**10**	**6**	15	10	12	3
Downstream								
Upgrader	**20**	**19**	**6**	**10**	49	108	16	9
Canadian Refined Products	**33**	**28**	**18**	**15**	79	83	66	16
U.S. Refining and Marketing	**72**	**68**	**62**	**22**	118	67	50	21
	125	**115**	**86**	**47**	246	258	132	46
Corporate	**34**	**22**	**12**	**3**	20	11	4	2
	1,332	**1,003**	**715**	**1,568**	1,433	874	587	677

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

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. 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 our internal control over financial reporting was effective as of December 31, 2011. 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 on behalf of the shareholders. KPMG LLP has full and free access to the Audit Committee.

Asim Ghosh

President & Chief Executive Officer

Alister Cowan

Chief Financial Officer

Calgary, Alberta, Canada

March 8, 2012

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, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for the years ended December 31, 2011 and December 31, 2010, 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, 2011, December 31, 2010 and January 1, 2010, and its consolidated results of operations and its cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

KPMG LLP

KPMG LLP

Chartered Accountants

Calgary, Alberta, Canada

March 8, 2012

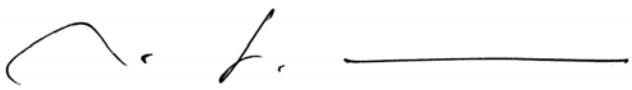
Consolidated Financial Statements

Consolidated Balance Sheets

(millions of dollars)	December 31, 2011	December 31, 2010	January 1, 2010
Assets			
Current assets			
Cash and cash equivalents *(note 9)*	**1,841**	252	392
Accounts receivable *(note 4)*	**1,235**	1,183	964
Income taxes receivable	**273**	346	23
Inventories *(note 5)*	**2,059**	1,935	1,520
Prepaid expenses	**36**	34	12
	5,444	3,750	2,911
Exploration and evaluation assets *(note 6)*	**746**	472	1,943
Property, plant and equipment, net *(note 7)*	**24,279**	21,770	18,584
Goodwill *(note 11)*	**674**	663	689
Contribution receivable *(notes 8, 22)*	**1,147**	1,284	1,313
Other assets	**136**	111	68
Total Assets	**32,426**	28,050	25,508
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(note 13)*	**2,867**	2,506	1,941
Income taxes payable	**–**	–	270
Asset retirement obligations *(note 16)*	**116**	63	29
Long-term debt due within one year *(note 14)*	**407**	–	–
	3,390	2,569	2,240
Long-term debt *(note 14)*	**3,504**	4,187	3,229
Other long-term financial liabilities *(note 22)*	**–**	102	96
Other long-term liabilities *(note 15)*	**342**	289	284
Contribution payable *(notes 8, 22)*	**1,437**	1,427	1,500
Deferred tax liabilities *(note 17)*	**4,329**	3,767	3,705
Asset retirement obligations *(note 16)*	**1,651**	1,135	738
Commitments and contingencies *(note 20)*			
Total Liabilities	**14,653**	13,476	11,792
Shareholders' equity			
Common shares *(note 18)*	**6,327**	4,574	3,585
Preferred shares *(note 18)*	**291**	–	–
Retained earnings	**11,097**	10,012	10,099
Other reserves	**58**	(12)	32
Total Shareholders' Equity	**17,773**	14,574	13,716
Total Liabilities and Shareholders' Equity	**32,426**	28,050	25,508

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

Year ended December 31 (millions of dollars, except share data)	2011	2010
Gross revenues	24,489	18,085
Royalties	(1,125)	(978)
Revenues, net of royalties	23,364	17,107
Expenses		
Purchases of crude oil and products	14,264	10,580
Production and operating expenses	2,518	2,309
Selling, general and administrative expenses	428	291
Depletion, depreciation, amortization and impairment *(note 7)*	2,519	1,992
Exploration and evaluation expenses *(note 6)*	470	438
Other – net	(189)	(15)
	20,010	15,595
Earnings from operating activities	3,354	1,512
Financial items *(note 14)*		
Net foreign exchange gains (losses)	10	(49)
Finance income	86	79
Finance expenses	(310)	(325)
	(214)	(295)
Earnings before income taxes	3,140	1,217
Provisions for income taxes *(note 17)*		
Current	354	188
Deferred	562	82
	916	270
Net earnings	2,224	947
Earnings per share *(note 18)*		
Basic	2.40	1.11
Diluted	2.34	1.05
Weighted average number of common shares outstanding *(millions)*		
Basic	923.8	852.7
Diluted	932.0	852.7

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

Consolidated Statements of Comprehensive Income

Year ended December 31 (millions of dollars)	2011	2010
Net earnings	2,224	947
Other comprehensive income (loss)		
Derivatives designated as cash flow hedges, net of tax *(note 22)*	–	6
Actuarial losses on pension plans, net of tax *(note 19)*	(20)	(14)
Exchange differences on translation of foreign operations, net of tax	88	(91)
Hedge of net investment , net of tax *(note 22)*	(18)	41
Other comprehensive income (loss)	50	(58)
Comprehensive income	2,274	889

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

Consolidated Statements of Changes in Shareholders' Equity

	Attributable to Equity Holders					
				Other Reserves		
(millions of dollars)	Common Shares *(note 18)*	Preferred Shares *(note 18)*	Retained Earnings	Foreign Currency Translation *(note 22)*	Hedging *(note 22)*	Total Shareholders' Equity
Balance as at January 1, 2010	3,585	–	10,099	40	(8)	13,716
Net earnings	–	–	947	–	–	947
Other comprehensive income (loss)						
Derivatives designated as cash flow hedges (net of tax of $2 million)	–	–	–	–	6	6
Actuarial losses on pension plans (net of tax of $6 million)	–	–	(14)	–	–	(14)
Exchange differences on translation of foreign operations (net of tax of $16 million)	–	–	–	(91)	–	(91)
Hedge of net investment (net of tax of nil)	–	–	–	41	–	41
Total comprehensive income (loss)	–	–	933	(50)	6	889
Transactions with owners recognized directly in equity						
Issue of common shares	1,000	–	–	–	–	1,000
Share issue costs	(12)	–	–	–	–	(12)
Exercise of options	1	–	–	–	–	1
Dividends declared on common shares *(note 18)*	–	–	(1,020)	–	–	(1,020)
Balance as at December 31, 2010	4,574	–	10,012	(10)	(2)	14,574
Net earnings	–	–	2,224	–	–	2,224
Other comprehensive income (loss)						
Derivatives designated as cash flow hedges (net of tax of less than $1 million)	–	–	–	–	–	–
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)	–	–	–	(18)	–	(18)
Total comprehensive income (loss)	–	–	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**

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

Consolidated Statements of Cash Flows

Year ended December 31 (millions of dollars)	2011	2010
Operating activities		
Net earnings	2,224	947
Items not affecting cash:		
Accretion *(note 14)*	79	57
Depletion, depreciation, amortization and impairment *(note 7)*	2,519	1,992
Exploration and evaluation expenses *(note 6)*	68	200
Deferred income taxes *(note 17)*	562	82
Foreign exchange	14	30
Stock-based compensation *(note 18)*	(1)	(13)
Gain on sale of assets	(261)	(2)
Other	(6)	(221)
Settlement of asset retirement obligations *(note 16)*	(105)	(60)
Income taxes paid	(282)	(784)
Interest received	12	1
Change in non-cash working capital *(note 9)*	269	(7)
Cash flow – operating activities	5,092	2,222
Financing activities		
Long-term debt issuance	5,054	6,108
Long-term debt repayment	(5,434)	(5,028)
Debt issue costs	(5)	(12)
Proceeds from common share issuance, net of share issue costs *(note 18)*	1,173	988
Proceeds from preferred share issuance, net of share issue costs *(note 18)*	291	–
Dividends on common shares *(note 18)*	(495)	(1,020)
Dividends on preferred shares *(note 18)*	(7)	–
Interest paid	(143)	(181)
Capitalized interest paid	(86)	(51)
Other	324	49
Change in non-cash working capital *(note 9)*	238	232
Cash flow – financing activities	910	1,085
Investing activities		
Capital expenditures	(4,800)	(3,379)
Proceeds from asset sales *(note 10)*	179	9
Other	(115)	(150)
Change in non-cash working capital *(note 9)*	316	67
Cash flow – investing activities	(4,420)	(3,453)
Increase (decrease) in cash and cash equivalents	1,582	(146)
Effect of exchange rates on cash and cash equivalents	7	6
Cash and cash equivalents at beginning of year	252	392
Cash and cash equivalents at end of year	1,841	252

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 segmented the Company's business based on differences in products and services and management responsibility. The Company's business is conducted predominantly through three major reportable business segments: Upstream, Midstream and Downstream.

Upstream includes exploration for, development and production of crude oil, bitumen, natural gas and natural gas liquids. The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada, offshore Greenland, offshore China and offshore Indonesia.

Midstream includes marketing of the Company's and other producers' crude oil, natural gas, natural gas liquids, sulphur and petroleum coke, pipeline transportation and processing of heavy crude oil and natural gas, storage of crude oil, diluents and natural gas and cogeneration of electrical and thermal energy (infrastructure and marketing).

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).

In the first quarter of 2011, the Company commenced evaluating and reporting its upgrading activities as part of Downstream operations. As a result, upgrading was moved from the Midstream segment to the Downstream segment. All prior periods have been reclassified to conform to these segment definitions.

In 2012, the Company commenced evaluating and reporting activities of the Midstream reporting segment as a service provider to the Upstream and Downstream operations. As a result, the Company will reclassify and report its Midstream activities into the Upstream and Downstream reportable business segments commencing the first quarter of 2012. Refer to Note 25.

Segmented Financial Information

	Upstream		Midstream	
			Infrastructure and Marketing	
Year ended December 31 ($ millions)	**2011**	2010	**2011**	2010
Gross revenues	**7,250**	5,744	**9,446**	7,002
Royalties	**(1,125)**	(978)	**–**	–
Revenues, net of royalties	**6,125**	4,766	**9,446**	7,002
Expenses				
Purchases of crude oil and products	**–**	–	**8,946**	6,521
Production and operating expenses	**1,672**	1,403	**95**	163
Selling, general and administrative expenses	**150**	152	**25**	22
Depletion, depreciation, amortization and impairment	**1,996**	1,521	**46**	43
Exploration and evaluation expenses	**470**	438	**–**	–
Other – net	**(259)**	1	**6**	34
Earnings (loss) from operating activities	**2,096**	1,251	**328**	219
Financial items				
Net foreign exchange gains (losses)	**–**	–	**–**	–
Finance income	**4**	–	**–**	–
Finance expenses	**(68)**	(40)	**–**	–
Earnings (loss) before income taxes	**2,032**	1,211	**328**	219
Provisions for (recovery of) income taxes				
Current	**2**	(23)	**121**	62
Deferred	**528**	373	**(39)**	(3)
Total income tax provision (recovery)	**530**	350	**82**	59
Net earnings (loss)	**1,502**	861	**246**	160
Intersegment revenues	**6,781**	5,374	**795**	707
Other material non-cash items				
Unrealized loss on gas storage contracts	**–**	–	**(11)**	(32)
Gain on sale of assets	**259**	2	**2**	–
Exploration and evaluation assets and property, plant and equipment as at December 31				
Exploration and evaluation assets	**746**	472	**–**	–
Developing and producing assets at cost	**33,640**	29,144	**–**	–
Accumulated depletion, depreciation and amortization	**(15,900)**	(13,919)	**–**	–
Other property, plant and equipment at cost	**–**	–	**930**	1,069
Accumulated depletion, depreciation and amortization	**–**	–	**(407)**	(449)
Exploration and evaluation assets and property, plant and equipment, net	**18,486**	15,697	**523**	620
Expenditures on property, plant and equipment – Year ended December 31[3]	**3,728**	2,171	**43**	40
Expenditures on exploration and evaluation assets – Year ended December 31[3]	**403**	641	**–**	–
Total Assets – As at December 31	**20,117**	17,354	**1,543**	1,325

[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.*

[2] *In 2011, the Company commenced evaluating and reporting Upgrading activities as part of Downstream operations. As a result, Upgrading was moved from the Midstream to the Downstream segment. All prior periods have been reclassified to conform to these segment definitions.*

[3] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the year. Includes assets acquired through acquisitions.*

Downstream						Corporate and Eliminations[1]		Total	
Upgrading[2]		Canadian Refined Products		U.S. Refining and Marketing					
2011	2010	2011	2010	2011	2010	2011	2010	2011	2010
2,217	1,570	3,860	2,975	9,593	7,107	(7,877)	(6,313)	24,489	18,085
–	–	–	–	–	–	–	–	(1,125)	(978)
2,217	1,570	3,860	2,975	9,593	7,107	(7,877)	(6,313)	23,364	17,107
1,581	1,258	3,248	2,498	8,303	6,558	(7,814)	(6,255)	14,264	10,580
188	181	182	181	391	377	(10)	4	2,518	2,309
3	–	49	49	7	7	194	61	428	291
164	74	80	88	195	191	38	75	2,519	1,992
–	–	–	–	–	–	–	–	470	438
67	(41)	–	(2)	–	–	(3)	(7)	(189)	(15)
214	98	301	161	697	(26)	(282)	(191)	3,354	1,512
–	–	–	–	–	–	10	(49)	10	(49)
–	–	–	–	–	–	82	79	86	79
(7)	(9)	(6)	(2)	(4)	(6)	(225)	(268)	(310)	(325)
207	89	295	159	693	(32)	(415)	(429)	3,140	1,217
–	1	25	56	74	–	132	92	354	188
54	25	50	(14)	179	(12)	(210)	(287)	562	82
54	26	75	42	253	(12)	(78)	(195)	916	270
153	63	220	117	440	(20)	(337)	(234)	2,224	947
120	76	174	151	7	5	–	–	7,877	6,313
–	–	–	–	–	–	–	–	(11)	(32)
–	–	–	–	–	–	–	–	261	2
–	–	–	–	–	–	–	–	746	472
–	–	–	–	–	–	–	–	33,640	29,144
–	–	–	–	–	–	–	–	(15,900)	(13,919)
1,972	1,974	2,208	2,085	4,325	4,001	557	487	9,992	9,616
(848)	(742)	(1,007)	(929)	(759)	(551)	(432)	(400)	(3,453)	(3,071)
1,124	1,232	1,201	1,156	3,566	3,450	125	87	25,025	22,242
55	182	94	244	224	256	71	37	4,215	2,930
–	–	–	–	–	–	–	–	403	641
1,315	1,987	1,623	1,517	5,476	5,092	2,352	775	32,426	28,050

Geographical Financial Information

($ millions)	Canada 2011	Canada 2010	United States 2011	United States 2010	Other International 2011	Other International 2010	Total 2011	Total 2010
Year ended December 31								
Gross revenues	12,881	9,642	11,298	8,083	310	360	24,489	18,085
Royalties	(1,024)	(903)	–	–	(101)	(75)	(1,125)	(978)
Revenue, net of royalties[1]	11,857	8,739	11,298	8,083	209	285	23,364	17,107
As at December 31								
Exploration and evaluation assets	421	252	–	44	325	176	746	472
Property, plant and equipment, net	19,481	17,720	3,572	3,454	1,226	596	24,279	21,770
Goodwill	160	160	514	503	–	–	674	663
Total non-current assets	21,315	19,531	4,103	3,997	1,564	772	26,982	24,300

[1] *Based on the geographical location of legal entities.*

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"). These accounting policies have been applied consistently for all periods presented in these consolidated financial statements and in preparing the opening IFRS balance sheet at January 1, 2010 subject to certain exceptions and exemptions allowed by IFRS 1, "First-time Adoption of International Financial Reporting Standards." Refer to Note 26.

These are the Company's first IFRS annual consolidated financial statements. Note 26 provides an explanation of how the transition to IFRS has affected the reported financial position and performance. This note includes reconciliations of equity and total comprehensive income for comparative periods, and a reconciliation of equity at January 1, 2010 and December 31, 2010 and for the year ended December 31, 2010 from Part V of Canadian generally accepted accounting principles ("Canadian GAAP") to IFRS.

These consolidated financial statements were approved and signed by the Chair of the Audit Committee and Chief Executive Officer on March 1, 2012, 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 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. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as the Company's operating environment changes.

Specifically, amounts recorded for depletion, depreciation, amortization and impairment, accretion, asset retirement obligations, fair value measurements, employee future benefits, income taxes, net assets acquired, and amounts used in impairment tests for goodwill, inventory, exploration and evaluation assets, and property, plant and equipment are based on estimates. These estimates include petroleum and natural gas reserves, future petroleum and natural gas prices, future interest rates and future costs required to develop those reserves as well as other fair value assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized on a prospective basis.

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.

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 a 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 purchased 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 fair value are included as gains or losses in other – net in the consolidated statements of income during the period of change. Previous 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 U.S. refining process. 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 stated 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 the costs incurred for oil and natural gas exploration, evaluation and development expenditures 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 associated with acquiring an exploration license, including costs to acquire acreage and exploration rights, legal and other professional fees and land brokerage fees are capitalized as exploration and evaluation assets. Pre-license costs and geological and geophysical costs associated with exploration licenses 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 further wells, the costs continue to be carried as an exploration and evaluation asset while sufficient and continued progress is made in assessing the commerciality of the hydrocarbons. 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. Impairment is recorded when the carrying value of the properties exceeds fair value. 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.

Capitalized exploration and evaluation expenditures related to wells that find proved reserves are transferred from exploration and evaluation assets to property, plant and equipment at the time of sanctioning of the development project.

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

Repairs 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 the 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 thirty-five years, and 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 fair value of net assets acquired. Goodwill, which is not amortized, is assigned to appropriate cash generating units ("CGUs") or groups of CGUs. Since goodwill results from business combinations, it is inherently imprecise and requires judgment in the determination of the fair value of assets and liabilities. 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 each reporting date to determine whether there is any indication of impairment. If such indication exists, the recoverable amount is estimated.

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 are also monitored as possible indications of impairment. 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 approved future development costs. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, marketing supply and demand, product margins and in the case of oil and gas properties, expected production volumes. Expected production volumes take into account assessments of field reservoir performance and include expectations about proved and 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 the calculations for recoverable amounts require the use of estimates and assumptions, 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 tangible 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.

Impairment losses recognized for other assets in prior years are assessed at each reporting date 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 Company's ARO mainly relates to the Upstream segment and the U.S. Downstream segment. The retirement of Upstream assets consists primarily of plugging and abandoning wells, removing and disposing surface and subsea 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 also adjusted 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, safety and public relations 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 changes to the ARO liability. Adjustments to the estimated amount 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 it becomes probable 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 financial assets.

Financial instruments classified as FVTPL or available-for-sale 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 available-for-sale 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 assets are recognized in other – net in the consolidated statements of income.

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 the risks that arise in the ordinary course of the Company's business. The Company may choose to apply hedge accounting to derivative instruments.

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 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 using the effective interest rate method. 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 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 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 each reporting date 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 available-for-sale 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.

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 OCI 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 are recognized for all deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable net earnings will be available against the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses that can be utilized. Deferred tax relating to items recognized directly in equity, including OCI, are recognized in equity.

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. The effect of a change to the tax rate on the future tax assets and liabilities is recognized in net earnings when substantively

enacted. 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. 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 the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. 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. 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.

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 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 over the period necessary to match the grant on a systematic basis to the costs that it is intended to compensate. 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) Presentation of Financial Statements

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.

ii) 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.

iii) 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 and is currently reviewing the classification of its joint arrangements. The extent of the impact of adoption of IFRS 11 has not yet been determined.

iv) 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. It is expected that IFRS 12 will increase the current level of disclosure related to the Company's interests in other entities upon adoption.

v) 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.

vi) 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 extent of the impact of adoption of IFRS 13 has not yet been determined.

vii) 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.

viii) 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.

ix) 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 significant impact to the Company's financial statements.

Note 4 Accounts Receivable

($ millions)	**December 31, 2011**	December 31, 2010	January 1, 2010
Trade receivables	**1,071**	1,159	948
Allowance for doubtful accounts	**(23)**	(19)	(18)
Derivatives due within one year	**66**	35	22
Other	**121**	8	12
	1,235	1,183	964

Note 5 Inventories

($ millions)	**December 31, 2011**	December 31, 2010	January 1, 2010
Crude oil, natural gas and sulphur	**1,476**	1,438	688
Refined petroleum products	**176**	148	451
Trading inventories measured at fair value less costs to sell	**284**	236	296
Materials, supplies and other	**123**	113	85
	2,059	1,935	1,520

Impairment of inventory to net realizable value for the year ended December 31, 2011 was $3 million (2010 – $35 million) primarily caused by a reduction in the market prices for asphalt and ethanol products. During 2011, inventory impairment reversals amounted to nil (2010 – $4 million).

Note 6 Exploration and Evaluation Costs

A reconciliation of the carrying amount of exploration and evaluation assets at December 31, 2011 and 2010 is set out below.

($ millions)	December 31, 2011	December 31, 2010
Beginning of year	472	1,943
Additions	331	946
Acquisitions *(note 10)*	116	3
Transfers to oil and gas properties *(note 7)*	(92)	(2,208)
Expensed exploration expenditures previously capitalized	(68)	(200)
Disposals *(note 10)*	(19)	(2)
Exchange adjustments	6	(10)
End of year	746	472

The following exploration and evaluation expenses for the years ended December 31, 2011 and 2010 relate to activities associated with the exploration for and evaluation of oil and natural gas resources. All such activities are recorded within the Upstream segment.

Exploration and Evaluation Expense Summary *($ millions)*	2011	2010
Seismic, geological and geophysical	170	186
Expensed drilling	245	252
Expensed land	55	–
	470	438

Note 7 Property, Plant and Equipment

($ millions)	Oil and Gas Properties	Processing, Transportation and Storage	Upgrading	Refining	Retail and Other	Total
Cost						
January 1, 2010	24,641	1,071	1,779	4,430	1,755	33,676
Additions	1,637	8	182	296	238	2,361
Acquisitions *(note 10)*	397	–	–	–	–	397
Transfers from exploration and evaluation *(note 6)*	2,208	–	–	–	–	2,208
Changes in asset retirement obligations	357	7	13	16	52	445
Disposals and derecognition	(28)	(17)	–	–	(17)	(62)
Exchange adjustments	(68)	–	–	(197)	–	(265)
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 *(note 10)*	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 *(notes 10, 21)*	(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**
Accumulated depletion, depreciation, amortization and impairment						
January 1, 2010	(12,435)	(422)	(673)	(639)	(923)	(15,092)
Depletion, depreciation and amortization[1]	(1,518)	(40)	(69)	(209)	(152)	(1,988)
Disposals and derecognition	22	13	–	1	13	49
Exchange adjustments	12	–	–	29	–	41
At 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)**
Net book value						
December 31, 2011	**17,740**	**523**	**1,124**	**3,870**	**1,022**	**24,279**
December 31, 2010 *(note 26)*	15,225	620	1,232	3,727	966	21,770
January 1, 2010 *(note 26)*	12,206	649	1,106	3,791	832	18,584

[1] *Depletion, depreciation, amortization and impairment does not include amortization of research and development assets of $10 million (year ended December 31, 2010 – $8 million) offset by exchange adjustments of $10 million (year ended December 31, 2010 – $4 million).*

Costs of property, plant and equipment, including major development projects, excluded from costs subject to depletion, depreciation and amortization as at December 31, 2011 were $5,282 million (December 31, 2010 – $4,076 million; January 1, 2010 – $3,417 million).

Assets under construction included within costs not subject to depletion, depreciation and amortization are as follows:

($ millions)	Net book value
December 31, 2011	**1,913**
December 31, 2010	736
January 1, 2010	555

Assets held under finance lease are included in the "Refining" class within property, plant and equipment and, included within costs not subject to depletion, depreciation and amortization are as follows:

($ millions)	Net book value
December 31, 2011	**32**
December 31, 2010	33
January 1, 2010	35

Included in depletion, depreciation, amortization and impairment expense recognized in the fourth quarter of 2011 is a non-cash impairment charge of $70 million (2010 – nil) on conventional natural gas assets located in East Central Alberta and included within the Upstream segment. The impairment charge was the result of lower estimated future natural gas prices for which the Company references third party estimates. The recoverable amount was estimated based on value-in-use methodology using estimated discounted cash flows based on proved plus probable reserves and discounted using an average pre-tax discount rate of 8%.

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 Toledo Refinery in Ohio. On March 31, 2008, the Company completed a transaction with BP whereby BP contributed the 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 sheet is as follows:

Contribution Payable *($ millions)*	December 31, 2011	December 31, 2010
Beginning of year	**1,427**	1,500
Accretion	**83**	87
Paid	**(103)**	(85)
Foreign exchange	**30**	(75)
End of year	**1,437**	1,427

The contribution payable accretes at a rate of 6% and is payable between December 31, 2011 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 downstream entity is included as part of the U.S. Refining and Marketing segment.

Summarized below is the Company's proportional share of operating results and financial position that have been included in the consolidated statements of income and the consolidated balance sheets and grouped in the Downstream segment:

Results of Operations *($ millions)*	2011	2010
Revenues	**2,632**	2,063
Expenses	**(2,389)**	(2,105)
Proportionate share of net income (loss)	**243**	(42)

Balance Sheets ($ millions)	December 31, 2011	December 31, 2010	January 1, 2010
Current assets	487	424	351
Non-current assets	1,859	1,800	1,910
Current liabilities	(223)	(218)	(179)
Non-current liabilities	(534)	(481)	(528)
Proportionate share of net assets	1,589	1,525	1,554

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, 2011 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 12 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)	December 31, 2011	December 31, 2010
Beginning of year	1,284	1,313
Accretion	71	76
Received	(234)	(38)
Foreign exchange	26	(67)
End of year	1,147	1,284

The Company currently holds a 40% interest in Husky-CNOOC Madura Ltd., which is engaged in exploring for oil and gas resources in Indonesia. Prior to January 13, 2011, the Company held a 50% interest in the joint venture; for details of this divestiture, refer to Note 10. Results of the joint venture are included 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 Ltd. that have been included in the consolidated statements of income and the consolidated balance sheets:

Results of Operations ($ millions)	2011	2010
Revenues	–	–
Expenses	(9)	(37)
Net financial items	97	10
Proportionate share of net income (loss)	88	(27)

Balance Sheets ($ millions)	December 31, 2011	December 31, 2010	January 1, 2010
Current assets	8	13	13
Non-current assets	1,778	1,645	1,631
Current liabilities	(38)	(28)	(16)
Non-current liabilities	(21)	(23)	(7)
Proportionate share of net assets	1,727	1,607	1,621

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

($ millions)	2011	2010
Decrease (increase) in non-cash working capital		
Accounts receivable	553	(531)
Inventories	(77)	(481)
Prepaid expenses	(8)	(17)
Accounts payable and accrued liabilities	355	1,321
Change in non-cash working capital	823	292
Relating to:		
Operating activities	269	(7)
Financing activities	238	232
Investing activities	316	67

Cash and cash equivalents at December 31, 2011 included $2 million of cash (December 31, 2010 – $185 million; January 1, 2010 – $65 million) and $1,839 million of short-term investments with maturities less than three months (December 31, 2010 – $67 million; January 1, 2010 – $327 million).

Note 10 Acquisitions and Dispositions

Acquisition of Oil and Natural Gas Properties

On February 4, 2011, the Company acquired oil and natural gas properties in Alberta and northeast British Columbia for consideration of $823 million before adjustments. The assets acquired are located in core areas of Husky's operations and include land, oil and gas wells, facilities, pipelines and seismic data. The fair value of the assets acquired and liabilities assumed on the date of acquisition was $836 million.

The amounts recognized on the date of acquisition for the identifiable assets acquired were:

($ millions)	Amount
Exploration and evaluation assets	68
Property, plant and equipment	830
Asset retirement obligations assumed	(62)
Total net assets acquired	836

Total cash consideration transferred for the net assets acquired was $836 million. In the period February 4, 2011 to December 31, 2011, the acquisition contributed revenues of $232 million and net earnings of $37 million which are included in the consolidated statements of income for the year ended December 31, 2011.

If the acquisition had occurred on January 1, 2011, management estimates that consolidated revenues would have increased by an additional $29 million and consolidated net earnings would have increased by $6 million for the year ended December 31, 2011. In determining these amounts, management has assumed that the fair value adjustments, determined provisionally, that arose on the date of acquisition would have been the same if the acquisition had occurred on January 1, 2011.

Property Exchange

On June 1, 2011, the Company exchanged, in a commercial transaction, certain oil and natural gas properties in Alberta, resulting in a pre-tax gain of $68 million on the Company's exchanged properties recorded in other – net in the consolidated statements of income measured on the basis of the fair value of the assets received.

Sale of Oil Sands Leases

On January 14, 2011, the Company completed the sale of 23 square miles of mining leases in Alberta for cash proceeds of $200 million, resulting in a gain recorded in other – net in the consolidated statements of income, subject to adjustments, of approximately $177 million. The first installment of $100 million was received on January 14, 2011 and the second installment of $100 million was received on January 13, 2012.

Completion of 10% Interest Sale of Husky-CNOOC Madura Ltd.

On January 13, 2011, a subsidiary of the Company, Husky Oil Madura Partnership ("HOMP"), and China National Offshore Oil Corporation Southeast Asia Limited ("CNOOCSE") both sold a 10% equity share in Husky-CNOOC Madura Ltd. to Samudra Energy Ltd. through its affiliate, SMS Development Ltd. ("SMS"). Following the completion of the sale, HOMP and CNOOCSE now each hold a 40% equity interest in Husky-CNOOC Madura Ltd. with the remaining 20% held by SMS. The sale resulted in a gain of $12 million recorded in other – net in the consolidated statements of income. The Company's share of the consideration was U.S. $12.5 million in cash and a deferred purchase price of U.S. $12.5 million which bears interest at a rate of 5% and is payable to the Company from SMS's share of future distributions from Husky-CNOOC Madura Ltd..

Acquisition of Natural Gas Properties

On November 30, 2010, the Company acquired natural gas properties in west central Alberta for consideration of $360 million prior to adjustments. The acquired assets include land, wells, facilities, and pipelines located in one of the Company's core producing areas. The fair value of the assets acquired and liabilities assumed on the date of acquisition was $356 million.

The amounts recognized on the date of acquisition for the identifiable assets acquired were:

($ millions)	Amount
Property, plant and equipment	380
Asset retirement obligations assumed	(24)
Total net assets acquired	356

Note 11 Goodwill

($ millions)	2011	2010
Beginning of year	663	689
Exchange adjustments	11	(26)
End of year	674	663

As at December 31, 2011, 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% (2010 – 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 average expected inflation rate for the U.S. of 2% (2010 – 2%). At December 31, 2011, the recoverable amount exceeded the carrying amount of the relevant CGUs and accordingly no impairment was recorded in 2011 (2010 – nil). The value-in-use calculation for the Lima Refinery CGU is particularly sensitive to changes in discount rates and forecasted crack spreads and realized refining margins.

Note 12 Bank Operating Loans

At December 31, 2011, the Company had unsecured short-term borrowing lines of credit with banks totalling $465 million (December 31, 2010 – $415 million; January 1, 2010 – $395 million) and letters of credit under these lines of credit totalled $250 million (December 31, 2010 – $116 million; January 1, 2010 – $133 million). As at December 31, 2011, bank operating loans (excluding reclassified outstanding cheques) were nil (December 31, 2010 and January 1, 2010 – nil). Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates. During 2011, the Company's weighted average interest rate on short-term borrowings was approximately 1.2% (2010 – 0.8%).

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, 2011, there was no balance outstanding under these facilities (December 31, 2010 and January 1, 2010 – 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, 2011, there was no balance outstanding under this credit facility (December 31, 2010 and January 1, 2010 – nil).

Note 13 Accounts Payable and Accrued Liabilities

($ millions)	December 31, 2011	December 31, 2010	January 1, 2010
Trade payables	**74**	106	40
Accrued liabilities	**2,178**	2,061	1,546
Dividend payable	**291**	255	255
Stock-based compensation *(note 18)*	**9**	10	23
Derivatives due within one year	**138**	9	2
Contingent consideration	**17**	–	–
Other	**160**	65	75
	2,867	2,506	1,941

Note 14 Long-term Debt

($ millions)	Maturity	Canadian $ Amount December 31, 2011	Canadian $ Amount December 31, 2010	Canadian $ Amount January 1, 2010	U.S. $ Denominated December 31, 2011	U.S. $ Denominated December 31, 2010	U.S. $ Denominated January 1, 2010
Long-term debt							
Syndicated credit facility	2015	–	380	–	–	–	–
6.25% notes[1]	2012	–	398	419	–	400	400
5.90% notes[2]	2014	763	750	785	750	750	750
3.75% medium-term notes[2]	2015	300	308	–	–	–	–
7.55% debentures[2]	2016	203	209	208	200	200	200
6.20% notes[2]	2017	305	316	312	300	300	300
6.15% notes	2019	305	298	314	300	300	300
7.25% notes	2019	763	746	785	750	750	750
5.00% medium-term notes	2020	400	400	–	–	–	–
6.80% notes	2037	393	385	405	387	387	387
Debt issue costs[3]		(21)	(26)	(26)	–	–	–
Unwound interest rate swaps		93	23	27	–	–	–
		3,504	4,187	3,229	2,687	3,087	3,087
Long-term debt due within one year							
6.25% notes[1]	2012	407	–	–	400	–	–

[1] *A portion of the Company's debt is designated in a cash flow hedging relationship for foreign currency risk management. Refer to Note 22.*
[2] *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. Refer to Note 22.*
[3] *Calculated using the effective interest rate method.*

Financial items for the years ended December 31, 2011 and 2010 were as follows:

($ millions)	2011	2010
Foreign exchange		
Gains (losses) on translation of U.S. dollar denominated long-term debt	**(47)**	108
Gains (losses) on cross currency swaps	**7**	(18)
Gains (losses) on contribution receivable	**34**	(67)
Other foreign exchange gains (losses)	**16**	(72)
	10	(49)
Finance income		
Contribution receivable	**71**	77
Other	**15**	2
	86	79
Finance expenses		
Long-term debt	**(226)**	(226)
Contribution payable	**(82)**	(87)
Short-term debt	**(9)**	(6)
	(317)	(319)
Interest capitalized[1]	**86**	51
	(231)	(268)
Accretion of asset retirement obligations *(note 16)*	**(73)**	(49)
Accretion of other long-term liabilities	**(6)**	(8)
	(310)	(325)
	(214)	(295)

[1] *Interest capitalized on project costs is calculated using the Company's annualized effective interest rate of 6% (2010 – 7%).*

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

Credit Facilities

The Company's revolving syndicated credit facility, which was entered into on November 15, 2011, allows it 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 facility. The Company also has a second revolving syndicated credit facility that allows it to borrow up to $1.7 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility, which was entered into on August 31, 2010 and increased from $1.5 billion to $1.7 billion in March 2011, is structured as a four-year committed revolving credit facility. 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, 2011, the Company had no borrowings under its $1.6 billion revolving syndicated credit facility, its $1.7 billion revolving syndicated credit facility or its $100 million bilateral credit facility (December 31, 2010 – $380 million under the $1.25 billion revolving syndicated credit facility, which was replaced by the $1.6 billion revolving syndicated facility in 2011, and no borrowings under the $1.5 billion revolving syndicated credit facility, which was increased to $1.7 billion in 2011, and the bilateral credit facilities; January 1, 2010 – no borrowings under the revolving syndicated or bilateral credit facilities). The $100 million revolving bilateral credit facility, maturing on June 30, 2012, was cancelled effective February 3, 2012.

Notes and Debentures

On March 12, 2010, the Company issued $300 million of 3.75% notes due March 12, 2015 and $400 million of 5.00% notes due March 12, 2020 pursuant to a medium term note shelf prospectus. The notes are redeemable at the option of the Company at any time, subject to a make whole provision. 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 November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units (the "Securities") in Canada until December 26, 2012. During the 25-month period that the shelf prospectus is effective, Securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in an accompanying prospectus supplement.

On June 13, 2011, Husky filed a universal short form base 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 until July 13, 2013.

The 6.25% and the 6.15% notes represent unsecured securities under a trust indenture dated June 14, 2002. Interest is payable semi-annually.

The 5.90% and the 7.25% notes, issued in 2009, represent unsecured securities under a trust indenture dated September 11, 2007. Interest is payable semi-annually.

The 7.55% debentures represent unsecured securities under a trust indenture dated October 31, 1996. Interest is payable semi-annually.

The 6.20% and the 6.80% notes represent unsecured securities under a trust indenture dated September 11, 2007. Interest is payable semi-annually.

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.

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 fair value hedges is included in the carrying value of long-term debt. Refer to Note 22.

Note 15 Other Long-term Liabilities

($ millions)	December 31, 2011	December 31, 2010	January 1, 2010
Employee future benefits *(note 19)*	**166**	140	124
Finance lease obligations	**33**	34	36
Stock-based compensation *(note 18)*	**8**	9	10
Contingent consideration *(note 22)*	**112**	53	85
Other	**23**	53	29
	342	289	284

Note 16 Asset Retirement Obligations

At December 31, 2011, the estimated total undiscounted inflation adjusted amount required to settle the Company's ARO was $8.5 billion (December 31, 2010 – $7.6 billion; January 1, 2010 – $5.9 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 30 years into the future. This amount has been discounted using a credit-adjusted risk free rate of 3% to 5% (December 31, 2010 – 6%; January 1, 2010 – 6%). Obligations related to environmental remediation and cleanup of oil and gas producing assets are included in the estimated ARO.

While the provision is based on the best estimates of future costs, discount rates, and the economic lives of the assets, there is uncertainty regarding the amount and timing of incurring these costs that are not always within management's control.

Changes to the ARO for the years ended December 31, 2011 and 2010 were as follows:

($ millions)	December 31, 2011	December 31, 2010
Beginning of year	1,198	767
Additions	188	135
Liabilities settled	(105)	(60)
Liabilities disposed	(6)	–
Change in discount rate	387	77
Change in estimates	32	233
Exchange adjustment	–	(3)
Accretion[1]	73	49
End of year	1,767	1,198
Expected to be incurred within 1 year	116	63
Expected to be incurred beyond 1 year	1,651	1,135

[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 were as follows:

($ millions)	2011	2010
Current income tax		
Current income tax charge	334	285
Adjustments in respect of current income tax of previous years	20	(97)
	354	188
Deferred income tax		
Relating to origination and reversal of temporary differences	511	11
Adjustments in respect of deferred income tax of previous years	51	71
	562	82

($ millions)	2011	2010
Deferred tax items expensed (recovered) directly in OCI		
Derivatives designated as cash flow hedges	–	2
Actuarial losses on pension plans	(8)	(6)
Exchange differences on translation of foreign operations	14	(16)
Hedge of net investment	(3)	–
	3	(20)

($ millions)	2011	2010
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 were accounted for as follows:

($ millions)	2011	2010
Earnings before income taxes		
Canada	2,556	1,466
United States	508	(211)
Other foreign jurisdictions	76	(38)
	3,140	1,217
Statutory income tax rate *(percent)*	27.3	28.9
Expected income tax	857	352
Effect on income tax resulting from:		
Rate benefit on partnership earnings	(56)	(15)
Capital gains and losses	2	(5)
Foreign jurisdictions	46	(16)
Non-taxable items	(5)	(14)
Adjustments in respect of previous years	71	(26)
Other – net	1	(6)
Income tax expense	916	270

The statutory tax rate was 27.3% in 2011 (2010 – 28.9%). The decrease from 2010 to 2011 was due to a reduction in the 2011 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:

($ 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)

($ millions)	January 1, 2010	Recognized in Earnings	Recognized in OCI	December 31, 2010
Deferred tax liabilities				
Exploration and evaluation assets and property, plant and equipment	(4,258)	(137)	24	(4,371)
Foreign exchange gains taxable on realization	(52)	(22)	–	(74)
Debt issue costs	(2)	(1)	–	(3)
Deferred tax assets				
Pension plans	32	–	6	38
Asset retirement obligations	214	94	–	308
Financial assets at fair value	(22)	27	(2)	3
Loss carry-forwards	369	(51)	(8)	310
Other temporary differences	14	8	–	22
	(3,705)	(82)	20	(3,767)

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

At December 31, 2011, the Company had $443 million (December 31, 2010 – $818 million; January 1, 2010 – $1 billion) of U.S. tax losses that will expire between 2028 and 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.

Changes to issued common share capital were as follows:

($ millions)	Number of Shares	Amount
January 1, 2010	849,860,935	3,585
Common shares issued, net of share issue costs	40,816,326	988
Options exercised	31,534	1
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**

On December 7, 2010, Husky issued 11.9 million common shares at a price of $24.50 per share for total gross proceeds of $293 million via an overnight-marketed public offering. The Company also issued a total of 28.9 million common shares to the principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l. at a price of $24.50 per share for total gross proceeds of $707 million. 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.

On June 29, 2011, Husky 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.

Amendments to Common Share Terms

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 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 would be 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, 2011, the Company declared dividends payable of $1.20 per common share (2010 – $1.20 per common share) resulting in dividends of $1.1 billion (2010 – $1.0 billion). At December 31, 2011, $287 million was payable to shareholders on account of dividends declared on November 3, 2011.

Preferred Shares

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

($ millions)	Number of Shares	Amount
January 1, 2011	–	–
Cumulative Redeemable Preferred Shares, Series 1 issued, net of share issue costs	12,000,000	291
December 31, 2011	**12,000,000**	**291**

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. 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 declared 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 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 rate dividends at a rate equal to the three-month Government of Canada Treasury Bill yield plus 1.73%.

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, 2011, the Company declared dividends payable of approximately $0.87 per Series 1 Preferred Share (2010 – nil). An aggregate of $7 million was paid for the year ended December 31, 2011 and $3 million representing approximately $0.28 per Series 1 Preferred Share (2010 – nil), was payable as dividends on the Series 1 Preferred Shares at December 31, 2011.

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. This 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 on the consolidated balance sheet at December 31, 2011 was $17 million (December 31, 2010 – $19 million; January 1, 2010 – $33 million) representing the estimated fair value of options outstanding. The total recovery recognized in selling, general and administrative expenses on the consolidated statements of income for the Option Plan for the year ended December 31, 2011 was $2 million (2010 – recovery of $13 million). At December 31, 2011, stock options exercisable for cash had an intrinsic value of nil (December 31, 2010 – nil; January 1, 2010 – $1 million).

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

	2011		2010	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding beginning of year	29,541	$ 37.04	28,399	$ 40.78
Granted[1]	9,618	$ 28.80	8,870	$ 27.95
Exercised for common shares	(5)	$ 28.19	(31)	$ 24.14
Surrendered for cash	–	$ –	(39)	$ 23.24
Expired or forfeited	(5,817)	$ 37.30	(7,658)	$ 40.50
Outstanding end of year	**33,337**	**$ 34.62**	29,541	$ 37.04
Exercisable end of year	**18,486**	**$ 39.50**	17,325	$ 41.20

[1] *Options granted during the year ended December 31, 2011 were attributed a fair value of $4.41 per option (2010 – $4.80) at grant date.*

	Outstanding Options			Options Exercisable	
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	17,504	$ 28.45	4	2,792	$ 28.06
$30.00 – $34.99	816	$ 31.25	2	677	$ 31.16
$35.00 – $39.99	210	$ 39.97	1	210	$ 39.97
$40.00 – $42.99	12,917	$ 41.60	–	12,917	$ 41.60
$43.00 – $45.02	1,890	$ 45.02	2	1,890	$ 45.02
December 31, 2011	**33,337**	**$ 34.62**	**2**	**18,486**	**$ 39.50**

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:

	December 31, 2011		December 31, 2010	
	Tandem Options	Tandem Performance Options	Tandem Options	Tandem Performance Options
Dividend per option	$ 1.33	$ 1.33	$ 1.21	$ 1.21
Range of expected volatilities used *(percent)*	21.3 – 35.9	21.3 – 32.0	14.5 – 39.2	14.5 – 39.1
Range of risk-free interest rates used *(percent)*	0.7 – 1.3	0.7 – 1.0	1.0 – 2.5	1.0 – 1.9
Expected life of share options from vesting date *(years)*	1.75	1.75	1.60	1.60
Expected forfeiture rate *(percent)*	11.5	11.5	12.1	12.1
Weighted average exercise price	$ 34.59	$ 41.51	$ 37.79	$ 41.18
Weighted average fair value	$ 0.82	$ 0.03	$ 1.07	$ 0.38

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 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 it 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. The carrying amount of the liability relating to PSUs was $1 million as at December 31, 2011 (December 31, 2010 and January 1, 2010 – nil).

The number of PSUs outstanding was as follows:

	2011	2010
Beginning of year	220,000	–
Granted	295,000	245,000
Forfeited	(15,000)	(25,000)
End of year	500,000	220,000

Earnings per Share

	2011	2010
Net earnings – basic *($ millions)*	2,214	947
Net earnings – diluted *($ millions)*	2,184	898
Weighted average common shares outstanding – basic *(millions)*	923.8	852.7
Weighted average common shares outstanding – diluted *(millions)*	932.0	852.7
Earnings per share – basic	$ 2.40	$ 1.11
Earnings per share – diluted	$ 2.34	$ 1.05

For the purposes of calculating net earnings – basic, net earnings were adjusted for dividends declared on preferred shares of $10 million for the year ended December 31, 2011 (2010 – nil). Net earnings – diluted was calculated by adjusting net earnings – basic for the more dilutive effect of stock compensation expense based on cash-settlement versus equity-settlement of stock options. For the purposes of determining net earnings – diluted, stock compensation recovery was $2 million based on cash-settlement for the year ended December 31, 2011 (2010 – recovery of $13 million). Stock compensation expense of $28 million for the year ended December 31, 2011 (2010 – $36 million) was used to determine net earnings – diluted based on equity-settlement.

The diluted weighted average common shares outstanding was adjusted for 8.2 million common shares that were declared as stock dividends for the year ended December 31, 2011 (2010 – nil). For the year ended December 31, 2011, 26 million tandem options and 7 million tandem performance options (2010 – 20 million tandem options and 10 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, 2011. The most recent actuarial valuation of the plans was December 31, 2008 and December 31, 2010 for the Canadian defined benefit plan and the other post-employment benefit plan, respectively. The most recent actuarial valuation of the U.S. plans was January 1, 2011.

Defined Contribution Pension Plan

During the year ended December 31, 2011, the Company recognized a $28 million expense (2010 – $25 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		OPEB Plan	
($ millions)	December 31, 2011	December 31, 2010	December 31, 2011	December 31, 2010
Fair value of plan assets	147	142	–	–
Defined benefit obligation	(183)	(170)	(120)	(100)
Funded status	(36)	(28)	(120)	(100)
Unrecognized past service costs	–	–	(10)	(12)
Net Liability	(36)	(28)	(130)	(112)
Current liability	–	–	–	–
Non-current liability	(36)	(28)	(130)	(112)

The following tables summarize changes to the net balance sheet position and amounts recognized in net earnings and other comprehensive income for the DB Pension Plan and the OPEB Plan for the years ended December 31, 2011 and 2010.

	DB Pension Plan		OPEB Plan	
($ millions)	**2011**	2010	**2011**	2010
Reconciliation of net asset (liability)				
Beginning of year	**(28)**	(30)	**(112)**	(94)
Employer contributions	**10**	14	**1**	1
Benefit cost	**–**	(3)	**(9)**	(8)
Actuarial loss	**(18)**	(9)	**(10)**	(11)
End of year	**(36)**	(28)	**(130)**	(112)

	DB Pension Plan		OPEB Plan	
($ millions)	**2011**	2010	**2011**	2010
Amounts recognized in net earnings				
Current service cost	**3**	4	**6**	5
Interest cost	**8**	8	**5**	5
Expected return on plan assets	**(10)**	(9)	**–**	–
Past service cost (credit)	**–**	–	**(2)**	(2)
Curtailment gain	**(1)**	–	**–**	–
Benefit cost	**–**	3	**9**	8
Amounts recognized in retained earnings				
Actuarial loss recognized during the year	**18**	9	**10**	11
Cumulative actuarial loss, end of year	**27**	9	**21**	11

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

	DB Pension Plan		OPEB Plan	
Defined Benefit Obligation *($ millions)*	**2011**	2010	**2011**	2010
Beginning of year	**170**	154	**100**	80
Current service cost	**3**	4	**6**	5
Interest cost	**8**	8	**5**	5
Benefits paid	**(10)**	(9)	**(1)**	(1)
Actuarial loss	**13**	13	**10**	11
Curtailment gain	**(1)**	–	**–**	–
End of year	**183**	170	**120**	100

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

Fair Value of Plan Assets *($ millions)*	**2011**	2010
Beginning of year	**142**	125
Contributions by employer	**10**	14
Benefits paid	**(10)**	(9)
Expected return on plan assets	**10**	8
Actuarial gain (loss)	**(5)**	4
End of year	**147**	142

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

	Canada – DB Pension Plan		U.S. – DB Pension Plan	
(percent)	**2011**	2010	**2011**	2010
Discount rate for benefit expense	**5.0**	5.7	**4.7**	5.4
Discount rate for benefit obligation	**4.1**	5.0	**3.9**	4.7
Rate of compensation expense	**4.0**	4.0	**4.5**	4.5
Expected rate of return on plan assets	**6.5**	7.0	**6.0**	6.6

	OPEB Plan	
(percent)	**2011**	2010
Discount rate for benefit expense	**4.9 – 5.2**	5.3 – 6.0
Discount rate for benefit obligation	**4.1 – 4.3**	4.9 – 5.2
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 9.0% for 2011, reduced by 0.5% per year for eight years to 5.0% in 2019 and thereafter. The average health care cost trend rate used for the obligation related to the Canadian OPEB Plan was 8.5% for 2012, reduced by 0.5% per year for seven years to 5.0% in 2019 and thereafter.

The average health care cost trend rate used for the benefit expense for the U.S. OPEB Plan was 8.0% for 2011, 2012 and 2013, and 7.0% for 2014, reduced by 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 2011, 2012 and 2013, and 7.0% for 2014, reduced by 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:

($ millions)	1% increase	1% decrease
Effect on benefit cost recognized in net earnings	2	(2)
Effect on defined benefit obligation	19	(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 2011 was 3% and 1% (2010 – 10% and 2%) for the Canadian and U.S. DB Pension Plans, respectively.

During 2011, Husky contributed $10 million (2010 – $14 million) to the defined benefit pension plan assets and is expecting to contribute $9 million in 2012. Benefits of $11 million are expected to be paid in 2012.

Husky 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, 2011 and 2010 was as follows:

(percent)	Target allocation range	**2011**	2010
Money market type funds	5 – 6	**6.8**	5.4
Equity securities	50 – 80	**56.1**	53.8
Debt securities	30 – 50	**36.7**	39.7
Real estate	0 – 5	**–**	–
Other	0 – 15	**0.4**	1.1

Note 20 Commitments and Contingencies

At December 31, 2011, the Company had commitments that require the following minimum future payments which are not accrued for in the consolidated balance sheets:

($ millions)	Within 1 year	After 1 year but not more than 5 years	More than 5 years	Total
Operating leases	108	288	119	515
Firm transportation agreements	187	767	3,291	4,245
Unconditional purchase obligations	2,926	1,661	89	4,676
Lease rentals and exploration work agreements	77	764	519	1,360
	3,298	3,480	4,018	10,796

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, 2011 and Husky's percentage equity interest (to the nearest whole number) are set out below.

Name	%	Jurisdiction
Subsidiaries of Husky Energy Inc.		
Husky Oil Operations Limited	100	Alberta
Subsidiaries 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
Husky-CNOOC Madura Ltd.	40	British Virgin Islands
BP-Husky Refining LLC	50	Delaware
Lima Refining Company	100	Delaware
Husky Marketing and Supply Company	100	Delaware

All related party transactions were 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. These notes were offered through an existing base shelf prospectus, which was filed with the Alberta Securities Commission and the U.S. Securities and Exchange Commission in February 2009. 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 apply with unrelated parties. At December 31, 2011, the senior notes are included in long-term debt on the Company's balance sheet.

On December 7, 2010, the Company issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million via a private placement to its principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whampoa Luxembourg Holdings S.à.r.l.

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

The Company continues to sell natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by the related party. These natural gas sales are related party transactions and have been measured at fair value. For the year ended December 31, 2011, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by the related party was $108 million (2010 – $95 million). For the year ended December 31, 2011, the total value of obligated steam purchases from the Meridian and other cogeneration facilities owned by the related party was $13 million (2010 – $20 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 on the consolidated statements of income for the year ended December 31, 2011 was $588 million (2010 – $412 million) as follows:

Compensation of Employees *($ millions)*	2011	2010
Short-term employee benefits	615	492
Post-employment benefits	37	36
Stock-based compensation	(1)	(13)
	651	515
Less: capitalized portion	(63)	(103)
	588	412

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)*	2011	2010
Short-term employee benefits	11	11
Post-employment benefits	–	–
Stock-based compensation	(2)	(1)
	9	10

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.

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, measured in accordance with IAS 19, "Employee Benefits."

Stock-based compensation represents the cost to the Company for participation in share-based payment plans measured in accordance with IFRS 2, "Share-based Payments."

Note 22 Financial Instruments and Risk Management

Financial Instruments

Financial instruments carried at fair value on the consolidated balance sheets include cash and cash equivalents, derivatives used for trading purposes and hedging activities, and contingent consideration recognized as part of a business acquisition included in accounts payable and accrued liabilities and other long-term liabilities. Other financial instruments, including accounts receivable, income taxes receivable, contribution receivable, accounts payable and accrued liabilities, income taxes payable, long-term debt and contribution payable, are classified as loans and receivables and are carried at amortized cost.

The carrying values of accounts receivable, accounts payable and accrued liabilities, other than derivatives and hedging activities, income taxes receivable, income taxes payable, contribution receivable and contribution payable 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, 2011 was $4.4 billion (December 31, 2010 – $4.6 billion; January 1, 2010 – $3.6 billion).

The following table summarizes by measurement classification, the derivatives, contingent consideration and hedging activities carried at fair value on the balance sheet:

($ millions)	**December 31, 2011**	December 31, 2010	January 1, 2010
Derivatives – FVTPL (held-for-trading)			
Accounts receivable	**65**	34	22
Accounts payable and accrued liabilities	**(45)**	(9)	(2)
Other assets, including derivatives	**2**	2	1
Other – FVTPL (held-for-trading)			
Accounts payable and accrued liabilities	**(17)**	–	–
Other long-term liabilities	**(112)**	(53)	(85)
Derivatives – Hedging			
Other assets, including derivatives	**–**	35	–
Accounts payable and accrued liabilities	**(93)**	–	–
Long-term debt	**(1,401)**	(1,062)	(1,055)
Other long-term financial liabilities	**–**	(102)	(96)
Net gains (losses) for the year ended	**(55)**	(8)	
Included in net earnings[1]	**(55)**	(14)	
Included in other comprehensive income	**–**	6	

[1] *During the year ended December 31, 2011 and 2010, there were no amounts reclassified from other comprehensive income to net earnings upon derecognition of financial assets.*

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 is determined by reference to quoted prices in active markets for identical assets and liabilities. 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 valuations 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.

($ millions)	**December 31, 2011**	December 31, 2010	January 1, 2010
Financial assets			
Level 2	**67**	71	23
Financial liabilities			
Level 2	**(1,539)**	(1,173)	(1,153)
Level 3	**(129)**	(53)	(85)
	(1,601)	(1,155)	(1,215)

The estimation of the fair value of commodity derivatives and held-for-trading inventories incorporates forward prices and adjustments for quality and location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability.

The contingent consideration payments, based on the average differential between heavy and synthetic crude oil prices until 2014, are classified as Level 3. The fair value of the contingent consideration is determined through independent price forecasts which were adjusted for price forecasts, forecasted synthetic crude oil volumes and forward price differentials deemed specific to the Company's Upgrader. A reconciliation of changes in fair value of financial liabilities classified as Level 3 is provided below:

($ millions)	**2011**	2010
Beginning of year	**53**	85
Accretion	**6**	8
Increase (decrease) on revaluation[1]	**70**	(40)
End of year	**129**	53
Expected to be incurred within 1 year	**17**	–
Expected to be incurred beyond 1 year	**112**	53

[1] *Loss (gain) on revaluation of the contingent consideration is recorded in other – net in the consolidated statements of income.*

Risk Management Overview

The Company is exposed to risks related to the volatility of commodity prices, foreign exchange rates and interest rates. 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. Risk management is ultimately established by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

The Company is exposed to risk factors associated with operating in developing countries, including political and regulatory instability. The Company monitors the changes to regulations and government policies in the areas within which it operates.

The Company's objectives, processes and policies for managing risk have not changed from the previous year.

Market Risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk and other price risks, for example, commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns.

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.

The Company's results are affected by the exchange rate between 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.

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 has entered into cash flow hedges using cross currency debt swaps. 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.

To mitigate risk related to interest rates, the Company may enter into fair value hedges using interest rate swaps.

Commodity Price Risk Management

a) Natural Gas Contracts

At December 31, 2011, the Company had the following third party offsetting physical natural gas purchase and sale contracts, which met the definition of a derivative instrument:

	Volumes *(mmcf)*	Fair Value *($ millions)*
Physical purchase contracts	11,628	(2)
Physical sale contracts	(10,099)	2

These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized loss of $1 million (2010 – unrealized loss of $2 million) has been recorded in other – net in the consolidated statements of income for the year ended December 31, 2011.

b) Natural Gas Storage Contracts

At December 31, 2011, the Company had the following third party physical natural gas storage purchase and sale derivative contracts:

	Volumes *(mmcf)*	Fair Value *($ millions)*
Physical purchase contracts	14,977	(8)
Physical sale contracts	(53,087)	32

The third party physical purchase and sale contracts have been recorded at their fair value in accrued liabilities and accounts receivable, respectively. The change in the fair value of these contracts resulted in an unrealized loss of $7 million (2010 – unrealized gain of $18 million) which has been recorded in other – net in the consolidated statements of income.

Natural gas inventories held in storage of 38,110 mmcf as at December 31, 2011 related to these contracts are recorded at fair value. At December 31, 2011, the fair value of the inventories was $121 million (December 31, 2010 – $131 million; January 1, 2010 – $173 million). The cumulative fair value change on this inventory as of December 31, 2011 was an unrealized loss of $9 million (2010 – unrealized loss of $6 million). The change in the fair value of inventory resulted in an unrealized loss of $3 million in 2011 (2010 – unrealized loss of $51 million) which has been recorded in other – net in the consolidated statements of income.

c) Oil Contracts

The Company designated certain crude oil purchase and sale derivative contracts as fair value hedges against the changes in the fair value of the inventory held in storage. The assessment of effectiveness for the fair value hedges excludes changes between current market prices and market prices on the settlement date in the future.

At December 31, 2011, the Company had the following third party crude oil purchase and sale derivative contracts which have been designated as a fair value hedge:

	Volumes *(bbls)*	Fair Value *($ millions)*
Physical purchase contracts	146,397	(8)

These contracts have been recorded at their fair value in accrued liabilities and the resulting unrealized loss of $8 million for the year ended December 31, 2011 (2010 – unrealized gain of $2 million) has been recorded in purchases of crude oil and products. The crude oil inventory held during the refining process is recorded at fair value. At December 31, 2011, the fair value of the inventory was $16 million (December 31, 2010 – $30 million; January 1, 2010 – $124 million), resulting in an unrealized gain of $2 million (2010 – unrealized loss of $2 million) recorded in purchases of crude oil and products for the year ended December 31, 2011.

The Company has entered into derivative contracts for future crude oil purchases, whereby there is a requirement to pay the market difference of the inventory price paid at delivery and the current market price at the settlement date in the future. The contracts have been recorded at fair value in accounts receivable and accrued liabilities. As at December 31, 2011, an unrealized loss related to these contracts of $7 million (2010 – unrealized loss of $1 million) was recorded in purchases of crude oil and products for the year ended December 31, 2011.

The Company enters into certain crude oil purchase and sale derivative contracts to minimize its exposure to fluctuations in the benchmark price between the time a sales agreement is entered into and the time inventory is delivered. The Company had the following crude oil contracts as at December 31, 2011:

	Volumes *(mbbls)*	Fair Value *($ millions)*
Physical purchase contracts	1,147	–
Physical sale contracts	(1,147)	–

These contracts have been recorded at their fair value in accounts receivable and accrued liabilities. At December 31, 2011, a resulting unrealized gain of $4 million for the year ended December 31, 2011 (2010 – unrealized loss of $8 million) was recorded in other – net in the consolidated statements of income. A portion of the crude oil inventory is sold to third parties. This inventory is considered held for realizing short term trading margins and as such, has been recorded at its fair value. At December 31, 2011, the fair value of inventory was $147 million (December 31, 2010 – $72 million; January 1, 2010 – nil), resulting in an unrealized gain of less than $1 million for the year ended December 31, 2011 (2010 – unrealized gain of $6 million) recorded in other – net in the consolidated statements of income.

d) Commodity Swaps

During the year ended December 31, 2011, the Company entered into third party commodity swaps. The Company had the following derivative contracts as at December 31, 2011:

	Volumes	Fair Value ($ millions)
Butane swap contracts *(tgal)*	1,260	–
Crude oil swap contracts *(mbbl)*	30	–

These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain of less than $1 million for the year ended December 31, 2011 (2010 – nil) has been recorded in other – net in the consolidated statements of income.

Interest Rate Risk Management

During the year ended December 31, 2011, the Company discontinued its fair value hedge designation using interest rate swap arrangements whereby the fixed interest rate coupon on the long-term debt was swapped to floating rates. These interest rate swap arrangements have been sold and derecognized during the year. Accordingly, the accrued gains on these interest rate swaps will be amortized over the remaining life of the underlying long term debt to which the hedging relationship was originally designated. The amortization period is two to five years.

During 2011, these swaps resulted in a reduction of finance expenses of $13 million (2010 – reduction of $23 million). The amortization of terminated interest rate swaps resulted in additional finance expenses of $8 million (2010 – addition of $2 million) for the year ended December 31, 2011. The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $9 million (2010 – $5 million).

Foreign Currency Risk Management

The Company manages its exposure to foreign exchange fluctuations by balancing the U.S. dollar denominated cash flows with U.S. dollar denominated borrowings and other financial instruments. The Company utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency.

At December 31, 2011, the Company had cash flow hedges using the following cross currency swaps:

Debt	Swap Amount (U.S.$ millions)	Canadian Equivalent ($ millions)	Swap Maturity	Interest Rate (percent)	Fair Value ($ millions)
6.25% notes	50	59	June 15, 2012	5.67	(8)
6.25% notes	75	89	June 15, 2012	5.65	(13)
6.25% notes	75	88	June 15, 2012	5.61	(11)
6.25% notes	150	211	June 15, 2012	7.41	(61)

These contracts have been recorded at their fair value of $93 million at December 31, 2011 in accounts payable and accrued liabilities (December 31, 2010 – $102 million in other long-term liabilities; January 1, 2010 – $96 million in other long-term liabilities). The effective portion of the gain or loss related to measuring the contract at fair value has been included in OCI. The foreign exchange on the translation of the swaps has been recorded in net earnings to offset the foreign exchange on the translation of the underlying debt and the remaining gain or loss is included in OCI. For the year ended December 31, 2011, the unrealized foreign exchange loss of less than $1 million (2010 – unrealized foreign exchange gain of $6 million), net of tax of less than $1 million (2010 – $2 million) was recorded in OCI. In 2011, this unrealized foreign exchange loss included the ineffective portion of the swaps that was recognized as a gain in other – net in the consolidated statements of income of $2 million (2010 – nil). At December 31, 2011, the balance in other reserves related to the derivatives designated as a cash flow hedge was less than $1 million (2010 – $8 million), net of tax of less than $1 million (2010 – $2 million). For the year ended December 31, 2011, the Company recognized an unrealized foreign exchange gain of $7 million (2010 – unrealized loss of $18 million) on the cross currency swaps.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars in order to hedge against the foreign exchange exposures from oil and natural gas revenues. Aside from offsetting unrealized gains or losses from oil and natural gas sales, these contracts had a resulting unrealized gain of $1 million (2010 – nil) based on changes in fair value recorded in other – net in the consolidated statements of income for the year ended December 31, 2011. For the year ended December 31, 2011, the impact of these contracts was a realized loss of $5 million (2010 – realized gain of $26 million) recorded in net foreign exchange gains and losses.

As at December 31, 2011, the Company had designated a portion of its U.S. denominated debt with a fair value of U.S. $1.3 billion (December 31, 2010 – U.S. $987 million) as a hedge of the Company's net investments in its U.S. refining operations. In 2011, the unrealized loss arising from the translation of the debt was $18 million (2010 – gain of $41 million), net of tax of $3 million (2010 – nil), which was recorded in OCI.

Sensitivity Analysis

A sensitivity analysis for foreign currency, commodities and interest rate risks has been calculated by increasing or decreasing commodity prices, interest rates or foreign currency exchange 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 *($ millions)*	10% price increase	10% price decrease
Crude oil price	6	(6)
Natural gas price	4	(4)

Interest Rate *($ millions)*	100 basis point increase	100 basis points decrease
LIBOR	–	–

Foreign Exchange Rate *($ millions)*	Canadian dollar $0.01 increase	Canadian dollar $0.01 decrease
U.S. dollar per Canadian dollar	(4)	5

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. 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 sufficient 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, 2011:

($ millions)	Available	Unused
Operating facilities[1]	465	215
Syndicated bank facilities	3,300	3,300
Bilateral credit facility[2]	100	100
	3,865	3,615

[1] *The operating facilities included $265 million of demand credit facilities and $200 million of committed credit facilities. The $200 million of committed credit facilities were increased to $250 million and converted to demand credit facilities in 2012.*
[2] *The $100 million bilateral credit facility was cancelled effective February 3, 2012.*

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 $1.4 billion and unused capacity under the universal short form base shelf prospectus filed in the United States of U.S. $2.0 billion. The unused capacity under the debt shelf prospectus filed in Canada of $300 million expired in January 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, 2011:

($ millions)	2012	2013	2014	2015	2016	Thereafter
Accounts payable and accrued liabilities	2,867	–	–	–	–	–
Other long-term liabilities	20	43	43	30	1	25
Long-term debt	407	–	779	306	208	2,211

The Company's contribution payable to the joint arrangement with BP (refer to Note 8) is payable between December 31, 2011 and December 31, 2015, with the final balance due and payable by December 31, 2015. Refer to Note 20 for additional contractual obligations.

Credit Risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial instrument, in owing an amount to the Company, fail to meet or discharge their obligation to the Company. 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, 2011 or 2010, 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 amount of accounts receivable and cash and cash equivalents represents the Company's maximum credit exposure.

The Company's accounts receivable was aged as follows at December 31, 2011:

($ millions)	**2011**
Current	**1,136**
Past due (1 – 30 days)	**81**
Past due (31 – 60 days)	**11**
Past due (61 – 90 days)	**7**
Past due (more than 90 days)	**23**
Allowance for doubtful accounts	**(23)**
	1,235

The Company recognizes an offsetting 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, 2011, the Company impaired $3 million (2010 – $2 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, 2011 was $21.7 billion (December 31, 2010 – $18.8 billion; January 1, 2010 – $16.9 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors 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 cash flow ratio of 1.5 to 2.5 times and a debt to capital employed target of 25% to 35%. At December 31, 2011, debt to capital employed was 18% (December 31, 2010 – 22%) 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, 2011, debt to cash flow was 0.8 times (December 31, 2010 – 1.4 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 bilateral credit facility included and the syndicated credit facilities include a debt to cash flow covenant. The Company was fully compliant with these covenants at December 31, 2011.

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 2011, the Company received $38 million (2010 – $50 million) under these programs. The grants accrued for operational purposes have been recorded as revenues in the consolidated statements of income.

Note 25 Subsequent Events

Reclassification of Segmented Financial Information

During the first quarter of 2012, the Company began evaluating and reporting the activities of the Midstream segment as a service provider to the Upstream and Downstream operations. Executive management has organized their assessment of the services of the Midstream segment and allocated such activities to the Company's core exploration and production, upgrading and refining businesses. This integration is consistent with the Company's strategic view of its business. In addition, the Company believes this change in segment presentation allows management and third parties to more effectively assess its performance against industry peers, who have similar approaches to evaluating and reporting their midstream operations. As a result, commencing in 2012, the segmented financial information for activities within the previously reported Midstream segment will be presented under the Upstream and Downstream segments to align with how the Company's results are assessed by management.

If the reclassification of the segmented financial information were to have occurred in 2011, the 2010 and 2011 segmented financial information would have been reclassified to reflect this change as follows:

Segmented Financial Information – Reclassified

	Upstream			
	Exploration and Production[1]		Infrastructure and Marketing	
Year ended December 31 ($ millions)	**2011**	2010	**2011**	2010
Gross revenues	**7,519**	6,021	**4,446**	2,883
Royalties	**(1,125)**	(978)	**–**	–
Revenues, net of royalties	**6,394**	5,043	**4,446**	2,883
Expenses				
Purchases of crude oil and products	**99**	97	**4,180**	2,634
Production and operating expenses	**1,714**	1,474	**43**	92
Selling, general and administrative expenses	**153**	155	**17**	14
Depletion, depreciation, amortization and impairment	**2,018**	1,539	**24**	25
Exploration and evaluation expenses	**470**	438	**–**	–
Other – net	**(261)**	1	**8**	34
Earnings (loss) from operating activities	**2,201**	1,339	**174**	84
Financial items				
Net foreign exchange gains (losses)	**–**	–	**–**	–
Finance income	**4**	–	**–**	–
Finance expenses	**(68)**	(40)	**–**	–
Earnings (loss) before income taxes	**2,137**	1,299	**174**	84
Provisions for (recovery of) income taxes				
Current	**41**	2	**64**	24
Deferred	**515**	372	**(20)**	(1)
Total income tax provision (recovery)	**556**	374	**44**	23
Net earnings (loss)	**1,581**	925	**130**	61
Intersegment revenues	**2,651**	2,406	**–**	–
Other material non-cash items				
Unrealized loss on gas storage contracts	**–**	–	**(11)**	(32)
Gain on sale of assets	**261**	2	**–**	–
Exploration and evaluation assets	**746**	472	**–**	–
Developing and producing assets at cost	**33,640**	29,144	**–**	–
Accumulated depletion, depreciation and amortization	**(15,900)**	(13,919)	**–**	–
Other property, plant and equipment at cost	**48**	153	**882**	916
Accumulated depletion, depreciation and amortization	**(27)**	(68)	**(380)**	(381)
Exploration and evaluation assets and property, plant and equipment, net	**18,507**	15,782	**502**	535
Expenditures on property, plant and equipment – Year ended December 31[3]	**3,771**	2,211	**–**	–
Expenditures on exploration and evaluation assets – Year ended December 31[3]	**403**	641	**–**	–
Total Assets – As at December 31	**20,141**	17,439	**1,509**	1,230

[1] *Includes allocated depletion, depreciation and amortization 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 year. Includes assets acquired through acquisitions.*

Downstream						Corporate and Eliminations[2]		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing					
2011	2010	2011	2010	2011	2010	2011	2010	2011	2010
2,217	1,570	3,877	2,975	9,752	7,318	(3,322)	(2,682)	24,489	18,085
–	–	–	–	–	–	–	–	(1,125)	(978)
2,217	1,570	3,877	2,975	9,752	7,318	(3,322)	(2,682)	23,364	17,107
1,586	1,259	3,265	2,498	8,453	6,762	(3,319)	(2,670)	14,264	10,580
188	181	182	181	391	377	–	4	2,518	2,309
3	–	49	49	12	12	194	61	428	291
164	74	80	88	195	191	38	75	2,519	1,992
–	–	–	–	–	–	–	–	470	438
67	(41)	–	(2)	–	–	(3)	(7)	(189)	(15)
209	97	301	161	701	(24)	(232)	(145)	3,354	1,512
–	–	–	–	–	–	10	(49)	10	(49)
–	–	–	–	–	–	82	79	86	79
(7)	(9)	(6)	(2)	(4)	(6)	(225)	(268)	(310)	(325)
202	88	295	159	697	(30)	(365)	(383)	3,140	1,217
(2)	1	25	56	76	–	150	105	354	188
54	25	50	(14)	178	(12)	(215)	(288)	562	82
52	26	75	42	254	(12)	(65)	(183)	916	270
150	62	220	117	443	(18)	(300)	(200)	2,224	947
504	125	167	151	–	–	–	–	3,322	2,682
–	–	–	–	–	–	–	–	(11)	(32)
–	–	–	–	–	–	–	–	261	2
–	–	–	–	–	–	–	–	746	472
–	–	–	–	–	–	–	–	33,640	29,144
–	–	–	–	–	–	–	–	(15,900)	(13,919)
1,972	1,974	2,208	2,085	4,325	4,001	557	487	9,992	9,616
(848)	(742)	(1,007)	(929)	(759)	(551)	(432)	(400)	(3,453)	(3,071)
1,124	1,232	1,201	1,156	3,566	3,450	125	87	25,025	22,242
55	182	94	244	224	256	71	37	4,215	2,930
–	–	–	–	–	–	–	–	403	641
1,316	1,989	1,632	1,525	5,476	5,092	2,352	775	32,426	28,050

Note 26 First-Time Adoption of International Financial Reporting Standards

The accounting policies in Note 3 have been applied in preparing the consolidated financial statements for the year ended December 31, 2010, the balance sheets as at December 31, 2010 and the preparation of an opening IFRS balance sheet on the transition date, January 1, 2010.

The consolidated financial statements for the year ended December 31, 2010, and the January 1, 2010 opening balance sheet on transition to IFRS have been adjusted from the amounts previously reported in accordance with Canadian GAAP.

An explanation of how the transition from Canadian GAAP to IFRS has affected the Company's financial position and financial performance is set out in the following tables.

Key First-Time Adoption Exemptions Applied

IFRS 1, "First-Time Adoption of International Financial Reporting Standards," allows first-time adopters certain exemptions from retrospective application of certain IFRSs.

The Company applied the following exemptions:

- Certain oil and gas assets in property, plant and equipment on the consolidated balance sheets were recognized and measured on a full cost basis in accordance with Canadian GAAP. The Company elected to measure its Canadian properties at the amount determined under Canadian GAAP as at January 1, 2010. Costs included in the full cost pool on January 1, 2010 were allocated on a pro-rata basis to the underlying assets on the basis of proved developed reserve volumes as at January 1, 2010. Associated decommissioning assets were also measured at their carrying value under Canadian GAAP while all decommissioning liabilities were measured using a consistent credit-adjusted risk free rate, with a corresponding adjustment recorded to opening retained earnings. The Company elected not to apply the IFRS 1 full cost exemption to its international upstream properties.
- IFRS 3, "Business Combinations," was not applied to acquisitions of subsidiaries or interests in joint ventures that occurred before January 1, 2010.
- The Company elected to apply IAS 23, "Borrowing Costs," with an effective date of January 1, 2003 which required mandatory capitalization of borrowing costs directly attributable to the acquisition, construction or production of qualifying assets. De-recognition of previously capitalized borrowing costs in accordance with Canadian GAAP did not have a material impact to the Company.
- The Company recognized all cumulative actuarial gains and losses on pensions and other post-retirement benefits in retained earnings as at January 1, 2010.
- Cumulative currency translation differences for all foreign operations were deemed to be zero as at January 1, 2010. Accordingly, all cumulative foreign exchange gains and losses in the Company's cumulative foreign currency translation account were recognized in retained earnings at January 1, 2010.
- IFRS 2, "Share-based Payment," was not applied to equity instruments related to stock-based compensation arrangements that were granted on or before November 7, 2002, and was not applied to equity instruments granted after November 7, 2002 that vested before January 1, 2010. For cash-settled share-based payment transactions, the Company did not apply IFRS 2 to liabilities that were settled before January 1, 2010.
- The Company did not reassess arrangements to determine whether they contained a lease if they had already been assessed under Canadian GAAP. Additionally, any arrangements that were not assessed under Canadian GAAP were assessed under International Financial Reporting Issues Committee ("IFRIC") Interpretation 4, "Determining Whether an Arrangement Contains a Lease," based on terms and conditions existing at January 1, 2010.

Reconciliation of Equity at January 1, 2010

($ millions)	Canadian GAAP	Effects of Transition to IFRS	IFRS
Assets			
Current assets			
Cash and cash equivalents	392	–	392
Accounts receivable	964	–	964
Income taxes receivable	23	–	23
Inventories	1,520	–	1,520
Prepaid expenses	12	–	12
	2,911	–	2,911
Exploration and evaluation assets *(notes a, d, j)*	–	1,943	1,943
Property, plant and equipment *(notes a, c, d, e, f, h)*	21,288	(2,704)	18,584
Goodwill	689	–	689
Contribution receivable	1,313	–	1,313
Other assets *(note b)*	94	(26)	68
Total Assets	26,295	(787)	25,508
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes d, f, g)*	1,915	26	1,941
Income taxes payable	270	–	270
Asset retirement obligations	29	–	29
	2,214	26	2,240
Long-term debt	3,229	–	3,229
Other long-term financial liabilities	96	–	96
Other long-term liabilities *(notes b, c, d, g, i)*	147	137	284
Contribution payable	1,500	–	1,500
Deferred tax liabilities *(note l)*	3,932	(227)	3,705
Asset retirement obligations *(notes d, f)*	764	(26)	738
Total Liabilities	11,882	(90)	11,792
Shareholders' equity			
Common shares	3,585	–	3,585
Retained earnings *(note m)*	10,832	(733)	10,099
Other reserves *(note d)*	(4)	36	32
Total Shareholders' Equity	14,413	(697)	13,716
Total Liabilities and Shareholders' Equity	26,295	(787)	25,508

Reconciliation of Equity at December 31, 2010

($ millions)	Canadian GAAP	Effects of Transition to IFRS	IFRS
Assets			
Current assets			
Cash and cash equivalents	252	–	252
Accounts receivable	1,183	–	1,183
Income taxes receivable	346	–	346
Inventories	1,935	–	1,935
Prepaid expenses	34	–	34
	3,750	–	3,750
Exploration and evaluation assets *(notes a, d, j)*	–	472	472
Property, plant and equipment *(notes a, c, d, e, f, h, j)*	23,299	(1,529)	21,770
Goodwill	663	–	663
Contribution receivable	1,284	–	1,284
Other assets *(note b)*	137	(26)	111
Total Assets	29,133	(1,083)	28,050
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities *(notes d, f, g)*	2,494	12	2,506
Asset retirement obligations	63	–	63
	2,557	12	2,569
Long-term debt	4,187	–	4,187
Other long-term financial liabilities	102	–	102
Other long-term liabilities *(notes b, c, d, g, i)*	165	124	289
Contribution payable	1,427	–	1,427
Deferred tax liabilities *(note l)*	4,115	(348)	3,767
Asset retirement obligations *(notes d, f)*	1,087	48	1,135
Total Liabilities	13,640	(164)	13,476
Shareholders' equity			
Common shares	4,574	–	4,574
Retained earnings *(note m)*	10,985	(973)	10,012
Other reserves *(note d)*	(66)	54	(12)
Total Shareholders' Equity	15,493	(919)	14,574
Total Liabilities and Shareholders' Equity	29,133	(1,083)	28,050

Reconciliation of Comprehensive Income for the Year ended December 31, 2010

($ millions)	Canadian GAAP *(Recasted)*	Effects of Transition to IFRS	IFRS
Gross revenues, net of royalties *(notes d, k, p)*	18,939	(854)	18,085
Royalties	(978)	–	(978)
Revenues, net of royalties	17,961	(854)	17,107
Expenses			
Purchases of crude oil and products *(notes d, k, p)*	11,434	(854)	10,580
Production and operating expenses	2,309	–	2,309
Selling, general and administrative expenses *(notes d, g)*	305	(14)	291
Depletion, depreciation and amortization *(notes a, c, d, e, h)*	2,073	(81)	1,992
Exploration and evaluation expenses *(note d)*	–	438	438
Other – net *(notes f, h, i)*	23	(38)	(15)
	16,144	(549)	15,595
Earnings from operating activities	1,817	(305)	1,512
Financial items			
Net foreign exchange gains (losses) *(note d)*	2	(51)	(49)
Finance income	79	–	79
Finance expenses *(notes d, f, j, i)*	(340)	15	(325)
	(259)	(36)	(295)
Earnings before income taxes	1,558	(341)	1,217
Provisions for income taxes			
Current	188	–	188
Deferred *(note l)*	197	(115)	82
	385	(115)	270
Net earnings	1,173	(226)	947
Other comprehensive income (loss)			
Derivatives designated as cash flow hedges, net of tax	6	–	6
Actuarial gains (losses) on pension plans, net of tax *(note b)*	–	(14)	(14)
Exchange differences on translation of foreign operations *(note d)*	(112)	21	(91)
Hedge of net investment, net of tax *(note d)*	44	(3)	41
Comprehensive income	1,111	(222)	889

Notes to the Reconciliations of Equity and Comprehensive Income from Canadian GAAP to IFRS

a) IFRS 6 Adjustments – Exploration for and Evaluation of Mineral Resources

i) Accounting for Oil and Gas Properties

Under Canadian GAAP, the Company followed the full cost method of accounting for oil and gas interests whereby all costs of acquisition, exploration for and development of oil and gas reserves were capitalized and accumulated within cost centres on a country-by-country basis. Depletion of oil and gas properties was calculated using the unit-of-production method based on proved oil and gas reserves for each cost centre. Under IFRS, pre-exploration and evaluation costs, which includes all exploratory costs incurred prior to the acquisition of the legal right to explore, are expensed as incurred. After the legal right to explore is acquired, land acquisition costs and expenditures directly associated with exploratory wells are capitalized as exploration and evaluation assets. Geological and geophysical and other exploration costs are immediately recognized in exploration and evaluation expenses. Land acquisition costs remain capitalized until the Company has chosen to discontinue all exploration activities in the associated area. Land acquisition costs associated with successful exploration are reclassified into property, plant and equipment. Exploratory wells remain capitalized until the drilling operation is complete and the results have been evaluated. If the well does not encounter reserves of a commercial quantity, either on its own or in combination with other exploration wells associated with the same area of exploration, the costs of drilling the well or wells are written-off to exploration and evaluation expenses. Wells that result in commercial quantities of reserves remain capitalized and are reclassified into property, plant, and equipment.

The Company elected to apply the IFRS 1 exemption for its Canadian oil and gas assets. For international cost centres where the Company elected not to apply the IFRS 1 deemed cost exemption, previously capitalized costs related to unsuccessful exploration drilling, geological and geophysical expenditures, exploratory seismic and lease rental expenses were recorded as a reduction to property, plant and equipment and opening retained earnings upon adoption of IFRS 6. As a result, inception to January 1, 2010 exploration activities that were expensed under IFRS totalled $516 million. For the year ended December 31, 2010, exploration and evaluation expenses totalled $438 million.

ii) Depletion Expense

The application of IFRS oil and gas accounting policies resulted in differences in the carrying costs subject to depletion under IFRS as compared to full cost accounting. Additionally, differences in depletion arose from the determination of depletion at the field level under IFRS versus a country level under full cost accounting. For the year ended December 31, 2010, the Company recognized reduced depletion, depreciation and amortization of $173 million under IFRS when compared to full cost accounting for international oil and gas properties and increased depletion, depreciation and amortization of $129 million under IFRS when compared to full cost accounting for Canadian oil and gas properties. This net reduction in depletion, depreciation and amortization is explained in part due to the opening adjustment to international oil and gas assets as described above.

iii) Exploration and Evaluation Assets

Under IFRS 6, management has assessed the classification of activities designated as exploratory or developmental, which then determines the appropriate accounting treatment and classification of the costs incurred. For capitalized costs associated with exploratory activities, the Company presented these costs separately on the consolidated balance sheet. Costs totalling $1,939 million as at January 1, 2010 and $477 million as at December 31, 2010 were reclassified from property, plant, and equipment to exploration and evaluation assets.

The total impact of this change decreased (increased) retained earnings as follows:

Consolidated Statement of Comprehensive Income *($ millions)*	2010
Increase in exploration and evaluation expenses	438
Decrease in depletion, depreciation and amortization	(44)
Adjustment before income taxes	394

Consolidated Balance Sheets *($ millions)*	January 1, 2010	December 31, 2010
Increase in exploration and evaluation assets	(1,939)	(477)
Decrease in property, plant and equipment	2,455	1,387
Decrease in retained earnings	516	910

b) IAS 19 Adjustments – Employee Benefits

IAS 19 allows the Company to recognize the unamortized net actuarial loss and past service costs for its defined benefit pension plans immediately in OCI. Canadian GAAP required amortization of these losses and costs to net earnings over the estimated average remaining service life, with disclosure of the total cumulative unrecognized amount in the notes to the consolidated financial statements. Upon adoption of IAS 19 at January 1, 2010, the Company recognized a decrease of $65 million and an increase of $12 million in opening retained earnings related to the Company's cumulative unrecognized actuarial losses and past service cost recoveries, respectively. For the year ended December 31, 2010, a charge to OCI of $20 million (before taxes of $6 million) was recorded in retained earnings representing an unamortized net actuarial loss for the year.

The total impact of this change decreased (increased) retained earnings as follows:

Consolidated Statement of Comprehensive Income *($ millions)*	2010
Decrease in other comprehensive income, before income taxes	20
Adjustment before income taxes	20

Consolidated Balance Sheets *($ millions)*	January 1, 2010	December 31, 2010
Decrease in other assets	26	26
Increase in other long-term liabilities	27	47
Decrease in retained earnings	53	73

c) IAS 20 Adjustments – Government Grants

Under IAS 20, government grants are recognized when there is reasonable assurance that the entity will comply with the conditions attached to them and the grants will be received. Under Canadian GAAP, government grants were recognized when received. The Company received government grants for the expansion of its ethanol plants which are subject to repayments dependent on the profitability of its operations as assessed annually until 2015. The Company does not have reasonable assurance of the amounts repayable on the grants until the repayment requirements are fulfilled. At January 1, 2010, the Company de-recognized these government grants until reasonable assurance of the measurement of repayments is determinable which increased property, plant, and equipment and other long-term liabilities by $15 million as at January 1, 2010 and December 31, 2010. The reclassification from property, plant, and equipment would have resulted in increased depletion, depreciation and amortization of $2 million from inception to January 1, 2010; this amount was recorded as a reduction of property, plant, and equipment and opening retained earnings. For the year ended December 31, 2010, the reclassification of government grants increased depletion, depreciation and amortization by less than $1 million.

d) IAS 21 Adjustments – The Effects of Changes in Foreign Exchange Rates

Under IFRS, the functional currency of an entity is determined by focusing on the primary economic environment in which it operates with lesser precedence being placed on factors regarding the financing from and operational involvement of the reporting entity which consolidates the entity in its financial statements. Under Canadian GAAP, equal precedence was placed on all factors. The effect of this change to IFRS resulted in two entities having a different functional currency than the Company's functional currency. As such, the translation of the results and balance sheets of the foreign operations into the Company's presentation currency required a translation of all assets and liabilities at the closing rate at each reporting date with all resulting foreign exchange gains or losses recognized in OCI. Revenues and expenses of foreign operations were translated using average monthly foreign exchange rates, which approximate the foreign exchange rates on the dates of the transactions with foreign exchange differences recognized in OCI. The retrospective application of IAS 21 resulted in a cumulative foreign currency exchange loss on revaluation of $29 million as at January 1, 2010 which was recognized in other reserves prior to applying the IFRS 1 exemption.

The Company elected to utilize the IFRS 1 exemption to deem all foreign currency translation differences of $36 million that arose prior to the date of transition with respect to all foreign operations to be nil at the date of transition. The Company reversed the balance of exchange differences on translation of foreign operations within other reserves and recorded a decrease to opening retained earnings of $65 million.

For the year ended December 31, 2010, net foreign exchange losses of $53 million and gains of $21 million were attributed to the above mentioned entities that were assessed as having a different functional currency than the Company's functional currency under IFRS; these amounts were reclassified from net earnings and OCI, respectively.

For the year ended December 31, 2010, the Company reclassified $3 million of foreign exchange gains on translation of its foreign operations from other reserves to net earnings under Canadian GAAP. Under IFRS, this reclassification is not required until the foreign operation is partially or fully disposed. The Company recorded increased net foreign exchange gains and reduced OCI of $3 million under IFRS for the year ended December 31, 2010.

The impact of this change decreased (increased) retained earnings as follows:

Consolidated Statement of Comprehensive Income *($ millions)*	2010
Decrease in gross revenues	2
Decrease in purchases of crude oil and other products	(2)
Decrease in selling, general and administrative expenses	(1)
Decrease in depletion, depreciation and amortization	(1)
Decrease in net foreign exchange gains	51
Increase in finance expenses	1
Adjustment before income taxes	50

Consolidated Balance Sheets *($ millions)*	January 1, 2010	December 31, 2010
Decrease in exploration and evaluation assets	39	11
Decrease (increase) in property, plant and equipment	(4)	58
Increase in accounts payable and other accrued liabilities	3	–
Decrease in asset retirement obligations	(9)	(8)
Decrease in retained earnings	65	115
Increase in other reserves	(36)	(54)

e) IAS 36 Adjustments – Impairment of Assets

Under Canadian GAAP, impairment of long-lived assets was assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment was indicated, discounted cash flows were prepared to quantify the amount of the impairment. Under IFRS, impairment is assessed based on discounted cash flows compared with the asset's carrying amount to determine the recoverable amount and measure the amount of the impairment. In addition, under IFRS, where a long-lived asset does not generate largely independent cash inflows, the Company is required to perform its test at the cash generating unit level, which is the smallest identifiable grouping of assets that generates largely independent cash inflows. Canadian GAAP impairment was based on undiscounted cash flows using asset groupings with both independent cash inflows and cash outflows.

With the adoption of IAS 36, the Company recorded impairments on its ethanol plants decreasing property, plant, and equipment by $91 million as at January 1, 2010 based on their recoverable amounts using a FVLCS valuation based on a 39-year cash flow projection discounted at a pre-tax rate of 11%. For the year ended December 31, 2010, the recognition of these impairments under IFRS resulted in reduced depletion, depreciation and amortization of $3 million.

The adoption of IAS 36 and application of the full cost exemption also resulted in an impairment of the carrying value of oil and gas properties in the East Central Alberta and Foothills West districts decreasing property, plant, and equipment by $66 million as at January 1, 2010. The recoverable amounts were based on FVLCS valuations using proved plus probable reserve life discounted

at pre-tax rates ranging from 13% to 14%. For the year ended December 31, 2010, the recognition of these impairments under IFRS resulted in reduced depletion, depreciation and amortization of $7 million.

The impact of this change decreased (increased) retained earnings as follows:

Consolidated Statement of Comprehensive Income *($ millions)*	2010
Decrease in depletion, depreciation and amortization	(10)
Adjustment before income taxes	(10)

Consolidated Balance Sheets *($ millions)*	January 1, 2010	December 31, 2010
Decrease in property, plant and equipment	157	147
Decrease in retained earnings	157	147

f) IAS 37 Adjustments – Provisions, Contingent Liabilities and Contingent Assets

i) Asset Retirement Obligations

Consistent with IFRS, decommissioning provisions (ARO) were measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to net present value upon initial recognition. Under IAS 37, ARO continues to be discounted using a credit-adjusted risk free rate; however, the liability is required to be re-measured based on changes in estimates including discount rates.

For ARO associated with Canadian oil and gas properties where the IFRS 1 exemption was utilized, the Company re-measured ARO as at January 1, 2010 under IAS 37 with a corresponding adjustment to opening retained earnings. The carrying values of Canadian oil and gas assets associated with ARO under Canadian GAAP were not adjusted on transition to IFRS. This resulted in a decrease in ARO and an increase in opening retained earnings of $13 million as at January 1, 2010. Accordingly, for the year ended December 31, 2010, the Company recorded reduced accretion of $3 million under IFRS. At December 31, 2010, the Company re-measured the ARO based on a change in the discount rate from 6.4% to 6.2% which increased property, plant, and equipment and ARO by $66 million.

The total impact of this change to ARO of Canadian oil and gas assets subject to the IFRS 1 exemption decreased (increased) retained earnings as follows:

Consolidated Statement of Comprehensive Income *($ millions)*	2010
Decrease in finance expenses	(3)
Adjustment before income taxes	(3)

Consolidated Balance Sheets *($ millions)*	January 1, 2010	December 31, 2010
Increase in property, plant and equipment	–	(66)
Increase (decrease) in asset retirement obligations	(13)	50
Increase in retained earnings	(13)	(16)

For asset retirement obligations associated with international oil and gas assets and midstream, downstream and corporate assets that were not subject to the IFRS 1 exemption, a retrospective application of IAS 37 was performed. This resulted in an increase in net property, plant, and equipment of $38 million as at January 1, 2010 and an incremental increase of $11 million for the year ended December 31, 2010. Asset retirement obligations decreased by $4 million as at January 1, 2010 and increased by an incremental $10 million for the year ended December 31, 2010. For the year ended December 31, 2010, the Company recorded reduced accretion of $1 million in pre-tax finance expenses.

The total impact of this change to asset retirement obligations associated with international oil and gas assets and midstream, downstream and corporate assets decreased (increased) retained earnings as follows:

Consolidated Statement of Comprehensive Income ($ millions)	2010
Decrease in finance expenses	(1)
Adjustment before income taxes	(1)

Consolidated Balance Sheets ($ millions)	January 1, 2010	December 31, 2010
Increase in property, plant, and equipment	(38)	(49)
Increase (decrease) in asset retirement obligations	(4)	6
Increase in retained earnings	(42)	(43)

Under Canadian GAAP, accretion of the asset retirement obligations was included in cost of sales and operating expenses; under IFRS, accretion is classified in finance expenses.

ii) Onerous Contracts

Under IAS 37, contracts that are deemed onerous are recognized as a present obligation when the unavoidable costs of meeting the obligations under the contract exceed the economic benefits expected to be received from the contract. There were no equivalent requirements under Canadian GAAP. The Company recorded a provision for a drilling rig commitment that was deemed onerous resulting in an increase in provisions of $1 million at January 1, 2010 with a corresponding decrease in retained earnings. The total provision for the year ended December 31, 2010 was $2 million recorded to accounts payable and accrued liabilities with a corresponding expense recorded to other – net.

g) IFRS 2 Adjustments – Share-based Payments

The Company has granted cash-settled share-based payments to certain employees in the past. Under IFRS, the related liability is adjusted to reflect the fair value of the outstanding cash-settled shared-based payment using an option pricing model. Canadian GAAP permitted share-based payments to be accounted for by reference to their intrinsic value.

The impact of this change decreased (increased) retained earnings as follows:

Consolidated Statement of Comprehensive Income ($ millions)	2010
Decrease in selling, general and administrative expenses	(13)
Adjustment before income taxes	(13)

Consolidated Balance Sheets ($ millions)	January 1, 2010	December 31, 2010
Increase in accounts payable and accrued liabilities	22	10
Increase in other long-term liabilities	10	9
Decrease in retained earnings	32	19

h) IAS 16 Adjustments – Property, Plant and Equipment

The Company reviewed the major components and useful lives of items of property, plant, and equipment. As a result of the retroactive treatment of component depreciation, the Company decreased property, plant and equipment by $144 million with an adjustment to opening retained earnings.

The Company also reviewed replacement of major components to determine if assets replaced prior to the end of their useful life required derecognition under IFRS. The Company determined that asset components with a net book value of $3 million required derecognition which was recorded as a decrease to opening retained earnings.

As a result of these adjustments, which reduced the net book value of assets on transition to IFRS, the Company recognized reduced pre-tax depletion, depreciation and amortization of $26 million for the year ended December 31, 2010. For the year ended December 31, 2010, the Company recognized $2 million on component disposals recorded as an expense to other – net.

The total impact of this change decreased (increased) retained earnings as follows:

Consolidated Statement of Comprehensive Income *($ millions)*	2010
Decrease in depletion, depreciation and amortization	(26)
Increase in other – net	2
Adjustment before income taxes	(24)

Consolidated Balance Sheets *($ millions)*	January 1, 2010	December 31, 2010
Decrease in property, plant and equipment	147	123
Decrease in retained earnings	147	123

i) IFRS 3 Adjustments – Business Combinations

Given that the Company elected to apply the IFRS 1 exemption which permits no adjustments to amounts recorded for acquisitions that occurred prior to January 1, 2010, no retrospective adjustments were required. The Company acquired the remaining interest in the Lloydminster Upgrader from the Government of Alberta in 1995 and is required to make payments to Natural Resources Canada and Alberta Department of Energy from 1995 to 2014 based on average differentials between heavy crude oil feedstock and the price of synthetic crude oil sales. Under IFRS, the Company is required to recognize this contingent consideration at its fair value as part of the acquisition and record a corresponding liability. Under Canadian GAAP, any contingent consideration was not required to be recognized unless amounts were resolved and payable on the date of acquisition. On transition to IFRS, Husky recognized a liability of $85 million, based on the fair value of remaining upside interest payments, with an adjustment to opening retained earnings. For the year ended December 31, 2010, the Company recognized pre-tax accretion of $9 million in finance expenses under IFRS. Changes in forecast differentials used to determine the fair value of the remaining upside interest payments resulted in the recognition of a pre-tax gain of $41 million for the year ended December 31, 2010.

The total impact of this change decreased (increased) retained earnings as follows:

Consolidated Statement of Comprehensive Income *($ millions)*	2010
Increase in finance expenses	9
Decrease in other – net	(41)
Adjustment before income taxes	(32)

Consolidated Balance Sheets *($ millions)*	January 1, 2010	December 31, 2010
Increase in other long-term liabilities	85	53
Decrease in retained earnings	85	53

j) IAS 23 Adjustments – Borrowing Costs

The Company elected to commence mandatory capitalization of borrowing costs for all major capital projects as at January 1, 2003, representing the date the Company commenced incurring capital expenditures on its Madura and Liwan projects, as permitted under IFRS 1. As a result, borrowing costs on major capital projects increased exploration and evaluation assets by $43 million as at January 1, 2010 with an adjustment to opening retained earnings.

During the year ended December 31, 2010, the major capital projects with capitalized borrowing costs under IFRS were transferred to the development phase and as a result $43 million of capitalized borrowing costs were reclassified to property, plant and equipment. Additionally, for the year ended December 31, 2010, the Company capitalized incremental borrowing costs of $6 million in exploration and evaluation assets and $15 million in property, plant, and equipment under IFRS with a corresponding adjustment to finance expenses.

The total impact of this change decreased (increased) retained earnings as follows:

Consolidated Statement of Comprehensive Income *($ millions)*	2010
Decrease in finance expenses	(21)
Adjustment before income taxes	(21)

Consolidated Balance Sheets *($ millions)*	January 1, 2010	December 31, 2010
Increase in exploration and evaluation assets	(43)	(6)
Increase in property, plant and equipment	–	(58)
Increase in retained earnings	(43)	(64)

k) IAS 18 Adjustments – Revenue

Under IFRS, realized and unrealized gains and losses on natural gas purchase and sale contracts are recorded on a net basis against sales and operating expenses. Under Canadian GAAP, these gains and losses were recorded on a gross basis. For the year ended December 31, 2010, the Company reclassified $852 million of losses on natural gas purchase contracts from purchases of crude oil and products to revenues.

l) IAS 12 Adjustments – Income Taxes

Nearly all recognized IFRS conversion adjustments as discussed in this transition note had related effects on deferred taxes. The tax impact of the above changes decreased (increased) the deferred tax liability as follows:

Consolidated Statement of Comprehensive Income *($ millions)*	2010
Exploration for and evaluation of mineral resources *(note a)*	114
Depletion of oil and gas properties *(note a)*	(11)
Employee benefits *(note b)*	6
Foreign currency translation *(note d)*	13
Impairment of assets *(note e)*	(3)
Asset retirement obligations *(note f)*	(1)
Share-based payments *(note g)*	(4)
Property, plant and equipment *(note h)*	(7)
Business combinations *(note i)*	(8)
Borrowing costs *(note j)*	(5)
Decrease in uncertain tax positions *(note l)*	27
Decrease in deferred tax expense	121

Consolidated Balance Sheets *($ millions)*	January 1, 2010	December 31, 2010
Exploration for and evaluation of mineral resources *(note a)*	154	268
Depletion of oil and gas properties *(note a)*	–	(11)
Employee benefits *(note b)*	16	22
Foreign currency translation *(note d)*	7	20
Impairment of assets *(note e)*	47	44
Asset retirement obligations *(note f)*	(16)	(17)
Share-based payments *(note g)*	10	6
Property, plant and equipment *(note h)*	44	37
Business combinations *(note i)*	25	17
Borrowing costs *(note j)*	(13)	(18)
Uncertain tax positions *(note l)*	(47)	(20)
Decrease in deferred tax liability	227	348

Under IFRS, the Company records and measures income tax uncertainties based on a single best estimate. Under Canadian GAAP the Company recorded uncertain tax positions if such positions were probable of being sustained. The impact of this change increased the deferred tax liability by $47 million as at January 1, 2010 and $20 million as at December 31, 2010 under IFRS.

For the year ended December 31, 2010, the Company recorded reduced deferred income tax expense of $115 million and $6 million which were recorded to net earnings and OCI, respectively.

m) Retained Earnings Adjustments

The above changes decreased (increased) retained earnings (each net of related tax) as follows:

($ millions)	2010
Exploration for and evaluation of mineral resources *(note a)*	324
Depletion of oil and gas properties *(note a)*	(33)
Employee benefits *(note b)*	14
Foreign currency translation *(note d)*	37
Impairment of assets *(note e)*	(7)
Asset retirement obligations *(note f)*	(3)
Provisions – onerous contracts *(note f)*	1
Share-based payments *(note g)*	(9)
Property, plant and equipment *(note h)*	(17)
Business combinations *(note i)*	(24)
Borrowing costs *(note j)*	(16)
Uncertain tax positions *(note l)*	(27)
Decrease in retained earnings	240

Consolidated Balance Sheets *($ millions)*	January 1, 2010	December 31, 2010
Exploration for and evaluation of mineral resources *(note a)*	362	686
Depletion of oil and gas properties *(note a)*	–	(33)
Employee benefits *(note b)*	37	51
Government grants *(note c)*	2	2
Foreign currency translation *(note d)*	58	95
Impairment of assets *(note e)*	110	103
Asset retirement obligations *(note f)*	(39)	(42)
Provisions – onerous contracts *(note f)*	1	2
Share-based payments *(note g)*	22	13
Property, plant and equipment *(note h)*	103	86
Business combinations *(note i)*	60	36
Borrowing costs *(note j)*	(30)	(46)
Uncertain tax positions *(note l)*	47	20
Decrease in retained earnings	733	973

n) Reclassifications

Certain amounts were reclassified to conform with current presentation.

o) Adjustments to the Company's Consolidated Statements of Cash Flow

As a result of Husky's changes to the accounting for oil and gas properties under IFRS, the consolidated statements of cash flows under IFRS compared to Canadian GAAP showed changes to both operating and investing cash flows.

p) Adjustments to the Company's Consolidated Statements of Income

In 2011, the Company changed its treatment of certain intersegment sales eliminations. Gross revenues and purchases of crude oil and products have been recast for 2010. The recasting reduced each of gross revenues and purchases of crude oil and products by $217 million and did not impact net earnings.

Supplemental Financial and Operating Information

Selected Ten-year Financial and Operating Summary

($ millions, except where indicated)	**2011**	2010	2009[1]	2008[1]	2007[1]	2006[1]	2005[1]	2004[1]	2003[1]	2002[1]
Financial Highlights										
Gross Revenues	**24,489**	18,085	15,935	26,744	16,583	13,478	11,085	9,151	8,242	6,844
Net earnings	**2,224**	947	1,416	3,751	3,201	2,734	1,996	1,001	1,374	794
Earnings per share										
Basic	**2.40**	1.11	1.67	4.42	3.77	3.21	2.35	1.18	1.64	0.95
Diluted	**2.34**	1.05	1.67	4.42	3.77	3.21	2.35	1.18	1.63	0.95
Expenditures on PP&E[2]	**4,618**	3,571	2,797	4,108	2,974	3,201	3,099	2,379	1,902	1,707
Total debt	**3,911**	4,187	3,229	1,957	2,814	1,611	1,886	2,204	2,094	2,740
Debt to capital employed *(percent)*[3]	**18**	22	18	12	19	14	20	26	27	37
Corporate reinvestment ratio *(percent)*[3]	**98**	134	111	66	86	71	80	112	92	79
Return on average capital employed *(percent)*[3]	**11.8**	6.4	9.1	25.1	25.6	27.1	22.7	13.0	18.9	12.3
Return on equity *(percent)*[3]	**13.8**	6.7	9.8	28.9	30.1	31.9	29.2	17.0	26.5	17.9
Upstream										
Daily production, before royalties										
Light crude oil & NGL *(mbbls/day)*	**87.6**	80.4	89.1	122.9	138.7	111.0	64.6	66.2	71.6	65.4
Medium crude oil *(mbbls/day)*	**24.5**	25.4	25.4	26.9	27.1	28.5	31.1	35.0	39.2	44.8
Heavy crude oil *(mbbls/day)*	**74.5**	74.5	78.6	84.3	86.5	88.5	88.0	90.2	85.1	76.1
Bitumen *(mbbls/day)*	**24.7**	22.3	23.1	22.7	20.4	19.6	18.0	18.7	14.8	19.0
	211.3	202.6	216.2	256.8	272.7	247.6	201.7	210.1	210.7	205.3
Natural gas *(mmcf/day)*	**607**	507	542	594	623	672	680	689	611	569
Total production *(mboe/day)*	**312.5**	287.1	306.5	355.9	376.6	359.7	315.0	325.0	312.5	300.2
Total proved reserves, before royalties *(mmboe)*[4]	**1,172**	1,081	933	896	1,014	1,004	985	791	887	918
Midstream										
Pipeline throughput *(mbbls/day)*	**559**	512	514	507	501	475	474	492	484	457
Downstream										
Synthetic crude oil sales *(mbbls/day)*	**55.3**	54.1	61.8	58.7	53.1	62.5	57.5	53.7	63.6	59.3
Upgrading differential *($/bbl)*	**27.34**	14.52	11.89	28.77	30.73	26.16	30.70	17.79	12.88	10.81
Light oil products sales *(million litres/day)*	**9.5**	8.2	7.6	7.9	8.7	8.7	8.9	8.4	8.2	7.7
Asphalt products sales *(mbbls/day)*	**25.3**	24.1	22.6	24.0	21.8	23.4	22.5	22.8	22.0	20.8
Refinery throughput										
Prince George refinery *(mbbls/day)*	**10.6**	10.0	10.3	10.1	10.5	9.0	9.7	9.8	10.3	10.1
Lloydminster refinery *(mbbls/day)*	**28.1**	27.8	24.1	26.1	25.3	27.1	25.5	25.3	25.7	22.0
Refinery utilization *(percent)*	**92**	92	86	91	90	90	101	100	103	92

(1) *Results are reported in accordance with previous Canadian GAAP. Certain reclassifications have been made to conform with current presentation.*
(2) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*
(3) *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.*
(4) *Total proved reserves, before royalties for 2011 and 2010 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.*

Segmented Financial Information

	Upstream					Midstream					Downstream				
						Infrastructure and Marketing					Upgrading[1]				
($ millions)	**2011**	2010	2009[3]	2008[3]	2007[3]	**2011**	2010	2009[3]	2008[3]	2007[3]	**2011**	2010	2009[3]	2008[3]	2007[3]
Year ended December 31															
Gross revenues	**7,250**	5,744	5,313	9,932	7,287	**9,446**	7,002	6,984	13,544	10,217	**2,217**	1,570	1,572	2,435	1,524
Royalties	**(1,125)**	(978)	(861)	(2,043)	(1,065)	**–**	–	–	–	–	**–**	–	–	–	–
Revenues, net of royalties	**6,125**	4,766	4,452	7,889	6,222	**9,446**	7,002	6,984	13,544	10,217	**2,217**	1,570	1,572	2,435	1,524
Expenses															
Purchases of crude oil and products and production and operating expenses	**1,672**	1,403	1,425	1,561	1,251	**9,041**	6,684	6,655	13,177	9,826	**1,769**	1,439	1,461	2,053	1,146
Selling, general and administrative expenses	**150**	152	70	66	57	**25**	22	14	15	12	**3**	–	–	–	–
Depletion, depreciation, amortization and impairment	**1,996**	1,521	1,397	1,505	1,615	**46**	43	36	31	28	**164**	74	34	31	25
Exploration and evaluation expenses	**470**	438	–	–	–	**–**	–	–	–	–	**–**	–	–	–	–
Other – net	**(259)**	1	–	–	–	**6**	34	–	–	–	**67**	(41)	–	–	–
Net financial items	**64**	40	–	–	–	**–**	–	–	–	–	**7**	9	–	–	–
	4,093	3,555	2,892	3,132	2,923	**9,118**	6,783	6,705	13,223	9,866	**2,010**	1,481	1,495	2,084	1,171
Earnings (loss) before income taxes	**2,032**	1,211	1,560	4,757	3,299	**328**	219	279	321	351	**207**	89	77	351	353
Current income taxes (recoveries)	**2**	(23)	909	585	122	**121**	62	101	126	68	**–**	1	111	84	10
Future income taxes (reductions)	**528**	373	(462)	795	581	**(39)**	(3)	(22)	(29)	30	**54**	25	(88)	21	75
Net earnings (loss)	**1,502**	861	1,113	3,377	2,596	**246**	160	200	224	253	**153**	63	54	246	268
Total assets - As at December 31	**20,117**	17,354	16,338	15,653	14,395	**1,543**	1,325	1,712	1,486	1,134	**1,315**	1,987	1,427	1,322	1,377

(1) *In 2011, the Company commenced evaluating and reporting Upgrading activities as part of Downstream operations. As a result, Upgrading was moved from the Midstream to the Downstream segment. All prior periods have been reclassified to conform to these segment definitions.*

(2) *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.*

(3) *Results are reported in accordance with previous Canadian GAAP. Certain reclassifications have been made to conform with current presentation.*

Downstream										Corporate and Eliminations[2]					Total				
Canadian Refined Products					U.S. Refining and Marketing														
2011	2010	2009[3]	2008[3]	2007[3]	**2011**	2010	2009[3]	2008[3]	2007[3]	**2011**	2010	2009[3]	2008[3]	2007[3]	**2011**	2010	2009[3]	2008[3]	2007[3]
3,860	2,975	2,495	3,564	2,916	**9,593**	7,107	5,349	7,802	2,383	**(7,877)**	(6,313)	(5,778)	(10,533)	(7,744)	**24,489**	18,085	15,935	26,744	16,583
–	–	–	–	–	**–**	–	–	–	–	**–**	–	–	–	–	**(1,125)**	(978)	(861)	(2,043)	(1,065)
3,860	2,975	2,495	3,564	2,916	**9,593**	7,107	5,349	7,802	2,383	**(7,877)**	(6,313)	(5,778)	(10,533)	(7,744)	**23,364**	17,107	15,074	24,701	15,518
3,430	2,679	2,174	3,308	2,583	**8,694**	6,935	4,955	8,278	2,167	**(7,824)**	(6,251)	(5,821)	(10,757)	(7,676)	**16,782**	12,889	10,849	17,620	9,297
49	49	30	32	24	**7**	7	2	2	–	**194**	61	158	177	134	**428**	291	274	292	227
80	88	93	81	66	**195**	191	194	154	47	**38**	75	51	30	25	**2,519**	1,992	1,805	1,832	1,806
–	–	–	–	–	**–**	–	–	–	–	**–**	–	–	–	–	**470**	438	–	–	–
–	(2)	–	–	–	**–**	–	–	–	–	**(3)**	(7)	–	–	–	**(189)**	(15)	–	–	–
6	2	–	–	–	**4**	6	3	3	1	**133**	238	186	(191)	78	**214**	295	189	(188)	79
3,565	2,816	2,297	3,421	2,673	**8,900**	7,139	5,154	8,437	2,215	**(7,462)**	(5,884)	(5,426)	(10,741)	(7,439)	**20,224**	15,890	13,117	19,556	11,409
295	159	198	143	243	**693**	(32)	195	(635)	168	**(415)**	(429)	(352)	208	(305)	**3,140**	1,217	1,957	5,145	4,109
25	56	38	28	17	**74**	–	3	(24)	28	**132**	92	100	102	102	**354**	188	1,262	901	347
50	(14)	19	11	33	**179**	(12)	68	(208)	35	**(210)**	(287)	(236)	(97)	(193)	**562**	82	(721)	493	561
220	117	141	104	193	**440**	(20)	124	(403)	105	**(337)**	(234)	(216)	203	(214)	**2,224**	947	1,416	3,751	3,201
1,623	1,517	1,430	1,375	1,332	**5,476**	5,092	4,771	5,380	3,058	**2,352**	775	617	1,270	370	**32,426**	28,050	26,295	26,486	21,666

Upstream Operating Information

	2011	2010	2009	2008	2007
Daily production, before royalties					
Light crude oil & NGL *(mbbls/day)*	**87.6**	80.4	89.1	122.9	138.7
Medium crude oil *(mbbls/day)*	**24.5**	25.4	25.4	26.9	27.1
Heavy crude oil *(mbbls/day)*	**74.5**	74.5	78.6	84.3	86.5
Bitumen *(mbbls/day)*	**24.7**	22.3	23.1	22.7	20.4
	211.3	202.6	216.2	256.8	272.7
Natural gas *(mmcf/day)*	**607.0**	506.8	541.7	594.4	623.3
Total production *(mboe/day)*	**312.5**	287.1	306.5	355.9	376.6
Average sales prices					
Light crude oil & NGL *($/bbl)*	**103.25**	76.90	62.70	97.28	73.54
Medium crude oil *($/bbl)*	**75.65**	64.92	56.37	81.79	51.12
Heavy crude oil *($/bbl)*	**66.99**	58.91	52.54	71.98	40.43
Bitumen *($/bbl)*	**64.34**	57.84	51.90	70.24	38.96
Natural gas *($/mcf)*	**3.55**	3.86	3.83	7.94	6.19
Operating costs *($/boe)*	**14.56**	13.35	11.82	10.93	9.09
Operating netbacks[1]					
Light crude oil *($/boe)*[2]	**69.61**	47.58	37.54	65.03	57.52
Medium crude oil *($/boe)*[2]	**41.76**	36.88	32.08	50.40	27.61
Heavy crude oil *($/boe)*[2]	**39.63**	34.51	31.58	47.22	23.84
Bitumen *($/boe)*[2]	**36.64**	28.96	28.46	36.89	14.09
Natural gas *($/mcfge)*[3]	**1.76**	1.93	2.08	5.02	3.80

(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.*

Western Canada and Oil Sands Wells Drilled

		2011		2010		2009		2008		2007	
		Gross	**Net**	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration	Oil	**50**	**40**	60	51	18	9	80	70	79	79
	Gas	**24**	**24**	37	31	37	22	102	79	114	92
	Dry	**3**	**3**	8	8	7	6	27	23	14	12
		77	**67**	105	90	62	37	209	172	207	183
Development	Oil	**880**	**765**	815	722	315	278	685	578	571	530
	Gas	**57**	**42**	73	53	122	61	435	270	343	251
	Dry	**4**	**4**	10	9	7	7	36	36	31	29
		941	**811**	898	784	444	346	1,156	884	945	810
		1,018	**878**	1,003	874	506	383	1,365	1,056	1,152	993
Success ratio *(percent)*		**99**	**99**	98	98	97	97	95	94	96	96

Netback Analysis

	2011	2010	2009
Total Upstream			
Crude oil equivalent *($/boe)*[1]			
Sales volume (mboe/day)	**312.5**	287.1	306.5
Price received ($/boe)	**63.23**	54.25	47.42
Royalties ($/boe)	**9.87**	9.33	7.70
Operating costs ($/boe)[2]	**14.56**	13.35	11.83
Offshore transportation ($/boe)[3]	**0.26**	0.25	0.37
Netback ($/boe)	**38.54**	31.32	27.52
DD&A ($/boe)	**17.51**	14.52	12.48
Administration expenses and other ($/boe)[2]	**1.69**	0.48	0.75
Earnings before taxes	**19.34**	16.32	14.29
Lloydminster Heavy Oil			
Thermal Oil			
Thermal Heavy Oil			
Sales volumes (mbbls/day)	**17.4**	18.3	19.2
Price received ($/bbl)	**66.00**	58.34	52.47
Royalties ($/bbl)	**10.78**	9.84	8.26
Operating costs ($/bbl)[2]	**15.89**	14.15	11.95
Netback ($/bbl)	**39.33**	34.35	32.26
Non Thermal Oil			
Medium Oil			
Sales volumes (mbbls/day)	**2.3**	2.3	2.5
Price received ($/bbl)	**75.19**	65.49	57.48
Royalties ($/bbl)	**5.10**	4.64	3.92
Heavy Oil			
Sales volumes (mbbls/day)	**60.2**	59.8	64.6
Price received ($/bbl)	**67.03**	58.70	52.72
Royalties ($/bbl)	**7.81**	7.50	7.08
Natural Gas			
Sales volumes (mmcf/day)	**29.3**	34.4	34.9
Price received ($/mcf)	**3.44**	3.74	3.57
Royalties ($/mcf)	**0.27**	0.31	0.26
Non Thermal Oil Total (mboe/day)[1]			
Sales volumes (boe/day)	**67.4**	67.8	72.9
Price received ($/boe)	**63.95**	55.86	50.39
Royalties ($/boe)	**7.27**	6.93	6.54
Operating costs ($/boe)[2]	**18.55**	16.07	13.60
Netback ($/boe)	**38.13**	32.86	30.25
Oil Sands			
Bitumen			
Total sales volumes (mbbls/day)	**7.3**	4.0	3.9
Price received ($/boe)	**60.42**	55.56	49.09
Royalties ($/boe)	**3.75**	2.46	1.44
Operating costs ($/boe)[2]	**26.43**	48.75	37.97
Netback ($/bbl)	**30.24**	4.35	9.68
Western Canada Conventional			
Crude Oil			
Light Oil			
Sales volumes (mbbls/day)	**16.5**	15.0	14.5
Price received ($/bbl)	**88.07**	74.02	61.87
Royalties ($/bbl)	**14.61**	12.57	8.85
Medium Oil			
Sales volumes (mbbls/day)	**22.2**	23.1	22.9
Price received ($/bbl)	**75.69**	64.87	56.25
Royalties ($/bbl)	**15.05**	12.28	9.32
Heavy Oil			
Sales volumes (mbbls/day)	**14.3**	14.7	14.0
Price received ($/bbl)	**66.81**	59.76	51.67
Royalties ($/bbl)	**13.16**	13.21	8.89
Western Canada Crude Oil Total			
Total sales volumes (boe/day)	**53.0**	52.8	51.3
Price received ($/boe)	**77.17**	66.05	56.59
Royalties ($/boe)	**14.40**	12.70	9.19
Operating costs ($/boe)[2]	**22.37**	16.79	16.74
Netback ($/bbl)	**40.40**	36.56	30.66

Netback Analysis (continued)

	2011	2010	2009
Natural Gas & NGLs			
Natural Gas Liquids			
Sales volumes (mbbls/day)	**8.3**	8.0	8.3
Price received ($/bbl)	**68.03**	52.13	41.95
Royalties ($/bbl)	**21.87**	18.07	15.82
Natural Gas			
Sales volumes (mmcfs/day)	**577.7**	472.4	506.8
Price received ($/mcf)[4]	**3.77**	3.93	3.86
Royalties ($/mcf)[5]	**0.18**	0.22	0.17
Western Canada Natural Gas & NGLs Total[1]			
Total sales volumes (mmcf/day)	**627.5**	520.4	556.8
Price received ($/mcf)	**4.37**	4.37	4.14
Royalties ($/mcf)	**0.45**	0.48	0.39
Operating costs ($/mcf)[2]	**1.75**	1.70	1.54
Netback ($/bbl)	**2.17**	2.19	2.21
Atlantic Region			
Light Oil			
Sales volumes (mbbls/day)	**54.3**	46.7	55.2
Price received ($/boe)	**112.11**	82.16	66.52
Royalties ($/boe)	**19.36**	19.25	16.35
Operating costs ($/boe)[2]	**8.75**	10.33	8.80
Transportation ($/boe)[3]	**1.52**	1.55	2.08
Netback ($/boe)	**82.48**	51.03	39.29
Southeast Asia			
Light Oil & NGL[1]			
Sales volumes (mboe/day)	**8.5**	10.7	11.1
Price received ($/boe)	**110.49**	83.38	69.75
Royalties ($/boe)	**32.75**	19.11	12.02
Operating costs ($/boe)[2]	**8.17**	6.06	5.49
Netback ($/boe)	**69.57**	58.21	52.24

(1) *Includes associated co-products converted to boe.*
(2) *Operating costs exclude accretion, which is included in administration expenses and other.*
(3) *Offshore transportation costs shown separately from price received.*
(4) *Includes sulphur sales revenues/royalties.*
(5) *Alberta Gas Cost Allowance reported exclusively as gas royalties.*

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; targeted production growth rate during the plan period; targeted reserves replacement ratio during the plan period; targeted increase in ROCE during the plan period; the Company's 2012 production guidance; anticipated production levels through the plan period; and the Company's 2012 Capital Program;
- with respect to the Company's Asia Pacific Region: anticipated timing of production of first gas at the Liwan Gas Project; planned timing of regulatory submissions for the MDA field and anticipated timing of first gas at the Madura BD field, both offshore Indonesia; and anticipated rates and timing of production for the Asia Pacific Region;
- with respect to the Company's Atlantic Region: evaluation of a concrete wellhead and drilling platform in the White Rose region;
- with respect to the Company's Oil Sands properties: anticipated timing of completion of the drilling program, project schedule and anticipated rates and timing of first production for Phase I of the Company's Sunrise Energy Project; expected timing of completion of FEED for the next development stage of the Sunrise Energy Project; and development plans at the Saleski property through the use of enhanced technologies and thermal recovery techniques;
- with respect to the Company's Heavy Oil properties: anticipated timing of first oil and rates of production for the Pikes Peak South and the Paradise Hill heavy oil thermal projects;
- with respect to the Company's Western Canadian oil and gas resource plays: initiation of an evaluation program at the Company's Central Mackenzie Valley properties; and
- with respect to the Company's Midstream operating segment: the expected timing and outcome of completion of a 300,000 barrel tank at the Hardisty terminal.

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, 2011, 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 average 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 section 11.3 Non-GAAP Measures contained in the Company's Management's Discussion and Analysis for the year ended December 31, 2011, which section is 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 Dec. 31, 2011.

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 contingent best-estimate 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.

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.

This document contains information with respect to the equipment constrained flow rates of an exploration well on the Madura Straits block. This test result is not necessarily indicative of long-term performance or ultimate recovery. Potential recovery of resources from the Madura Straits block is subject to certain risks and uncertainties, including competition, delays and cost overruns of capital projects, operational risks and hazards, environmental regulation, general economic conditions, cost or availability of oil and gas field equipment, government approvals, acts of nature, negotiations of adequate gas sales/pricing, availability of markets, competition from other energy sources, and climatic conditions.

The 2011 reserve replacement ratio was determined by taking the Company's 2011 incremental proved reserve additions divided by 2011 upstream gross production. The 2011 netback was determined by taking 2011 upstream netback (sales less operating costs less royalties) divided by 2011 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 "contingent resources" and "equipment-constrained flow rates" 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.

Board of Directors


Victor T.K. Li


Canning K.N. Fok


William Shurniak


Asim Ghosh


Stephen E. Bradley

Victor T.K. Li, Co-Chairman, a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Li is Managing Director and Deputy Chairman of Cheung Kong (Holdings) Limited. He is Deputy Chairman and Executive Director of Hutchison Whampoa Limited, Chairman and Executive Director of Cheung Kong Infrastructure Holdings Limited and of CK Life Sciences Int'l., (Holdings) Inc. Mr. Li is an Executive Director of Power Assets Holdings Limited (formerly known as Hongkong Electric Holdings Limited), and a Non-executive Director of The Hongkong and Shanghai Banking Corporation Limited.

Canning K.N. Fok [2], Co-Chairman, a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Fok is Group Managing Director and Executive Director of Hutchison Whampoa Limited. He is Chairman and a Director of Hutchison Harbour Ring Limited, Hutchison Telecommunications Hong Kong Holding Limited (HTHKH), Hutchison Telecommunications (Australia) Limited, and Power Assets Holdings Limited (formerly known as Hongkong Electric Holdings Limited) and Hutchison Port Holdings Management Pte, Limited as the trustee-manager of Hutchison Port Holdings Trust. Mr. Fok is the Deputy Chairman and a Director of Cheung Kong Infrastructure Holdings Limited, a Director of Cheung Kong (Holdings) Limited and an Alternate Director of HTHKH.

William Shurniak [1], Deputy Chairman, a resident of Limerick, Saskatchewan, has been a Director of Husky Energy Inc. since 2000. Mr. Shurniak is a Director of Hutchison Whampoa Limited and recently retired from his position as a Director and Chairman of Northern Gas Networks Limited in the U.K., which he held from May 31, 2005 until June 28, 2011.

Asim Ghosh, President & Chief Executive Officer, Director, a resident of Calgary, Alberta, has been a Director of Husky Energy Inc. since May 2009. Mr. Ghosh is an independent Director of Kotak Mahindra Bank Limited, a listed bank in India.

Stephen E. Bradley [3], Director, a resident of Hong Kong, has been a Director of Husky Energy Inc. since July 2010. Mr. Bradley is a Director of Broadlea Group Ltd., Senior Representative (China), Grosvenor Ltd., Vice Chairman, ICAP (Asia Pacific) and a Director of Swire Properties Ltd. and Special Advisor to the Chief Executive Officer of Rio Tinto Ltd.

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

[1] *Audit Committee*
[2] *Compensation Committee*
[3] *Corporate Governance Committee*
[4] *Health, Safety & Environment Committee*


Martin J.G. Glynn

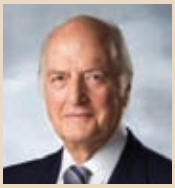

Stanley T.L. Kwok


Colin S. Russel


Poh Chan Koh


Eva L. Kwok


Frederick S-H Ma


George C. Magnus


Wayne E. Shaw


Frank J. Sixt

Martin J.G. Glynn [2] [3], Director,
a resident of Vancouver, B.C., has been a Director of Husky Energy Inc. since 2000. Mr. Glynn is a Director of the VinaCapital Vietnam Opportunity Fund Limited, Sun Life Financial Inc., Sun Life Assurance Company of Canada and UBC Investment Management Trust Inc.

Poh Chan Koh, Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Miss Koh is the Finance Director of Harbour Plaza Hotel Management (International) Ltd.

Eva L. Kwok [2] [3], Director,
a resident of Vancouver, B.C., has been a Director of Husky Energy Inc. since 2000. Mrs. Kwok is a Director, Chairman and Chief Executive Officer of Amara Holdings Inc. She is a Director of CK Life Sciences Int'l. (Holdings) Inc., Cheung Kong Infrastructure Holdings Limited and the Li Ka Shing (Canada) Foundation.

Stanley T.L. Kwok [4], Director,
a resident of Vancouver, B.C., has been a Director of Husky Energy Inc. since 2000. Mr. Kwok is the President and a Director of Stanley Kwok Consultants. He is President and a Director of Amara Holdings Inc. and a Director of Cheung Kong (Holdings) Limited and CTC Bank of Canada.

Frederick S-H Ma [1] [4], Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since July 2010. Mr. Ma is a prominent figure in Hong Kong, having served in senior positions in the private sector and has held Principal Official positions (minister equivalent) with the Hong Kong SAR Government. Mr. Ma is currently a member of the International Advisory Council of China Investment Corporation, China's Sovereign Fund, as well as an Honourary Professor of the University of Hong Kong.

George C. Magnus [1], Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since July 2010. Mr. Magnus has been a Non-executive Director of Cheung Kong (Holdings) Limited since November 2005. He is also a Non-executive Director of Hutchison Whampoa Limited, Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited (formerly known as Hongkong Electric Holdings Limited), all listed companies.

Colin S. Russel [1] [4], Director,
a resident of the United Kingdom, has been a Director of Husky Energy Inc. since 2008. Mr. Russel is the founder and Managing Director of Emerging Markets Advisory Services Ltd. Mr. Russel is a Director of Cheung Kong Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd.

Wayne E. Shaw [3] [4], Director,
a resident of Toronto, Ontario, has been a Director of Husky Energy Inc. since 2000. Mr. Shaw is a Senior Partner at Stikeman Elliott LLP Barristers & Solicitors, and a Director of the Li Ka Shing (Canada) Foundation.

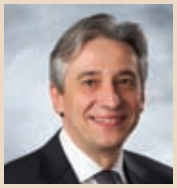
Frank J. Sixt [2], Director,
a resident of Hong Kong, has been a Director of Husky Energy Inc. since 2000. Mr. Sixt is Group Finance Director and Executive Director of Hutchison Whampoa Limited. He is the Non-executive Chairman and a Director of TOM Group Limited and Executive Director of Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited (formerly known as Hongkong Electric Holdings Limited), and a Director of Cheung Kong (Holdings) Limited, Hutchison Telecommunications International Limited, Hutchison Telecommunications (Australia) Limited, Partner Communications Company Ltd. and the Li Ka Shing (Canada) Foundation.

Officers/ Executives


Asim Ghosh


Alister Cowan


Robert J. Peabody


James D. Girgulis


Brad Allison


Bob I. Baird


Edward T. Connolly


Nancy Foster

Husky Energy Inc.

Asim Ghosh, President & Chief Executive Officer
Mr. Ghosh has been on the Board of Directors of Husky Energy since May 2009 and President and Chief Executive Officer since June 2010. He is the former Managing Director and Chief Executive Officer of Vodafone Essar Limited. Mr. Ghosh started his career with Procter & Gamble in Canada and subsequently became a Senior Vice President of Carling O'Keefe. He later became founding Chief Executive Officer of Pepsi Foods' start up operations in India and subsequently served in senior executive positions and as Chief Executive Officer of the AS Watson consumer packaged goods subsidiary of Hutchison Whampoa. He is a member of the Board of Directors of Kotak Mahindra Bank Limited.

Alister Cowan, Chief Financial Officer
Mr. Cowan was appointed Chief Financial Officer in July 2008. He was previously Executive Vice President and Chief Financial Officer, British Columbia Hydro & Power Authority. He is a member of the Institute of Chartered Accountants of Scotland and is a Past Chair of the Financial Executives International (FEI) Canada Committee on Corporate Reporting.

Robert J. Peabody, Chief Operating Officer
Appointed in 2006, Mr. Peabody is responsible for leading Husky Energy's Upstream and Downstream segments, including Western Canada Conventional and Unconventional, Heavy Oil, Oil Sands, Atlantic Region and Exploration, as well as Refining and Upgrading operations. He is also responsible for the Safety, Engineering, Project Management and Procurement functions. Prior to joining Husky, he led four major businesses for BP plc in Europe and the United States. Mr. Peabody is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

James D. Girgulis, Q.C., Vice President, Legal & Corporate Secretary
Mr. Girgulis was appointed Vice President, Legal & Corporate Secretary of Husky Energy in 2000. He was previously General Counsel and Corporate Secretary of Husky Oil Limited. Mr. Girgulis was called to the Alberta Bar in 1982 and was appointed Queen's Counsel in 2005.

Husky Oil Operations Limited

Brad Allison, Vice President, Exploration
Mr. Allison was appointed Vice President, Exploration in June 2010 with responsibilities for resource capture and appraisal as well as geological and geophysical services and business development. Mr. Allison joined Husky in 2002 as Deep Basin Exploration Manager and prior to his appointment, he was General Manager, Canadian/ International Exploration. Mr. Allison started his career with Imperial Oil Limited where he held a number of technical and management roles involving Western Canada exploration, Canadian Frontiers, Oil Sands and an assignment with Esso UK in the Central North Sea. Mr. Allison holds a Professional Geologist designation and is a member of the Canadian Society of Petroleum Geologists and American Association of Petroleum Geologists.

Bob I. Baird, Vice President, Downstream
Mr. Baird was appointed Vice President, Downstream in 2010. He was previously Vice President, Upgrading and Refining for Canada. He is responsible for overseeing all Canadian upgrading and refining operations, and providing oversight on the operation of Husky's U.S. refineries. Prior to joining Husky, Mr. Baird worked in several senior refining and strategy roles for Royal Dutch Shell in Canada and Europe.

Edward T. Connolly, Vice President, Heavy Oil
Mr. Connolly joined Husky as Vice President, Heavy Oil in 2006 and has responsibility for managing the heavy oil reserves and production portfolio. Mr. Connolly was previously Manager, Drilling, Well Completions and Facilities Construction with Talisman Energy Canada, and Facilities Construction Project Manager with BP Canada Ltd. Mr Connolly is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Nancy Foster, Vice President, Human & Corporate Resources
Ms. Foster was appointed Vice President, Human & Corporate Resources in 2011, with responsibilities for Human Resources, Diversity, Corporate Responsibility, Information Services, Real Estate, and Corporate Services. Ms. Foster was previously Senior Vice President, Human Resources & Corporate Services, prior to becoming Country Manager, Norway for Nexen Inc. She worked for Husky from 1984 to 1993, becoming Manager, Corporate Planning & Economics. She has served on a number of industry-related and charitable committees.


Robert Hinkel


Paul J. McCloskey


Rob Symonds


Terrance E. Kutryk


Terry Manning


John Myer


Roy C. Warnock

Robert Hinkel, Chief Operating Officer, Asia Pacific
Mr. Hinkel was appointed Chief Operating Officer, Asia Pacific in December 2010 with responsibility for Husky's operations in the Asia Pacific region. Prior to joining Husky, he held positions of increasing responsibility in the oil, gas, and mining industries including President and CEO of Enventure Global Technology, a subsidiary of the Shell Group and CEO of Molycorp, a subsidiary of Unocal Corporation. Mr. Hinkel spent 21 years with Unocal in various positions including Senior Vice President – Indonesia and General Manager – Global Procurement. He has been an active member of the Society of Petroleum Engineers for more than 30 years.

Terrance E. Kutryk, Vice President, Midstream & Refined Products
Mr. Kutryk was appointed Vice President, Midstream & Refined Products in 2008. He was formerly General Manager, Facilities & New Ventures, and was Vice President, Refined Products & New Ventures with Husky Marketing & Supply Company. He is a member of the American Society of Mechanical Engineers, Canadian Institute of Mining, Metallurgy and Petroleum, Canadian Heavy Oil Association and the CFA Institute. He is Chairman of the Board of Sultran Ltd. and Pacific Coast Terminals Co. Ltd.

Terry Manning, Vice President, Safety, Engineering & Procurement
Mr. Manning was appointed Vice President, Safety, Engineering & Procurement in January 2012 with responsibilities for safety, procurement, material and services management, project management and technical services for Husky. Prior to that, he was Vice President, Engineering & Procurement Management. He was previously Vice President, Capital Projects with Barrick Gold Corporation; General Manager, Project Management Office with Suncor Energy Inc., and Director of Projects at Agrium. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and the Association of Professional Engineers and Geoscientists of British Columbia.

Paul J. McCloskey, Vice President, Atlantic Region
Mr. McCloskey was appointed Vice President, Atlantic Region in 2009. Prior to joining Husky, he was Managing Director at North Alamein Petroleum Company (NALPETCO). Previous to that, he led various businesses in Hess Corporation and LASMO, where he was Group General Manager for Production & Development, and held senior engineering roles at Conoco. A member of the Society of Petroleum Engineers, he served as a Director of the Board of the Aberdeen (Scotland) section.

John Myer, Vice President, Oil Sands
Mr. Myer was appointed Vice President, Oil Sands in November 2010 with responsibilities to develop and operate the Sunrise SAGD asset and advance Husky's portfolio of emerging properties in the Oil Sands region. Prior to his appointment at Husky he was with Suncor Energy for 20 years including roles as Vice President Exploration and Development, Vice President In-situ and Vice President Production. Mr. Myer is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, Society of Petroleum Engineers and Canadian Heavy Oil Association.

Rob W. Symonds, Vice President, Western Canada Production
Mr. Symonds was appointed Vice President, Western Canada Production in June 2011. He is responsible for the leadership and management of Husky's Upstream business in Western Canada excluding Heavy Oil and Oil Sands. Prior to his appointment, he was Vice President, Canadian Operations with Enerplus Corporation in Calgary. Mr. Symonds holds a Master of Science in Petroleum Engineering from the University of Alberta and a Bachelor of Science (Chemical Engineering) from the University of Edinburgh. He holds a Professional Engineer designation and is a member of the Society of Petroleum Engineers.

Roy C. Warnock, Vice President & General Manager, Lima Refining Company
Mr. Warnock was appointed Vice President & General Manager, Lima Refining Company, in 2007. Previously, he served as Vice President, Upgrading & Refining, responsible for the operations of the Husky Lloydminster Refinery, Lloydminster Upgrader, Lloydminster Meridian Cogeneration Facility, Prince George Refinery and the Lloydminster and Minnedosa ethanol plants. Prior to joining the Company in 1983, he held a number of engineering and operations positions with Imperial Oil and Bechtel Canada Ltd. Mr. Warnock is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Investor Information

Common Share Information

Year ended December 31		**2011**	2010	2009
Share price *(dollars)*	High	**30.58**	30.88	36.09
	Low	**20.63**	24.21	24.78
	Close at December 31	**24.55**	26.55	30.08
Average daily trading volumes *(thousands)*		**1,183**	1,173	1,232
Number of common shares outstanding *(thousands)*		**957,537**	890,709	849,861
Weighted average number of common shares outstanding *(thousands)*				
	Basic	**923,821**	852,670	849,679
	Diluted	**931,978**	852,670	849,679

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, 2011 was 957,537,098.

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).

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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 Thursday, April 26, 2012, in the Imperial Ballroom, Hyatt Regency Calgary, 700 Centre Street, S.E., Calgary, Alberta.

Additional Publications

The following publications are available on our website or from our Investor Relations department:

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



Dividends

Husky's Board of Directors has approved a dividend policy that pays quarterly dividends.

The following table is restated for the two-for-one split of the common shares that occurred in July 2007.

Declaration Date	Quarter Dividend	Special Dividend
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	
October 2007	0.330	
August 2007	0.250	
May 2007	0.250	
February 2007	0.250	$ 0.250
October 2006	0.250	
July 2006	0.250	
April 2006	0.125	
February 2006	0.125	
October 2005	0.125	0.500
July 2005	0.070	
April 2005	0.070	
February 2005	0.060	
November 2004	0.060	0.270
July 2004	0.060	
April 2004	0.060	
February 2004	0.050	

Husky Energy

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www.huskyenergy.com

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