2011

United States Securities and Exchange Commission

Washington, D.C. 20549

Form 40-F

☐ Registration Statement pursuant to section 12 of the Securities Exchange Act of 1934

☒ Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2011 **Commission File Number: 001-04307**

Husky Energy Inc.

(Exact name of Registrant as specified in its charter)

Alberta, Canada	**1311**	**Not Applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Numbers (if applicable))	(I.R.S. Employer Identification Number (if applicable))

707-8th Avenue S.W., P.O. Box 6525 Station D, Calgary, Alberta, Canada T2P 3G7
(403) 298-6111
(Address and telephone number of Registrant's principal executive office)

CT Corporation System, 111 Eighth Avenue, New York, New York 10011
(212) 894-8400
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:
Title of Class: None

Securities registered or to be registered pursuant to Section 12(g) of the Act:
Title of Class: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
Title of Class: Common Shares

For annual reports, indicate by check mark the information filed with this Form:

☒ Annual information form ☒ Audited annual financial statements

Number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

957,537,098 Common Shares outstanding as of December 31, 2011

12,000,000 Cumulative Redeemable Preferred Shares, Series 1 outstanding as of December 31, 2011

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (s.232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ☐ No ☐

The Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the Registrant's Registration Statement under the Securities Act of 1933: Form F-10 File No. 333-174554.

Principal Documents

The following documents have been filed as part of this Annual Report on Form 40-F:

A. Annual Information Form

The Annual Information Form of Husky Energy Inc. ("Husky" or "the Company") for the year ended December 31, 2011 is included as Document A of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

Husky's audited consolidated financial statements for the years ended December 31, 2011 and December 31, 2010, including the auditors' report with respect thereto, is included as Document B of this Annual Report on Form 40-F.

C. Management's Discussion and Analysis

Husky's Management's Discussion and Analysis for the year ended December 31, 2011 is included as Document C of this Annual Report on Form 40-F.

Certifications

See Exhibits 23.1, 23.2, 31.1, 31.2, 32.1 and 32.2, which are included as Exhibits to this Annual Report on Form 40-F.

Supplemental Reserves Information

See Exhibit 99.1 for the Supplemental Reserves Information, which is included as an Exhibit to this Annual Report on Form 40-F.

Disclosure Controls and Procedures

See the section "Disclosure Controls and Procedures" in Husky's Management's Discussion and Analysis for the year ended December 31, 2011 which is included as Document C to this Annual Report on Form 40-F.

Management's Annual Report on Internal Control Over Financial Reporting

The section "Management's Annual Report on Internal Control over Financial Reporting" in Husky's Management's Discussion and Analysis, is included as Document C to this Annual Report on Form 40-F.

Attestation Report of the Registered Public Accounting Firm

The required disclosure is included in the "Independent Auditors' Report of Registered Public Accounting Firm" that accompanies Husky's consolidated financial statements for the year ended December 31, 2011, which is included as Document B to this Annual Report on Form 40-F.

Changes in Internal Control Over Financial Reporting

The required disclosure is included in the section "Disclosure Controls and Procedures" in Husky's Management's Discussion and Analysis for the year ended December 31, 2011, which is included as Document C to this Annual Report on Form 40-F.

Notice Pursuant to Regulation BTR

Not Applicable.

Audit Committee Financial Expert

The Board of Directors of Husky has determined that William Shurniak is an "audit committee financial expert" (as defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its Audit Committee. Pursuant to paragraph 8(a)(2) of General Instruction B to Form 40-F, the Board has applied the definition of independence applicable to the audit committee members of New York Stock Exchange listed companies. Mr. Shurniak is a corporate director and is independent under the New York Stock Exchange standards. For a description of Mr. Shurniak's relevant experience in financial matters, see Mr. Shurniak's history in the section "Directors and Officers" and in the section "Audit Committee" in Husky's Annual Information Form for the year ended December 31, 2011, which is included as Document A of this Annual Report on Form 40-F.

Code of Business Conduct and Ethics

Husky's Code of Ethics is disclosed in its Code of Business Conduct, which is applicable to its principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions and to all of its other employees, and is posted on its website at www.huskyenergy.com. In September 2011, Husky made amendments to its Code of Business Conduct to clarify that any employee that is concerned about a potential instance of non-compliance with the code is encouraged to discuss the matter with the employee's supervisor or manager or a Human Resources advisor or report the matter through Husky's Ethics Help Line or to specified senior executives. A copy of Husky's Code of Business Conduct, as amended, is included as Exhibit 99.2 to this Annual Report on Form 40-F . In the fiscal year ended December 31, 2011, Husky has not granted a waiver including an implicit waiver from a provision of its Code of Ethics. In the event that, during Husky's ensuing fiscal year, Husky:

i. amends any provision of its Code of Business Conduct that applies to its principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions that relates to any element of the code of ethics definition enumerated in paragraph (9)(b) of General Instruction B to Form 40-F, or

ii. grants a waiver, including an implicit waiver, from a provision of its Code of Business Conduct to any of its principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions that relates to one or more of the items set forth in paragraph (9)(b) of General Instruction B to Form 40-F,

Husky will promptly disclose such occurrences on its website following the date of such amendment or waiver and will specifically describe the nature of any amendment or waiver, and in the case of a waiver, name the person to whom the waiver was granted and the date of the waiver.

Principal Accountant Fees and Services

See the section "External Auditor Service Fees" in the Annual Information Form for the year ended December 31, 2011, which is included as Document A to this Annual Report on Form 40-F.

Off-Balance Sheet Arrangements

See the section "Off-Balance Sheet Arrangements" in Husky's Management's Discussion and Analysis for the year ended December 31, 2011, which is included as Document C to this Annual Report on Form 40-F.

Tabular Disclosure of Contractual Obligations

See the section "Cash Requirements" in Husky's Management's Discussion and Analysis for the year ended December 31, 2011, which is included as Document C to this Annual Report on Form 40-F.

Identification of the Audit Committee

Husky has a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: W. Shurniak, C.S. Russel, F.S.H. Ma and G.C. Magnus.

Interactive Data File

Not applicable.

Mine Safety Disclosure

Not applicable.

Undertaking and Consent to Service of Process

Undertaking

Husky undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

Consent to Service of Process

A Form F-X signed by Husky and its agent for service of process has been filed with the Commission together with Form F-10 (333 - 174554) in connection with its common shares registered on such form.

Any change to the name or address of the agent for service of process of Husky shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of Husky.

Signatures

Pursuant to the requirements of the Exchange Act, Husky Energy Inc. certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereto duly authorized.

Dated this 8th day of March, 2012

Husky Energy Inc.

By: /s/ Asim Ghosh
Name: Asim Ghosh
Title: President & Chief Executive Officer

By: /s/ James D. Girgulis
Name: James D. Girgulis
Title: Vice President, Legal & Corporate Secretary

Document A
Form 40-F

Annual Information Form

For the Year Ended December 31, 2011

Husky Energy Inc.

Annual Information Form

For the Year Ended December 31, 2011

March 8, 2012

TABLE OF CONTENTS

In this Annual Information Form, the terms "Husky," "we," "our," "us," and "the Company," means Husky Energy Inc. and its subsidiaries and partnership interests on a consolidated basis including information with respect to predecessor corporations.

Disclosure of Oil and Gas Information

Unless otherwise noted in this document, all reserves estimates given have an effective date of December 31, 2011. Gross reserves or gross production are reserves or production attributable to Husky's interest prior to deduction of royalties; net reserves or net production are reserves or production net of such royalties. Gross or net production reported refers to sales volume, unless otherwise indicated. Unless otherwise noted production and reserves figures are stated on a gross basis. Unless otherwise indicated, oil and gas commodity prices are quoted after the effect of hedging gains and losses. Unless otherwise indicated, all financial information is in accordance with accounting principles generally accepted in Canada. Husky completed a transition to International Financial Reporting Standards in 2011 and all 2011 and 2010 financial information has been prepared using IFRS. Periods beginning prior to 2010 have not been restated.

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

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

This Annual Information Form contains forward-looking information and statements within the meaning of applicable securities laws. For a full discussion of the forward-looking information and statements and the risks to which they are subject, see the "Special Note Regarding Forward-Looking Statements" in this Annual Information Form.

EXCHANGE RATE INFORMATION

Except where otherwise indicated, all dollar amounts stated in this Annual Information Form ("AIF") are Canadian dollars. The following table discloses various indicators of the Canadian dollar/U.S. dollar rate of exchange or the cost of a U.S. dollar in Canadian currency for the three years indicated[(1) (2)].

	Year ended December 31		
(Cdn $ per U.S. $)	**2011**	**2010**	**2009**
Year end	1.017	0.995	1.047
Low	0.941	0.995	1.029
High	1.066	1.078	1.300
Average	0.989	1.030	1.136

(1) The exchange rates were as quoted by the Federal Reserve Bank of New York for the noon buying rate.
(2) The high, low and average rates were either quoted or calculated as of the last day of the relevant period.

DISCLOSURE OF EXEMPTION UNDER NATIONAL INSTRUMENT 51-101

Husky sought and was granted by the Canadian Securities Administrators ("CSA") an exemption from the requirement under National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") to involve independent qualified oil and gas reserves evaluators or auditors. Notwithstanding this exemption, the Company involves independent qualified reserves auditors as part of Husky's corporate governance practices. Their involvement helps assure that our internal oil and gas reserves estimates are materially correct.

In Husky's view, the reliability of Husky's internally generated oil and gas reserves data is not materially different than would be afforded by Husky involving independent qualified reserves evaluators to evaluate and review the reserves data. The primary factors supporting the involvement of independent qualified reserves evaluators apply when (i) their knowledge of, and experience with, a reporting issuer's reserves data are superior to that of the internal evaluators and (ii) the work of the independent qualified reserves evaluator is significantly less likely to be adversely influenced by self-interest or management of the reporting issuer than the work of internal reserves evaluation staff. In Husky's view, neither of these factors applies in Husky's circumstances.

The following oil and gas reserves disclosure has been prepared in accordance with 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 ("SEC") 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 CSA to also disclose its reserves using U.S. Rules 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.

Information to further an investor's understanding is specifically encouraged to be included in the Company's Management's Discussion and Analysis ("MD&A"). The MD&A is intended to be a narrative explanation describing the Company, both its history and prospects, as perceived by management. The readers of the AIF are encouraged to also read the Company's MD&A, which is filed, in accordance with the requirements of the CSA, on the System for Electronic Data Analysis and Retrieval ("SEDAR"). Documents filed on SEDAR may be accessed online at www.sedar.com. This AIF together with the MD&A and the Company's Audited Consolidated Financial Statements are included in Husky's Form 40-F which is filed with SEC's Electronic Data Gathering Analysis and Retrieval ("EDGAR") system, which may be accessed online at www.sec.gov.

CORPORATE STRUCTURE

Husky Energy Inc.

Husky Energy Inc. was incorporated under the *Business Corporations Act* (Alberta) on June 21, 2000. The Company's Articles were amended effective February 28, 2011 to permit the issuance of common shares as payment of stock dividends on the common shares and to authorize preferred shares to be issued in one or more series. The Company's Articles were also amended effective March 3, 2011 to create Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") and Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares").

Husky Energy Inc. has its registered office and its head and principal office at 707, 8th Avenue S.W., P.O. Box 6525, Station D, Calgary, Alberta, T2P 3G7.

Intercorporate Relationships

The principal subsidiaries of Husky and place of incorporation, continuance or place of organization, as the case may be, are as follows [(1)]. All of the following companies and partnerships, except as otherwise indicated, are 100% beneficially owned or controlled or directed, directly or indirectly.

Name	Jurisdiction
Subsidiaries of Husky Energy Inc.	
Husky Oil Operations Limited ("HOOL")	Alberta
Subsidiaries of Husky Oil Operations Limited	
Husky Oil Limited Partnership	Alberta
Husky Terra Nova Partnership	Alberta
Husky Downstream General Partnership	Alberta
Husky Energy Marketing Partnership	Alberta
Sunrise Oil Sands Partnership (50%)	Alberta
BP Husky Refining LLC (50%)	Delaware
Lima Refining Company	Delaware
Husky Marketing and Supply Company	Delaware

(1) Principal operating subsidiaries exclusive of intercorporate relationships due to financing related receivables and investments.

GENERAL DEVELOPMENT OF HUSKY

Three Year History of Husky

2009

In 2009, Husky completed drilling and testing of three appraisal wells at the Liwan 3-1 field on Block 29/26, in the South China Sea.

In 2009, an application was made in the East Bawean II Production Sharing Contract ("PSC") to relinquish the block. The application was based on the drilling of two exploration wells, the Adiyasa 1 and Kukura 1, which were abandoned without testing in 2009.

Husky filed a debt shelf prospectus with the Alberta Securities Commission on February 26, 2009 and the SEC on February 27, 2009. The shelf prospectus enabled Husky to offer up to U.S. $3.0 billion of debt securities in the U.S. until March 26, 2011.

On May 11, 2009, Husky issued U.S. $750 million of 5.90% notes due June 15, 2014 and U.S. $750 million of 7.25% notes due December 15, 2019 under the debt shelf prospectus filed in February 2009.

On October 29, 2009, Husky announced it had completed and tested two exploratory wells to evaluate the shale gas potential in the Montney and Doig formations in northeast British Columbia.

On November 23, 2009, Husky announced the discovery of additional oil resources in the White Rose area.

On November 30, 2009, Husky announced an agreement to purchase Penn West Energy Trust's heavy oil properties contained within Husky's Lloydminster area of operations in Alberta and Saskatchewan.

On December 8, 2009, Husky announced a significant new natural gas discovery at Liuhua 34-2-1 on Block

29/26 in the South China Sea.

On December 10, 2009, Husky announced that it entered into an agreement with Suncor Energy Inc. and Suncor Energy Products Inc. to purchase 98 retail outlets in the Ontario market. The first site was transferred to Husky in March 2010, with the remaining sites transferred between April and November 2010.

On December 21, 2009, Husky filed a debt shelf prospectus that enabled Husky to offer up to $1.0 billion of medium term notes in Canada until January 21, 2012.

2010

On January 20, 2010, Husky announced that it had completed the front end engineering design ("FEED") for Phase I of the Sunrise Energy Project, located 60 kilometers northeast of Fort McMurray. The Company also obtained the necessary approvals from the Government of Alberta, Environment Department and the Energy Resources and Conservation Board ("ERCB") to proceed with the project. Husky later announced in November 2010 that it was moving forward with the construction of facilities for the phased development of the Sunrise oil sands lease in the Fort McMurray region of northern Alberta. This first phase is expected to cost approximately $2.5 billion and is expected to produce approximately 60,000 barrels per day gross beginning in 2014. Further, Sunrise will use steam-assisted gravity drainage ("SAGD") technology which limits site disturbance. In November 2010, sanction for Phase I was announced.

On February 8, 2010, Husky announced its third significant gas discovery on Block 29/26 in the South China Sea.

On March 9, 2010, Husky announced that it would issue $700 million in medium term notes under the $1 billion shelf prospectus which was filed by the Company in December 2009 with the securities regulatory authorities in each of the provinces of Canada. The medium term notes were issued in two tranches: $300 million at 3.75% maturing on March 12, 2015 and $400 million at 5.00% maturing on March 12, 2020. The transaction closed on March 12, 2010.

On May 21, 2010, Husky announced the appointment of Mr. Asim Ghosh as President and Chief Executive Officer of the Company, effective June 1, 2010. Mr. Ghosh was previously appointed to the Board of Directors in May, 2009. The Company's former President and Chief Executive Officer, Mr. John C.S. Lau, was appointed President and Chief Executive Officer, Asia Pacific, in May 2010 after stepping down as President and Chief Executive Officer of Husky Energy Inc. after 18 years in the position.

On May 31, 2010, Husky completed drilling and successful testing of the first appraisal well at the Liuhua 29-1 discovery Block 29/26 in the South China Sea with encouraging results.

On May 31, 2010, Husky also announced that oil production had been achieved from the North Amethyst field, offshore Newfoundland and Labrador. North Amethyst is the first satellite field development at Husky's White Rose project and was brought on production less than four years after discovery. It is also the first subsea tieback project in Canada.

On September 1, 2010, Husky announced that a purchase agreement had been signed to acquire natural gas properties in west central Alberta, which added 10.8 mboe/day of gross production, 32.9 mmboe of proved reserves and 10.7 mmboe of probable reserves, and extended the optimum utilization of its Ram River gas plant. The acquisition also added 160,000 acres of land to the Company's holdings, including 122,000 undeveloped acres, doubling Husky's land holdings in the region. This purchase closed on November 30, 2010 and had an effective date of June 1, 2010. The reserves estimates are as at December 31, 2010.

On October 27, 2010, Husky announced that it had completed the successful drilling of a second appraisal well at the Liuhua 29-1 discovery Block 29/26 in the South China Sea. Additional appraisal drilling will be undertaken to further define the resource size and prepare the Plan of Development for the field once the well data has been integrated.

On October 28, 2010, Husky announced that it had received approval from the Government of Indonesia for a 20 year extension to the existing Madura Strait PSC, originally awarded in 1982. The Madura Strait PSC includes the Madura BD and MDA fields, as well as numerous other prospects and leads. Husky and its partner in the Madura Strait also agreed to sell a 10% equity stake each, in the Madura PSC to Samudra Energy Ltd., through its affiliate SMS Development Ltd. Following the completion of the sale, Husky and China National Offshore Oil Corporation ("CNOOC") respectively hold a 40% equity interest in Husky Oil (Madura) Limited, with the remaining 20% held by Samudra Energy Ltd. This sale closed on January 13, 2011 and subsequently Husky Oil (Madura) Ltd. has changed its name to Husky-CNOOC Madura Ltd.

Effective November 26, 2010, Husky filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada. The shelf prospectus enables Husky to offer up to $3

billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units in Canada until December 2012.

Husky signed an $860 million purchase and sale agreement to acquire oil and natural gas properties in Alberta and northeast British Columbia. This purchase included 16.3 mboe/day of gross natural gas production, 4.8 mbbls/day of gross oil production, and 0.8 mbbls/day of natural gas liquids ("NGL's"). Husky estimated reserves acquired of 104 mmboe of proved reserves and nine mmboe of probable reserves based on an effective date of December 1, 2010. The purchase transaction closed on February 4, 2011.

Husky also announced that it decided to retain its Asia Pacific assets citing the Company's view that it is in the best interest of the shareholders to continue to build this material business in the resource-rich region and leverage the close proximity to major energy markets in Hong Kong and Mainland China.

The Government of China approved the Original-Gas-in-Place ("OGIP") report for the Liwan 3-1 field. Tendering for major equipment and facilities is underway and key contracts are expected to be awarded in the near term in order to achieve first gas production in late 2013.

On December 7, 2010 Husky issued equity by way of a public overnight-marketed common share offering and a private placement to its principal shareholders. Pursuant to the public offering, the Company issued a total of 11.9 million common shares at a price of $24.50 per share for total gross proceeds of approximately $293 million. The public offering was conducted under the Company's previously filed shelf prospectus and supplement to the shelf prospectus. 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 approximately $707 million via a private placement. The public offering and private placement closed on December 7, 2010.

On December 7, 2010, Husky announced that it had signed a Heads of Agreement with CNOOC, specifying the key principles of cooperation for funding and operation of the Liwan 3-1 deep water gas field development. Under the agreement for the Liwan 3-1 field development, Husky will operate the deep water portion of the project involving development drilling and completions, subsea equipment and controls, and subsea tie-backs to a shallow water platform. CNOOC will operate the shallow water portion of the project including a shallow water platform, approximately 270 kilometers of subsea pipeline to shore, and the onshore gas processing plant.

2011

On February 28, 2011, Husky announced that its shareholders voted in favour of an amendment to the Company's Articles, which will allow shareholders to accept dividends in cash or in common shares. The shareholders also approved an amendment to allow for the issuance of preferred shares.

On March 18, 2011, Husky issued 12 million Series 1 Preferred Shares at a price of $25.00 per share for aggregate gross proceeds of $300 million. 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. 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 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%.

On June 13, 2011, Husky filed a universal short form base shelf prospectus with the Alberta Securities Commission and the SEC. The prospectus will enable Husky to offer up to U.S. $3 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and units in the United States until July 13, 2013.

On June 29, 2011, Husky completed a $1 billion public offering and a $200 million private placement to its principal shareholders, L.F. Investments (Barbados) Limited and Hutchison Whompoa Luxembourg Holdings S.a.r.l. The Company issued approximately 37 million common shares at $27.50 per share in the public offering and approximately 7 million common shares at a price of $27.50 per share in the private placement. The public offering was made pursuant to a prospectus supplement to the Company's universal base shelf prospectus filed November 26, 2010 with the securities regulatory authorities in all provinces of Canada and to the Company's universal base shelf prospectus filed June 13, 2011, with the Alberta Securities Commission and the SEC.

On September 19, 2011, Husky announced that it had sanctioned the development of the Liwan 3-1 and Liuhua 34-2 fields, the principal fields of the Liwan Gas Project in the South China Sea. The project, which is being jointly developed by Husky and CNOOC, aims to bring at least three natural gas discoveries on Block 29/26 to market. The Overall Development Plan ("ODP") for Liwan 3-1 was submitted to the Chinese government authorities for regulatory approval and a gas sales agreement for production from the field is in place. The gas sales agreement was executed with CNOOC Gas & Power Group, Guangdong Branch for volumes from the Liwan 3-1 field. Production from the field will supply the Guangdong Province natural gas grid from an onshore gas plant at Gaolan Island, Zhuahai.

Business Environment Trends

There are a number of trends that are developing that may have both short and long-term effects on the oil and gas industry in Canada. Production from oil sands projects are expected to continue to accelerate as the dominant source of crude oil product in the decades to come. During 2010, production of bitumen from oil sands from both mining and in-situ operations increased by 9% compared with 2009. Non-upgraded bitumen and synthetic crude oil from oil sands accounted for 52% of Canadian production in 2010, an increase of 2% from 2009. Production of crude oil, including bitumen and synthetic crude oil, was 5% higher in 2010 compared with 2009. From 2004 to 2010, conventional crude oil production replacement in Canada averaged 85% [(1)]. In its June 2011 forecast, the Canadian Association of Petroleum Producers ("CAPP") projected total Canadian production to increase by approximately 67% to 4.7 mmbbls/day by 2025, of which 3.7 mmbbls/day would be from oil sands. Production above 3.3 mmbbls/day would be sourced from new oil sands projects that were not under construction at the forecast date. In addition, the decade long decline in conventional crude oil production was effectively halted in 2010. This resulted from the application of new technologies in resource plays in Western Canada such as horizontal wells combined with multi-stage fracturing and by favourable royalty amendments by the Government of Alberta[(2)].

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 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[(3)]. Conventional natural gas exploration is expected to be focused on the traditionally less accessible areas in the overthrust belt along the eastern slope of the Rocky Mountains.

The trend of volatile commodity prices is expected to continue. Natural gas prices are sensitive to regional supply and demand imbalances, regional industrial activity levels, weather patterns and access to cheaper sources of energy. Oil prices are subject to potential supply disruptions and increased demand from emerging economies. Notwithstanding supply disruptions or major policy changes in respect of greenhouse gas emissions, recent forecasts [(4)] by the Energy Information Administration ("EIA") in the United States include significant long-term potential for increased crude oil supply from producers outside of the Organization of the Petroleum Exporting Countries ("OPEC") over the next two and a half decades, particularly conventional production from Brazil, Russia, and Kazakhstan and further investment in exploration. Also, with the economic viability of Canada's oil sands supported by rising world oil prices and advances in production technology, Canadian oil sands production is projected by the EIA to reach 5.0 mmbbls/day in 2035. World oil prices declined in the second half of 2008 from their mid-July peak and trended upward through 2009, 2010 and 2011. By February 7, 2012, West Texas Intermediate ("WTI") spot prices had averaged U.S. $99.75/bbl and Brent spot averaged U.S. $111.25/bbl during the first few weeks of 2012. The EIA's reference case forecasts prices to gradually rise as the world economy recovers and global demand grows more rapidly than crude oil supplies from non-OPEC producers.

Transportation and market access in North America for crude oil emerged as a major issue in 2011, contributing to regional price volatility. Crude oil with access to water borne transportation receives a higher Brent based price, due to its increased mobility, compared to on-shore North American crude which is valued based on WTI pricing. Most western Canadian, on-shore crude is transported to Cushing, Oklahoma where the price for WTI is set. For most of 2011, Cushing was oversupplied with crude as a result of limited capacity to transport crude to US Gulf Coast refineries and from an increase of on-shore production from emerging resource plays like the North Dakota Bakken and Canadian oil sands, increasing the price differential between Brent crude and WTI crude. There are several transportation projects under development or being considered that could help reduce the crude price disparity in the longer term such as the Seaway Pipeline reversal, Wrangler Pipeline, Keystone XL Pipeline, Northern Gateway Pipeline and Trans Mountain Pipeline expansion, however considerable uncertainty exists on when and if each of these solutions will be in service.

The EIA Short-Term Energy Outlook[(5)] was published on February 7, 2012 and provides 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 1% to reach 87.9 mmbbls/day in 2011 and is expected to grow by 1.5% per year in 2012 and 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. OPEC's spare capacity is expected to rise from 2.2 mmbbls/day in December 2011 to 3.9 mmbbls/day by the end of 2013.

There are many significant uncertainties that could result in higher or lower oil prices. Should a significant oil supply disruption occur, and OPEC members fail to increase production or anticipated non-OPEC oil developments are delayed, oil prices could be significantly higher than projected. If the pace of economic recovery fails to

accelerate in OECD countries or if economic growth slows in non-OECD countries, reduced demand could result in lower prices.

(1) "Canadian Energy Overview 2010", July 2011, National Energy Board.

(2) "Crude Oil Forecast, Markets and Pipelines", June 2011, Canadian Association of Petroleum Producers.

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

(4) "Annual Energy Outlook 2012 Early Release Overview", January 23, 2012, Energy Information Administration U.S. Department of Energy.

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

DESCRIPTION OF HUSKY'S BUSINESS

General

Husky is a publicly traded integrated international energy company headquartered in Calgary, Alberta, Canada.

Husky's business is conducted predominantly in three 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 Eastern Canada, offshore Greenland, offshore China, and offshore Indonesia.

Midstream includes marketing of the Company's and other producers' crude oil, bitumen, 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.

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.

Social and Environmental Policy

Husky approaches social responsibility and sustainable development by seeking a balance among economic, operational reliability, health, safety, environmental and social issues while maintaining growth. Husky strives to find solutions to these issues that do not compromise the needs of future generations. In 2008, Husky implemented the Husky Operational Integrity Management System ("HOIMS") which is followed by all Husky businesses, with particular emphasis on projects and operations and management of the operational integrity of assets throughout its life cycle. HOIMS includes 14 fundamental elements; each element contains well defined objectives and expectations that guide Husky to continuously improve operational integrity performance outlining the overall intent behind each element and the individual activities that are undertaken to support these objectives. HOIMS is designed to guide Husky's employees in effectively managing the risks associated with Husky's business while creating a safe and secure place to work. Resources are applied and dedicated to the continued implementation and execution of HOIMS, and progress is monitored at all levels of the Company. Periodic reviews and audits are conducted to help ensure that HOIMS is effectively integrated into daily operations.

The fundamental elements of HOIMS are:

1. Ensure all levels of management demonstrate leadership and commitment to operational integrity. Define and ensure appropriate accountability for HOIMS throughout the organization.
2. Prevent incidents by identifying and minimizing workplace and personal health risks. Promote and reinforce all safe behaviours.
3. Manage risks by performing comprehensive risk assessments to provide essential decision-making information. Develop and implement plans to manage significant risks and impacts to as low as reasonably practical levels.
4. Be prepared for an emergency or security threat. Identify all necessary actions to be taken to protect people, the environment, the organization's assets and reputation in the event of an emergency or security threat.
5. Maintain operations reliability and integrity by use of clearly defined and documented operational, maintenance, inspection and corrosion programs. Seek improvements in process and equipment dependability by systematically eliminating defects and sources of loss.
6. Provide assurance that personnel possess the necessary competencies, knowledge, abilities and behaviours to perform and demonstrate designated tasks and responsibilities effectively, efficiently and safely.
7. Report and investigate all incidents. Learn from incidents and use the information to take corrective action and prevent recurrence.
8. Operate responsibly to minimize the environmental impact of operations. Leave a positive legacy behind when operations cease.
9. Ensure that risks and exposures from proposed changes are identified, evaluated and managed to remain at an acceptable level.
10. Identify, maintain and safeguard important information. Ensure personnel can readily access and retrieve information. Promote and encourage constructive dialogue within the organization to share industry recommended practices and acquired knowledge.
11. Ensure conformance with Corporate policies and compliance with all relevant government regulations. Work constructively to influence proposed laws and regulations, and debate on emerging issues.
12. Design, construct, commission, operate and decommission all assets in a healthy, safe, secure, environmentally sound, reliable and efficient manner.
13. Ensure contractors and suppliers perform in a manner that is consistent and compatible with Husky's policies and business performance standards. Ensure contracted services and procured materials meet the requirements and expectations of Husky's standards.
14. Confirm that HOIMS processes are implemented and assess whether they are working effectively. Measure progress and continually improve towards meeting HOIMS objectives, targets, and key performance indicators.

Health, Safety and Environment

The Health, Safety and Environment Committee of the Board of Directors is responsible for reviewing and recommending for approval by the Board of Directors updates to the health, safety and environment policy and the development with management and achievement of specific environmental objectives and targets, and for monitoring compliance with the Company's environmental policies and regulatory requirements. The mandate of the Health, Safety and Environment Committee is available on the Husky website at www.huskyenergy.com.

Environmental Protection

Husky's operations are subject to various environmental requirements under federal, provincial, state and local laws and regulations, as well as international conventions. These laws and regulations cover matters such as air emissions, wastewater discharge, freshwater use, land disturbances and handling and disposal of waste materials. These laws and regulations have proliferated and become more complex over time, governing an increasingly broad aspect of the industry's mode of operating and product characteristics. Husky continues to monitor emerging environmental laws and regulations and proactively implements programs as required for compliance. According to the American Petroleum Institute, the oil and gas industry has invested over U.S. $209 billion since 1990 toward improving the environmental performance of its products, facilities and operations. In 2009, the refining sector

accounted for 63% and the upstream sector accounted for 24% of total oil and gas industry environmental expenditures in the United States. In 2009, just over half of the industry's environment expenditures were directed toward reducing emissions into the atmosphere. [1]

Husky is required by the Government of Canada to report facilities that emit greater than 50,000 tonnes of carbon dioxide equivalence ("CO_2E"). The Lloydminster Upgrader, Lloydminster Refinery, Prince George Refinery, SeaRose floating, production and storage offloading vessel ("FPSO"), Ram River gas plant, Rainbow Lake gas plant, Tucker thermal oil plant, Bolney SAGD thermal plant, Pikes Peak CSS thermal plant and the Lloydminster and Minnedosa ethanol plants are in this category. Husky has implemented an Environmental Performance Reporting System ("EPRS") that will gather, consolidate, calculate, report and identify trends including greenhouse gas emissions.

Husky is also a member of the Integrated Carbon Dioxide ("CO_2") Network, which is working to reduce greenhouse gas emissions. The group continues to study technologies related to the capture, transportation and storage of CO_2. A project is underway at Husky to capture, compress and liquefy CO_2 from the Lloydminster ethanol plant for injection into heavy oil fields for Enhanced Oil Recovery. At Lloydminster and Rainbow Lake, Husky utilizes cogeneration to produce both electricity and thermal energy for use at its processing facilities. This configuration has less adverse effects on the environment and is cost effective. Electrical energy in excess of Husky's requirements is sold into the grid. At Husky's Tucker SAGD project vapour recovery systems are in use on all tanks and process vessels.

Husky has undertaken programs to minimize water consumption, particularly freshwater, and minimize risk to water resources. At the Tucker project, 90% of water is recycled and very saline (i.e. non-potable) water is used for make-up water. Husky is implementing various technologies to reduce water usage. Husky's alkaline surfactant polymer floods ("ASP"), which increases the efficiency of water and the use of CO_2 to mobilize heavy oil in the reservoir are being evaluated in pilots to reduce overall water consumption.

Ongoing remediation and reclamation work is occurring at approximately 2,680 well sites and facilities. In 2011, Husky spent $105 million on remediation activities and expects to spend approximately $116 million in 2012 on environmental remediation.

At December 31, 2011, Husky had 549 retail locations in its light refined products operations, which consisted of 396 owned or leased locations (Husky controlled) and 153 independent retailer locations. Husky is continually monitoring the owned and leased locations for environmental compliance and, where required, performing remediation including routine underground tank replacements. Husky has several "legacy" (inactive facility) sites which require remediation. These inactive sites range from refinery sites to retail locations.

It is not possible to predict with certainty the amount of additional investment in new or existing facilities required to be incurred in the future for environmental protection or to address regulatory compliance requirements, such as reporting. Although these costs may be significant, Husky does not expect that they will have a material adverse effect on liquidity and financial position over the long-term.

[1] "Environmental Expenditures by the U.S. Oil and Natural Gas Industry," 2011, American Petroleum Institute.

Risk Factors

The following factors should be considered in evaluating Husky:

Adequacy of crude oil and natural gas prices

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

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

Husky's natural gas production is located entirely in Western Canada and is, therefore, subject to North American market forces. North American natural gas supply and demand is affected by a number of factors including, but not limited to, the amount of natural gas available to specific market areas either from the well head or from storage facilities, prevailing weather patterns, the price of crude oil, the U.S. and Canadian economies, the occurrence of natural disasters and pipeline restrictions.

Demand for Husky's other products and services and the cost of required inputs

Husky's results of operations and financial condition are dependent on the price of refinery feedstock, the price of energy, the demand and pricing for refined petroleum products and electrical power and the ability of Husky to recover the increased cost of these inputs from the customer. Husky is also dependent on the demand for pipeline and processing capacity.

Reserves data and future net revenue estimates

The reserves data in this Annual Information Form represent estimates only. In general, estimates of economically recoverable crude oil and gas reserves and the future net cash flows there from are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the assumed effects of regulation by governmental agencies, including with respect to royalty payments, all of which may vary considerably from actual results. All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected there from, prepared by different engineers or by the same engineers at different times, may vary substantially.

Additions to reserves are required to maintain asset value and production

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

Competition

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

Delays and cost overruns of capital projects

Husky is involved in capital projects such as exploration programs, development of oil and gas properties, plant and facilities construction, expansion and modification. Project delays can adversely affect expected cash flow and overall project costs thereby eroding project economics. Risk factors include, but are not limited to:

- availability and cost of capital;
- availability of skilled labour;
- availability of manufacturing capacity, supplies, material and equipment;
- regulatory approvals;

- faulty construction and design errors;
- accidents, labour disruptions, bankruptcies and productivity issues affecting Husky directly or indirectly; and
- unexpected changes in the scope of a project.

Foreign exchange risk

Husky's results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of expenditures are in Canadian dollars. The majority of 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 the costs in Canadian dollars associated with Husky's U.S. dollar denominated debt. At December 31, 2011, 82% or $3.1 billion of Husky's long-term debt was denominated in U.S. dollars. The percentage of long-term debt exposed to the U.S./Cdn exchange rate decreases to 73% when cross currency swaps are included. Additionally, U.S. $1.3 billion of the Company's U.S. dollar denominated debt has been designated as a hedge of a net investment, further reducing the long-term debt exposed to the U.S./Cdn exchange rate to 27%.

The Company holds 50% of a contribution receivable representing BP's obligation to fund capital expenditures related to the Sunrise Oil Sands Project. The receivable is denominated in U.S. dollars and gains and losses from changes in the value of the Canadian dollar versus the U.S. dollar are recorded in net foreign exchange gains and losses in the current period earnings. At December 31, 2011, Husky's share of the balance of this receivable was U.S. $1.1 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 other comprehensive income in the Statement of Comprehensive Income as this item relates to a U.S. dollar functional currency foreign operation. At December 31, 2011, Husky's share of the balance of this obligation was U.S. $1.4 billion including accrued interest.

Operational risks and hazards

Husky's businesses are subject to inherent operational risks and hazards in respect of safety and the environment that requires continuous vigilance. The Company seeks to minimize these operational risks and hazards by carefully designing and building its facilities and conducting its operations in a safe and reliable manner. However, failure to manage these operational risks and hazards effectively could result in unexpected incidents, including releases of restricted substances, explosions, marine catastrophe or mechanical failures resulting in personal injuries, loss of life, environmental damage, property damage, loss of revenues, legal liability and/or disruption to operations. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks and hazards. Nonetheless, insurance proceeds may not be sufficient to cover all losses. Insurance coverage might not remain available for all types of operational risks and hazards at reasonable rates.

Environmental regulation

All phases of the oil and natural gas business are subject to environmental regulation pursuant to a variety of federal, provincial, state and local laws and regulations, as well as international conventions (collectively, "environmental legislation").

Environmental legislation imposes, among other things, restrictions, liabilities, and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. Environmental legislation also requires that wells, facilities and other properties associated with Husky's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments. Compliance with environmental legislation can require significant expenditures and failure to comply with environmental legislation may result in the imposition of fines and penalties and liability for clean-up costs and damages. Husky believes it is in material compliance with current environmental legislation.

Husky anticipates that changes in environmental legislation may require reductions in emissions from its operations and result in increased capital expenditures. Further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures

and operating costs, which could have a material adverse effect on our financial condition and results of operations.

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 operations. Stricter regulation of offshore oil and gas operations has already been implemented 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 the Gulf of Mexico. 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.

Husky continues to monitor the international efforts to address climate change, including developments on the Kyoto Protocol and the Copenhagen Accord. Canada has withdrawn from participation in the Kyoto Protocol. The effect of these initiatives on the Company's operations cannot be determined with any certainty at this time. The Federal Government of Canada has announced certain regulations in respect of greenhouse gases and other pollutants. Although the impact of these regulations is uncertain, they may adversely affect the Company's operations and increase costs. These regulations may become more onerous over time as public and political pressures increase to implement initiatives that further reduce the emission of greenhouse gases.

The United States Environmental Protection Agency ("EPA") has promulgated the so-called 'Tailoring Rule', which, beginning January 2, 2011, phases in over time restrictions on greenhouse gas emissions from stationary sources, including power plants and petroleum refineries, beginning with the largest emitters, where such sources are required to obtain a new or modified permit based on non-greenhouse gas emissions. The EPA has also promulgated regulations that require data collection and reporting of greenhouse gas emissions from stationary sources in the oil and gas industry. This reporting requirement applies to Husky's U.S. operations. While these EPA regulations are currently in effect, they have not yet had a material impact on Husky. Husky's operations may be impacted 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.

Changes to government fiscal policy

All of Husky's oil and gas production is subject to royalties which are potentially impacted by changes in government fiscal policies. The Company maintains close contact with governments in the areas within which it operates.

General economic conditions

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

Cost or availability of oil and gas field equipment

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

International operations

International operations can expose the Company to uncertain political, economic and other risks. The Company's operations in certain jurisdictions may be adversely affected by political, economic or social instability or events. These events may include, but are not limited to, acts of war, terrorism, abduction, expropriation, onerous fiscal policy, renegotiation or nullification of agreements, imposition of onerous regulation, financial constraints and unreasonable taxation. This could adversely affect the Company's interest in its foreign operations and future profitability.

Climatic conditions

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

Recruitment, retention and succession

Failure to retain current employees and attract new skilled employees could materially affect the Company's ability to conduct its business. Demand for qualified employees with appropriate experience remains high and may increase as a significant portion of the global workforce reaches retirement age in the near term.

Market access

The Company's results depend upon the Company's ability to deliver products to the most attractive markets. These results could be impacted due to lack of pipeline or other transportation alternatives, regulatory or other barriers. The Company seeks to minimize these risks by committing to multiple pipeline alternatives, maintaining proprietary storage access, pursuing new markets and utilizing a diverse market portfolio.

Credit rating risk

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.

Upstream Operations

Disclosures of Oil and Gas Activities

Production History

Average Gross Daily Production:	Year Ended	Three Months Ended			
	Dec 31, 2011	Dec 31, 2011	Sept 30, 2011	June 30, 2011	Mar 31, 2011
Canada – Western Canada					
Light crude oil and NGL (mbbls/day)	24.8	28.8	22.9	21.7	25.9
Medium Crude Oil (mbbls/day)	24.5	24.3	24.6	24.6	24.6
Heavy crude oil (mbbls/day)	74.5	75.8	75.1	73.6	73.4
Bitumen (mbbls/day)	24.7	27.4	23.6	23.6	24.2
Natural gas (mmcf/day)	607.0	597.9	614.7	631.8	583.3
Canada – Atlantic Region					
Light crude oil (mbbls/day)	54.3	54.6	53.4	53.7	55.5
China					
Light crude oil and NGL (mbbls/day)	8.5	8.3	7.0	9.1	9.6
Total gross production (mboe/day)	**312.5**	**318.9**	**309.1**	**311.6**	**310.4**

Average Gross Daily Production:	Year Ended	Three Months Ended			
	Dec 31, 2010	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010
Canada – Western Canada					
Light crude oil and NGL (mbbls/day)	23.0	23.0	23.5	22.5	23.4
Medium Crude Oil (mbbls/day)	25.4	25.3	25.7	25.1	25.3
Heavy crude oil (mbbls/day)	74.5	74.6	72.4	74.6	76.4
Bitumen (mbbls/day)	22.3	23.1	21.9	21.5	22.6
Natural gas (mmcf/day)	506.8	494.2	505.5	503.9	523.7
Canada – Atlantic Region					
Light crude oil (mbbls/day)	46.7	41.3	50.8	45.0	49.9
China					
Light crude oil and NGL (mbbls/day)	10.7	10.8	10.1	11.2	11.0
Total gross production (mboe/day)	**287.1**	**280.5**	**288.7**	**283.9**	**295.9**

Average Gross Daily Production:	Year Ended	Three Months Ended			
	Dec 31, 2009	Dec 31, 2009	Sept 30, 2009	June 30, 2009	Mar 31, 2009
Canada – Western Canada					
Light crude oil and NGL (mbbls/day)	22.8	22.4	23.0	21.7	24.2
Medium Crude Oil (mbbls/day)	25.4	24.8	24.8	25.6	26.3
Heavy crude oil (mbbls/day)	78.6	78.6	75.7	78.1	82.1
Bitumen (mbbls/day)	23.1	23.3	24.0	22.2	22.7
Natural gas (mmcf/day)	541.7	528.7	535.0	552.3	551.2
Canada – Atlantic Region					
Light crude oil (mbbls/day)	55.2	43.8	29.0	65.9	82.6
China					
Light crude oil (mbbl/day)	11.1	10.5	10.5	11.7	12.1
Total gross production (mboe/day)	**306.5**	**291.5**	**276.2**	**317.2**	**342.0**

The following tables show Husky's netback analysis by product and area. The netback analysis has been revised relative to previous years to provide greater detail at the product level. Prior periods are restated to reflect current presentation.

Average Per Unit Amounts:	**Year Ended**	**Three Months Ended**			
	Dec 31, 2011	**Dec 31, 2011**	**Sept 30, 2011**	**Jun 30, 2011**	**Mar 31, 2011**
Light crude oil and NGL ($/bbl)					
Canada – Western Canada					
Price received	81.38	86.71	74.16	85.29	78.55
Royalties	17.04	19.98	14.77	17.20	15.52
Production costs	22.88	22.02	21.16	23.78	24.68
Netback	41.46	44.71	38.23	44.31	38.35
Canada – Atlantic Canada					
Price received	112.11	114.65	110.50	115.39	107.95
Royalties	19.36	22.35	17.12	19.61	18.31
Production costs	8.75	8.54	9.82	9.00	7.67
Transportation costs [(1)]	1.52	1.59	1.62	0.97	1.72
Netback	82.48	82.17	81.94	85.81	80.25
Canada – Total					
Price received [(1)]	105.33	107.59	102.69	110.83	100.50
Royalties	18.25	21.37	16.02	18.32	17.05
Production costs	13.49	13.47	13.44	13.64	13.43
Netback	73.59	72.75	73.23	78.87	70.02
China					
Price received	110.49	115.55	109.76	111.85	105.25
Royalties	32.75	36.39	32.34	37.22	25.54
Production costs	8.17	9.18	10.41	7.38	6.34
Netback	69.57	69.98	67.01	67.25	73.37
Company Total					
Price received [(1)]	102.31	105.02	99.40	106.68	98.13
Royalties	20.00	22.87	17.76	20.89	18.28
Production costs	12.70	12.83	12.98	12.62	12.37
Netback	69.61	69.32	68.66	73.17	67.48
Medium crude oil ($/bbl)					
Canada – Western Canada					
Price received	75.65	84.32	70.11	80.27	67.83
Royalties	14.13	15.24	13.58	15.24	12.41
Production costs	19.76	20.97	21.14	17.69	19.21
Netback	41.76	48.11	35.39	47.34	36.21
Heavy crude oil ($/bbl)					
Canada – Western Canada					
Price received	66.99	75.60	61.61	71.59	58.86
Royalties	8.83	9.47	8.09	9.88	7.86
Production costs	18.53	18.51	18.94	18.36	18.29
Netback	39.63	47.62	34.58	43.35	32.71
Bitumen ($/bbl)					
Canada – Western Canada					
Price received	64.34	73.24	58.70	68.62	55.41
Royalties	8.69	9.75	6.73	7.91	10.18
Production costs	19.01	19.76	18.43	19.31	18.45
Netback	36.64	43.73	33.54	41.40	26.78
Natural gas ($/mcf)					
Canada – Western Canada [(2)]					
Price received	3.75	3.40	3.97	3.86	3.77
Royalties	0.18	0.23	0.17	0.19	0.13
Production costs	1.81	1.86	1.95	1.78	1.66
Netback	1.76	1.31	1.85	1.89	1.98

(1) Transportation costs are shown separately from price in Canada – Atlantic Region. This cost category is netted against price when calculating Canada Total and Company Total balances.

(2) Includes sulphur sales and royalties.

Average Per Unit Amounts:	Year Ended	Three Months Ended			
	Dec 31, 2010	Dec 31, 2010	Sept 30, 2010	Jun 30, 2010	Mar 31, 2010
Light crude oil and NGL ($/bbl)					
Canada – Western Canada					
Price received	66.40	69.84	62.34	64.02	69.41
Royalties	14.49	11.62	14.08	14.89	17.38
Production costs	16.25	17.49	10.59	17.69	19.45
Netback	35.66	40.73	37.67	31.44	32.58
Canada – Atlantic Canada					
Price received	82.16	89.65	79.43	79.49	81.10
Royalties	19.25	16.35	16.49	21.78	22.28
Production costs	10.33	11.43	10.48	11.20	8.45
Transportation costs [1]	1.55	1.32	1.32	1.83	1.72
Netback	51.03	60.55	51.14	44.68	48.65
Canada – Total					
Price received [1]	79.01	85.30	76.46	76.12	78.72
Royalties	17.62	14.05	15.41	19.83	21.04
Production costs	12.56	14.13	10.35	13.86	12.23
Netback	48.83	57.12	50.70	42.43	45.45
China [2]					
Price received	83.38	89.62	79.67	84.17	79.71
Royalties	19.11	21.86	17.32	18.48	18.67
Production costs	6.06	6.28	7.69	6.23	4.11
Netback	58.21	61.48	54.66	59.46	56.93
Company Total					
Price received [1]	76.91	82.86	73.90	74.68	76.65
Royalties	17.87	15.69	15.91	19.34	20.45
Production costs	11.46	12.55	10.18	12.34	10.95
Netback	47.58	54.62	47.81	43.00	45.25
Medium crude oil ($/bbl)					
Canada – Western Canada					
Price received	64.92	65.75	60.88	63.90	69.30
Royalties	11.58	10.96	10.37	11.83	13.21
Production costs	16.46	15.30	15.91	17.98	16.71
Netback	36.88	39.49	34.60	34.09	39.38
Heavy crude oil ($/bbl)					
Canada – Western Canada					
Price received	58.91	58.82	56.96	56.18	63.31
Royalties	8.63	7.67	8.25	8.58	10.02
Production costs	15.77	16.63	15.91	15.58	14.94
Netback	34.51	34.52	32.80	32.02	38.35
Bitumen ($/bbl)					
Canada – Western Canada					
Price received	57.84	59.14	55.41	52.58	61.82
Royalties	8.51	7.54	9.30	9.06	8.21
Production costs	20.37	21.70	17.99	19.56	22.08
Netback	28.96	29.90	28.12	23.96	31.53
Natural gas ($/mcf)					
Canada – Western Canada [2]					
Price received	3.92	3.62	3.54	3.51	4.99
Royalties	0.23	0.17	0.23	0.18	0.32
Production costs	1.76	1.70	2.01	1.66	1.70
Netback	1.93	1.75	1.30	1.67	2.97

(1) Transportation costs are shown separately from price in Canada – Atlantic Region. This cost category is netted against price when calculating Canada Total and Company Total balances.

(2) Includes sulphur sales and royalties.

Average Per Unit Amounts:	Year Ended	Three Months Ended			
	Dec 31, 2009	Dec 31, 2009	Sept 30, 2009	Jun 30, 2009	Mar 31, 2009
Light crude oil and NGL ($/bbl)					
Canada – Western Canada					
Price received	54.60	65.44	59.93	51.48	42.01
Royalties	11.39	13.87	12.14	9.56	9.93
Production costs	17.15	18.44	11.14	19.41	19.72
Netback	26.06	33.13	36.65	22.51	12.36
Canada – Atlantic Canada					
Price received	66.52	78.71	73.47	70.44	54.24
Royalties	16.34	18.51	17.32	19.04	12.64
Production costs	8.80	8.26	22.84	7.73	4.90
Transportation costs [1]	2.09	2.49	4.05	2.14	1.11
Netback	39.29	49.45	29.26	41.53	35.59
Canada – Total					
Price received [1]	63.90	75.48	69.33	66.80	52.00
Royalties	14.78	16.83	14.95	16.74	11.85
Production costs	11.48	12.23	18.97	10.76	8.16
Netback	37.64	46.42	35.41	39.30	31.99
China					
Price received	69.75	79.16	78.51	74.45	48.74
Royalties	12.01	17.88	15.33	11.59	4.15
Production costs	5.50	7.53	5.25	4.45	4.94
Netback	52.24	53.75	57.93	58.41	39.65
Company Total					
Price received [1]	62.59	73.47	67.54	65.33	50.42
Royalties	14.53	17.07	15.09	16.09	11.23
Production costs	10.52	11.13	15.49	9.92	7.91
Netback	37.54	45.27	36.96	39.32	31.28
Medium crude oil ($/bbl)					
Canada – Western Canada					
Price received	56.37	65.78	61.28	58.32	40.68
Royalties	8.79	10.15	11.52	8.02	5.57
Production costs	15.50	14.81	15.58	14.83	16.77
Netback	32.08	40.82	34.18	35.47	18.34
Heavy crude oil ($/bbl)					
Canada – Western Canada					
Price received	52.54	61.55	59.21	54.22	35.80
Royalties	7.40	8.85	8.57	8.14	4.18
Production costs	13.56	14.90	13.29	12.22	13.76
Netback	31.58	37.80	37.35	33.86	17.86
Bitumen ($/bbl)					
Canada – Western Canada					
Price received	51.90	60.70	58.44	53.32	34.23
Royalties	7.10	14.07	6.70	5.65	1.67
Production costs	16.34	20.02	13.50	13.88	17.96
Netback	28.46	26.61	38.24	33.79	14.60
Natural gas ($/bbl)					
Canada – Western Canada [2]					
Price received	3.84	3.97	2.83	3.25	5.30
Royalties	0.17	0.29	(0.11)	(0.16)	0.69
Production costs	1.59	1.38	1.77	1.59	1.59
Netback	2.08	2.30	1.17	1.82	3.02

(1) Transportation costs are shown separately from price in Canada – Atlantic Region. This cost category is netted against price when calculating Canada Total and Company Total balances.

(2) Includes sulphur sales and royalties.

Producing and Non-Producing Wells [1] [2] [3]

Productive Wells

	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Canada						
Alberta	4,607	3,792	5,883	4,371	10,490	8,163
Saskatchewan	6,753	5,797	1,416	1,293	8,169	7,090
British Columbia	200	58	304	264	504	322
Newfoundland	28	11	-	-	28	11
	11,588	9,658	7,603	5,928	19,191	15,586
International						
China	33	13	-	-	33	13
As at December 31, 2011	11,621	9,671	7,603	5,928	19,224	15,599
Canada						
Alberta	4,484	3,580	5,770	4,407	10,254	7,987
Saskatchewan	6,582	5,488	1,446	1,311	8,028	6,799
British Columbia	204	59	283	242	487	301
Newfoundland	25	9	-	-	25	9
	11,295	9,136	7,499	5,960	18,794	15,096
International						
China	32	13	-	-	32	13
Libya	3	1	-	-	3	1
	35	14	-	-	35	14
As at December 31, 2010	11,330	9,150	7,499	5,960	18,829	15,110
Canada						
Alberta	4,281	3,395	5,834	4,480	10,115	7,875
Saskatchewan	5,818	4,789	1,395	1,261	7,213	6,050
British Columbia	203	58	253	214	456	272
Newfoundland	23	8	-	-	23	8
	10,325	8,250	7,482	5,955	17,807	14,205
International						
China	31	12	-	-	31	12
Libya	2	1	-	-	2	1
	33	13	-	-	33	13
As at December 31, 2009	10,358	8,263	7,482	5,955	17,840	14,218

Non-Producing Wells

	2011					
	Oil Wells		Natural Gas Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Canada	4,442	3,916	1,571	1,327	6,013	5,243
Libya	3	1	-	-	3	1
	4,445	3,917	1,571	1,327	6,016	5,244

(1) The number of gross wells is the total number of wells in which Husky owns a working interest. The number of net wells is the sum of the fractional interests owned in the gross wells. Productive wells are those producing or capable of producing at December 31, 2011.

(2) The above table does not include producing wells in which Husky has no working interest but does have a royalty interest. At December 31, 2011, Husky had a royalty interest in 4,087 wells of which 1,246 were oil producers and 2,841 were gas producers.

(3) For purposes of the above table, multiple completions are counted as a single well. Where one of the completions in a given well is an oil completion, the well is classified as an oil well. In 2011, there were 476 gross and 458 net oil wells and 942 gross and 729 net natural gas wells which were completed in two or more formations and from which production is not commingled.

Landholdings

	Developed Acreage	
	Gross	**Net**
	(thousands of acres)	
As at December 31, 2011		
Western Canada		
Alberta	4,594	2,908
Saskatchewan	878	699
British Columbia	187	147
Manitoba	19	2
	5,678	3,756
Eastern Canada	58	20
	5,736	3,776
China	17	7
Libya	7	2
	5,760	3,785
As at December 31, 2010		
Western Canada		
Alberta	4,172	2,729
Saskatchewan	891	704
British Columbia	172	133
Manitoba	2	-
	5,237	3,566
Eastern Canada	54	18
	5,291	3,584
China	17	7
Libya	7	2
	5,315	3,593
As at December 31, 2009		
Western Canada		
Alberta	4,100	2,692
Saskatchewan	856	672
British Columbia	168	128
	5,124	3,492
Eastern Canada	54	18
	5,178	3,510
China	17	7
Libya	7	2
	5,202	3,519

Landholdings (continued)

	Undeveloped Acreage	
	Gross	**Net**
	(thousands of acres)	
As at December 31, 2011		
Western Canada		
Alberta	5,353	3,930
Saskatchewan	1,654	141
British Columbia	1,037	774
Manitoba	3	1
	8,047	4,846
Canada – Northwest Territories and Arctic	1,156	633
Canada – Atlantic Region	5,548	3,339
	14,751	8,818
United States	1,076	398
China	990	484
Indonesia	1,628	1,213
Greenland	8,471	5,983
	26,916	16,896
As at December 31, 2010		
Western Canada		
Alberta	4,801	3,407
Saskatchewan	1,712	1,522
British Columbia	1,020	747
Manitoba	4	1
	7,537	5,677
Canada – Northwest Territories and Arctic	943	303
Canada – Atlantic Region	4,777	2,989
	13,257	8,969
United States	1,100	484
China	990	990
Indonesia	1,940	1,595
Greenland	8,471	5,983
	25,758	18,021
As at December 31, 2009		
Western Canada		
Alberta	4,941	3,523
Saskatchewan	1,571	1,384
British Columbia	996	739
Manitoba	4	1
	7,512	5,647
Canada – Northwest Territories and Arctic	1,207	487
Canada – Atlantic Region	5,128	3,137
	13,847	9,271
United States	1,707	422
China	1,970	1,970
Indonesia	1,940	1,595
Greenland	8,471	5,983
	27,935	19,241

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

The Company has a $376 million work commitment associated with its undeveloped land holdings in the Canadian Northwest Territories and Arctic. In total, the Company has $549 million in exploration work commitments to be incurred over the next five years. Over the next 12 months, approximately 916,000 net undeveloped acres or less than 5% of the Company's net undeveloped landholdings in Canada will be subject to expiry.

Husky holds interests in a diverse portfolio of undeveloped petroleum assets in Western Canada, the Atlantic Region and in several other areas (offshore Greenland, China and Indonesia, the United States and the Canadian North West Territories and Arctic). As part of its active portfolio management, Husky continually reviews the economic viability of its undeveloped properties using industry standard economic evaluation techniques and pricing and economic environment assumptions. Each year, as part of this active management process, some properties are selected for further development activities, while others are held in abeyance, sold, swapped or relinquished back to the mineral rights owner. There is no guarantee that commercial reserves will be discovered or developed on these properties.

Drilling Activity

	Year ended December 31					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Canada – Western Canada						
Exploration						
Oil	50	40	60	51	18	9
Gas	24	24	37	31	37	22
Dry	3	3	8	8	7	6
	77	67	105	90	62	37
Development						
Oil	880	765	815	722	315	278
Gas	57	42	73	53	122	61
Dry	4	4	10	9	7	7
	941	811	898	784	444	346
	1,018	878	1,003	874	506	383
Canada – Atlantic Region						
Development						
Oil	3	2.1	2	1.4	-	-
China						
Exploration						
Dry	-	-	-	-	1	0.5
Development						
Oil	1	0.4	1	0.4	2	0.8
Gas	4	2.0	2	1.0	-	-
	5	2.4	3	1.4	2	0.8

Service/Stratigraphic Test Wells	2011	
	Gross	Net
Canada – Western Canada	211	189.0
Canada – Atlantic Region	2	0.9
China	8	6.8

Current Activities

	Exploratory		Development	
Wells Drilling [1]	Gross	Net	Gross	Net
Canada – Western Canada	9	8.5	27	24.5
Canada – Atlantic Region	-	-	-	-
China	-	-	1	0.5

Service/Stratigraphic Test Wells [1]	2011	
	Gross	Net
Canada	5	3.0

[1] Denotes wells that were being drilled at February 20, 2012.

Costs Incurred

	2011							
	Total	Western Canada	Atlantic Region	Total Canada	United States	China	Indonesia	Libya
	($ millions)							
Property acquisition								
Unproven	82	82	-	82	-	-	-	-
Proven	792	792	-	792	-	-	-	-
Exploration	723	342	115	457	1	233	32	-
Development	2,935	2,131	258	2,389	-	546	-	-
	4,532	3,347	373	3,720	1	779	32	-

	2010 [1]							
	Total	Western Canada	Atlantic Region	Total Canada	United States	China	Indonesia	Libya
	($ millions)							
Property acquisition								
Unproven	62	62	-	62	-	-	-	-
Proven	327	327	-	327	-	-	-	-
Exploration	687	210	96	306	-	369	12	-
Development	2,048	1,589	396	1,985	-	60	-	3
	3,124	2,188	492	2,680	-	429	12	3

	2009 [1]							
	Total	Western Canada	Atlantic Region	Total Canada	United States	China	Indonesia	Libya
	($ millions)							
Property acquisition								
Unproven	89	87	-	87	2	-	-	-
Proven	220	220	-	220	-	-	-	-
Exploration	841	228	95	323	23	458	37	-
Development	1,150	628	510	1,138	-	7	-	5
	2,300	1,163	605	1,768	25	465	37	5

[1] In 2011, the Company revised its definition of costs incurred on exploration and development activities to exclude asset retirement and other environmental reclamation costs. Prior periods have been restated to conform to the current year's presentation.

Oil and Gas Reserves Disclosures

Husky's oil and gas reserves are estimated in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH") and the reserve data disclosed conforms with the requirements of NI 51-101. Husky's oil and gas reserves are prepared by internal reserves evaluation staff using a formalized process for determining, approving and booking reserves. This process requires all reserves evaluations to be done on a consistent basis using established definitions and guidelines. Approval of individually significant reserve changes requires review by an internal panel of qualified reserves evaluators.

The material differences between reserve quantities disclosed under NI 51-101 and those disclosed under the U.S. Rules is that NI 51-101 requires the determination of reserve quantities to be based on forecast pricing assumptions whereas the U.S. Rules require the determination of reserve quantities to be based on constant price assumptions calculated using a 12 month average price for the year (sum of the benchmark price on the first calendar day of each month in the year divided by 12).

Audit of Oil and Gas Reserves

McDaniel & Associates Consultants Ltd., an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and NGL reserve estimates. McDaniel & Associates Consultants Ltd. issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values based on forecast assumptions are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the COGEH.

Note that the numbers in each column of the tables throughout this section may not add due to rounding.

Summary of Oil and Natural Gas Reserves
As at December 31, 2011
Forecast Prices and Costs

Canada

	Light Crude Oil (mmbbls)		Medium Crude Oil (mmbbls)		Heavy Crude Oil (mmbbls)		Bitumen (mmbbls)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	146.4	122.5	75.4	65.6	73.5	65.1	55.8	50.2
Developed Non-producing	1.9	1.6	1.6	1.4	13.1	12.3	-	-
Undeveloped	22.5	20.4	12.6	11.5	26.2	23.6	252.7	218.8
Total Proved	170.8	144.5	89.6	78.5	112.7	101.0	308.5	269.0
Probable	97.8	83.6	19.2	15.9	37.9	33.9	1,400.7	1,116.8
Total Proved Plus Probable	268.6	228.1	108.8	94.4	150.6	134.9	1,709.3	1,385.8

	Coal Bed Methane (bcf)		Natural Gas (bcf)		Natural Gas Liquids (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	24.4	22.9	1,744.0	1,524.6	63.6	49.3	709.4	610.5
Developed Non-producing	1.5	1.3	146.2	132.7	1.3	1.0	42.5	38.7
Undeveloped	9.0	8.6	327.4	311.9	10.5	8.7	380.6	336.4
Total Proved	34.9	32.8	2,217.7	1,969.2	75.4	58.9	1,132.5	985.6
Probable	1.9	1.8	559.2	480.0	17.8	13.8	1,667.0	1,344.2
Total Proved Plus Probable	36.8	34.6	2,776.9	2,449.2	93.3	72.8	2,799.5	2,329.8

China

	Light Crude Oil (mmbbls)		Medium Crude Oil (mmbbls)		Heavy Crude Oil (mmbbls)		Bitumen (mmbbls)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	4.8	3.4	-	-	-	-	-	-
Developed Non-producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	4.8	3.4	-	-	-	-	-	-
Probable	3.1	2.2	-	-	-	-	-	-
Total Proved Plus Probable	7.9	5.6	-	-	-	-	-	-

	Coal Bed Methane (bcf)		Natural Gas (bcf)		Natural Gas Liquids (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	-	-	-	-	0.1	0.1	4.9	3.4
Developed Non-producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	-	-	-	0.1	0.1	4.9	3.4
Probable	-	-	-	-	0.1	0.1	3.2	2.3
Total Proved Plus Probable	-	-	-	-	0.2	0.2	8.0	5.7

Indonesia

	Light Crude Oil (mmbbls)		Medium Crude Oil (mmbbls)		Heavy Crude Oil (mmbbls)		Bitumen (mmbbls)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	-	-	-	-	-	-	-	-
Developed Non-producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	-	-	-	-	-	-	-
Probable	-	-	-	-	-	-	-	-
Total Proved Plus Probable	-	-	-	-	-	-	-	-

	Coal Bed Methane (bcf)		Natural Gas (bcf)		Natural Gas Liquids (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	-	-	-	-	-	-	-	-
Developed Non-producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	167.2	108.8	7.2	3.6	35.0	21.7
Total Proved	-	-	167.2	108.8	7.2	3.6	35.0	21.7
Probable	-	-	39.4	21.0	1.7	0.6	8.2	4.1
Total Proved Plus Probable	-	-	206.6	129.8	8.8	4.1	43.3	25.8

Total

	Light Crude Oil (mmbbls)		Medium Crude Oil (mmbbls)		Heavy Crude Oil (mmbbls)		Bitumen (mmbbls)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	151.1	125.8	75.4	65.6	73.5	65.1	55.8	50.2
Developed Non-producing	1.9	1.6	1.6	1.4	13.1	12.3	-	-
Undeveloped	22.5	20.4	12.6	11.5	26.2	23.6	252.7	218.8
Total Proved	175.5	147.9	89.6	78.5	112.7	101.0	308.5	269.0
Probable	100.9	85.7	19.2	15.9	37.9	33.9	1,400.7	1,116.8
Total Proved Plus Probable	276.4	233.6	108.8	94.4	150.6	134.9	1,709.3	1,385.8

	Coal Bed Methane (bcf)		Natural Gas (bcf)		Natural Gas Liquids (mmbbls)		Total (mmboe)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved:								
Developed Producing	24.4	22.9	1,744.0	1,524.6	63.7	49.4	714.3	613.9
Developed Non-producing	1.5	1.3	146.2	132.7	1.3	1.0	42.5	38.7
Undeveloped	9.0	8.6	494.6	420.7	17.7	12.2	415.6	358.1
Total Proved	34.9	32.8	2,384.8	2,078.0	82.7	62.6	1,172.4	1,010.7
Probable	1.9	1.8	598.6	501.0	19.6	14.5	1,678.4	1,350.6
Total Proved Plus Probable	36.8	34.6	2,983.5	2,579.0	102.3	77.1	2,850.8	2,361.3

Summary of Net Present Values of Future Net Revenue
As at December 31, 2011
Forecast Prices and Costs

Canada

	Before Income Taxes and Discounted at (%/year)			
($ millions)	5%	10%	15%	20%
Proved:				
Developed Producing	14,808	11,956	10,152	8,898
Developed Non-producing	947	745	615	523
Undeveloped	5,104	3,082	1,906	1,164
Total Proved	20,860	15,782	12,673	10,585
Probable	16,666	7,591	4,288	2,753
Total Proved Plus Probable	37,525	23,373	16,962	13,337

China

	Before Income Taxes and Discounted at (%/year)			
($ millions)	5%	10%	15%	20%
Proved:				
Developed Producing	304	289	275	262
Developed Non-producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved	304	289	275	262
Probable	229	202	180	162
Total Proved Plus Probable	532	491	455	424

Indonesia

	Before Income Taxes and Discounted at (%/year)			
($ millions)	5%	10%	15%	20%
Proved:				
Developed Producing	-	-	-	-
Developed Non-producing	-	-	-	-
Undeveloped	290	195	132	89
Total Proved	290	195	132	89
Probable	55	30	17	11
Total Proved Plus Probable	345	225	149	100

Total

	Before Income Taxes and Discounted at (%/year)			
($ millions)	5%	10%	15%	20%
Proved:				
Developed Producing	15,112	12,245	10,428	9,161
Developed Non-producing	947	745	615	523
Undeveloped	5,394	3,277	2,038	1,253
Total Proved	21,454	16,266	13,081	10,936
Probable	16,949	7,823	4,485	2,925
Total Proved Plus Probable	38,403	24,089	17,566	13,861

Summary of Net Present Values of Future Net Revenue
As at December 31, 2011
Forecast Prices and Costs

Canada

	After Income Taxes and Discounted at (%/year)			
($ millions)	5%	10%	15%	20%
Proved:				
Developed Producing	10,964	8,842	7,500	6,567
Developed Non-producing	697	545	448	379
Undeveloped	3,746	2,167	1,247	667
Total Proved	15,408	11,554	9,195	7,612
Probable	12,185	5,383	2,926	1,795
Total Proved Plus Probable	27,592	16,936	12,121	9,408

China

	After Income Taxes and Discounted at (%/year)			
($ millions)	5%	10%	15%	20%
Proved:				
Developed Producing	203	194	185	176
Developed Non-producing	-	-	-	-
Undeveloped	-	-	-	-
Total Proved	203	194	185	176
Probable	154	135	120	108
Total Proved Plus Probable	357	329	305	284

Indonesia

	After Income Taxes and Discounted at (%/year)			
($ millions)	5%	10%	15%	20%
Proved:				
Developed Producing	-	-	-	-
Developed Non-producing	-	-	-	-
Undeveloped	196	131	87	56
Total Proved	196	131	87	56
Probable	33	18	11	7
Total Proved Plus Probable	229	149	98	63

Total

	After Income Taxes and Discounted at (%/year)			
($ millions)	5%	10%	15%	20%
Proved:				
Developed Producing	11,167	9,036	7,684	6,743
Developed Non-producing	697	545	448	379
Undeveloped	3,942	2,298	1,334	723
Total Proved	15,807	11,878	9,466	7,845
Probable	12,371	5,536	3,057	1,910
Total Proved Plus Probable	28,178	17,414	12,523	9,755

Total Future Net Revenue for Total Proved Reserves - Undiscounted
As at December 31, 2011
Forecast Prices and Costs

($ millions)	Revenue	Royalties	Operating Costs	Develop-ment Cost	Abandon-ment and Reclama-tion Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada								
Proved:								
Developed Producing	46,883	8,013	14,864	1,599	2,282	20,125	5,207	14,919
Developed Non-producing	2,370	280	623	139	-	1,328	345	983
Undeveloped	26,647	3,740	8,532	5,302	60	9,014	2,223	6,790
Total Proved	75,900	12,033	24,019	7,040	2,342	30,467	7,775	22,692
Probable	152,872	31,567	50,142	19,177	246	51,741	13,084	38,657
Total Proved Plus Probable	228,772	43,600	74,160	26,216	2,587	82,208	20,859	61,349
China								
Proved:								
Developed Producing	500	36	129	-	17	318	106	212
Developed Non-producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	500	36	129	-	17	318	106	212
Probable	323	25	14	22	-	262	85	177
Total Proved Plus Probable	823	60	143	22	17	580	191	389
Indonesia								
Proved:								
Developed Producing	-	-	-	-	-	-	-	-
Developed Non-producing	-	-	-	-	-	-	-	-
Undeveloped	1,053	-	464	150	-	439	143	296
Total Proved	1,053	-	464	150	-	439	143	296
Probable	196	-	88	-	-	109	44	64
Total Proved Plus Probable	1,249	-	551	150	-	548	187	360
Total								
Proved:								
Developed Producing	47,384	8,048	14,993	1,599	2,299	20,444	5,313	15,131
Developed Non-producing	2,370	280	623	139	-	1,328	345	983
Undeveloped	27,700	3,740	8,995	5,452	60	9,453	2,367	7,086
Total Proved	77,454	12,068	24,611	7,190	2,360	31,224	8,024	23,200
Probable	153,391	31,592	50,244	19,199	246	52,111	13,214	38,898
Total Proved Plus Probable	230,844	43,660	74,855	26,389	2,605	83,336	21,238	62,098

Future Net Revenue by Production Group
As at December 31, 2011
Forecast Prices and Costs

	Future Net Revenue Before Income Taxes (discounted at 10%/year)							
	Canada		China		Indonesia		Total	
	($millions)	*($/boe)*	*($millions)*	*($/boe)*	*($millions)*	*($/boe)*	*($millions)*	*($/boe)*
Proved								
Developed producing								
Light crude oil & NGL	4,794	33	289	84	-	-	5,084	34
Medium crude oil	1,391	21	-	-	-	-	1,391	21
Heavy crude oil	1,533	24	-	-	-	-	1,533	24
Natural gas	2,853	10	-	-	-	-	2,853	10
Coal bed methane	27	7	-	-	-	-	27	7
Bitumen	1,357	27	-	-	-	-	1,357	27
Developed non-producing								
Light crude oil & NGL	60	37	-	-	-	-	60	37
Medium crude oil	51	36	-	-	-	-	51	36
Heavy crude oil	402	33	-	-	-	-	402	33
Natural gas	231	10	-	-	-	-	231	10
Coal bed methane	1	6	-	-	-	-	1	6
Bitumen	-	-	-	-	-	-	-	-
Undeveloped								
Light crude oil & NGL	548	27	-	-	-	-	548	27
Medium crude oil	239	21	-	-	-	-	239	21
Heavy crude oil	558	24	-	-	-	-	558	24
Natural gas	120	2	-	-	195	9	315	4
Coal bed methane	1	1	-	-	-	-	1	1
Bitumen	1,615	7	-	-	-	-	1,615	7
Total Proved								
Light crude oil & NGL	5,403	32	289	84	-	-	5,692	33
Medium crude oil	1,681	21	-	-	-	-	1,681	21
Heavy crude oil	2,492	25	-	-	-	-	2,492	25
Natural gas	3,204	9	-	-	195	9	3,399	9
Coal bed methane	30	5	-	-	-	-	30	5
Bitumen	2,973	11	-	-	-	-	2,973	11
Probable								
Light crude oil & NGL	2,275	25	202	88	-	-	2,477	27
Medium crude oil	416	26	-	-	-	-	416	26
Heavy crude oil	755	22	-	-	-	-	755	22
Natural gas	519	6	-	-	30	7	549	6
Coal bed methane	4	13	-	-	-	-	4	13
Bitumen	3,622	3	-	-	-	-	3,622	3
Total Proved Plus Probable								
Light crude oil & NGL	7,678	30	491	86	-	-	8,169	31
Medium crude oil	2,097	22	-	-	-	-	2,097	22
Heavy crude oil	3,248	24	-	-	-	-	3,248	24
Natural gas	3,723	8	-	-	225	9	3,948	8
Coal bed methane	33	6	-	-	-	-	33	6
Bitumen	6,594	5	-	-	-	-	6,594	5

Pricing Assumptions

The pricing assumptions disclosed in the table below were derived using the industry averages prescribed by McDaniel & Associates Consultants Ltd, Sproule Associates Limited, and GLJ Petroleum Consultants Ltd.

	Crude Oil		Natural Gas			
	WTI (USD $/bbl)	Brent (USD $/bbl)	NYMEX (USD $/mmbtu)	NIT (Cdn $/GJ)	Inflation rates [1]	Exchange rates [2]
Historical:						
2007	72.31	72.52	6.86	6.26		0.931
2008	99.65	96.99	9.04	7.70		0.937
2009	61.80	61.54	3.99	3.92		0.880
2010	79.46	79.42	4.39	3.91		0.971
2011	95.12	111.27	4.04	3.48		1.011
Forecast:						
2012	97.52	106.38	3.70	3.21	2.0%	0.989
2013	97.47	103.25	4.39	3.83	2.0%	0.989
2014	97.33	100.77	4.86	4.24	2.0%	0.989
2015	99.41	102.25	5.65	4.96	2.0%	0.989
2016	100.36	103.24	6.01	5.28	2.0%	0.989

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rate used to generate the benchmark reference prices.

Reconciliation of Gross Proved Reserves

	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Bitumen (mmbbls)	Total (mmboe)
Canada – Western Canada						
End of 2010	133.7	87.7	110.2	2,186.0	246.8	942.9
Revisions – Technical	(3.7)	0.4	6.9	(0.8)	1.8	5.3
Revisions – Economic	(2.2)	0.1	-	(184.6)	-	(32.9)
Purchases	41.2	0.1	4.4	398.1	-	112.0
Sales	-	-	(2.5)	(1.3)	-	(2.8)
Discoveries	1.4	-	-	9.8	-	3.0
Extensions	7.5	6.1	20.0	65.8	64.8	109.5
Improved recovery	1.1	4.3	0.8	1.0	4.1	10.4
Production	(9.1)	(8.9)	(27.2)	(221.5)	(9.0)	(91.1)
End of 2011	169.9	89.6	112.7	2,252.6	308.5	1,056.2
Canada – Atlantic Region						
End of 2010	87.5	-	-	-	-	87.5
Revisions – Technical	3.9	-	-	-	-	3.9
Revisions – Economic	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Sales	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Extensions	1.4	-	-	-	-	1.4
Improved recovery	3.3	-	-	-	-	3.3
Production	(19.8)	-	-	-	-	(19.8)
End of 2011	76.3	-	-	-	-	76.3
China						
End of 2010	7.1	-	-	-	-	7.1
Revisions – Technical	0.7	-	-	-	-	0.7
Revisions – Economic	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Sales	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Extensions	0.2	-	-	-	-	0.2
Improved recovery	-	-	-	-	-	-
Production	(3.1)	-	-	-	-	(3.1)
End of 2011	4.9	-	-	-	-	4.9
Indonesia						
End of 2010	9.0	-	-	209.0	-	43.8
Revisions – Technical	-	-	-	-	-	-
Revisions – Economic	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Sales	(1.8)	-	-	(41.8)	-	(8.8)
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Production	-	-	-	-	-	-
End of 2011	7.2	-	-	167.2	-	35.0
Libya						
End of 2010	0.2	-	-	-	-	0.2
Revisions – Technical	(0.2)	-	-	-	-	(0.2)
Revisions – Economic	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Sales	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Production	-	-	-	-	-	-
End of 2011	-	-	-	-	-	-

	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	Total Company (mmboe)
Total			
End of 2010	682.3	2,395.0	1,081.5
Revisions – Technical	9.9	(0.8)	9.8
Revisions – Economic	(2.2)	(184.6)	(32.9)
Purchases	45.7	398.1	112.0
Sales	(4.4)	(43.1)	(11.6)
Discoveries	1.4	9.8	3.0
Extensions	100.0	65.8	111.0
Improved recovery	13.5	1.0	13.7
Production	(77.1)	(221.5)	(114.1)
End of 2011	769.1	2,419.8	1,172.4

Major additions to proved reserves in 2011 include:

- 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 oil and gas properties in Alberta and British Columbia resulted in booking of 108 mmboe in proved reserves; and
- the extension through additional drilling locations at Ansell in the Alberta Deep Basin area resulting in the booking of 12 mmboe of natural gas and natural gas liquids in proved reserves.

Reconciliation of Gross Probable Reserves

	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Bitumen (mmbbls)	Total (mmboe)
Canada – Western Canada						
End of 2010	43.4	20.2	32.4	579.4	1,039.8	1,232.4
Revisions – Technical	(4.5)	(2.1)	(1.1)	(19.4)	(0.7)	(11.6)
Revisions – Economic	(0.6)	-	-	(69.8)	-	(12.2)
Revisions – Transfer to Proved	(0.8)	(0.8)	(7.4)	(12.1)	(0.6)	(11.8)
Purchases	11.0	-	7.8	58.3		28.5
Sales	-	-	(0.7)	(0.1)	-	(0.7)
Discoveries	-	-	-	3.1	-	-
Extensions	1.6	0.8	6.9	21.5	358.6	371.5
Improved recovery	0.4	1.1	-	0.1	3.7	5.3
Production	-	-	-	-	-	-
End of 2011	50.6	19.2	37.9	561.1	1,400.7	1,601.9
Canada – Atlantic Region						
End of 2010	71.4	-	-	-	-	71.4
Revisions – Technical	(1.5)	-	-	-	-	(1.5)
Revisions – Economic	-	-	-	-	-	-
Revisions – Transfer to Proved	(4.9)	-	-	-	-	(4.9)
Purchases	-	-	-	-	-	-
Sales	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Production	-	-	-	-	-	-
End of 2011	65.0	-	-	-	-	65.0
China						
End of 2010	3.3	-	-	-	-	3.3
Revisions – Technical	(0.1)	-	-	-	-	(0.1)
Revisions – Economic		-	-	-	-	
Revisions – Transfer to Proved	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Sales	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Production	-	-	-	-	-	-
End of 2011	3.2	-	-	-	-	3.2
Indonesia						
End of 2010	2.1	-	-	43.9	-	10.3
Revisions – Technical	-	-	-	-	-	-
Revisions – Economic	-	-	-	-	-	-
Revisions – Transfer to Proved	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Sales	(0.4)	-	-	(4.5)	-	(2.1)
Discoveries	-	-	-	-	-	-
Extension	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Production		-	-	-	-	-
End of 2011	1.7	-	-	39.4	-	8.2

	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	Total Company (mmboe)
Total			
End of 2010	1,212.6	628.7	1,317.4
Revisions – Technical	(10.0)	(19.4)	(13.2)
Revisions – Economic	(0.6)	(69.8)	(12.2)
Revisions – Transfer to Proved	(14.6)	(12.1)	(16.6)
Purchases	18.8	58.3	28.5
Sales	(1.1)	(10.0)	(2.8)
Discoveries	-	3.1	0.6
Extensions	367.9	21.5	371.5
Improved recovery	5.2	0.1	5.3
Production	-	-	-
End of 2011	1,578.3	600.5	1,678.4

Major changes to probable reserves in 2011 include:

- the extension through additional drilling and seismic interpretation of the Sunrise Energy Project that resulted in transferring 351 mmbbls of bitumen from possible reserves to probable reserves; and
- the acquisition of properties resulted in booking of 19 mmboe in probable reserves.

Reconciliation of Gross Proved Plus Probable Reserves

	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Bitumen (mmbbls)	Total (mmboe)
Canada – Western Canada						
End of 2010	177.2	107.9	142.6	2,765.4	1,286.6	2,175.2
Revisions – Technical	(8.1)	(1.8)	5.9	(20.2)	1.1	(6.3)
Revisions – Economic	(2.8)	0.1	-	(254.3)	-	(45.1)
Revisions – Transfer to Proved	(0.8)	(0.8)	(7.4)	(12.1)	(0.6)	(11.8)
Purchases	52.2	0.1	12.2	456.4	-	140.6
Sales	(0.1)	-	(3.3)	(1.4)	-	(3.5)
Discoveries	1.4	-	-	13.0	-	3.6
Extensions	9.1	6.9	26.9	87.3	423.4	481.0
Improved recovery	1.5	5.4	0.8	1.1	7.7	15.6
Production	(9.1)	(8.9)	(27.2)	(221.5)	(9.0)	(91.1)
End of 2011	220.5	108.8	150.6	2,813.7	1,709.3	2,658.1
Canada – Atlantic Region						
End of 2010	158.9	-	-	-	-	158.9
Revisions – Technical	2.5	-	-	-	-	2.5
Revisions – Economic	-	-	-	-	-	-
Revisions – Transfer to Proved	(4.9)	-	-	-	-	(4.9)
Purchases	-	-	-	-	-	-
Sales	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Extensions	1.4	-	-	-	-	1.4
Improved recovery	3.3	-	-	-	-	3.3
Production	(19.8)	-	-	-	-	(19.8)
End of 2011	141.3	-	-	-	-	141.3
China						
End of 2010	10.4	-	-	-	-	10.4
Revisions – Technical	0.5	-	-	-	-	0.5
Revisions – Economic	-	-	-	-	-	-
Revisions – Transfer to Proved	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Sales	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Extensions	0.2	-	-	-	-	0.2
Improved recovery	-	-	-	-	-	-
Production	(3.1)	-	-	-	-	(3.1)
End of 2011	8.0	-	-	-	-	8.0
Indonesia						
End of 2010	11.1	-	-	258.3	-	54.1
Revisions – Technical	-	-	-	-	-	-
Revisions – Economic	-	-	-	-	-	-
Revisions – Transfer to Proved	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Sales	(2.2)	-	-	(51.7)	-	(10.8)
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Production	-	-	-	-	-	-
End of 2011	8.8	-	-	206.6	-	43.3
Libya						
End of 2010	0.2	-	-	-	-	0.2
Revisions – Technical	(0.2)	-	-	-	-	(0.2)
Revisions – Economic	-	-	-	-	-	-
Revisions – Transfer to Proved	-	-	-	-	-	-
Purchases	-	-	-	-	-	-
Sales	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-
Production	-	-	-	-	-	-
End of 2011	-	-	-	-	-	-

	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	Total Company (mmboe)
Total			
End of 2010	1,894.9	3,023.6	2,398.8
Revisions – Technical	(0.1)	(20.2)	(3.4)
Revisions – Economic	(2.7)	(254.3)	(45.1)
Revisions – Transfer to Proved	(14.6)	(12.1)	(16.6)
Purchases	64.5	456.4	140.6
Sales	(5.5)	(53.0)	(14.4)
Discoveries	1.4	13.0	3.6
Extensions	468.0	87.3	482.5
Improved recovery	18.7	1.1	18.9
Production	(77.1)	(221.5)	(114.1)
End of 2011	2,347.4	3,020.3	2,850.8

Undeveloped Reserves

Undeveloped reserves are attributed internally in accordance with standards and procedures contained in the COGEH. Proved undeveloped oil and gas reserves are those reserves that can be estimated with a high degree of certainty to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Probable undeveloped oil and gas reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves. Classifications of reserves as proved or probable are only attempts to define the degree of uncertainty associated with the estimates. In addition, whereas proved reserves are those reserves that can be estimated with a high degree of certainty to be economically producible, probable reserves are those reserves that are as likely as not to be recovered. Therefore, probable reserves estimates, by definition, have a higher degree of uncertainty than proved reserves.

Husky funds capital programs by cash generated from operating activities, cash on hand, equity issuances, and short-term and long-term debt. Decisions to develop proved undeveloped and probable undeveloped reserves are based on various factors including economic conditions, technical performance and size of the development program. Approximately 43% of Husky's gross proved undeveloped reserves are assigned to the Sunrise Energy Project. Phase I of this project was sanctioned in November 2010 and the drilling program for Phase I (49 well pairs) is on track to be completed by the second half of 2012, with over half of the wells drilled as of December 31, 2011. First production is expected in 2014. As at December 31, 2011, there are no material proved undeveloped reserves that have remained undeveloped for greater than five years.

Proved Undeveloped Reserves

First attributed	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Bitumen (mmbbls)	Natural Gas (bcf)	Total Oil & NGL (mmbbls)
Year						
Prior	44.7	8.7	38.0	68.1	490.6	160.0
2009	10.4	0.9	9.7	69.2	35.4	90.1
2010	17.1	4.7	7.5	65.6	294.1	94.8
2011	7.0	6.0	10.1	68.8	33.8	91.9

Probable Undeveloped Reserves

First attributed	Light Crude Oil & NGL (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Bitumen (mmbbls)	Natural Gas (bcf)	Total Oil & NGL (mmbbls)
Year						
Prior	130.3	7.7	31.3	1,791.7	229.3	1,961.0
2009	1.9	0.3	9.7	3.4	33.4	15.2
2010	7.1	3.8	8.7	2.8	47.0	22.4
2011	6.3	1.9	12.5	362.2	21.2	382.9

Future Development Costs – Undiscounted

Forecast Prices and Costs

The Company expects to fund its future development costs by cash generated from operating activities, cash on hand, and short-term and long-term debt. The Company also has access to available amounts through credit facilities on which it can draw funds and the ability to issue equity through shelf prospectuses. The cost associated with this funding would not affect reserves and would not be material in comparison with future net revenues.

($million)	Canada		China		Indonesia	
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves	Proved Plus Probable Reserves
2012	1,803	2,161	-	17	13	13
2013	1,412	1,867	-	5	78	78
2014	775	1,251	-	-	60	60
2015	565	1,578	-	-	-	-
2016	414	1,613	-	-	-	-
Remaining	4,413	20,334	17	17	-	-
Total	9,382	28,804	17	40	150	150

($million)	Total	
Year	Proved Reserves	Proved Plus Probable Reserves
2012	1,816	2,191
2013	1,490	1,949
2014	835	1,311
2015	565	1,578
2016	414	1,613
Remaining	4,431	20,351
Total	9,550	28,993

Additional Information Concerning Abandonment and Reclamation Costs

The Company estimates the costs associated with abandonment and reclamation costs for surface leases, wells, facilities, and pipelines through its previous experience, where available, or by estimating such costs. With respect to abandonment and reclamation costs for surface leases, wells, facilities, and pipelines, the Company expects to incur these costs on approximately 28,100 net wells for a total undiscounted amount of $2.6 billion. Discounted at 10% per year, the total abandonment costs, net of estimated salvage value, for wells is $612 million. This amount was deducted in estimating the future net revenue. Of the undiscounted portion of the total abandonment and reclamation costs, $149 million is expected to be paid in the next three years.

Production Estimates
Yearly Production Estimates for 2012

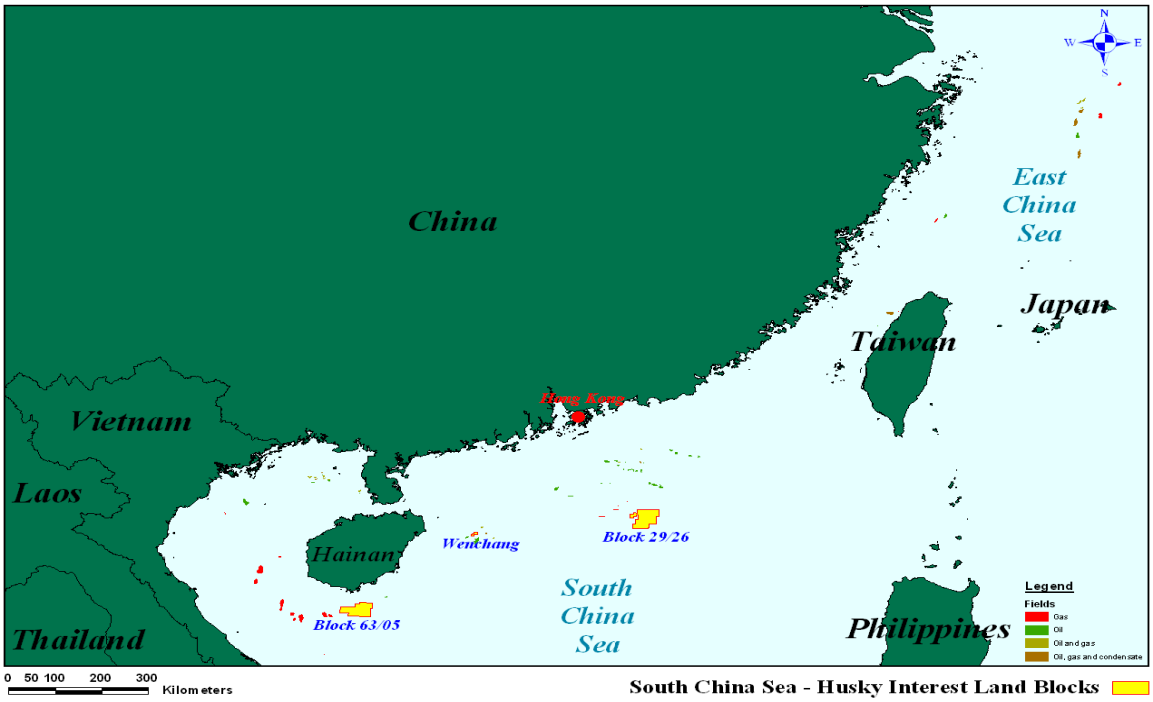
	Light Crude Oil (mmbbls)	Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Natural Gas (bcf)	Bitumen (mmbbls)
Canada:					
Total gross proved	22.2	9.1	25.2	199.9	12.0
Total gross probable	0.8	0.3	1.1	4.9	0.3
Total gross proved plus probable	23.0	9.4	26.3	204.9	12.3
International:					
Total gross proved	1.9	-	-	-	-
Total gross probable	0.4	-	-	-	-
Total gross proved plus probable	2.3	-	-	-	-
Total					
Total gross proved	24.1	9.1	25.2	199.9	12.0
Total gross probable	1.2	0.3	1.1	4.9	0.3
Total gross proved plus probable	25.3	9.4	26.3	204.9	12.3

No individual property accounts for 20% or more of the estimated production disclosed.

Description of Major Properties and Facilities

Husky's portfolio of Upstream assets includes properties with reserves of light crude oil (30° API and lighter), medium crude oil (between 20° and 30° API), heavy crude oil (between 20° API and 10° API and is liquid), bitumen (solid or semi-solid with a viscosity greater than 10,000 centipoise at original temperature in the deposit and atmospheric pressure), NGL, natural gas and sulphur.

China



Wenchang

The Wenchang field is located in the western Pearl River Mouth Basin, approximately 400 kilometers south of Hong Kong and 100 kilometers east of Hainan Island. Husky holds a 40% working interest in two oil fields, which commenced production in July 2002. The Wenchang 13-1 and 13-2 oil fields are currently producing from 32 wells in 100 meters of water into an FPSO vessel stationed between fixed platforms located in each of the two fields. The blended crude oil from the two fields averages approximately 35° API. Husky's gross production averaged 8.4 mbbls/day during 2011.

Block 29/26

Husky executed a PSC with CNOOC for the Contract Area 29/26 exploration block on October 1, 2004. The block is located in the Pearl River Mouth Basin of the South China Sea approximately 300 kilometers southeast of Hong Kong and 65 kilometers southeast of the Panyu gas discovery. The third Exploration Phase of the PSC has been completed and the retained area for development and production is approximately 55,100 acres (223 square kilometers).

In 2006, Husky drilled the Liwan 3-1-1 well natural gas discovery. The well was drilled in 1,500 meters of water to a total depth of 3,843 meters. In 2010 the Government of China approved the Original-Gas-in-Place ("OGIP") report for the Liwan 3-1 field. During 2009, Husky discovered an additional gas field at Liuhua 34-2, approximately 23 kilometers to the northeast of the Liwan 3-1 field. In 2010, the Company drilled into another natural gas discovery at Liuhua 29-1, approximately 43 kilometers to the northeast of the Liwan 3-1 field. In 2011, the Company drilled two exploration wells in the Liwan gas field without encountering commercial amounts of hydrocarbon and an additional exploration well in the Liuhua gas field which was cased and suspended in anticipation of further evaluation in 2012.

The Liwan 3-1 natural gas field development FEED study was initiated in the second quarter of 2009 and completed in early 2010. The design contemplates that the Liwan 3-1 field would use a subsea production system connected to a central shallow water platform by flow lines. The platform will then be connected by pipeline to an onshore gas plant with access to the energy markets of Hong Kong and Guangdong province on the China Mainland. The Liuhua 34-2 field and Liuhua 29-1 field discoveries will also be tied into the proposed shallow water infrastructure.

In late 2010, Husky Oil China Ltd. signed a Heads of Agreement with CNOOC which specified CNOOC's election to participate in the development of the Block 29/26 discoveries to its maximum 51% working interest and key principles of the partnership to fund, develop and operate the Liwan 3-1 deep water gas field. It was agreed that the project would be separated into deep water and shallow water development projects with Husky acting as deep water operator and CNOOC acting as shallow water operator.

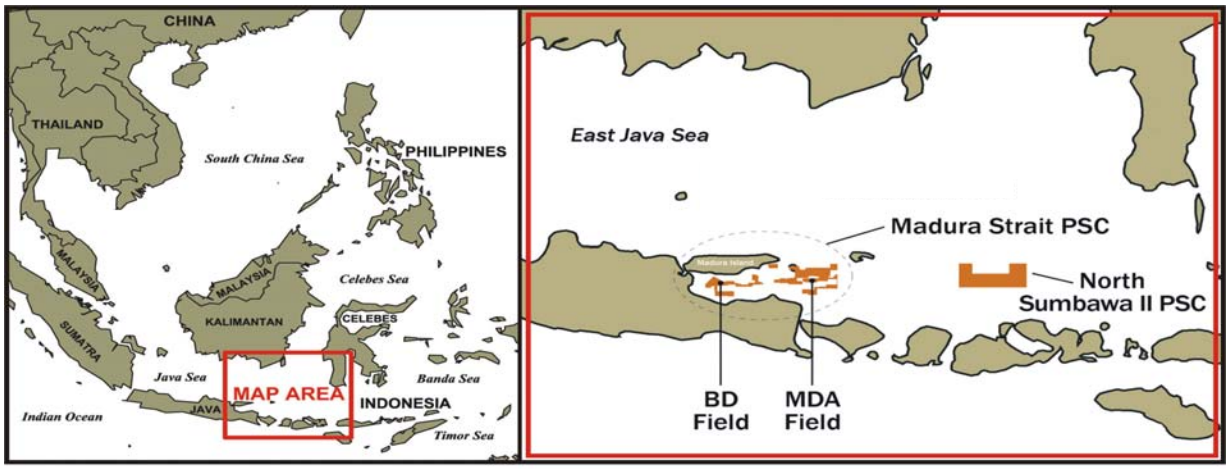
In 2011, Husky completed tendering the major deep water equipment and installation activity and CNOOC commenced the shallow water pipe laying and onshore gas plant construction. A gas sales agreement was executed with CNOOC Gas & Power Group, Guangdong Branch for volumes from the Liwan 3-1 field and the Overall Development Plan for the Liwan 3-1 field development was submitted to the Chinese government authorities for regulatory approval.

The project is proceeding on schedule towards planned first gas delivery in 2013/2014. The Liuhua 34-2 field is planned to be developed for first gas delivery on the same timetable. Production from the Liwan 3-1 and Liuhua 34-2 fields is expected to ramp up through 2014 towards a rate above 300 mmcf/day (gross). Once the Liuhua 29-1 field is approved and developed, the project is expected to reach gross production of approximately 500 mmcf/day in the 2015 time-frame.

Block 63/05

Husky executed a PSC with CNOOC for the Contract Area 63/05 exploration block on June 25, 2008. The block is located in the Qiongdongnan Basin of the South China Sea approximately 50 kilometers south of Hainan Island and covers an area of approximately 439,100 acres (1,777 square kilometers). In 2011, Husky drilled an exploration well, in accordance with the minimum exploration work commitment of the first phase of the exploration period, without encountering commercial amounts of hydrocarbon. Having identified no further prospects on the block, Husky requested and CNOOC agreed to terminate the PSC.

Indonesia



Madura Strait

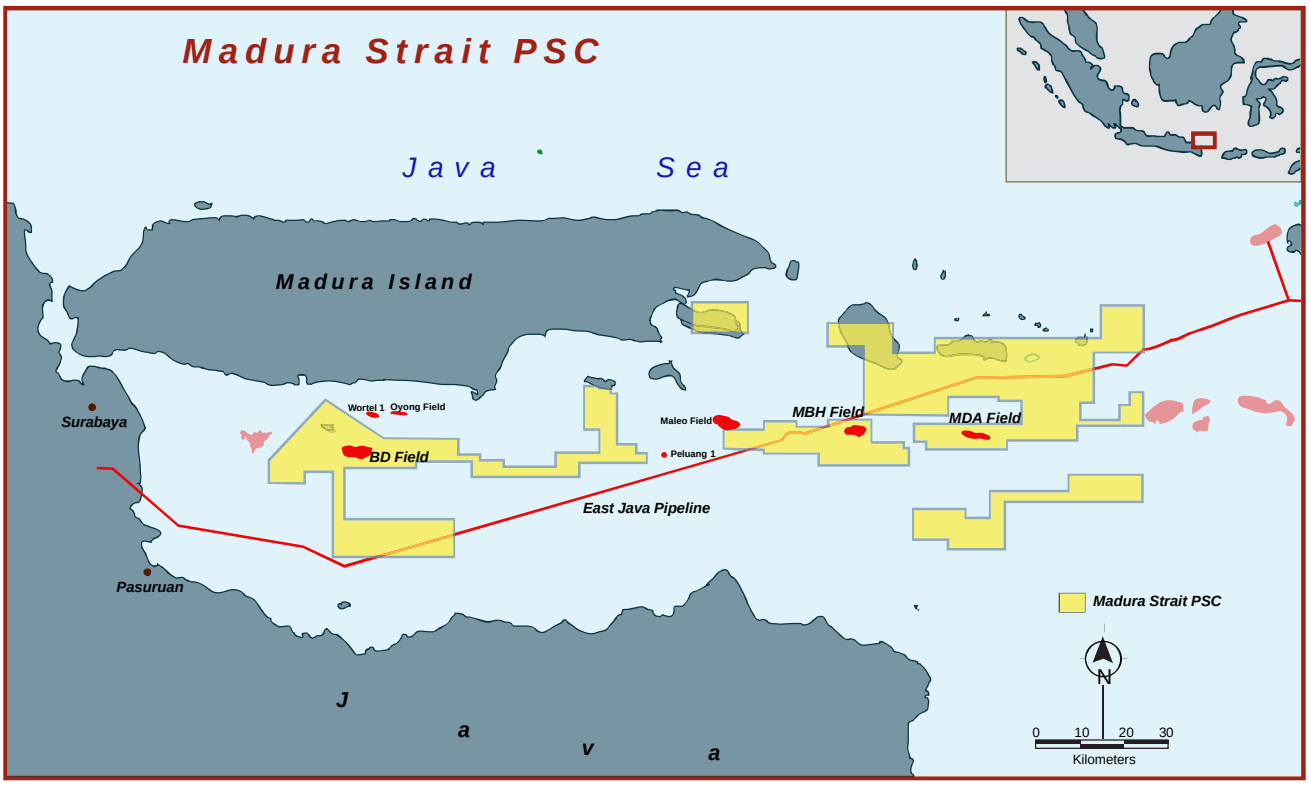
Husky has a 40% interest in approximately 690,400 acres (2,800 square kilometers) of the Madura Strait block, located offshore East Java, south of Madura Island, Indonesia. Husky's two partners are CNOOC which is the operator and has a 40% working interest, and Samudra Energy Ltd., an affiliate of SMS Development Ltd. which has the remaining 20% interest.

The BD gas field was granted commercial status and the Plan of Development was approved by the Indonesian state oil company in 1995. The field was to supply natural gas to a proposed independent power plant; however, construction of the power plant did not proceed due to economic issues that occurred in Indonesia at that time and as a result the BD development was deferred. Market conditions became more favourable for the BD development to supply gas to meet the demand of the East Java region and an updated development plan was approved in 2008 by the Government of Indonesia.

In October 2010, the Government of Indonesia approved an extension of the PSC that was originally awarded in 1982. The approval provided a 20-year extension to the contract which now runs until 2032. FEED was completed in the second quarter of 2010 and gas sales contracts previously signed in 2010 with three gas buyers were amended in 2011. Tendering for a FPSO, wellhead platform and sales pipeline is in progress.

Also in 2011, CNOOC drilled an appraisal well which confirmed commercial quantities of hydrocarbons in the MDA field. An exploration well was also drilled in 2011 on the MBH field and a new gas field was discovered. Studies are in progress to consider development of the MDA and MBH fields together as a cluster development.

First production from the block is planned for 2014.



North Sumbawa II

Husky executed a PSC in November 2008 with the Government of Indonesia for the North Sumbawa II contract area. Husky holds a 100% interest in the North Sumbawa II block, which is located in the East Java Basin approximately 300 kilometers east of the Madura Strait block and covers an area of 1,249,831 acres (5,058 square kilometers). The PSC requires the acquisition of two dimensional ("2-D") seismic with a commitment of U.S. $2 million, and the drilling of one exploration well with a commitment of U.S. $10 million within the first four years of the contract, including an approved one year extension. Husky satisfied its seismic work commitment by acquiring 1,020 kilometers of 2-D seismic data in December 2009. Husky has used this data to identify a potential exploration prospect and drilling is under consideration.

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. Husky holds a portfolio of exploration licences offshore Greenland.

White Rose Oil Field

The White Rose oil field is located 354 kilometers off the coast of Newfoundland and Labrador approximately 48 kilometers east of the Hibernia oil field on the eastern section of the Jeanne d'Arc Basin. Husky is the operator of the White Rose field and satellite tiebacks, including North Amethyst and West White Rose, and has a 72.5% working interest in the core field, and a 68.875% working interest in the satellite fields.

First oil was achieved at White Rose in November 2005. The White Rose field was the third oil field developed offshore Newfoundland and Labrador. The field currently has eight production wells, 10 water injectors, and three gas injectors. Husky continues to look at means of enhancing oil recovery from the core field. During 2011, Husky's gross production from the White Rose field averaged 23.9 mbbls/day.

On May 31, 2010, first oil was achieved from North Amethyst, the first satellite field extension for the White Rose field. The field is located approximately six kilometers southwest of the SeaRose FPSO vessel. Production flows from North Amethyst to the SeaRose FPSO through a series of subsea flow lines. During 2011, Husky's gross production from North Amethyst averaged 23.6 mbbls/day. As of December 31, 2011, the field had three production wells and three water injection wells. Development drilling is expected to continue through 2013. Up to 11 wells are currently planned for the main North Amethyst development.

In December 2011, Husky filed a Development Plan Amendment ("DPA") with the Canada-Newfoundland and Labrador Offshore Petroleum Board requesting approval to produce from a second, deeper formation at North Amethyst. Drilled in 2008, the Hibernia formation well is expected to provide incremental recovery from the field. The DPA currently envisions drilling one production well and one water injector, utilizing existing infrastructure at the North Amethyst Drill Centre. Further assessment of the Hibernia sandstone potential beneath the main White Rose field is continuing.

Husky continues to progress plans for a staged development of the West White Rose field through a two-well pilot project. First production was achieved in September 2011 with Husky's cumulative gross production of approximately 455,000 barrels in the third and fourth quarters of 2011 or 3.9 mbbls/day during the same period. A supporting water injection well has been drilled to total depth and is expected to be completed in 2012. These wells will provide additional information on the reservoir to refine development plans for the full West White Rose field.

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 in the first quarter of 2012. The South White Rose extension, the smallest of the satellite tie-back developments, was approved by the federal and provincial governments in September 2007. Husky continues to look at this area in the context of all three tie-back opportunities with a view toward optimizing the overall White Rose Extension Project.

Husky continues to consider technical options for the development of natural gas in the Jeanne d'Arc Basin.

Terra Nova Oil Field

The Terra Nova oil field is located approximately 350 kilometers southeast of St. John's, Newfoundland & Labrador in 91 to 100 meters of water. The Terra Nova oil field is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Production at Terra Nova commenced in January 2002.

Effective December 1, 2010, Husky's working interest in the field increased to 13.00% from 12.51%, following completion of a redetermination process.

Husky's gross production in 2011 from the Terra Nova field was 2.0 mmbbls or an average 5.6 mbbls/day.

As at December 31, 2011, there were 14 development wells drilled in the Graben area, eight production wells, three water injection wells and three gas injection wells. In the East Flank area there were 12 development wells including seven production wells and five water injection wells. There is one extended reach producer and an extended reach water injection well in the Far East area. Terra Nova owners signed a new rig sharing agreement in 2010 and completed one new development well in August 2011. Drilling operations are expected to continue in 2012 on two additional development wells.

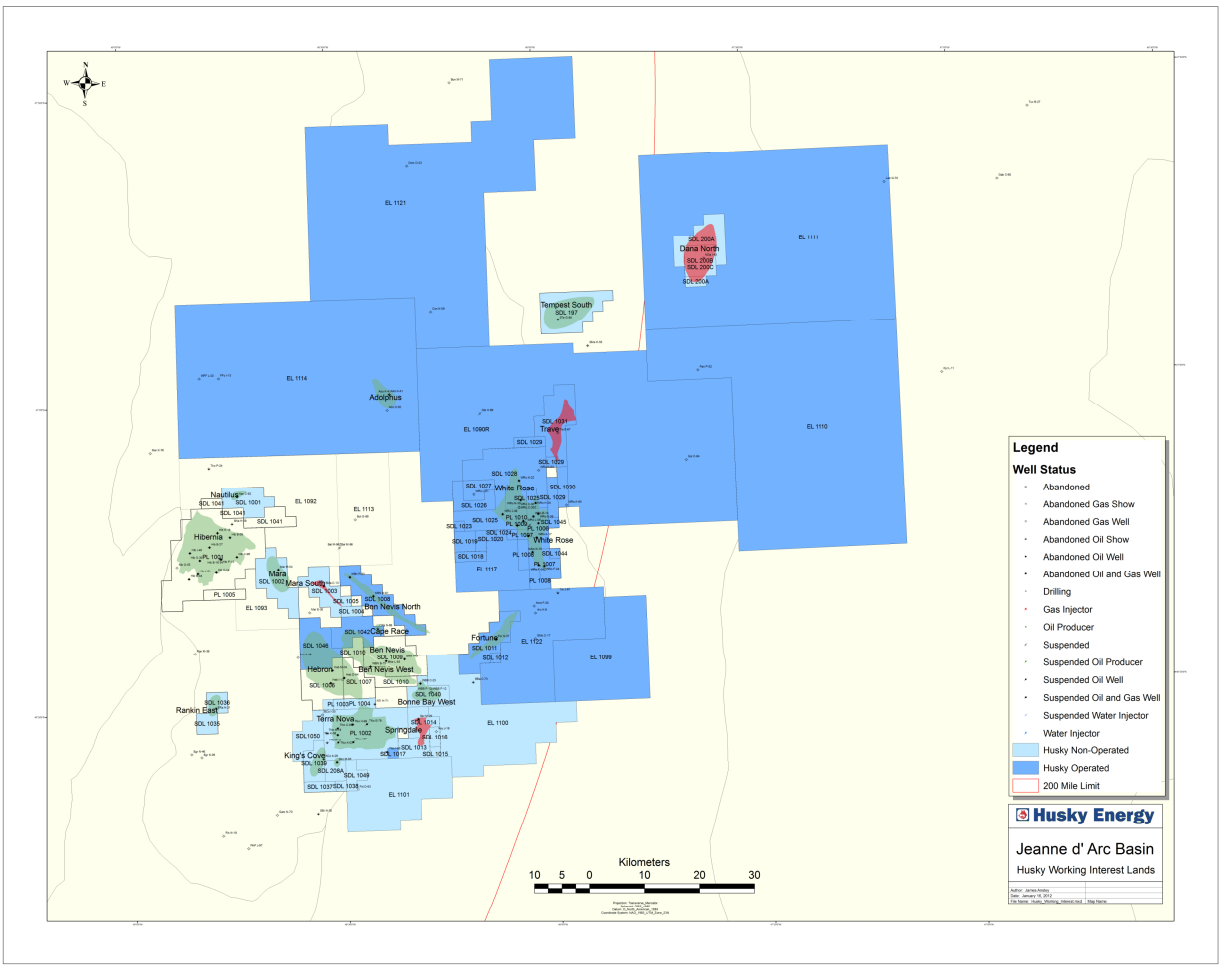
East Coast Exploration

Husky believes that the areas offshore Canada's East Coast have exploration potential, and that the Company's position there will provide growth opportunities for light crude oil and natural gas development in the medium to long-term. Husky presently holds working interests ranging from 5.8% to 73.125% in 18 significant discovery licence areas ("SDLs") in the Jeanne d'Arc Basin, as well as interests ranging from 17.1% to 19.4% in five SDLs on the Labrador Shelf, a region that could be significant, in the long-term, for natural gas reserves.

Husky participated in two exploration and delineation wells in 2011. A delineation well was drilled on the Mizzen SDL in the third quarter of 2011, while an exploration well was drilled on the Fiddlehead prospect, south of the Terra Nova field, in the fourth quarter of 2011. The results of both wells are still being evaluated. Husky is a 50% partner in the Fiddlehead well, and holds a 35% working interest at Mizzen.

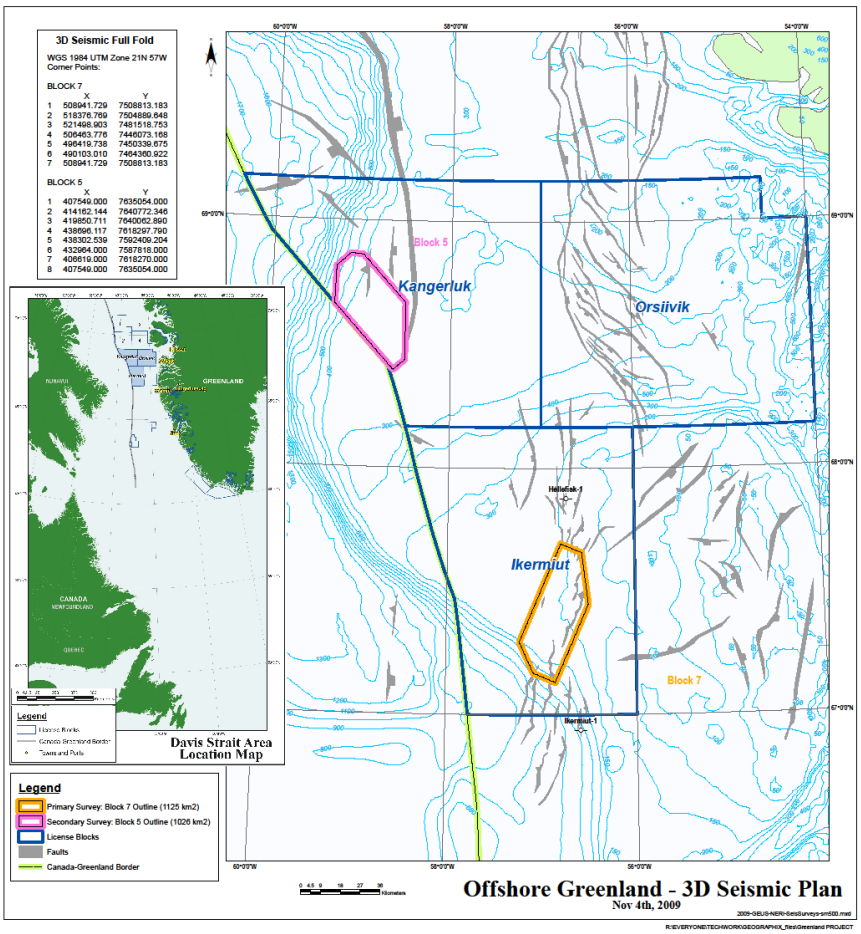
As of January 31, 2012, Husky held a working interest in 18 Exploration Licences ("ELs") offshore Newfoundland and Labrador and Greenland, primarily in the Jeanne d'Arc Basin. Husky is the operator for 13 of these EL's and has working interests ranging from 13% to 100%.

Husky continues to evaluate drilling opportunities in the context of its full portfolio of Atlantic Region land holdings, and plans to participate in one to two exploration wells in 2012.



Greenland

Husky holds three ELs totalling 34,280 square kilometers offshore the west coast of Disko Island, Greenland. Husky has acquired 2,200 square kilometers of three dimensional ("3-D") seismic over the two Husky operated licences 2007/22 and 2007/24 (Husky 87.5% working interest). This program represents the first 3-D seismic acquired offshore Greenland. In 2011, evaluation of this seismic data resulted in the identification of several potential drilling locations and work will continue in 2012 to further evaluate these opportunities.



Oil Sands

Sunrise Energy Project

On March 31, 2008, Husky and BP completed a transaction that created an integrated North American oil sands business. The business comprises a 50/50 partnership to develop the Sunrise Energy Project, operated by Husky, and a 50/50 limited liability company for the Toledo, Ohio Refinery, operated by BP.

FEED for Phase I of the Sunrise in-situ SAGD oil sands project, located in the Athabasca region of northern Alberta, was completed in December 2009. During 2010, the partnership reached an agreement on the movement of diluted bitumen to market and transportation of diluent to the Sunrise oil sands site. Project sanction for Phase I was announced in late 2010 and Husky awarded major engineering and construction contracts for the central processing and field facilities. Development drilling commenced in the first quarter of 2011. First production for Phase I is planned for 2014.

The Sunrise Energy Project was approved by the ERCB in December 2005. An amendment to the application was submitted in April of 2007, which outlined changes and optimizations resulting from ongoing depletion planning and FEED. Amendment approvals from the ERCB were received in January 2009 and approval from Alberta Environment was received in the first quarter of 2009. A second amendment to optimize the central plant facility design was filed with the regulators in July 2009 and approval was received from both the ERCB and Alberta Environment in December 2009. To date Husky has regulatory approvals to produce 200 mbbls/day.

The drilling program for Phase I (49 well pairs) is on track to be completed by the second half of 2012, with over half of the wells drilled as of December 31, 2011. Work is ongoing with various industry participants on regional infrastructure initiative; an air strip became operational in 2008 and a new access road was completed in 2010.

Tucker Oil Sands Project

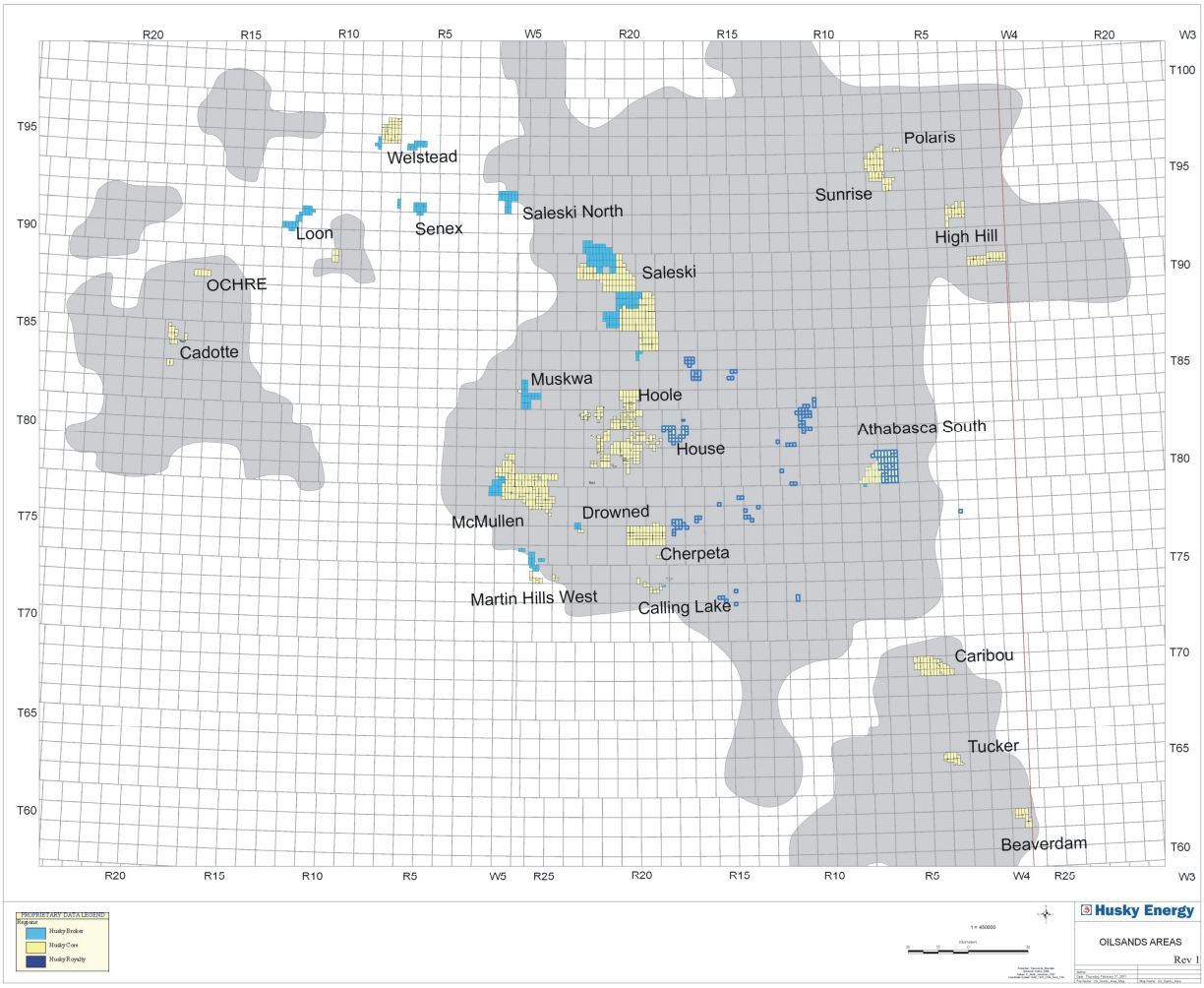
Tucker is an in-situ SAGD oil sands project located 30 kilometers northwest of Cold Lake, Alberta that commenced production at the end of 2006. Based on a greater understanding of the Tucker reservoir, Husky is addressing production challenges by remediating older wells with innovative new stimulation techniques, drilling new wells and initiating new start up procedures, the results of which will be evaluated over the next six to twelve months. Husky drilled 32 wells (16 well pairs) in 2010 and another eight wells (four well pairs) in 2011. Gross production at Tucker in December 2011 was 9.5 mbbls/day. Several applications to the ERCB have been approved or are proceeding for additional drilling and field development through 2015.

Undeveloped Oil Sands Assets

Husky holds approximately 550,000 acres in 13 undeveloped oil sands leases. Husky has a 100% working interest in the leases except in Athabasca South in which it has a 50% working interest.

In Saleski, just north of the Hamlet of Wabasca, Alberta, Husky is drilling wells to high-grade its acreage and selecting an initial pilot production area by 2013. Husky's pilot is expected to be on stream by the middle of the decade.

Further portfolio activity is expected to focus on accelerating and highgrading the development of Husky's other oil sands leases.



Heavy Oil

Lloydminster Heavy Oil and Gas

Husky's heavy oil assets are primarily concentrated in a large producing region in the Lloydminster, Alberta/Saskatchewan area. The Company maintains a land position of approximately two million gross acres within this area. Over 90% of Husky's proved reserves in the region are contained in the heavy crude oil producing areas of Pikes Peak, Edam, Tangleflags, Celtic, Bolney, Paradise Hill, Westhazel, Big Gully, Mervin, Marwayne, Lashburn, Gully Lake, Vermilion, Swimming, Morgan, Lindbergh, Aberfieldy, Mardsen, Epping, Furness and Rush Lake, and in the medium gravity crude oil producing fields of Wildmere and Wainwright. These fields contain accumulations of heavy crude oil at relatively shallow depths and are all located within 100 kilometers of the town of Lloydminster, Alberta.

Husky currently produces from oil and gas wells ranging in depth from 450 meters to 650 meters and holds a 100% working interest in the majority of these wells. Production of heavy oil from the Lloydminster area uses a variety of techniques, including primary production methods, horizontal well technology, cyclic steam stimulation ("CSS"), and SAGD. Husky has increased primary production from the area through cold production techniques which utilize progressive cavity pumps capable of simultaneous production of sand and heavy oil from unconsolidated formations. Husky's gross heavy and medium crude oil production from the area totalled 80.0 mbbls/day in 2011. Of the total gross crude oil production, 60.3 mbbls/day was primary production of heavy crude oil, including cold heavy oil production with sand ("CHOPS") and horizontal technologies, 17.4 mbbls/day was production from Husky's thermal operations and 2.3 mbbls/day was from the medium gravity waterflooded fields in the Wainwright and Wildmere areas. Husky also produces natural gas from numerous small shallow pools in the Lloydminster region and recovers solution gas produced from heavy oil wells. During 2011, Husky's gross natural gas production from the Lloydminster region averaged 29.3 mmcf/day.

In the Lloydminster area, the Company owns and operates 21 oil treating facilities which are tied into the Husky heavy oil pipeline systems. These pipeline systems transport heavy crude oil from the field locations to the Husky Lloydminster asphalt refinery, the Husky Lloydminster Upgrader and the third party pipeline systems at Hardisty, Alberta.

The Company is focused on increasing its heavy oil production and believes that its undeveloped land position, coupled with the development and application of improved recovery technologies, will maintain heavy crude oil production in the Lloydminster area.

Non-Thermal Enhanced Oil Recovery ("EOR")

Husky operated four solvent EOR pilot programs in 2011. A CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant is nearly complete with expected commissioning in the first quarter of 2012. This liquefied CO_2 is to be used in the ongoing EOR piloting program.

Western Canada (excluding Heavy Oil and Oil Sands)

East Central Alberta

Husky's East Central Alberta operations are located primarily in central Alberta, in a band extending from the foothills to east of the Alberta/Saskatchewan border. Husky operates 67 facilities in the area. Husky's 2011 gross production from the East Central Alberta area averaged 95 mmcf/day of natural gas and 16.3 mbbls/day of oil and NGL.

Husky plans to continue its Viking resource oil drilling program which targets medium productivity reservoirs enhanced by utilizing horizontal drilling and multiple-stage fracturing treatments. Husky plans to drill up to 58 Viking wells in 2012, primarily at Redwater (20 kilometers northeast of Edmonton) and Elrose (80 kilometers southwest of Saskatoon), Husky currently has approximately 60 wells producing from the play and plans to continue to develop infrastructure in both areas.

Husky continues to focus on the Macklin field where petrophysical and coreflood studies to investigate ASP flooding potential were recently completed, with very encouraging results. Optimization of the existing pattern waterflood, which is necessary prior to ASP implementation, is underway in 2012. At Red Deer, Husky expects to focus on acquisition and development of additional oil resource properties. Development of Husky's gas properties has been deferred with the exception of some liquids-rich gas prospects in the Hussar field.

Southern Alberta and Southern Saskatchewan

Husky is the operator of a number of properties in southern Alberta and southern Saskatchewan. Husky's gross production from properties in southern Alberta averaged 7.6 mbbls/day of crude oil and NGL and 21.2 mmcf/day of natural gas during 2011. In southern Saskatchewan, 2011 gross production averaged 13.5 mbbls/day of crude oil and NGL and 18.8 mmcf/day of natural gas.

Husky's ASP EOR program is used at Warner and Crowsnest in southern Alberta and at Gull Lake in southern Saskatchewan. In addition, Husky holds a 20.3% non-operating working interest in the Instow, Saskatchewan ASP flood, where oil response continues to increase in line with expectations. Husky's gross incremental production at December 2011 for its ASP EOR program was approximately 3.9 mbbls/day. Future floods under development include Fosterton, Saskatchewan. At Fosterton, the facility construction commenced in 2011 with an expected start up in the second half of 2012. Husky is the operator and holds a 62.4% working interest in this project.

Production and evaluation of the Lower Shaunavon and Bakken zones continues in southern Saskatchewan. In the Lower Shaunavon zone, four net wells were drilled and three net wells were put on production in 2011. In the Bakken zone, 12 net wells were drilled and put on production in 2011. Husky's gross incremental production at December 2011 in these zones totalled approximately 1.6 mbbls/day.

Foothills Northwest Plains

The Foothills Northwest Plains area is located in Northern Alberta and British Columbia as well as Western Alberta. The area is made up of five distinct districts: Rainbow Lake, Northern Alberta, Northern Alberta & British Columbia Plains, Ansell-Galloway and Foothills. Gross production from these areas averaged 97.2 mboe/day in 2011, including the February 2011 acquisition of additional interests in the Rainbow Lake, Northern Alberta & British Columbia Plains and Foothills districts. The acquisition added approximately 97.8 mmcf/day of gross natural gas production and 5.6 mbbls/day of gross crude oil and NGL production and approximately 123 mmboe of proved plus probable reserves (104 mmboe proved).

Rainbow Lake, located approximately 700 kilometers northwest of Edmonton, Alberta, is the site of Husky's largest light oil production operation in Western Canada. Husky's gross production for 2011 from the Rainbow Lake district averaged 8.2 mbbls/day of light crude oil and NGL and 108.2 mmcf/day of natural gas. With the acquisition of properties, Husky now holds a 100% interest in the Rainbow Lake processing plant. Husky's position in the Rainbow Lake district was further enhanced with the March 2011 acquisition of properties in the area. This transaction provided approximately 2.1 mboe/day of additional gross production and 5.2 mmboe of additional proved plus probable reserves (4.1 mmboe proved reserves). Husky has commenced exploration activities within the Muskwa resource oil play in which Husky holds a 100% working interest. Three vertical wells and two horizontal wells were drilled in 2011.

The Northern Alberta District surrounds the communities of Peace River and Slave Lake northwest of Edmonton, Alberta and produces shallow gas and heavy oil. Husky's gross production for 2011 from this District averaged 5.0 mbbls/day of heavy oil and 37.2 mmcf/day of natural gas. Husky drilled 80 wells in 2011 to expand its primary heavy oil production from the McMullen field, located 40 kilometers southwest of the Hamlet of Wabasca, Alberta. The Company also proceeded with an EOR pilot project in 2011 which includes construction of facilities and drilling of observation wells and a horizontal production well.

Gross production from the Northern Alberta & British Columbia Plains district averaged approximately 4.5 mbbls/day of light crude oil and NGL and 92.3 mmcf/day of natural gas in 2011. The Company commenced development of the Cardium oil resource plays in the Wapiti and Kakwa areas, in which Husky holds 100% and 60% working interests, respectively.

The Ansell-Galloway district was formed on September 1, 2011 and produced approximately 1.9 mbbls/day of NGLs and 45.0 mmcf/day of natural gas in 2011. In 2011, an offload facility was completed, adding 18.0 mmcf/day of capacity. Seven multi-zone and 35 Cardium wells were drilled in 2011.

The Foothills district produced approximately 4.0 mbbls/day of light crude oil and NGL and 157.6 mmcf/day of natural gas during the year ended December 31, 2011. Production from the area is predominantly processed at the Ram River gas plant, with Husky operating and holding an average 84% interest in the Ram River sour gas plant and related processing facilities located in the Foothills district.

Northwest Territories ("NWT")

In the NWT, Husky added to its legacy land position in 2011. Two ELs totalling approximately 437,000 net acres were acquired with a work commitment of $188 million per licence to be spent over a five-year term. 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 kilometre 3-D seismic program will assist in the structural interpretation of the area as well as position for future activity, if warranted. Husky drilled one vertical pilot well to total depth in early 2012 with the second vertical well planned for late 2012.

The primary target is the Canol shale oil resource play which exists in the Central Mackenzie Valley to the southwest of the Norman Wells oilfield. Outcrop work provided in a report from the Geological Survey of Canada, coupled with Husky proprietary data, points to an oil petroleum prospect over the two licences. The two vertical pilot wells were approved for drilling where core and geophysical log data will be collected to assist in the characterization of the geochemical and geomechanical attributes of the reservoir and the bounding stratigraphic units. The results of this information will determine subsequent activities.

Within the Mackenzie Valley area, Husky also holds interests in two SDL's in the Summit/Stewart Creek areas along with a small freehold lease position.

Columbia River Basin (Washington and Oregon State – USA)

Husky holds 398,000 net acres of undeveloped land in the Columbia River Basin located in the states of Washington and Oregon. This under-explored basin is characterized by tertiary sandstones that lie below a layer of volcanic basalt. The potential exists to unlock a large gas resource that is located in an area containing existing natural gas pipelines that transport gas to the states of Washington, Oregon and California. Due to low gas prices in 2011, no significant activity occurred and Husky's focus has been on high-grading its land and preserving those leases that lie in the most prospective fairways.

Distribution of Oil and Gas Production

Crude Oil and NGL

Husky provides heavy crude oil feedstock to its Upgrader and its asphalt refinery, which are located at Lloydminster, Alberta/Saskatchewan. The combined dry crude feedstock requirements of the Upgrader and asphalt refinery are equal to approximately 130% of Husky's heavy crude oil production from the Lloydminster area. Therefore, in order to keep all units running at the Upgrader and refinery, purchase of third party production is required. Husky also markets heavy crude oil production directly to refiners located in the mid-west and eastern United States and Canada. Husky markets its light and synthetic crude oil production to third-party refiners in Canada, the United States and Asia. NGL are sold to local petrochemical end users, retail and wholesale distributors and refiners in North America.

Husky markets third party volumes of light crude oil, heavy crude oil and NGL in addition to its own production.

Natural Gas

The following table shows the distribution of Husky's gross average daily natural gas production for the years indicated. The Company also markets third party natural gas production in addition to its own production.

	Years ended December 31,		
	2011	**2010**	**2009**
		(mmcf/day)	
Sales to end users			
United States	163	223	271
Canada	297	164	181
	460	387	452
Sales to aggregators	3	3	5
Internal use [(1)]	144	117	85
	607	507	542

[(1)] Husky consumes natural gas for fuel at several of its facilities.

Delivery Commitments

The following table shows the future commitments to deliver natural gas from Husky reserves. Husky's proved developed reserves of natural gas in Western Canada are more than adequate to meet future delivery commitments.

	Fixed Price	
	Bcf	**$/mmbtu**
2012	19.1	4.41
2013	17.9	4.53
2014	9.6	3.48

Midstream Operations

Overview

The Midstream operations include:

- Infrastructure — pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas, extraction of NGL from natural gas, cogeneration of electrical and thermal energy; and
- Commodity Marketing — the purchase and marketing of Husky's and other producers' crude oil, natural gas, NGL, sulphur, petroleum coke and electrical power.

Infrastructure

Husky has been involved in the gathering, transporting and storage of heavy crude oil in the Lloydminster area since the early 1960s. Husky's crude oil pipeline systems include more than 2,000 kilometers of pipeline and are capable of transporting up to 710 mbbls/day of blended heavy crude oil, diluent and synthetic crude oil, assuming the systems are fully powered. The pipeline systems transport blended heavy crude oil to Lloydminster, accessing markets through Husky's Upgrader and asphalt refinery in Lloydminster. Blended heavy crude oil from the field and synthetic crude oil from the upgrading operations are transported south to Hardisty, Alberta to a connection with the major export trunk pipelines: Enbridge Pipeline multi-line system, Kinder Morgan Express Pipeline, TransCanada's Keystone Pipeline and the smaller IPF Pipeline. The blended crude oil is transported to eastern and southern markets on these pipelines. Husky's crude oil pipeline systems also have feeder pipeline interconnections with the IPF Pipeline at Cold Lake, the Echo Pipeline at Hardisty, the Gibsons Hardisty Terminal, the Enbridge Hardisty Caverns and Merchant Terminal, the Enbridge Athabasca Pipeline and the Talisman Chauvin Pipeline.

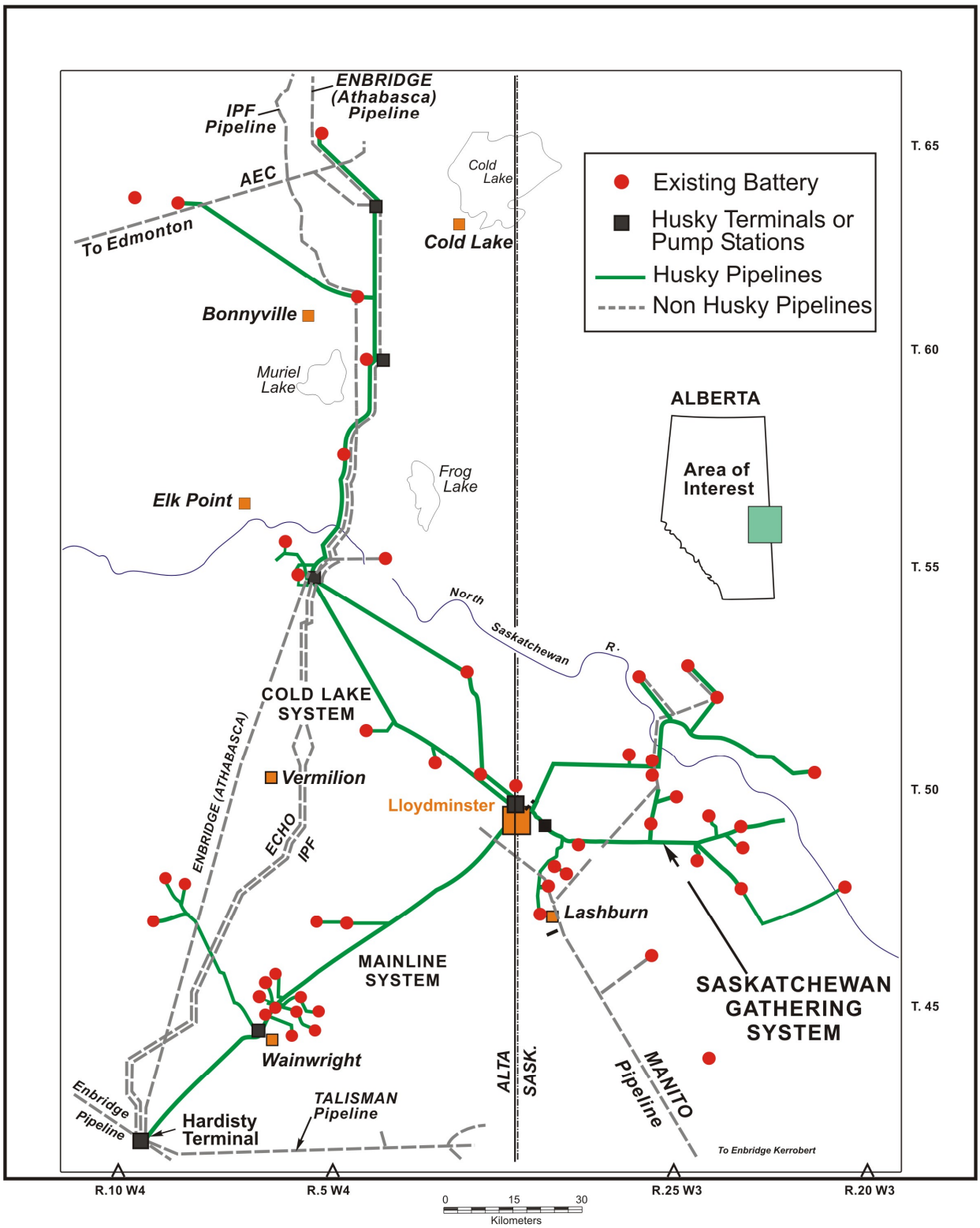
The following table shows the average daily pipeline throughput for the periods indicated:

	Years ended December 31,		
(mbbls/day)	**2011**	**2010**	**2009**
Combined pipeline throughput	559	512	514

In recent years Husky has incurred a number of expansions on its pipeline system and Hardisty terminal facilities to capitalize on anticipated increases in heavy oil production from the Lloydminster and Cold Lake areas and to service the new incremental take-away capacity from the Keystone Pipeline.

Husky's heavy crude oil processing facilities are located throughout the Lloydminster area and are connected to Husky's pipeline system. These facilities process Husky's and other producers' raw heavy crude oil from the field production by removing sand, water and other impurities to produce clean dry heavy crude oil. There are also third party processing facilities connected to Husky's pipeline. The heavy crude oil is blended with a diluent to reduce both viscosity and density in order to meet pipeline specifications for transportation.

Heavy Oil Pipeline Systems

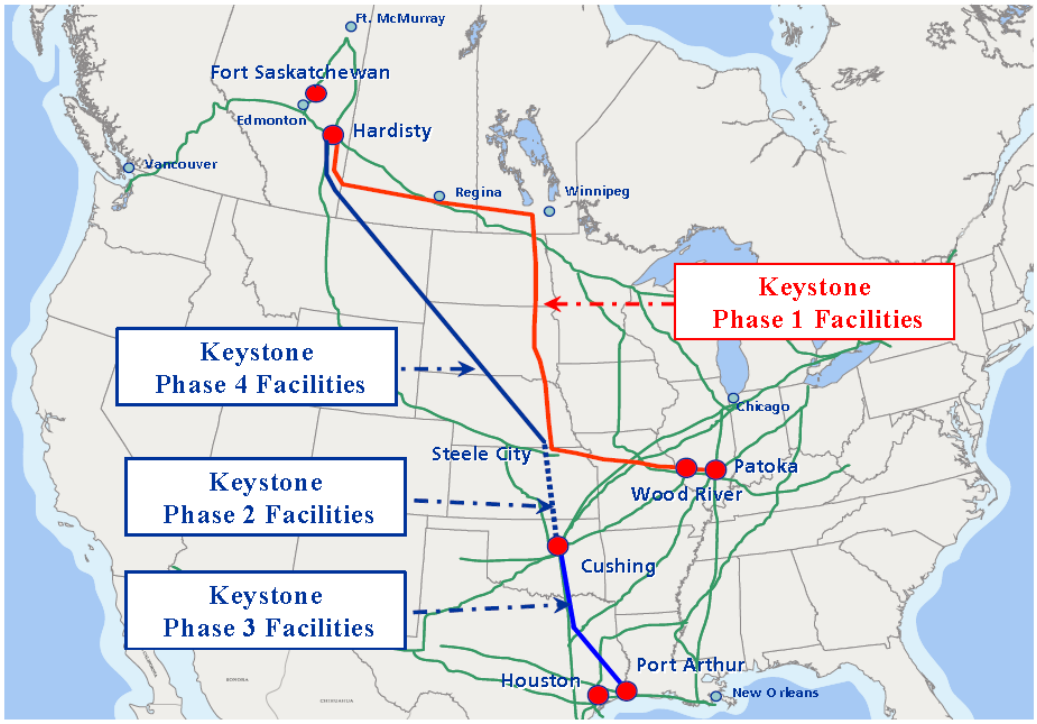


In 2010, Husky commenced its pipeline commitment on the Keystone pipeline system which ships Canadian crude oil from Hardisty, Alberta to Patoka, Illinois. This commitment was part of a corporate initiative, agreed upon in 2006, to expand the market for Husky's crude oil into the midwest United States. This initiative was further supported through the acquisition of the Lima Refinery in 2007, which now enables Husky's Canadian synthetic crude oil production (along with additional third-party purchases) to be processed at the refinery.

Due to Husky's ongoing Keystone pipeline commitment, the Lima Refinery now has the option, depending on the economics, to access a significant amount of Canadian crude oil as part of its crude feedstock requirements.

Keystone Pipeline has also enabled Husky to sell heavy crude supply on the Gulf Coast, through interconnecting pipeline systems. This provides the benefits of diversifying Husky's commodity markets and improving the Company's Upstream production netback pricing.

During the Enbridge Pipeline outages in late 2010, the Keystone Pipeline was a major factor in alleviating the shut-in pressures felt by many Canadian producers. It also helped ensure that Husky avoided any production shut-in and maintained crude sales.



Cogeneration

The Company holds a 50% interest in a 90 megawatts ("MW") natural gas fired cogeneration facility adjacent to Husky's Rainbow Lake processing plant. The cogeneration facility produces electricity for the Power Pool of Alberta and thermal energy (steam) for the Rainbow Lake processing plant. It provides power directly to the Power Pool of Alberta under an agreement with the Alberta Electric System Operator to provide additional electricity generating capacity and system stability for northwestern Alberta. The power plant has the capability of being expanded to approximately 110 MW in total. ATCO Power is the operator of the facility and a hands-on operator of the Rainbow #5 electricity generator. Husky contract-operates the Rainbow #4 electricity generator, the Once-Through Steam Generator and the Water Treatment Plant. All of this equipment constitutes part of the cogeneration facility.

Effective January 1, 2011, Husky sold its 50% interest in a 215 MW natural gas fired cogeneration facility at the site of the Lloydminster Upgrader.

Natural Gas Storage Facilities

Husky has been operating a natural gas storage facility at Hussar, Alberta since April 2000. Husky also operates and has a 50% interest in a natural gas storage facility at East Cantuar near Swift Current, Saskatchewan. Husky also contracts additional natural gas storage under long-term arrangements. At December 31, 2011, Husky managed a total natural gas storage capacity of approximately 45 bcf. The Company is continuing to evaluate additional storage opportunities within Western Canada.

Commodity Marketing

Husky is a marketer of both its own and third-party production of crude oil, synthetic crude oil, NGL, natural gas and sulphur. The Company also markets petroleum coke, a by-product from the Lloydminster Upgrader.

Husky supplies feedstock to its Lloydminster Upgrader and asphalt refinery from its own and third-party heavy oil production sourced from the Lloydminster and Cold Lake areas. The Company also sells blended heavy crude

oil directly to refiners based in the United States and Canada. Husky's extensive infrastructure in the Lloydminster area supports its heavy crude oil refining and marketing operations.

Husky markets light and medium crude oil and NGL sourced from Husky's own production and third-party production. Light crude oil is acquired for processing by third-party refiners at Edmonton, Alberta and by Husky's refinery at Prince George, British Columbia. Husky markets the synthetic crude oil produced at its Upgrader in Lloydminster to refiners in Canada and the United States.

Husky markets natural gas sourced from its own production and third-party production. The Company is currently committed to gas sales contracts with third parties, which in aggregate do not exceed amounts forecast to be deliverable from Husky's reserves. The natural gas sales contracted are primarily at market prices. At December 31, 2011, Husky's long-term fixed price natural gas sales contracts totalled 46.6 bcf over three years deliverable at the rate of 41% in 2012, 38% in 2013 and 21% in 2014. Husky has acquired rights to firm pipeline capacity to transport the natural gas to most of these contracted markets. The Company manages and trades natural gas in conjunction with Husky owned and operated natural gas storage facilities.

Husky has developed its commodity marketing operations to include the acquisition of third-party volumes in order to increase volumes and enhance the value of its midstream assets. The Company plans to expand its marketing operations by continuing to increase marketing activities. The Company believes that this increase will generate synergies with the marketing of its own production volumes and the optimization of its assets.

Downstream Operations

United States Refining and Marketing

Lima, Ohio Refinery

Husky's acquisition of the Lima Refining Company closed on July 3, 2007. The Lima Refinery has an atmospheric crude throughput capacity of 160 mbbls per stream day. During 2011, crude oil feedstock throughput averaged 144 mbbls/day. The refinery is located in Ohio between Toledo and Dayton and currently processes both light sweet crude oil feedstock sourced from the United States and Africa and since 2010, with the commissioning of the Keystone Pipeline system, Canadian synthetic crudes, including Husky Synthetic Blend ("HSB") produced by the Lloydminster Upgrader. The refinery produces gasoline, gasoline blend stocks, diesel, jet fuel, petrochemical feedstock and other by-products. The feedstock is received via the Mid-Valley and Marathon Pipelines and the refined products are transported via the Buckeye and Inland pipeline systems and by rail car to primary markets in Ohio, Illinois, Indiana and southern Michigan.

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% of its operating units. The refinery is expected to be shut down for 45 days during the turnaround. The remaining 30% of operating units will be addressed in a major turnaround currently planned for 2015. Husky 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. The kerosene hydrotreater is expected to be operational in the first quarter of 2013.

Toledo, Ohio Refinery

The Toledo Refinery has an atmospheric crude throughput capacity of 160 mbbls per stream day. Products include low sulphur gasoline, ultra low sulphur diesel, aviation fuels, propane, kerosene and asphalt. It is located in one of the highest energy consumption regions in the United States.

Husky and BP plan to expand the refinery's bitumen processing capacity to align with the first two 60 mbbls/day phases of the Sunrise Energy Project SAGD development. BP currently markets 100% of the refinery's output, however, once Sunrise Phase I reaches design production rates, Husky will have the right to market its own share of the refined products.

In 2010, Husky and BP announced the sanction of the Continuous Catalyst Regeneration Reformer Project at the Toledo Refinery. This project will improve the efficiency and competitiveness of the refinery by reducing energy consumption and lowering operating costs with the replacement of two naphtha reformers and one hydrogen plant with a 42,000 bbls/day continuous catalyst regeneration reformer system plant. Project construction formally commenced in August 2010. Project completion is anticipated in the fourth quarter of 2012.

During the twelve months ended December 31, 2011, crude oil feedstock throughput averaged 64 mbbls/day (Husky's share). Production of gasoline averaged 40 mbbls/day, middle distillates averaged 17 mbbls/day and other fuel and feedstock averaged 7 mbbls/day.

Upgrading Operations

Husky owns and operates the Husky Lloydminster Upgrader, a heavy oil upgrading facility located in Lloydminster, Saskatchewan. The Upgrader is designed to process blended heavy crude oil feedstock into high quality, low sulphur synthetic crude oil. Synthetic crude oil is used as refinery feedstock for the production of premium transportation fuels in Canada and the United States. In addition, the Upgrader recovers the diluent, which is blended with the heavy crude oil prior to pipeline transportation to reduce viscosity and facilitate its movement, and returns it to the field to be reused.

The Upgrader was commissioned in 1992 with an original design capacity of 46 mbbls/day of synthetic crude oil. Current production is considerably higher than the original design rate capacity as a result of throughput modifications and improved reliability. In 2007, the Upgrader commenced production of off-road diesel for locomotive and other uses. The Upgrader's current rated production capacity is 82 mbbls/day of synthetic crude oil, diluents, low sulphur diesel and ultra low sulphur diesel.

Production at the Upgrader averaged 55 mbbls/day of synthetic crude oil, 11 mbbls/day of diluent and 3 mbbls/day of low sulphur diesel in 2011. In addition, the Upgrader also produced, as by-products of its upgrading operations, approximately 328 lt/day of sulphur and 312 lt/day of petroleum coke during 2011. These products are sold in Canadian and international markets. Production in 2011 was impacted by a fire that occurred in February 2011 in Plant 24.

Canadian Refined Products

Husky's Canadian refined products operations include refining of light crude oil, manufacturing of fuel and fuel grade ethanol, manufacturing of asphalt products from heavy crude oil and acquisition by purchase and exchange of refined petroleum products. Husky's retail distribution network includes the wholesale, commercial and retail marketing of refined petroleum products and provides a platform for non-fuel related convenience product businesses.

Light oil refined products are produced at the Husky refinery at Prince George, British Columbia and are also acquired from third-party refiners and marketed through Husky and Mohawk branded retail and commercial petroleum outlets and through direct marketing to third-party dealers and end users. Asphalt and residual products are produced at Husky's asphalt refinery at Lloydminster, Alberta and are marketed directly or through Husky's eight emulsion plants, five of which are also asphalt terminals located throughout Western Canada.

Prince George Refinery

The Prince George Refinery production is equal to approximately 18% of Husky's total refined product supply requirements and is the source of its lowest cost refined products. The refinery produces all grades of unleaded gasoline, seasonal ultra low sulphur diesel fuels, mixed propane and butane stream and heavy oil products.

Lloydminster Asphalt Refinery

Husky's Lloydminster Refinery processes heavy crude oil into asphalt products used in road construction and maintenance and industrial asphalt products. The refinery has a throughput capacity of 29 mbbls/day of heavy crude oil. The refinery also produces straight run gasoline, bulk distillates and residuals. The straight run gasoline stream is removed and re-circulated into the heavy oil pipeline network as pipeline diluent and the distillate stream is used by the Upgrader to make low sulphur diesel. The bulk distillates are hydrogen deficient and are transferred directly to the Upgrader and then treated for blending into the HSB stream. Residuals are a blend of medium and light distillate and gas oil streams, which are sold directly to customers typically as drilling and well fracturing fluids or used in asphalt cutbacks and emulsions.

The following table shows average daily sales volumes of products primarily produced at the Lloydminster Refinery for the years indicated:

	Years ended December 31,		
(mbbls/day)	**2011**	**2010**	**2009**
Asphalt	15.0	14.9	13.6
Residual and other	10.3	9.2	9.0
	25.3	24.1	22.6

Refinery throughput averaged 28.1 mbbls/day of blended heavy crude oil feedstock during 2011. Due to the seasonal demand for asphalt products, most asphalt refineries typically operate at full capacity only during the normal paving season in Canada and the northern United States. Husky has implemented various plans to increase

refinery throughput during the other months of the year, such as increasing storage capacity and developing U.S. markets for asphalt products. This is intended to allow Husky to run at or near full capacity year round.

Asphalt Distribution Network

Husky's Pounder Emulsions division has a significant market share in Western Canada for road application emulsion products. Additional non-asphalt based road maintenance products are also marketed and distributed through Pounder Emulsions. The Company's sales to the United States and eastern Canada accounted for 50% of asphalt sales in 2011. Exported asphalt products are shipped as far as Texas, Florida and Quebec. Husky typically sells in excess of 5 mmbbls of asphalt cements each year.

Husky's asphalt distribution network consists of emulsion plants and asphalt terminals located at Kamloops, British Columbia, Edmonton and Lethbridge, Alberta, Yorkton, Saskatchewan and Winnipeg, Manitoba and three emulsion plants located at Watson Lake, Yukon and Lloydminster and Saskatoon, Saskatchewan. Husky also terminals asphalt at its Prince George Refinery and uses an independently operated terminal at Langley, British Columbia.

All of Husky's asphalt requirements are supplied by Husky's asphalt refinery.

Husky's strategy with respect to its asphalt marketing business is to strengthen Husky's retail market position given changes occurring in the market, convert from wholesale to retail, expand the residual business, and continue to differentiate through product development and innovation of asphalt, residual, and emulsion products.

In 2012, Husky plans to direct its efforts to increasing terminal capacity at the Yorkton and Winnipeg facilities, develop retail capacity in U.S. markets, expand sales for road stabilization, preservation and recycling, look at increasing residual sales relative to diluents and bulk distillates to enhance margins, increase sales of higher quality products with larger margins, implement safety and reliability improvements and develop new products while improving existing products.

Ethanol Plants

In September 2006, Husky commissioned an ethanol plant in Lloydminster, Saskatchewan. This plant has an annual nameplate capacity of 130 million litres. In December 2007, the Minnedosa, Manitoba ethanol plant was commissioned also with an annual nameplate capacity of 130 million litres; the plant is operating above that capacity.

Husky's ethanol production supports its ethanol-blended gasoline marketing program. When added to gasoline, ethanol promotes more complete fuel combustion, prevents fuel line freezing and reduces carbon monoxide emissions, ozone precursors and net emissions of greenhouse gases. Environment Canada has designated ethanol-blended gasoline as an "Environmental Choice" product. Husky sells a large portion of its production to other major oil companies for their ethanol blending requirements in Western Canada.

Husky continued to position its refined products business segment as the leader in ethanol blended fuels in Western Canada.

Other Supply Arrangements

In addition to the refined petroleum products supplied by the Prince George Refinery of 1.9 mbbls/day and by the Husky Lloydminster Upgrader of 2.6 mbbls/day, Husky has rack-based pricing purchase agreements for refined products with all major Canadian refiners. During 2011, Husky purchased approximately 40.2 mbbls/day of refined petroleum products from refiners and acquired approximately 9.0 mbbls/day of refined petroleum products pursuant to exchange agreements with third-party refiners.

Branded Petroleum Product Outlets and Commercial Distribution

As of December 31, 2011, there were 549 independently operated Husky and Mohawk branded petroleum product outlets. These petroleum product outlets include travel centres, convenience stores, cardlock operations and bulk distribution facilities located from the Ontario/Quebec border to the West Coast. The travel centre network is strategically located on major highways and serves the retail market and commercial transporters with quality products and full-service Husky House restaurants. At most locations, the travel centre network also features the proprietary "Route Commander" cardlock system that enables commercial users to purchase products using a card system that electronically processes transactions and provides detailed billing, sales tax and other information. A variety of full and self-serve retail locations under the Husky and Mohawk brand names serve urban and rural markets, while Husky and Mohawk bulk distributors offer direct sales to commercial and farm markets in Western Canada.

Independent retailers or agents operate all Husky and Mohawk branded petroleum product outlets. Retail outlets feature varying services such as convenience stores, service bays, 24-hour service, car washes, Husky House full-service, family-style restaurants, proprietary and co-branded quick serve restaurants and bank machines. In addition to ethanol-blended gasoline, Husky offers additive-enhanced DieselMax and propane services together with Chevron lubricants. Husky supplies refined petroleum products to its branded independent retailers on an exclusive basis and provides financial and other assistance for location improvements, marketing support and related services. Husky's brands are promoted through Husky's sponsorship of Alpine Canada, the Western Hockey League and various university athletics, as well as advertising designed to reach both national and regional audiences.

The following table shows the number of Husky and Mohawk branded petroleum outlets by province as of December 31, 2011:

	British Columbia & Yukon	Alberta	Sask.	Manitoba	Ontario	2011 Total	2010 Total
Branded Petroleum Outlets							
Retail owned outlets	61	76	15	17	78	247	250
Leased	43	51	5	11	39	149	153
Independent retailers	52	68	16	7	10	153	152
Total	**156**	**195**	**36**	**35**	**127**	**549**	**555**
Cardlocks [1]	23	32	6	6	21	88	92
Convenience stores [1]	50	61	14	6	9	140	201
Restaurants	12	13	4	2	16	47	48

[1] Located at branded petroleum outlets.

Husky also markets refined petroleum products directly to various commercial markets, including independent dealers, national rail companies and major industrial and commercial customers in Western Canada and the northwestern United States.

The following table shows average daily sales volumes of light refined petroleum products for the periods indicated:

	Years ended December 31,		
(mbbls/day)	2011	2010	2009
Gasoline	27.7	24.9	25.3
Diesel fuel	26.0	25.7	21.8
Liquefied petroleum gas	0.6	0.7	0.8
	54.3	51.3	47.9

Human Resources

The number of Husky's permanent employees was as follows:

	December 31,		
	2011	2010	2009
	4,726	4,380	4,272

DIVIDENDS

The following table shows the aggregate amount of the dividends per common share and Series 1 Preferred Shares of the Company declared payable in respect of its last three years ended December 31:

	2011	2010	2009
Dividends per Common Share	$ 1.20	$ 1.20	$ 1.20
Dividends per Series 1 Preferred Shares	$ 0.87	$ -	$ -

Dividend Policy and Restrictions

Common Share Dividends

The Board of Directors has established a dividend policy that pays quarterly dividends. The dividend was reviewed in July 2006 and increased to $0.25 ($1.00 annually) per common share and again in October 2007 when it was increased to $0.33 ($1.32 annually). The dividend was reviewed in April 2008 and increased to $0.40 ($1.60 annually) per common share and then again in July 2008 resulting in an increase to $0.50 ($2.00 annually). In February 2009, the dividend was reviewed and decreased to $0.30 ($1.20 annually) per common share.

The Board declared special dividends in the amount of $0.50 per common share in July 2003 and $0.27 per common share in November 2004. In October 2005, the Board declared a special dividend of $0.50 per common share. In February 2007, the Board declared a special dividend of $0.25 per common share.

In February 2011, Husky's shareholders approved amendments to the common share terms to provide the shareholders with the ability to receive dividends in common shares or in cash. Quarterly dividends would be declared in an amount expressed in dollars per common share and would be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares 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.

Husky's dividend policy will continue to be reviewed and there can be no assurance that further dividends will be declared or the amount of any future dividend.

The declaration and payment of dividends are at the discretion of the Board of Directors, which will consider earnings, capital requirements and financial condition of Husky, the satisfaction of the applicable solvency test in Husky's governing corporate statute, the Business Corporations Act (Alberta), and other relevant factors.

Cumulative Redeemable Preferred Shares, Series 1 ("Series 1 Preferred Shares") Dividends

Holders of 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 the 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 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% as and when declared by the Board of Directors.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

Husky is authorized to issue an unlimited number of common shares. Holders of common shares are entitled to receive notice of and attend all meetings of shareholders, except meetings at which only holders of a specified class or series of shares are entitled to vote, and are entitled to one vote per common share held. Holders of common shares are also entitled to receive dividends as declared by the Board of Directors on the common shares payable in whole or in part as a stock dividend in fully paid and non-assessable common shares or by the payment of cash. Holders are also entitled to receive the remaining property of Husky upon dissolution in equal rank with the holders of all other common shares. See "Dividend Policy and Restrictions".

If the Board of Directors declares a dividend on the common shares payable in whole or in part as a stock dividend, shareholders of record wishing to accept a payment of future stock dividends declared by the Board of Directors in the form of common shares are required to complete and 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. The Stock Dividend Confirmation Notice permits shareholders to confirm that they will accept common shares as payment of the dividend on all or a stated number of their common shares. A Stock Dividend Confirmation Notice will remain in effect for all stock dividends on the common shares to which it relates and which are held by the shareholder unless the shareholder delivers a revocation notice to Husky's transfer agent, in which case the Stock Dividend Confirmation Notice will not be effective for any dividends having a declaration date that is more than five business days following receipt of the revocation notice by Husky's transfer agent.

In the event a shareholder fails to deliver a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend, or delivers a Stock Dividend Confirmation Notice confirming that the holder of common shares accepts the common shares as payment of the dividend on some but not all of the holder's common shares, the dividend on common shares for which no Stock Dividend Confirmation Notice was delivered or the dividend on those of the holder's common shares in respect of which the holder did not deliver a Stock Dividend Confirmation Notice, will be paid in cash.

Preferred Shares

Husky is authorized to issue an unlimited number of preferred shares. The preferred shares as a class have attached thereto the rights, privileges, restrictions and conditions set forth below.

The preferred shares may from time to time be issued in one or more series, and the Board of Directors may fix from time to time before such issue the number of preferred shares which is to comprise each series and the designation, rights, privileges, restrictions and conditions attached to each series of preferred shares including, without limiting the generality of the foregoing, any voting rights, the rate or amount of dividends or, the method of calculating dividends, the dates of payment thereof, the terms and conditions of redemption, purchase and conversion if any, and any sinking fund or other provision.

The preferred shares of each series shall, with respect to the payment of dividends and the distribution of assets or return of capital in the event of liquidation, dissolution or winding up of Husky, whether voluntary or involuntary, or any other return of capital or distribution of assets of Husky amongst its shareholders for the purpose of winding up its affairs, be entitled to preference over the common shares of Husky and over any other shares of Husky ranking by their terms junior to the preferred shares of that series. The preferred shares of any series may also be given such other preferences over the common shares of Husky and any other such preferred shares.

If any cumulative dividends or amounts payable on the return of capital in respect of a series of preferred shares are not paid in full, all series of preferred shares shall participate ratably in respect of accumulated dividends and return of capital.

Husky issued 12,000,000 Series 1 Preferred Shares and authorized the issuance of 12,000,000 Series 2 Preferred Shares. See "Dividend Policy and Restrictions – Cumulative Redeemable Preferred Shares, Series 1 ("Series 1 Preferred Shares") Dividends".

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.

	Outlook	Rating	Last Review	Last Rating Change
Moody's:				
Senior Unsecured Debt	Stable	Baa2	August 17, 2011	April 25, 2001
Standard and Poor's:				
Senior Unsecured Debt	Stable	BBB+	December 9, 2011	July 27, 2006
Series 1 Preferred Shares	Stable	P-2 (low)	March 11, 2011	March 11, 2011
Dominion Bond Rating Service:				
Senior Unsecured Debt	Stable	A (low)	March 10, 2011	March 31, 2008
Series 1 Preferred Shares	Stable	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 inasmuch as such ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

Moody's

Moody's credit rating system ranges from Aaa (highest) to C (lowest). Debt securities rated within the Baa category are considered medium grade debts; they are neither highly protected nor poorly secured. Interest payments and principal security appear to be adequate at the time of the rating; however, they are subject to potential adverse circumstances over time. As a result, these debt securities possess some speculative characteristics. The addition of a 1, 2 or 3 modifier indicates an additional relative standing within the general rating classification. The addition of the modifier 1 indicates the debt is positioned in the top one third of the general rating classification, 2 indicates the mid one third and 3 indicates the bottom one third.

Standard and Poor's

Standard and Poor's credit rating system for debt ranges from AAA (highest) to D (lowest). Debt securities rated within the BBB category are considered to possess adequate protection parameters. However, they could potentially change subject to adverse economic conditions or other circumstances that may result in reduced capacity of the debtor to continue to meet principal and interest payments. As a result, these debt securities possess some speculative characteristics. The addition of the modifier + or - indicates the debt is positioned above (+) or below (-) the mid range of the general category.

Standard and Poor's began rating Husky's Series 1 Preferred Shares on its Canadian preferred share scale on March 11, 2011. Preferred share ratings have a direct correlation to the degree of credit worthiness provided by the debt ratings system except that ratings on preferred shares refer to the entity's ability to fulfill the obligations specific to the preferred shares. A P-2 (low) rating on the Canadian preferred share rating scale is equivalent to a BBB- rating on the debt rating scale.

Dominion Bond Rating Service

Dominion Bond Rating Service's credit rating system for debt ranges from AAA (highest) to D (lowest). Debt securities rated within the A category are considered to be of satisfactory credit quality. Protection of interest and principal is considered acceptable, but the debtor is susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the debtor and its rated debt. The addition of the high or low modifier denotes that the rating is either above or below the mid range of the general rating category.

Dominion Bond Rating Service began rating Husky's Series 1 Preferred Shares on its Canadian preferred share scale on March 10, 2011. Preferred share ratings have a direct correlation to the degree of credit worthiness provided by the debt ratings system except that ratings on preferred shares refers to the entity's ability to fulfill the obligations specific to the preferred shares. A Pfd-2(low) rating on the Canadian preferred share rating scale is equivalent to an A category rating on the debt rating scale.

MARKET FOR SECURITIES

Husky's common shares and Series 1 Preferred Shares are listed and posted for trading on the Toronto Stock Exchange under the respective trading symbols "HSE" and "HSE.PR.A". The Series 1 Preferred Shares began trading on the Toronto Stock Exchange on March 18, 2011.

The following table discloses the trading price range and volume of Husky's common shares traded on the Toronto Stock Exchange during Husky's financial year ended December 31, 2011:

	High	Low	Volume (000's)
January	27.12	25.60	17,787
February	30.05	27.15	22,884
March	30.58	27.68	28,111
April	30.00	27.20	13,593
May	29.80	27.56	25,096
June	29.79	26.11	27,835
July	27.19	26.01	17,632
August	26.78	23.74	31,785
September	24.57	21.36	31,686
October	26.04	20.63	17,271
November	25.97	22.82	27,941
December	26.21	23.21	34,011

The following table discloses the trading price range and volume of the Series 1 Preferred Shares traded on the Toronto Stock Exchange from March 18, 2011 to Husky's financial year ended December 31, 2011:

	High	Low	Volume (000's)
March (18th – 31st)	25.39	24.70	28,111
April	25.85	25.30	13,593
May	25.92	25.46	25,096
June	25.81	25.50	1,122
July	25.88	25.60	552
August	26.08	25.31	618
September	25.85	25.20	661
October	26.00	24.57	163
November	26.18	25.10	185
December	25.88	25.22	221

DIRECTORS AND OFFICERS

The following are the names and residences of the directors and officers of Husky as of the date of this Annual Information Form, their positions and offices with Husky and their principal occupations for at least five preceding years. Each director will hold office until the Company's next annual general meeting or until his or her successor is appointed or elected.

Directors

Name & Residence	Office or Position	Principal Occupation During Past 5 Years
Li, Victor T.K. Hong Kong	Director and Co-Chair Director of Husky since 2000	Mr. Li is Managing Director and Deputy Chairman of Cheung Kong (Holdings) Limited (a public investment holding and project management company). Mr. Li is also Deputy Chairman and Executive Director of Hutchison Whampoa Limited (an investment holding company); Chairman and Executive Director of Cheung Kong Infrastructure Holdings Limited (an infrastructure company) and of CK Life Sciences Int'l., (Holdings) Inc. (a biotechnology company); Executive Director of Power Assets Holdings Limited (formerly Hongkong Electric Holdings Limited) (a holding company); and a non-executive Director of The Hongkong and Shanghai Banking Corporation Limited. Mr. Li is a member of the Standing Committee of the 11th National Committee of the Chinese People's Political Consultative Conference of the People's Republic of China and he is also a member of the Commission on Strategic Development and the Council for Sustainable Development of the Hong Kong Special Administrative Region and Vice Chairman of the Hong Kong General Chamber of Commerce. Mr. Li is also the Honorary Consul of Barbados in Hong Kong. Mr. Li holds a Bachelor of Science degree in Civil Engineering and a Masters of Science degree in Structural Engineering, both from Stanford University in 1987. He obtained an honorary degree, Doctor of Laws, honoris causa (LL.D) from The University of Western Ontario in 2009.

Fok, Canning K.N. Hong Kong	Director, Co-Chair and Chair of the Compensation Committee Director of Husky since 2000	Mr. Fok is Group Managing Director and Executive Director of Hutchison Whampoa Limited. Mr. Fok is also Chairman and Executive Director of Hutchison Harbour Ring Limited (an investment holding company), and Power Assets Holdings Limited (formerly Hongkong Electric Holdings Limited) (a holding company); Chairman and non-executive Director of Hutchison Telecommunications Hong Kong Holdings Limited (a telecommunications company) and Hutchison Port Holdings Management Pte. Limited as the trustee-manager of Hutchison Port Holdings Trust (a business trust); Chairman and Director of Hutchison Telecommunications (Australia) Limited (a telecommunications company); Deputy Chairman and Executive Director of Cheung Kong Infrastructure Holdings Limited (an infrastructure company), and a non-executive Director of Cheung Kong (Holdings) Limited (an investment company). Mr. Fok was also Chairman and a Director of Partner Communications Company Ltd. from 1998 to 2009 and Chairman and non-executive Director of Hutchison Telecommunications International Limited from 2004 to 2010. Mr. Fok obtained a Bachelor of Arts degree from St. John's University, Minnesota in 1974 and a Diploma in Financial Management from University of New England, Australia in 1976. He has been a member of the Institute of Chartered Accountants in Australia since 1979.
Bradley, Stephen E. Hong Kong	Director Director of Husky since July 2010	Mr. Bradley is a director of Broadlea Group Ltd., Senior Representative (China), Grosvenor Ltd., Vice Chair-man, ICAP (Asia Pacific) and a director of Swire Properties Ltd. and Special Advisor to the Chief Executive Officer of Rio Tinto Ltd. Mr. Bradley entered the Foreign and Commonwealth Office in 1981 and served in various capacities including Director of Trade & Investment Promotions (Paris) from 1999 to 2002; Minister, DHM & Consul-General (Beijing) from 2002 to 2003 and HM Consul-General (Hong Kong) from 2003 to 2008. Mr. Bradley retired from the HM Diplomatic Service in 2009. Mr. Bradley obtained a Bachelor of Arts degree from Balliol College, Oxford University in 1980 and a post-graduate diploma from Fudan University, Shanghai in 1981.

Ghosh, Asim Alberta, Canada	Director, President & Chief Executive Officer Director of Husky since May 2009	Mr. Ghosh was appointed the President & Chief Executive Officer of Husky on June 1, 2010. Prior thereto Mr. Ghosh was the Managing Director and Chief Executive Officer of Vodafone Essar Limited (a telecommunications company) until March 2009. Mr. Ghosh began his career with Procter & Gamble in Canada in 1971 and subsequently worked with Rothmans International in what was then its Carling O'Keefe subsidiary from 1980 to 1988, his last position being Senior Vice President of the brewery operations. In 1989, Mr. Ghosh moved to India as the Chief Executive Officer of the Pepsi Foods (Frito Lay) start up in India. From 1991 to 1998 he held senior executive positions and then the position of Chief Executive Officer of the A S Watson Industries subsidiary (a manufacturer of consumer goods) of Hutchison Whampoa Limited. In August 1998, he became Managing Director and Chief Executive Officer of the company that would become Vodafone Essar Limited. Mr. Ghosh was Chairman of the Cellular Operators Association of India and of the National Telecom Committee of the Confederation of Indian Industries. He is an independent director of Kotak Mahindra Bank Limited, a listed bank in India, and was on the Board of Directors of Vodafone Essar Limited until February 2010. Mr. Ghosh obtained an undergraduate degree in Electrical Engineering from the Indian Institute of Technology in 1969 and received a Master's degree in Business Administration from the Wharton School, University of Pennsylvania in 1971.

Glynn, Martin J.G. British Columbia, Canada	Director, Chair of the Corporate Governance Committee and a Member of the Compensation Committee Director of Husky since 2000	Mr. Glynn is a director of VinaCapital Vietnam Opportunity Fund Limited (an investment fund), Sun Life Financial Inc., Sun Life Assurance Company of Canada and UBC Investment Management Trust Inc. Mr. Glynn was a director from 2000 to 2006 and President and Chief Executive Officer of HSBC Bank USA N.A. from 2003 until his retirement in 2006. Mr. Glynn was a director of HSBC Bank Canada from 1999 to 2006 and President and Chief Executive Officer from 1999 to 2003. Mr. Glynn obtained a Bachelor of Arts, Honours degree from Carleton University, Canada in 1974 and a Master's degree in Business Administration from University of British Columbia in 1976.
Koh, Poh Chan Hong Kong	Director Director of Husky since 2000	Ms. Koh is Finance Director of Harbour Plaza Hotel Management (International) Ltd. (a hotel management company). Ms. Koh is qualified as a Fellow Member (FCA) of the Institute of Chartered Accountants in England and Wales and is an Associate of the Canadian Institute of Chartered Accountants and the Chartered Institute of Taxation in the U.K. Ms. Koh graduated from the London School of Accountancy in 1971 and become a member of the Institute of Chartered Accountants in England and Wales in 1973.
Kwok, Eva L. British Columbia, Canada	Director, Member of the Compensation Committee and the Corporate Governance Committee Director of Husky since 2000	Mrs. Kwok is Chairman, a director and Chief Executive Officer of Amara Holdings Inc. (a private investment holding company). Mrs. Kwok is also a director of CK Life Sciences Int'l., (Holdings) Inc. and Cheung Kong Infrastructure Holdings Limited. Mrs. Kwok is also a director of the Li Ka Shing (Canada) Foundation. Mrs. Kwok was a director of Shoppers Drug Mart Corporation from 2004 to 2006 and of the Bank of Montreal Group of Companies until March 2009. Mrs. Kwok obtained a Master's degree in Science from the University of London in 1967.

Kwok, Stanley T.L. British Columbia, Canada	Director and Chair of the Health, Safety and Environment Committee Director of Husky since 2000	Mr. Kwok is a director and President of Stanley Kwok Consultants (a planning and development company). Mr. Kwok is also a director and President of Amara Holdings Inc. and a director of Cheung Kong (Holdings) Limited and CTL Bank of Canada. Mr. Kwok obtained a Bachelor of Science degree (Architecture) from St. John's University, Shanghai in 1949 and an A.A. Diploma from the Architectural Association School of Architecture in London, England in 1954.
Ma, Frederick S. H. GBS, JP Hong Kong	Director and Member of the Audit Committee and the Health, Safety and Environment Committee Director of Husky since July 2010	Mr. Ma has held senior management positions in international financial institutions and Hong Kong publicly listed companies in his career. He was also a former Principal Official with the Hong Kong SAR Government. He is a non-executive director of China Resources Land Limited, a Hong Kong listed company; a non-executive director and Chairman of the Audit Committee of Agricultural Bank of China, which is listed in Hong Kong and Shanghai; a non-executive director of COFCO Corporation and a non-executive director of Hutchison Port Holdings Management Pte. Limited, as the trustee-manager of Hutchison Port Holdings Trust. In July 2002, Mr. Ma joined the Government of the Hong Kong Special Administrative Region as the Secretary for Financial Services and the Treasury. He assumed the post of Secretary for Commerce and Economic Development in July 2007 but resigned from the Government in July 2008 due to medical reasons. In October 2008, he was appointed an Honorary Professor of the School of Economics and Finance at the University of Hong Kong. In July 2009, he was appointed as a Member of the International Advisory Council of China Investment Corporation. Mr. Ma obtained a Bachelor of Arts (Honours) degree in Economics and History from the University of Hong Kong in 1973.

Magnus, George C. Hong Kong	Director and Member of the Audit Committee Director of Husky since July 2010	Mr. Magnus has been a non-executive Director of Cheung Kong (Holdings) Limited since November 2005. He has also been a non-executive Director of Hutchison Whampoa Limited, Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited (formerly Hongkong Electric Holdings Limited) since 2005. Mr. Magnus acted as an Executive Director of Cheung Kong (Holdings) Limited from 1980 and as Deputy Chairman from 1985 until his retirement from these positions in October 2005. He served as Deputy Chairman of Hutchison Whampoa Limited from 1985 to 1993 and as Executive Director from 1993 to 2005. He also served as Chairman of Hongkong Electric Holdings Limited (now known as Power Assets Holdings Limited) from 1993 to 2005. Mr. Magnus obtained a Master's degree in Economics from King's College, Cambridge University in 1959.
Russel, Colin S. Gloucestershire, United Kingdom	Director, Member of the Audit Committee and the Health, Safety and Environment Committee Director of Husky since 2008	Mr. Russel is the founder and Managing Director of Emerging Markets Advisory Services Ltd. (a business advisory company). Mr. Russel is a director of Cheung Kong Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd. Mr. Russel was the Canadian Ambassador to Venezuela, Consul General for Canada in Hong Kong, Director for China of the Department of Foreign Affairs, Ottawa, Director for East Asian Trade in Ottawa, Senior Trade Commissioner for Canada in Hong Kong, Director for Japan Trade in Ottawa and was in the Trade Commissioner Service for Canada in Spain, Hong Kong, Morocco, the Philippines, London and India. Mr. Russel is a Professional Engineer and Qualified Commercial Mediator. He received his degree in Electrical Engineering in 1962 and a Master's degree in Business Administration in 1971 both from McGill University, Canada.
Shaw, Wayne E. Ontario, Canada	Director, Member of the Corporate Governance Committee and the Health, Safety and Environment Committee Director of Husky since 2000	Mr. Shaw is a Senior Partner with Stikeman Elliott LLP, Barristers and Solicitors. Mr. Shaw is also a director of the Li Ka Shing (Canada) Foundation. Mr. Shaw obtained a Bachelor of Arts degree from University of Alberta in 1964 and a Bachelor of Laws degree from University of Alberta in 1967. Mr. Shaw is a member of the Law Society of Ontario and the Bar of Alberta.

Shurniak, William Saskatchewan, Canada	Director, Deputy Chair and Member of the Audit Committee Director of Husky since 2000	Mr. Shurniak is a director of Hutchison Whampoa Limited and from May 2005 to June 2011 he was a director and Chairman of Northern Gas Networks Limited (a private distributor of natural gas in Northern England). Mr. Shurniak also held the following positions until his return to Canada in 2005: Director and Chairman of ETSA Utilities (a utility company) since 2000, Powercor Australia Limited (a utility company) since 2000, CitiPower Pty Ltd. (a utility company) since 2002, and a director of Envestra Limited (a natural gas distributor) since 2000, CrossCity Motorways Pty Ltd. (an infrastructure and transportation company) since 2002 and Lane Cove Tunnel Company Pty Ltd. (an infrastructure and transportation company) since 2004. Mr. Shurniak obtained an Honorary Doctor of Laws degree from the University of Saskatchewan in May, 1998 and from The University of Western Ontario in October, 2000 and in 2009 he was awarded the Saskatchewan Order of Merit by the government of the Province of Saskatchewan.
Sixt, Frank J. Hong Kong	Director & Member of the Compensation Committee Director of Husky since 2000	Mr. Sixt is Group Finance Director and Executive Director of Hutchison Whampoa Limited. Mr. Sixt is also Chairman and a non-executive Director of TOM Group Limited (an investment holding company); an Executive Director of Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited (formerly Hongkong Electric Holdings Limited); a non-executive Director of Cheung Kong (Holdings) Limited, Hutchison Telecommunications Hong Kong Holdings Limited and Hutchison Port Holdings Management Pte. Limited as the trustee-manager of Hutchison Port Holdings Trust and a Director of Hutchison Telecommunications (Australia) Limited. Mr. Sixt is also a Director of the Li Ka Shing (Canada) Foundation. He was previously a Director of Partner Communications Ltd. from 1998 to 2009 and a non-executive Director of Hutchison Telecommunications International Limited from 2004 to 2011. Mr. Sixt obtained a Master's degree in Arts from McGill University, Canada in 1978 and a Bachelor's degree in Civil Law from Université de Montréal in 1978. He is a member of the Bar and of the Law Society of the Provinces of Quebec and Ontario, Canada.

Officers

Name and Residence	Office or Position	Principal Occupation During Past 5 Years
Cowan, Alister Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Husky Energy Inc. since July 2008. He was previously Executive Vice President and Chief Financial Officer, British Columbia Hydro & Power Authority from 2004 to 2008, Vice President, Direct Energy Marketing Limited from 2003 to 2004 and Vice President and Comptroller, TransAlta Corporation from 2000 to 2003.
Peabody, Robert J. Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Husky since January 2006. Prior to joining Husky, Mr. Peabody held the following positions with BP: Director Innovence Separation & Initial Public Offering Project from 2005 to 2006, President of Global Polymers, Chemicals from 2004 to 2005, Vice President, Polyester and Aromatics Americas from 2002 to 2004 and Vice President, BP Group Strategy & Planning from 1991 to 2001.
Girgulis, James D. Alberta, Canada	Vice President, Legal & Corporate Secretary	Vice President, Legal & Corporate Secretary of Husky since August 2000.

As at February 29, 2012, the directors and officers of Husky, as a group, beneficially owned or controlled or directed, directly or indirectly, 436,709 common shares of Husky representing less than 1% of the issued and outstanding common shares.

Conflicts of Interest

The officers and directors of Husky may also become officers and/or directors of other companies engaged in the oil and gas business generally and which may own interests in oil and gas properties in which Husky holds or may in the future, hold an interest. As a result, situations may arise where the interests of such directors and officers conflict with their interests as directors and officers of other companies. In the case of the directors, the resolution of such conflicts is governed by applicable corporate laws which require that directors act honestly, in good faith and with a view to the best interests of Husky and, in respect of the Business Corporations Act (Alberta), Husky's governing statute, that directors declare, and refrain from voting on, any matter in which a director may have a conflict of interest.

Corporate Cease Trade Orders or Bankruptcies

None of those persons who are directors or executive officers of Husky is or have been within the past ten years, a director, chief executive officer or chief financial officer of any company, including Husky and any personal holding companies of such person, that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, for a period of more than 30 consecutive days, or after such persons ceased to be a director, chief executive officer or chief financial officer of the company was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, for a period of more than 30 consecutive days, which resulted from an event that occurred while such person was acting in such capacity.

In addition, none of those persons who are directors or executive officers of Husky is, or has been within the past ten years, a director or executive officer of any company, including Husky and any personal holding companies of such persons, that while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manger or trustee appointed to hold its assets, other than as follows. Eva L. Kwok was a director of Air Canada in 2003 at the time it became subject to creditor protection under the Companies Creditors Arrangement Act (Canada). Until April 12, 2002, Frank J. Sixt was a director of vLinx Inc., a private Canadian company which was petitioned into bankruptcy on April 15, 2002. vLinx Inc. developed technology and software

to facilitate international trade. Victor T. K. Li was a director of Star River Investment Limited, a Hong Kong company, until June 4, 2005, which commenced creditors voluntary wind up on September 28, 2004. Star River Investments Limited was owned as to 50% by Cheung Kong (Holdings) Limited and a wholly owned subsidiary of Cheung Kong (Holdings) Limited was the petitioning creditor. The company was subsequently dissolved on June 4, 2005. Mr. Glynn was director of MF Global Holdings Ltd. when it filed for Chapter 11 bankruptcy in the United States on October 31, 2011. Mr. Glynn is no longer a director of MF Global Holdings Ltd.

Individual Penalties, Sanctions or Bankruptcies

None of the persons who are directors or executive officers of Husky (or any personal holding companies of such persons) have, within the past ten years become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or were subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold his or her assets.

None of the persons who are directors or executive officers of the Company (or any personal holding companies of such persons) have been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or have entered into a settlement agreement with a securities regulatory authority or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

The members of Husky's Audit Committee (the "Committee") are William Shurniak (Chair), Colin S. Russel, Frederick S.H. Ma and George C. Magnus. Each of the members of the Committee are independent in that each member does not have a direct or indirect material relationship with the Company. Multilateral Instrument 52-110 — "Audit Committees" provides that a material relationship is a relationship which could, in the view of the Company's Board of Directors, reasonably interfere with the exercise of a member's independent judgment.

The Committee's Mandate provides that the Committee is to be comprised of at least three (3) members of the Board, all of whom shall be independent and meet the financial literacy requirements of applicable laws and regulations. Each member of the Committee is financially literate in that each has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements.

The education and experience of each Audit Committee member that is relevant to the performance of his responsibilities as an Audit Committee member is as follows.

William Shurniak (Chair) — Mr. Shurniak is an independent, non-executive director and member of the audit committee of Hutchison Whampoa Limited and from May 2005 to June 2011, a director and Chairman of Northern Gas Networks Limited, a private company in the U.K.. He has broad banking experience and prior to his moving back to Canada in 2005, he spent five years in Australia where he was a director of a public company engaged in the distribution of natural gas. He was also a director and member of the audit committees of five other private companies, three of which are regulated electricity distribution companies.

Colin S. Russel — Mr. Russel is the founder and Managing Director of Emerging Markets Advisory Services Ltd. Mr. Russel is a director and an audit committee member of Cheung Kong Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd.

Frederick S.H. Ma — Mr. Ma has 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 Honorary Professor of the University of Hong Kong.

George C. Magnus — 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 Hongkong Electric Holdings Limited.

Husky's Audit Committee Mandate is attached hereto as Schedule "A."

External Auditor Service Fees

The following table provides information about the fees billed to the Company for professional services rendered by KPMG LLP, the Company's external auditor, during the fiscal years indicated:

	Aggregate fees billed by the External Auditor	
($ thousands)	**2011**	**2010**
Audit fees	2,113	2,745
Audit-related fees	977	873
Tax fees	160	126
All other fees	-	-
	3,250	3,744

Audit fees consist of fees for the audit of the Company's annual financial statements or services that are normally provided in connection with statutory and regulatory filings, including the Sarbanes-Oxley Act of 2002. Audit-related fees included fees for attest services not required by statute or regulation and services with respect to acquisitions and dispositions. Tax fees included fees for tax planning and various taxation matters.

The Company's Audit Committee has the sole authority to review in advance, and grant any appropriate pre-approvals, of all non-audit services to be provided by the independent auditors and to approve fees, in connection therewith. The Audit Committee pre-approved all of the audit-related and tax services provided by KPMG LLP in 2011.

LEGAL PROCEEDINGS

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 or other matters or amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Company's directors, executive officers or persons or companies that beneficially own or control or direct, directly or indirectly or a combination of both, more than 10% of Husky's common shares, or their associates and affiliates, had any material interest, direct or indirect, in any transaction with the Company within the three most recently completed financial years or during the current financial year that has materially affected or would reasonably be expected to materially affect the Company.

TRANSFER AGENT AND REGISTRARS

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, Inc. The registers for transfers of the Company's common and preferred shares are maintained by Computershare Trust Company of Canada at its principal offices in the cities of Calgary, Alberta and Toronto, Ontario. Queries should be directed to Computershare Trust Company at 1-888-267-6555 (toll free in North America).

INTERESTS OF EXPERTS

Certain information relating to the Company's reserves included in this Annual Information Form has been calculated by the Company and audited and opined upon as of December 31, 2011 by McDaniel & Associates Consultants Ltd. ("McDaniel"), independent petroleum engineering consultants retained by Husky, and has been so included in reliance on the opinion and analysis of McDaniel, given upon the authority of said firm as experts in reserves engineering. The partners of McDaniel as a group beneficially own, directly or indirectly, less than 1% of the Company's securities of any class.

KPMG LLP are the auditors of the Company and have confirmed that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and within the meaning of the U.S. Securities Act of 1933 and the applicable rules and regulations thereunder adopted by the SEC and the Public Company Accounting Oversight Board (United States).

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal shareholders of Husky's common shares and a description of options to purchase common shares will be contained in Husky's Management Information Circular prepared in connection with the annual meeting of shareholders to be held on April 26, 2012.

Additional financial information is provided in Husky's Consolidated Financial Statements and Management's Discussion and Analysis for the most recently completed fiscal year ended December 31, 2011.

Additional information relating to Husky Energy Inc. is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

ABBREVIATIONS AND GLOSSARY OF TERMS

When used in this Annual Information Form, the following terms have the meanings indicated:

Units of Measure	
bbl	-barrel
bbls	-barrels
mbbls	-thousand barrels
mmbbls	-million barrels
bbls/day	-barrels per calendar day
bpd	-barrels per day
bopd	-barrels of oil per day
mbbls/day	-thousand barrels per calendar day
boe	-barrels of oil equivalent
lt	-litres
lt/day	-litres per day
mboe	-thousand barrels of oil equivalent
mmboe	-million barrels of oil equivalent
boe/day	-barrels of oil equivalent per calendar day
mboe/day	-thousand barrels of oil equivalent per day
bps	-basis points
m	-meters
mcf	-thousand cubic feet
mmcf	-million cubic feet
bcf	-billion cubic feet
mmcf/day	-million cubic feet per calendar day
mmbtu	-million British thermal units
km	-kilometers
sq km	-square kilometers
CO_2	-carbon dioxide
MW	-megawatts
GJ	-gigajoule

Acronyms	
API	-American Petroleum Institute
ASP	-alkaline surfactant polymer
CDOR	-Certificate of Deposit Offered Rate
CHOPS	-cold heavy oil production with sand
CNOOC	-China National Offshore Oil Corporation
COGEH	-Canadian Oil and Gas Evaluation Handbook
CSS	-cyclic steam stimulation
EIA	-Energy Information Administration
EL	-Exploration Licence
EOR	-enhanced oil recovery
ERCB	-Energy Resources Conservation Board
FAS	-Financial Accounting Statement
FASB	-Financial Accounting Standards Board
FEED	-front end engineering design
FPSO	-Floating production, storage and offloading vessel
GAAP	-Generally Accepted Accounting Principles
LIBOR	-London Interbank Offered Rate
LLB	-Lloydminster Blend
MD&A	-Management's Discussion and Analysis
NGL	-Natural gas liquids

NIT	-NOVA Inventory Transfer
NWT	-Northwest Territories
NYMEX	-New York Mercantile Exchange
OPEC	-Organization of Petroleum Exporting Countries
PIIP	-Petroleum initially-in-place
PSC	-Production Sharing Contract
SAGD	-Steam assisted gravity drainage
SDL	-Significant Discovery Licence
SEC	-Securities and Exchange Commission of the United States
SEDAR	-System for Electronic Document Analysis and Retrieval
WCSB	-Western Canada Sedimentary Basin
WTI	-West Texas Intermediate crude oil

API° gravity

Measure of oil density or specific gravity used in the petroleum industry. The American Petroleum Institute (API) scale expresses density such that the greater the density of the petroleum, the lower the degree of API gravity.

Barrel

A unit of volume equal to 42 U.S. gallons.

Bitumen

Bitumen is solid or semi-solid with a viscosity greater than 10,000 centipoise at original temperature in the deposit and atmospheric pressure.

Bulk terminal

A facility used primarily for the storage and/or marketing of petroleum products.

Coal bed methane

The primary energy source of natural gas is methane. Coal bed methane is methane found and recovered from the coal bed seams. The methane is normally trapped in coal by water that is under pressure. When the water is removed the methane is released.

Cold production

A non-thermal production process for heavy oil in unconsolidated sand formations. During the cold production process, heavy oil and sand are produced simultaneously through the use of progressive cavity pumps, which produce high pressure in the reservoir.

Debottleneck

To remove restrictions thus improving flow rates and productive capacity.

Delineation well

A well in close proximity to an oil or gas well that helps determine the aerial extent of the reservoir.

Developed area

A drainage unit having a well completed thereon capable of producing oil or gas in paying quantities.

Development well

A well drilled within the proved area of an oil and gas reservoir to the depth of a stratigraphic horizon known to be productive.

Diluent

A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to improve the transmissibility of the oil through a pipeline.

Dry and abandoned well

A well found to be incapable of producing oil or gas in sufficient quantities to justify completion as a producing oil or gas well.

Enhanced recovery

The increased recovery from a crude oil pool achieved by artificial means or by the application of energy extrinsic to the pool. An artificial means or application includes pressuring, cycling, pressure maintenance or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of aiding in the lifting of fluids in the well, or stimulation of the reservoir at or near the well by mechanical, chemical, thermal or explosive means.

Exploration Licence ("EL")

A licence with respect to the Canadian offshore or the Northwest or Yukon Territories conferring the right to explore for, and the exclusive right to drill and test for, petroleum; the exclusive right to develop the applicable area in order to produce petroleum; and, subject to satisfying the requirements for issuance of a production licence and compliance with the terms of the licence and other provisions of the relevant legislation, the exclusive right to obtain a production licence.

Exploratory well

A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well, an extension well, or a stratigraphic test well as those items are defined herein.

Extension well

A well drilled to extend the limits of a known reservoir.

Field

An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

Gathering system

Pipeline system and associated facilities used to gather natural gas or crude oil from various wells and deliver it to a central point where it can be moved from there by a single pipeline to a processing facility or sales point.

Heavy crude oil

Crude oil measured between 20 API° and 10 API° and is liquid at original temperature in the deposit and atmospheric pressure.

Horizontal drilling

Drilling horizontally rather than vertically through a reservoir, thereby exposing more of the well to the reservoir and increasing production.

Hydrogen sulphide

A poisonous gas which is colourless and heavier than air and is found in sour gas.

Infill well

A well drilled on an irregular pattern disregarding normal spacing requirements. These wells are drilled to produce from parts of a reservoir that would otherwise not be recovered through existing wells drilled in accordance with normal spacing.

Light crude oil

Crude oil measured at 30 API° or lighter.

Liquefied petroleum gas

Liquefied propanes and butanes, separately or in mixtures.

Medium crude oil

Crude oil measured between 20 API° and 30 API°.

Metocean data

Meteorological and oceanographic data used for, among other things, the design of marine structures.

Miscible flood

An enhanced recovery method which requires that three fluids exist in the reservoir: the mobile oil to be recovered, a displacing fluid (NGL) injected to move as a bank behind the oil, and a fluid injected to propel the displacing fluid (chase gas) through the reservoir.

Multiple completion well

A well producing from two or more formations by means of separate tubing strings running inside the casing, each of which carry hydrocarbons from a separate and distinct producing formation.

Natural gas liquids

Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and condensate, or a combination thereof.

Oil battery

An accessible area to accommodate separators, treaters, storage tanks and other equipment necessary to process and store crude oil and other fluids prior to transportation.

Oil sands

Sands and other rock materials which contain crude bitumen and include all other mineral substances in association therewith.

Overriding royalty interests

An interest acquired or withheld in the oil and gas produced (or the proceeds from the sale of such oil and gas), received free and clear of all costs of development, operation, or maintenance and in addition to the usual landowner's royalty reserved to the lessor in an oil and gas lease.

Primary recovery

The oil and gas recovered by any method that may be employed to produce the oil or gas through a single well bore. The fluid enters the well bore by the action of native reservoir energy or gravity.

Production Sharing Contract ("PSC")

A contract for the development of resources under which the contractor's costs (investment) are recoverable each year out of the production but there is a maximum amount of production which can be applied to the cost recovery in any year. This annual allocation of production is referred to as cost oil; the remainder is referred to as profit oil and is divided in accordance with the contract between the contractor and the host government.

Raw gas

Gas as produced from a well before the separation of liquefiable hydrocarbons or other substances contained therein.

Reserve Replacement Ratio

The reserve replacement ratio represents the rate at which the Company replaces reserve volumes realized through current production for a given period. The ratio is calculated as the sum of: closing reserve volumes less opening reserve volumes plus production volumes divided by production volumes.

Secondary recovery

Oil or gas recovered by injecting water or gas into the reservoir to force additional oil or gas to the producing wells. Usually, but not necessarily, this is done after the primary recovery phase has passed.

Seismic (survey)

A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with

a seismograph, the rate of transmission of shock waves through the various rock formations. The rate at which the waves are transmitted varies with the medium through which they pass.

Service well

A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation or injection for in-situ combustion.

Significant Discovery Licence ("SDL")

A licence issued following the declaration of a significant discovery, which is indicated by the first exploration well that demonstrates by flow testing the existence of sufficient hydrocarbons in a particular geological feature to suggest potential for sustained production. A Significant Discovery Licence confers the same rights as that of an Exploration Licence.

Sour gas

Natural gas contaminated with chemical impurities, notably hydrogen sulphide or other sulphur compounds. Such compounds must be removed before the gas can be used for commercial or domestic purposes.

Specific gravity

The ratio between the weight of equal volumes of water and another liquid measured at standard temperature, the weight of water is assigned a value of one. However, the specific gravity of oil is normally expressed in degrees of API gravity as follows:

$$\text{Degrees API} = \frac{141.5}{\text{Specific gravity @ F60 degrees}} - 131.5$$

Spot price

The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased "on the spot" at current market rates.

Steam assisted gravity drainage ("SAGD")

A recovery method used to produce heavy crude oil and bitumen in-situ. Steam is injected via a horizontal well along a producing formation. The temperature in the formation increases and lowers the viscosity of the crude oil allowing it to fall to a horizontal production well beneath the steam injection well.

Step-out well

A well drilled adjacent to a proven well but located in an unproven area; a well drilled in an effort to ascertain the extent and boundaries of a producing formation.

Stratigraphic test well

A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) "exploratory-type," if not drilled in a proved area, or (ii) "development-type," if drilled in a proved area.

Synthetic oil

A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content.

Tertiary recovery

The recovery of oil and gas by using exotic or complex recovery schemes involving steam, chemicals, gases or heat. Usually, but not necessarily, this is done after the secondary recovery phase has passed.

Three dimensional ("3-D") seismic survey

Three dimensional seismic imaging which uses a grid of numerous cables rather than a few lines stretched in one line.

Turnaround

Perform maintenance at a plant or facility which requires the plant or facility to be completely or partially shutdown for the duration.

Undeveloped area

An area that has not been established by drilling operations whether oil and/or gas may be found in commercial quantities.

Waterflood

One method of secondary recovery in which water is injected into an oil reservoir for the purpose of forcing oil out of the reservoir and into the bore of a producing well.

Well abandonment costs

Costs of abandoning a well, net of any salvage value, and disconnecting the well from the surface gathering system.

Wellhead

The structure, sometimes called the "Christmas tree," that is positioned on the surface over a well that is used to control the flow of oil or gas as it emerges from the subsurface casinghead.

Working interest

An interest in the net revenues of an oil and gas property which is proportionate to the share of exploration and development costs borne until such costs have been recovered, and which entitles the holder to participate in a share of net revenue thereafter.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Information Form 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 Annual Information Form 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; future development costs of the Company's proved and probable reserves through to 2016; anticipated cost of abandonment and reclamation; and 2012 production estimates;
- with respect to the Company's Asia Pacific Region: evaluation plans, anticipated rates of production and anticipated timing of first gas for the Company's Liwan Gas Project; development plans and anticipated timing of first gas at the Company's Madura Straits block, offshore Indonesia; and exploration and drilling plans for the Company's North Sumbawa II block, offshore Indonesia;
- with respect to the Company's Atlantic Region: development plans, timing of well completions and expected effect of the pilot program at the Company's West White Rose field; development and drilling plans at the Company's North Amethyst and White Rose fields; drilling plans for the Company's Terra Nova field; exploration plans for offshore Canada's East Coast and Greenland; and continued evaluation of a concrete wellhead and drilling platform in the White Rose region, including the awarding of Pre-FEED and FEED contracts to support the work;

- with respect to the Company's Oil Sands properties: project schedule, drilling plans, anticipated costs and anticipated timing and rates of first production at Phase I of the Company's Sunrise Energy Project; drilling and development plans and timetable for the Company's Tucker project; and exploration plans and anticipated timing of production at the Company's Saleski property;
- with respect to the Company's Heavy Oil properties: the expected maintenance of heavy crude oil production in the Lloydminster area; and the expected timing of commissioning of the CO2 capture and liquefaction plant project at the Company's Lloydminster Ethanol Plant, and planned use of CO2 from the plant;
- with respect to the Company's Western Canadian oil and gas resource plays: progress of the ASP EOR Program at the Company's Fosterton and Macklin properties; acquisition and development of oil resource properties in the Red Deer area; drilling plans for the Company's Redwater and Elrose properties; progression and anticipated timing of completion for the Company's Fosterton facility construction; timing and expected outcome of the Company's pilot drilling program at the Canol shale oil resource play; and exploration and evaluation plans for the Canol shale oil resource play;
- with respect to the Company's Midstream operating segment: the evaluation of storage opportunities in Western Canada; and plans regarding and anticipated results of the expansion of the Company's commodity marketing operations; and
- with respect to the Company's Downstream operating segment: bitumen processing expansion plans for the Company's Toledo Refinery; anticipated timing of completion and expected outcomes of the Company's Continuous Catalyst Regeneration Reformer Project; anticipated timing and expected outcomes of the construction of the kerosene hydrotreater at the Lima Refinery; the timing and expected impact of planned outages and turnarounds at the Lima Refinery; and 2012 business plans for the Company's asphalt distribution network.

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 Annual Information Form 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. The material factors and assumptions used to develop the forward-looking statements include, but are not limited to:

- with respect to the business, operations and results of the Company generally: the absence of significant adverse changes to commodity prices, interest, applicable royalty rates and tax laws, and foreign exchange rates; the absence of significant adverse changes to energy markets, competitive conditions, the supply and demand for crude oil, natural gas, NGL and refined petroleum products, or the political, economic and social stability of the jurisdictions in which the Company operates; continuing availability of economical capital resources, labour and services; demand for products and cost of operations; the absence of significant adverse legislative and regulatory changes, in particular changes to the legislation and regulation governing fiscal regimes and environmental issues; and stability of general domestic and global economic, market and business conditions;
- with respect to the Company's Asia Pacific Region, Atlantic Region, Oil Sands properties, Heavy Oil properties and Western Canadian oil and gas resources plays: the accuracy of future production rates and reserve and resource estimates; the securing of sales agreements to underpin the commercial development and regulatory approvals for the development of the Company's properties; the absence of significant delays of the procurement, development, construction or commissioning of our projects, for which the Company or a third party is the designated operator, that may result from the inability of suppliers to meet their commitments, lack of regulatory or third-party approvals or other governmental actions, harsh weather or other calamitous event; the absence of significant disruption of operations such as may result from harsh weather, natural disaster, accident, civil unrest or other calamitous event; the absence of significant unexpected technological or commercial difficulties that adversely affect exploration, development, production, processing or transportation; the sufficiency of budgeted capital expenditures in carrying out planned activities; and the absence of significant increase in the cost of major growth projects; and

- with respect to the Company's Midstream and Downstream operating segments: the absence of significant delays of the development, construction or commissioning of our projects that may result from the inability of suppliers to meet their commitments, lack of regulatory or third-party approvals or other governmental actions, harsh weather or other calamitous event; the absence of significant disruption of operations such as may result from harsh weather, natural disaster, accident, civil unrest or other calamitous event; the absence of significant unexpected technological or commercial difficulties that adversely affect processing or transportation; the sufficiency of budgeted capital expenditures in carrying out planned activities; and the absence of significant increase in the cost of major growth projects.

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 risks, uncertainties and other factors, many of which are beyond Husky's control, that could cause actual results to differ (potentially significantly) from those expressed in the forward-looking statements include, but are not limited to:

- with respect to the business, operations and results of the Company generally: those risks, uncertainties and other factors described under "Risk Factors" in this Annual Information Form and throughout our Management's Discussion and Analysis for the year ended December 31, 2011; the demand for the Company's products and prices received for crude oil and natural gas production and refined petroleum products; the economic conditions of the markets in which the Company conducts business; the exchange rate between the Canadian and U.S. dollar; the ability to replace reserves of oil and gas, whether sourced from exploration, improved recovery or acquisitions; 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 royalty regimes; changes to government fiscal, monetary and other financial policies; changes in workforce demographics; and the cost and availability of capital, including access to capital markets at acceptable rates;
- with respect to the Company's Asia Pacific Region, Atlantic Region, Oil Sands properties, Heavy Oil properties and Western Canadian oil and gas resources plays: the availability of prospective drilling rights; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project development; the availability and cost of labour, technical expertise, material and equipment to efficiently, effectively and safely undertake capital projects; the costs to operate properties, plants and equipment in an efficient, reliable and safe manner; prevailing climatic conditions in the Company's operating locations; regulations to deal with climate change issues; the competitive actions of other companies, including increased competition from other oil and gas companies; business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting the Company or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; the co-operation of business partners especially where the Company is not operator of production projects or developments in which it has an interest; the inability to obtain regulatory approvals to operate existing properties or develop significant growth projects; risk associated with transportation of production or product to market or transportation of feedstock to processing facilities resulting from an interruption in pipeline and other transportation services both owned and contracted due to calamitous event or regulatory obligation; and the inability to reach estimated production levels from existing and future oil and gas development projects as a result of technological or commercial difficulties; and
- with respect to the Company's Midstream and Downstream operating segments: the costs to operate properties, plants and equipment in an efficient, reliable and safe manner; prevailing climatic conditions in the Company's operating locations; regulations to deal with climate change issues; the competitive actions of other companies, including increased competition from other oil and gas companies; business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting Husky or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; risk associated with transportation of production or product to market or transportation of feedstock to processing facilities resulting from an interruption in pipeline and other transportation services both owned and contracted due to calamitous event or regulatory obligation; and the inability to obtain regulatory approvals to operate existing properties or develop significant growth projects.

These and other factors are discussed throughout this Annual Information Form and in the Management's

Discussion and Analysis for the year ended December 31, 2011 available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

In the discussions above, the Company has categorized the material factors and assumptions used to develop the forward-looking statements, and the risks, uncertainties and other factors that could influence actual results, by region, properties, plays and segments. These categories reflect the Company's current views regarding the factors, assumptions, risks and uncertainties most relevant to the particular region, property, play or segment. Other factors, assumptions, risks or uncertainties could impact a particular region, property, play or segment, and a factor, assumption, risk or uncertainty categorized under a particular region, property, play or segment could also influence results with respect to another region, property, play or segment.

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.

Schedule A

Husky Energy Inc.

Audit Committee Mandate

Purpose

The Audit Committee (the "Committee") is a committee of the Board of Directors (the "Board") of Husky Energy Inc. (the "Corporation"). The Committee's primary function is to assist the Board in carrying out its responsibilities with respect to:

1. the quarterly and annual financial statements and quarterly and annual MD&A, which are to be provided to shareholders and the appropriate regulatory agencies;
2. earnings press releases before the Corporation publicly discloses this information;
3. the system of internal controls that management has established;
4. the internal and external audit process;
5. the appointment of external auditors;
6. the appointment of qualified reserves evaluators or auditors;
7. the filing of statements and reports with respect to the Corporation's oil and gas reserves; and
8. the identification, management and mitigation of major financial risk exposures of the Corporation.

In addition, the Committee provides an avenue for communication between the Board and each of the Chief Financial Officer of the Corporation and other senior financial management, internal audit, the external auditors, external qualified reserves evaluators or auditors and internal qualified reserves evaluators. It is expected that the Committee will have a clear understanding with the external auditors and the external reserve evaluators or auditors that an open and transparent relationship must be maintained with the Committee.

While the Committee has the responsibilities and powers set forth it this Mandate, the role of the Committee is oversight. The members of the Committee are not full time employees of the Corporation and may or may not be accountants or auditors by profession or experts in the fields of accounting, or auditing and, in any event, do not serve in such capacity. Consequently, it is not the duty of the Committee to plan or conduct financial audits or reserve audits or evaluations, or to determine that the Corporation's financial statements are complete, accurate and are in accordance with applicable accounting or reserve principles.

This is the responsibility of management and the external auditors and, as to reserves, the external reserve evaluators or auditors. Management and the external auditors will also have the responsibility to conduct investigations and to assure compliance with laws and regulations and the Corporation's business conduct guidelines.

Composition

The Committee will consist of not less than three directors, all of whom will be independent and will satisfy the financial literacy requirements of securities regulatory requirements.

One of the members of the Committee will be an audit committee financial expert as defined in applicable securities regulatory requirements.

Members of the Committee will be appointed annually at a meeting of the Board, on the recommendation of the Corporate Governance Committee to the Co-Chairs of the Board and will be listed in the annual report to shareholders.

Committee members may be removed or replaced at any time by the Board, and will, in any event, cease to be a member of the Committee upon ceasing to be a member of the Board. Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

The Committee Chair will be appointed by the Board, on the recommendation of the Corporate Governance Committee to the Co-Chairs of the Board.

Meetings

The Committee will meet at least four times annually on dates determined by the Chair or at the call of the

Chair or any other Committee member, and as many additional times as the Committee deems necessary.

Committee members will strive to be present at all meetings either in person, by telephone or other communications facilities as permit all persons participating in the meeting to hear each other.

A majority of Committee members, present in person, by telephone, or by other permissible communication facilities will constitute a quorum.

The Committee will appoint a secretary, who need not be a member of the Committee, or a director of the Corporation. The secretary will keep minutes of the meetings of the Committee. Minutes will be sent to all Committee members, on a timely basis.

As necessary or desirable, but in any case at least quarterly, the Committee shall meet with members of management and representatives of the external auditors and internal audit in separate executive sessions to discuss any matters that the Committee or any of these groups believes should be discussed privately.

As necessary or desirable, but in any case at least annually, the Committee will meet the management and representatives of the external reserves evaluators or auditors and internal reserves evaluators in separate executive sessions to discuss matters that the Committee or any of these groups believes should be discussed privately.

Authority

Subject to any prior specific directive by the Board, the Committee is granted the authority to investigate any matter or activity involving financial accounting and financial reporting, the internal controls of the Corporation and the reporting of the Corporation's reserves and oil and gas activities.

The Committee has the authority to engage and set the compensation of independent counsel and other advisors, at the Corporation's expense, as it determines necessary to carry out its duties.

In recognition of the fact that the external auditors are ultimately accountable to the Committee, the Committee will have the authority and responsibility to recommend to the Board the external auditors that will be proposed for nomination at the annual general meeting. The external auditors will report directly to the Committee, and the Committee will evaluate and, where appropriate, replace the external auditors. The Committee will approve the fees and terms for all audit engagements and all non-audit engagements with the external auditors. The Committee will consult with management and the internal audit group regarding the engagement of the external auditors but will not delegate these responsibilities.

The external qualified reserves evaluators or auditors will report directly to the Committee, and the Committee will evaluate and, where appropriate, replace the external qualified reserves evaluators or auditors. The Committee will approve the fees and terms for all reserves evaluators or audit engagements. The Committee will consult with management and the internal qualified reserves evaluators group regarding the engagement of the external qualified reserves evaluators or auditors but will not delegate these responsibilities.

Specific Duties & Responsibilities

The Committee will have the oversight responsibilities and specific duties as described below.

Audit

1. Review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Corporate Governance Committee and the Board for approval.
2. Review with the Corporation's management, internal audit and the external auditors and recommend to the Board for approval the Corporation's annual financial statements and annual MD&A which is to be provided to shareholders and the appropriate regulatory agencies and any financial statement contained in a prospectus, information circular, registration statement or other similar document.
3. Review with the Corporation's management, internal audit and the external auditors and approve the Corporation's quarterly financial statements and quarterly MD&A which is to be provided to shareholders and the appropriate regulatory agencies.
4. Review with the Corporation’s management and approve earnings press releases before the Corporation publicly discloses this information.

5. Be responsible for the oversight of the work of the external auditors, including the resolution of disagreements between management of the Corporation and the external auditors regarding financial reporting.
6. Review with the Corporation's management, internal audit and the external auditors the Corporation's accounting and financial reporting controls and obtain annually, in writing from the external auditors their observations, if any, on material weaknesses in internal controls over financial reporting as noted during the course of their work.
7. Review with the Corporation's management, internal audit and the external auditors significant accounting and reporting principles, practices and procedures applied by the Corporation in preparing its financial statements, and discuss with the external auditors their judgments about the quality (not just the acceptability) of the Corporation's accounting principles used in financial reporting.
8. Review the scope of internal audit's work plan for the year and receive a summary report of major findings by internal audit and how management is addressing the conditions reported.
9. Review the scope and general extent of the external auditors' annual audit, such review to include an explanation from the external auditors of the factors considered in determining the audit scope, including the major risk factors, and the external auditors confirmation whether or not any limitations have been placed on the scope or nature of their audit procedures.
10. Inquire as to the independence of the external auditors and obtain from the external auditors, at least annually, a formal written statement delineating all relationships between the external auditors and the Corporation as contemplated by Independence Standards Board Standard No. 1, Independence Discussions with Audit Committees.
11. Arrange with the external auditors that (a) they will advise the Committee, through its Chair and management of the Corporation, of any matters identified through procedures followed for the review of interim quarterly financial statements of the Corporation, such notification is to be made prior to the related press release and (b), for written confirmation at the end of each of the first three quarters of the year, that they have nothing to report to the Committee, if that is the case, or the written enumeration of required reporting issues.
12. Review at the completion of the annual audit, with senior management, internal audit and the external auditors the following:
    i. the annual financial statements and related footnotes and financial information to be included in the Corporation's annual report to shareholders;
    ii. results of the audit of the financial statements and the related report thereon and, if applicable, a report on changes during the year in accounting principles and their application;
    iii. significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit;
    iv. inquire about the cooperation received by the external auditors during their audit, including access to all requested records, data and information; and
    v. inquire of the external auditors whether there have been any material disagreements with management, which, if not satisfactorily resolved, would have caused them to issue a non-standard report on the Corporation's financial statements.
13. Discuss (a) with the external auditors, without management being present, (i) the quality of the Corporation's financial and accounting personnel, and (ii) the completeness and accuracy of the Corporation's financial statements, and (b) elicit the comments of senior management regarding the responsiveness of the external auditors to the Corporation's needs.
14. Meet with management to discuss any relevant significant recommendations that the external auditors may have, particularly those characterized as 'material' or 'serious' (typically, such recommendations will be presented by the external auditors in the form of a Letter of Comments and Recommendations to the Committee) and review the responses of management to the Letter of Comments and Recommendations and receive follow-up reports on action taken concerning the aforementioned recommendations.
15. Review and approve disclosures required to be included in periodic reports filed with Canadian and U.S. securities regulators with respect to non-audit services performed by the external auditors.

16. Establish adequate procedures for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, and periodically assess the adequacy of those procedures.
17. Establish procedures for (a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters, and (b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
18. Review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors.
19. Review the appointment and replacement of the senior internal audit executive.
20. Review with management, internal audit and the external auditors the methods used to establish and monitor the Corporation's policies with respect to unethical or illegal activities by the Corporation's employees that may have a material impact on the financial statements or other reporting of the Corporation.
21. Reviewing generally, as part of the review of the annual financial statements, a report, from the Corporation's general counsel concerning legal, regulatory and compliance matters that may have a material impact on the financial statements or other reporting of the Corporation.
22. Review and discuss with management, on a regular basis, the identification, management and mitigation of major financial risk exposures across the Corporation.

Reserves

23. Review, with reasonable frequency, the Corporation's procedures relating to the disclosure of information with respect to the Corporation's oil and gas reserves, including the Corporation's procedures for complying with the disclosure requirements and restrictions of applicable regulatory requirements.
24. Review with management the appointment of the external qualified reserves evaluators or auditors, and in the case of any proposed change in such appointment, determine the reasons for the change and whether there have been disputes between management and the appointed external qualified reserves evaluators or auditors.
25. Review, with reasonable frequency, the Corporation's procedures for providing information to the external qualified reserves evaluators or auditors who report on reserves and data for the purposes of compliance with applicable securities regulatory requirements.
26. Meet, before the approval and release of the Corporation's reserves data and the report of the qualified reserve evaluators or auditors thereon, with senior management, the external qualified reserves evaluators or auditors and the internal qualified reserves evaluators to determine whether any restrictions affect their ability to report on reserves data without reservation and to review the reserves data and the report of the qualified reserves evaluators or auditors.
27. Recommend to the Board for approval of the content and filing of required statements and reports relating to the Corporation's disclosure of reserves data as prescribed by applicable regulatory requirements.

Miscellaneous

28. Review and approve (a) any change or waiver in the Corporation's Code of Business Conduct for the President and Chief Executive Officer and senior financial officers and (b) any public disclosure made regarding such change or waiver and, if satisfied, refer the matter to the Board for approval.
29. Act in an advisory capacity to the Board.
30. Carry out such other responsibilities as the Board may, from time to time, set forth.
31. Advise and report to the Co-Chairs of the Board and the Board, relative to the duties and responsibilities set out above, from time to time, and in such details as is reasonably appropriate.

Effective Date: November 20, 2010

Schedule B

Husky Energy Inc.

Report on Reserves Data by Qualified Reserves Evaluator

To the Board of Directors of Husky Energy Inc. (Husky):

1. Our staff has evaluated Husky's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

2. The reserves data are the responsibility of Husky's management. As the Internal Qualified Reserves Evaluator our responsibility is to certify that the reserves data has been properly calculated in accordance with generally accepted procedures for the estimation of reserves data.

   We carried out our evaluation in accordance with generally accepted procedures for the estimation of oil and gas reserves data and standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society). Our internal reserves evaluators are not independent of Husky, within the meaning of the term "independent" under those standards.

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with the principles and definitions presented in the COGE Handbook.

4. The following table sets forth the evaluated estimated future net revenue (before deducting income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Husky evaluated for the year ended December 31, 2011 and reported to the Audit Committee of the Board of Directors:

Location of Reserves	Discounted Future Net Cash Flows before income taxes, 10% discount rate
	($ millions)
Canada	23,373
China	491
Indonesia	225
	24,089

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined in accordance with the principles and definitions presented in the COGE Handbook.

6. We have no responsibility to update our evaluation for events and circumstances occurring after the date of this report.

7. Because, the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Calgary, Alberta
February 8, 2012

/s/ Frederick Au-Yeung
Frederick Au-Yeung, P. Eng
Manager of Reservoir Engineering

Schedule C

Husky Energy Inc.

Report of Management and Directors on Oil and Gas Disclosure

Management of Husky Energy Inc. ("Husky") are responsible for the preparation and disclosure of information with respect to Husky's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

Husky's oil and gas reserves evaluation process involves applying generally accepted procedures for the estimation of oil and gas reserves data for the purposes of complying with the legal requirements of NI 51-101. Husky's Internal Qualified Reserves Evaluator is the Manager of Reservoir Engineering, who is an employee of Husky and has evaluated Husky's oil and gas reserves data and certified that Husky's Reserves Data Process has been followed. The Report on Reserves Data by Husky's Internal Qualified Reserves Evaluator accompanies this report and will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the Board of Directors has:

(a) reviewed Husky's procedures for providing information to the Internal Qualified Reserves Evaluator and the external reserves auditors;

(b) met with the Internal Qualified Reserves Evaluator and external reserves auditors to determine whether any restrictions placed by management affect the ability of the Internal Qualified Reserves Evaluator and the external reserves auditors to report without reservation; and

(c) reviewed the reserves data with management, the Internal Qualified Reserves Evaluator and the external reserves auditors.

The Audit Committee of the Board of Directors has reviewed Husky's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved, on the recommendation of the Audit Committee:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2, which is the Report on Reserves Data of Husky's Internal Qualified Reserves Evaluator; and

(c) the content and filing of this report.

Husky sought and was granted by the Canadian Securities Administrators an exemption from the requirement under National Instrument 51-101 *"Standards of Disclosure for Oil and Gas Disclosure"* to involve independent qualified oil and gas reserve evaluators or auditors. Notwithstanding this exemption, we involve independent qualified reserve auditors as part of Husky's corporate governance practices. Their involvement helps assure that our internal oil and gas reserve estimates are materially correct.

In Husky's view, the reliability of Husky's internally generated oil and gas reserves data is not materially different than would be afforded by Husky involving independent qualified reserves evaluators or independent qualified reserves auditors to evaluate or audit and review the reserves data. The primary factors supporting the involvement of independent qualified reserves evaluators or independent qualified reserves auditors apply when (i) their knowledge of, and experience with, a reporting issuer's reserves data are superior to that of the internal evaluators and (ii) the work of the independent qualified reserves evaluator or independent qualified reserves auditors is significantly less likely to be adversely influenced by self-interest or management of the reporting issuer than the work of internal reserves evaluation staff. In Husky's view, neither of these factors applies in Husky's circumstances.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

/s/ Asim Ghosh March 8, 2012

Asim Ghosh
President & Chief Executive Officer

/s/ James D. Girgulis March 8, 2012

James D. Girgulis
Vice President, Legal & Corporate Secretary

/s/ William Shurniak March 8, 2012

William Shurniak
Director

/s/ Colin S. Russel March 8, 2012

Colin S. Russel
Director

Schedule D

Husky Energy Inc.

Independent Engineer's Audit Opinion

Husky Energy Inc.

707 - 8th Avenue S.W.
Calgary, Alberta
T2P 3G7

To Whom It May Concern:

Pursuant to Husky's request we have conducted an audit of the reserves estimates and the respective net present value of these reserves of Husky Energy Inc., as at December 31, 2011. The Company's detailed reserves information were provided to us for this audit. Our responsibility is to express an independent opinion on the reserves and the respective present worth value estimates, in the aggregate, based on our audit tests and procedures.

We conducted our audit in accordance with generally accepted audit standards as recommended by the Society of Petroleum Engineers and as recommended in the Canadian Oil and Gas Evaluation Handbook (COGEH) Volume 1 Section 12. Those standards require that we review and assess the policies, procedures, documentation and guidelines of the Company with respect to the estimation, review and approval of Husky's reserves information. An audit includes examining, on a test basis, to confirm that there is adherence on the part of Husky's internal reserves evaluators and other employees to the reserves management and administration policies and procedures established by the Company. An audit also includes conducting reserves evaluation on a sufficient number of the Company's properties as considered necessary in order to express an opinion.

Based on the results of our audit, it is our opinion that Husky's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the Canadian Oil and Gas Evaluation Handbook.

The results of the Husky internally generated reserves and net present values (based on forecast prices) supplied to us as part of the audit process are summarized in the attached table.

Sincerely,

McDaniel & Associates Consultants Ltd.

/s/ B. J. Wurster, P. Eng.
B. J. Wurster, P. Eng.
Vice President

Calgary, Alberta
January 24, 2012

Total Company Reserve and Net Present Value
Forecast Prices and Costs as at December 31, 2011

	Company share of Remaining Reserves (mmbbls, bcf, mmboe)		Company share of Net Present Value Before Income Tax (MM$)				
	Gross	Net	0%	5%	10%	15%	20%
Proved:							
Developed Producing							
Light Crude Oil	151	128	9,387	6,453	5,084	4,262	3,705
Medium Crude Oil	75	63	1,944	1,636	1,391	1,212	1,078
Heavy Crude Oil	73	65	1,179	1,526	1,533	1,484	1,427
Natural Gas	1,744	1,525	5,960	3,884	2,853	2,245	1,850
Coal Bed Methane	24	23	41	33	27	23	21
Bitumen	56	50	1,932	1,580	1,357	1,200	1,081
Natural Gas Liquids[1]	64	49					
Total	714	614	20,443	15,112	12,245	10,427	9,161
Developed Non-Producing							
Light Crude Oil	2	2	96	74	60	51	44
Medium Crude Oil	2	1	83	62	51	43	37
Heavy Crude Oil	13	12	607	480	402	345	302
Natural Gas	146	133	540	330	231	175	139
Coal Bed Methane	2	1	2	2	1	1	1
Bitumen	-	-	-	-	-	-	-
Natural Gas Liquids[1]	1	1					
Total	43	39	1,328	947	745	615	523
Undeveloped							
Light Crude Oil	22	20	1,020	734	548	418	323
Medium Crude Oil	13	12	546	352	239	167	119
Heavy Crude Oil	26	24	915	704	558	451	370
Natural Gas	495	421	1,616	722	315	102	(22)
Coal Bed Methane	9	9	6	3	1	-	(1)
Bitumen	253	219	5,349	2,880	1,615	900	464
Natural Gas Liquids[1]	18	12					
Total	416	358	9,453	5,394	3,277	2,038	1,253
Total Proved:							
Light Crude Oil	176	150	10,503	7,261	5,692	4,732	4,072
Medium Crude Oil	90	76	2,574	2,050	1,681	1,422	1,234
Heavy Crude Oil	113	101	2,701	2,710	2,492	2,281	2,099
Natural Gas	2,385	2,078	8,116	4,936	3,399	2,521	1,966
Coal Bed Methane	35	33	49	37	30	24	20
Bitumen	309	269	7,281	4,459	2,973	2,100	1,545
Natural Gas Liquids[1]	83	63					
Total	1,172	1,011	31,224	21,454	16,266	13,081	10,936
Probable:							
Developed Producing							
Light Crude Oil	101	86	6,516	3,633	2,477	1,851	1,460
Medium Crude Oil	19	15	1,018	609	416	305	233
Heavy Crude Oil	38	34	1,591	1,054	755	567	440
Natural Gas	599	501	2,404	1,026	549	325	203
Coal Bed Methane	2	2	6	5	4	3	3
Bitumen	1,401	1,117	40,577	10,623	3,622	1,433	586
Natural Gas Liquids[1]	20	15					
Total	1,678	1,351	52,111	16,949	7,823	4,485	2,925
Total Proved Plus Probable:							
Light Crude Oil	276	236	17,019	10,894	8,169	6,583	5,532
Medium Crude Oil	109	92	3,591	2,659	2,097	1,728	1,467
Heavy Crude Oil	151	135	4,292	3,764	3,248	2,848	2,539
Natural Gas	2,983	2,579	10,520	5,962	3,948	2,847	2,169
Coal Bed Methane	37	35	55	42	33	27	23
Bitumen	1,709	1,386	47,858	15,082	6,594	3,534	2,131
Natural Gas Liquids[1]	102	77					
Total	2,851	2,361	83,335	38,403	24,089	17,566	13,861

[1] Natural Gas Liquid volumes are identified separately but the value is included with the Natural Gas.

Document B
Form 40-F

Consolidated Financial Statements and Auditors' Report to Shareholders

For the Year Ended December 31, 2011

Husky Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2011

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.

/s/ Asim Ghosh

Asim Ghosh

President & Chief Executive Officer

/s/ Alister Cowan

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.

/s/ KPMG LLP

KPMG LLP

Chartered Accountants

Calgary, Alberta, Canada

March 8, 2012

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

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 financial performance and its consolidated 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.

Other Matter

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Husky Energy Inc.'s internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 8, 2012 expressed an unmodified opinion on the effectiveness of Husky Energy Inc.'s internal control over financial reporting.

/s/ KPMG LLP

KPMG LLP

Chartered Accountants

Calgary, Canada

March 8, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Husky Energy Inc. ("the Company")'s internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Husky Energy Inc. as of December 31, 2011, December 31, 2010, and January 1, 2010 and the related consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for each of the years in the two-year period ended December 31, 2011, and our report dated March 8, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

KPMG LLP

Chartered Accountants

Calgary, 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:

/s/ Asim Ghosh

Asim Ghosh
Director

/s/ William Shurniak

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			U.S. $ Denominated		
		December 31, 2011	December 31, 2010	January 1, 2010	December 31, 2011	December 31, 2010	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.

Document C
Form 40-F

Management's Discussion and Analysis

March 8, 2012

Husky Energy Inc.

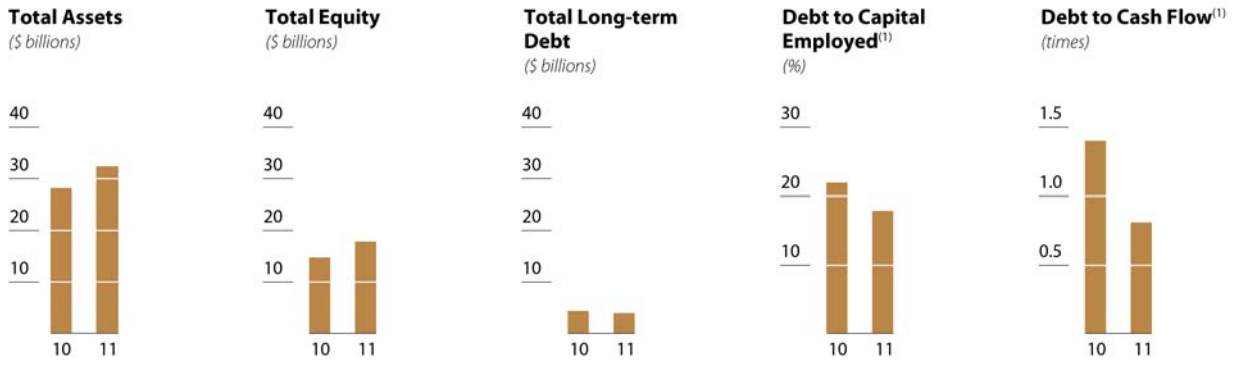
Management's Discussion and Analysis

For the Year Ended December 31, 2011
March 8, 2012

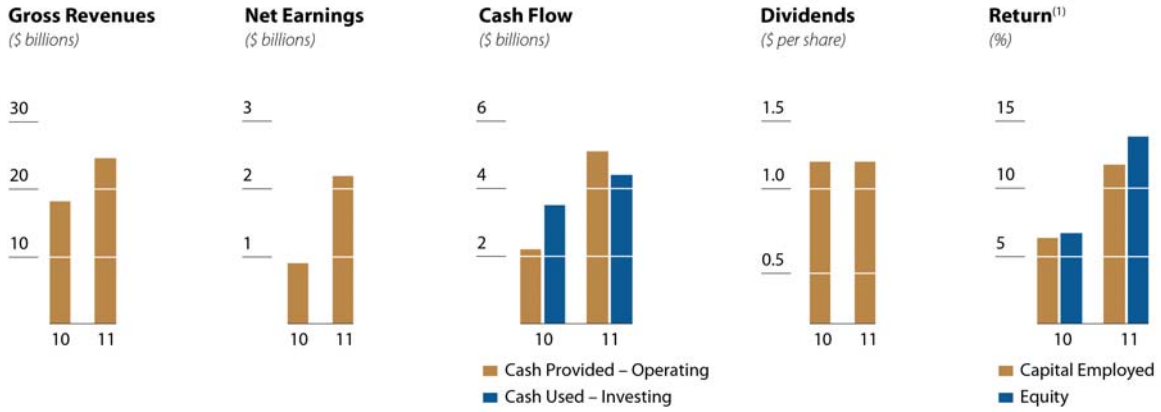
MANAGEMENT'S DISCUSSION AND ANALYSIS

1.0 Financial Summary

1.1 Financial Position



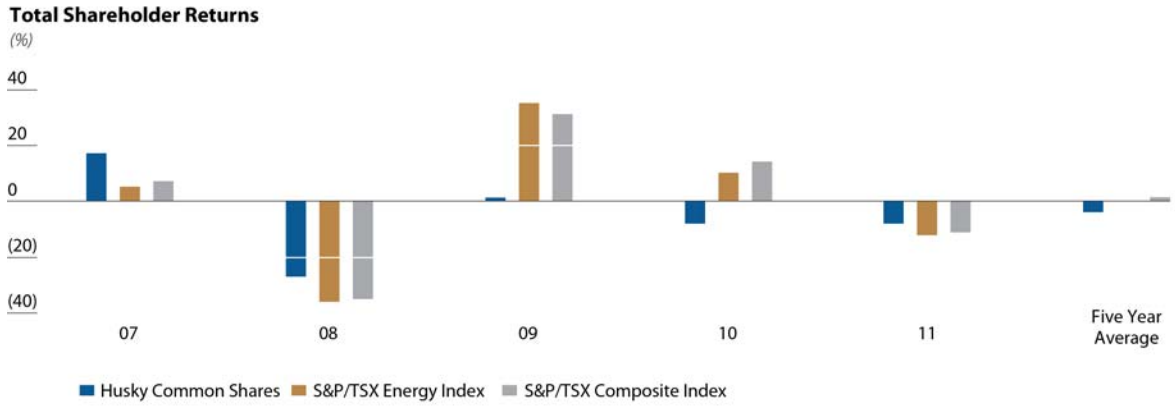
1.2 Financial Performance



(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.



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

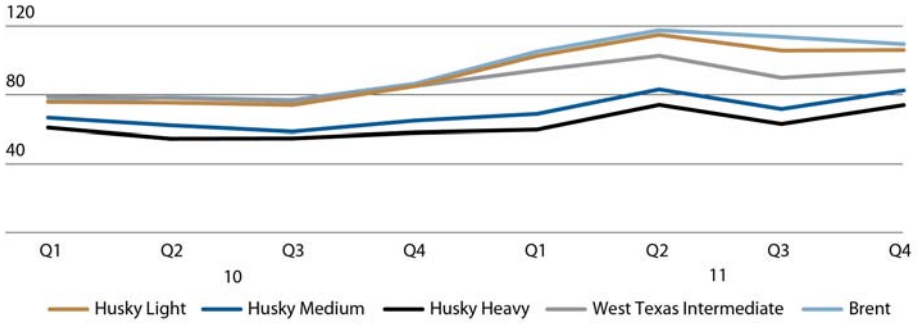
Average Benchmarks		2011	2010
WTI crude oil	*(U.S. $/bbl)*	**95.12**	79.46
Brent crude oil	*(U.S. $/bbl)*	**111.27**	79.42
Canadian light crude 0.3% sulphur	*($/bbl)*	**95.32**	77.75
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**67.61**	59.87
NYMEX natural gas	*(U.S. $/mmbtu)*	**4.04**	4.39
NIT natural gas	*($/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.

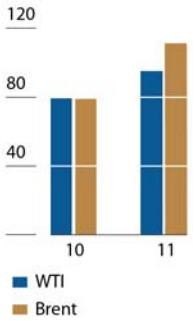
The Downstream segment is heavily impacted by the price of crude oil and natural gas. The largest cost factor in the Downstream segment is crude oil feedstock, a portion of which is heavy crude oil. In the upgrading business segment, heavy crude oil feedstock is processed into light synthetic crude oil.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



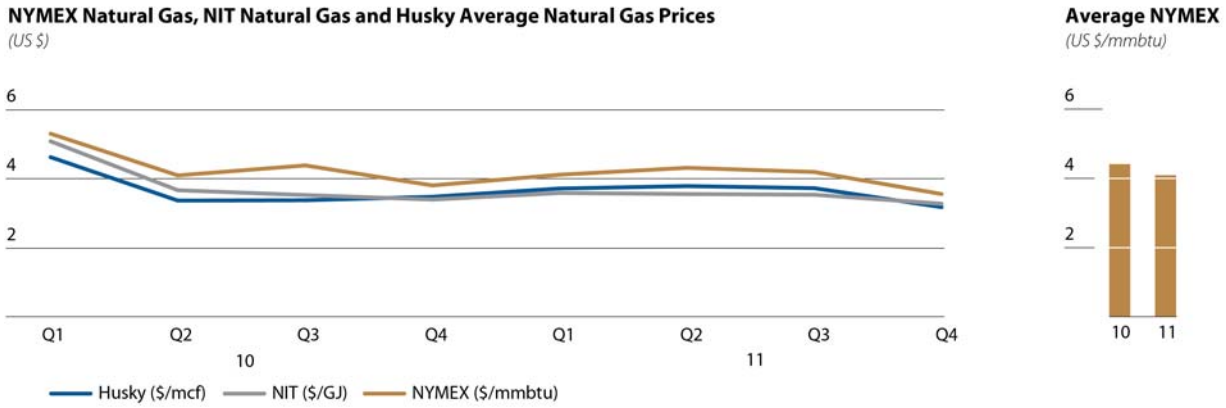
Average WTI and Brent
(US $/bbl)



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.

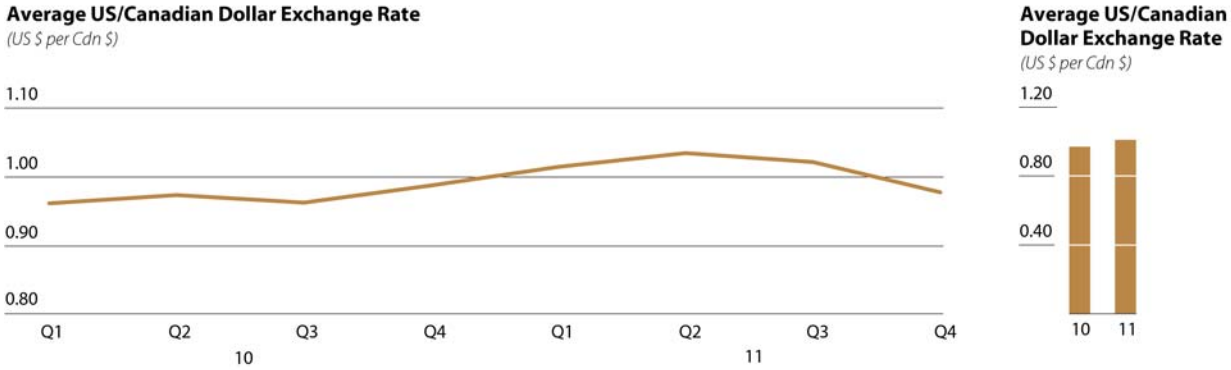
A portion of Husky's crude oil production is classified as either heavy crude oil or bitumen, which trades at a discount to light crude oil. In 2011, 47% of Husky's crude oil production was heavy crude oil or bitumen compared with 48% in 2010. The light/heavy crude oil differential averaged U.S. $17.44/bbl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

Natural Gas



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



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.

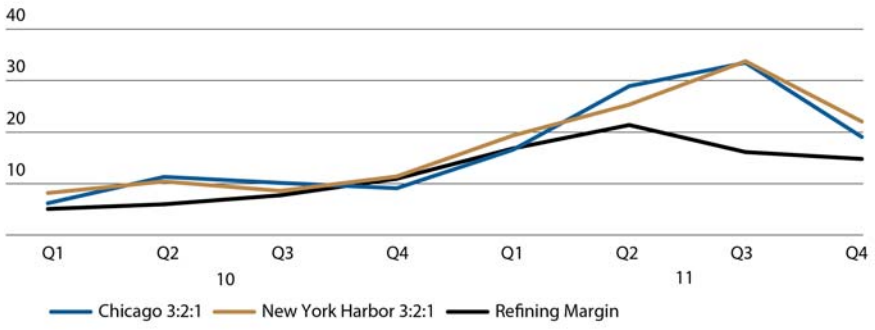
Refining Crack Spreads

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").

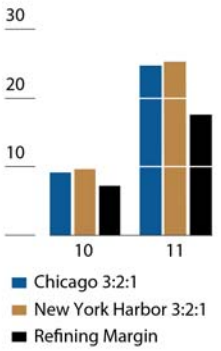
The New York Harbor 3:2:1 refining crack spread benchmark is calculated as the difference between the price of a barrel of WTI crude oil and the sum of the price of two-thirds of a barrel of reformulated gasoline and the price of one-third of a barrel of heating oil. The Chicago 3:2:1 refining crack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

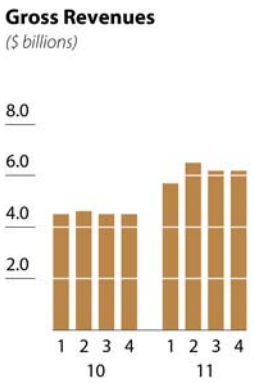
7.0 Results of Operations

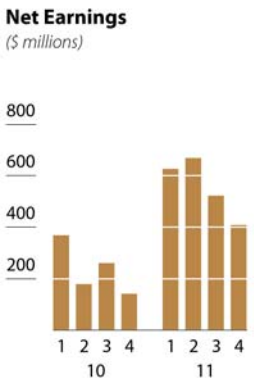
7.1 Segment Earnings

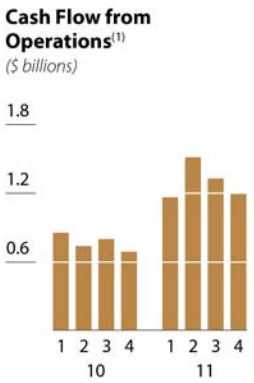
($ millions)	Earnings (Loss) before Income Taxes 2011	2010	Net Earnings (Loss) 2011	2010	Capital Expenditures[1] 2011	2010
Upstream	**2,032**	1,211	**1,502**	861	**4,131**	2,812
Midstream	**328**	219	**246**	160	**43**	40
Downstream						
Upgrading	**207**	89	**153**	63	**55**	182
Canadian Refined Products	**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

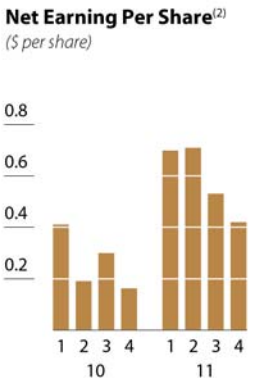
[1] *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the period.*

7.2 Summary of Quarterly Results





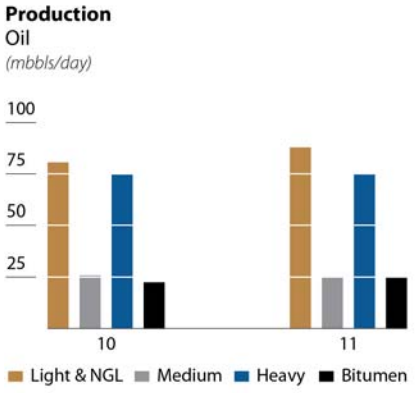


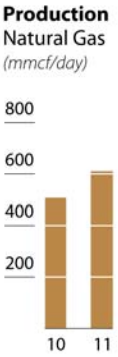


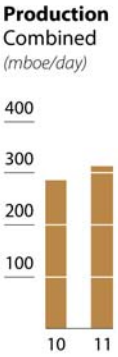
[1] *Cash flow from operations is a non-GAAP measure. (Refer to Section 11.3)*
[2] *Reported figure represents net earnings per share – diluted*

7.3 Upstream

2011 Earnings $1,502 million

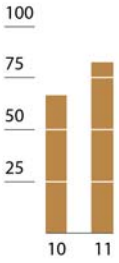




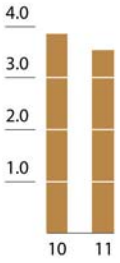


Upstream Earnings Summary *($ millions)*	2011	2010
Gross revenues	**7,250**	5,744
Royalties	**1,125**	978
Net revenues	**6,125**	4,766
Operating, transportation and administration expenses	**1,890**	1,595
Exploration and evaluation expense	**470**	438
Depletion, depreciation, amortization and impairment	**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)

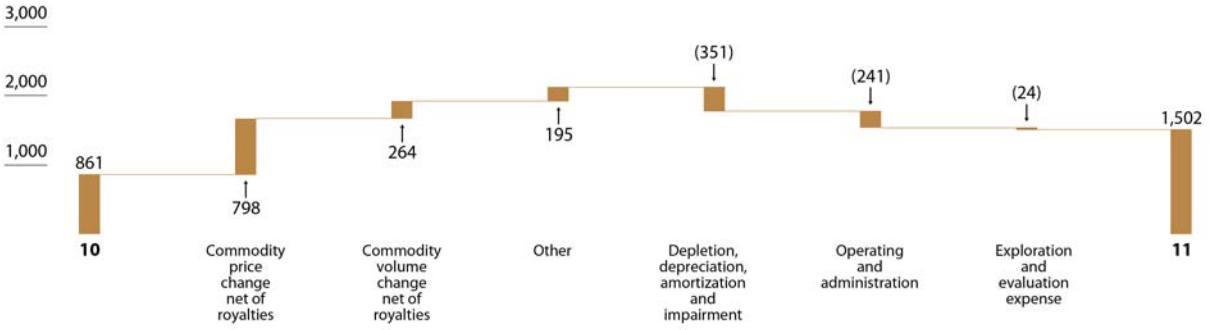


Average Sales Prices Realized	2011	2010
Crude oil *($/bbl)*		
Light crude oil & NGL	**103.25**	76.90
Medium crude oil	**75.65**	64.92
Heavy crude oil	**66.99**	58.91
Bitumen	**64.34**	57.84
Total average	**82.72**	66.70
Natural gas average *($/mcf)*	**3.55**	3.86
Total average *($/boe)*	**63.23**	54.25

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

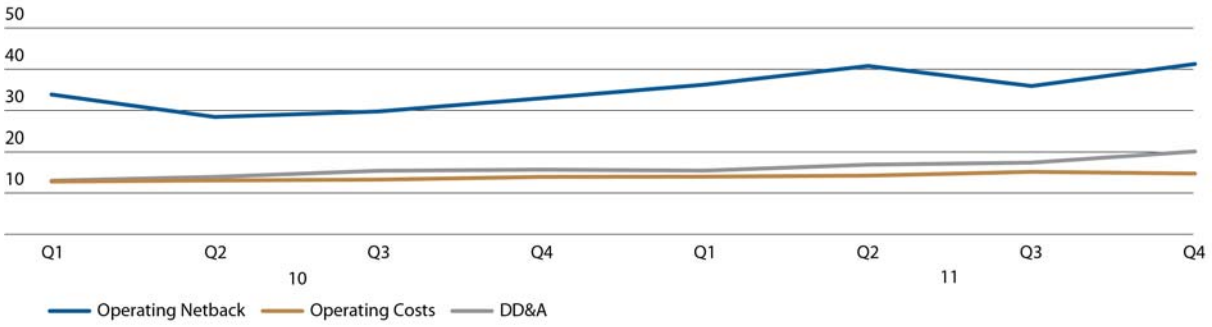
Total exploration and evaluation expenses increased in 2011 to $470 million from $438 million in 2010 due to land costs of $43 million relating to the Columbia River Basin located in the states of Washington and Oregon that were expensed in 2011.

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.

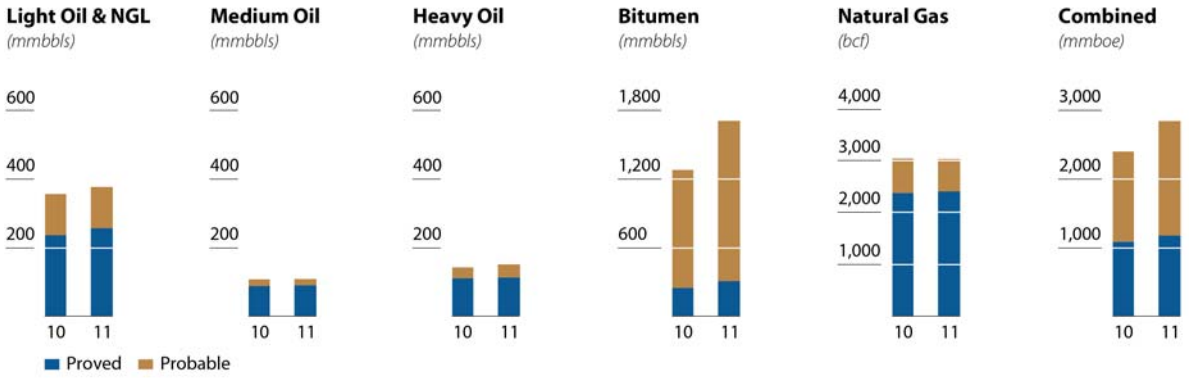
Upstream Planned Turnarounds

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 .

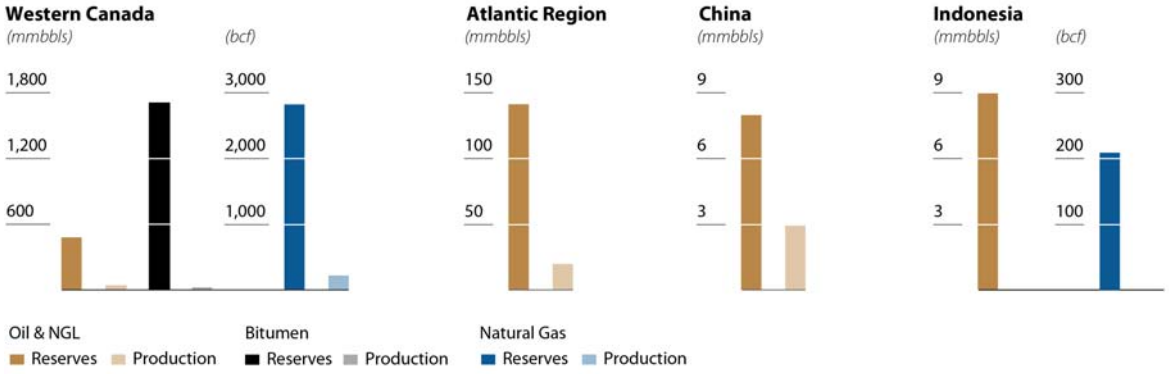


The Company's complete Oil and Gas Reserves Disclosure prepared in accordance with NI 51-101 is contained in Husky's Annual Information Form available at www.sedar.com or Husky's Form 40-F available at www.sec.gov or on the Company's website at www.huskyenergy.com.

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.

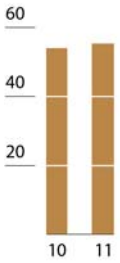
7.5 Downstream

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

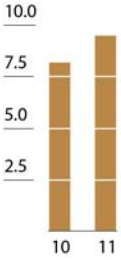
[1] *Throughput includes diluent returned to the field.*
[2] *Based on throughput.*

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.

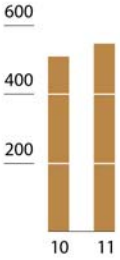
During 2011, the price of Husky's synthetic crude oil averaged $101.68/bbl compared with the average cost of blended heavy crude oil from the Lloydminster area of $74.34/bbl. During 2010, the price of Husky's synthetic crude oil averaged $80.97/bbl compared with the average cost of blended heavy crude 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

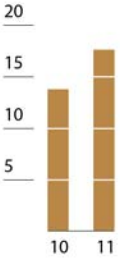
Volume
(millions of litres/day)



Outlets

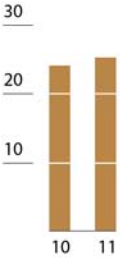


Volume per Outlet
(thousands of litres/day)



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]

($ millions)	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	2010 Q3	2010 Q2	2010 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.*

Exhibit No.	Description
23.1	Consent of KPMG LLP, independent registered public accounting firm.
23.2	Consent of McDaniel and Associates Consultants Ltd., independent engineers.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
32.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(b) or Rule 15d-14(b)and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
32.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
99.1	Supplemental Disclosures of Oil and Gas Activities.
99.2	Amended Code of Business Conduct.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors of Husky Energy Inc.

We consent to the incorporation by reference in the registration statement (No. 333-174554) on Form F-10 of Husky Energy Inc. of:

- our independent auditors' report dated March 8, 2012, with respect to the consolidated balance sheets of Husky Energy Inc. as at December 31, 2011, December 31, 2010 and January 1, 2010, and the consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for each of the years in the two-year period ended December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information;

- our independent auditors' report of registered public accounting firm dated March 8, 2012, with respect to the consolidated balance sheets of Husky Energy Inc. as at December 31, 2011, December 31, 2010 and January 1, 2010, and the consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for each of the years in the two-year period ended December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information; and

- our report of independent registered public accounting firm dated March 8, 2012 on the effectiveness of internal control over financial reporting,

which reports appear in the December 31, 2011 annual report on Form 40-F of Husky Energy Inc. for the fiscal year ended December 31, 2011, and further consent to the use of such reports in such annual report on Form 40-F.

/s/ KPMG LLP
KPMG LLP
Chartered Accountants
Calgary, Canada
March 8, 2012

Exhibit 23.2

Consent of Independent Engineers

We refer to our report auditing estimates of the natural gas, natural gas liquids and conventional oil reserves attributable to Husky Energy Inc. (the "Company") as of December 31, 2011 (the "Report").

We hereby consent to references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, and the Company's registration statement on Form F-10 (File No. 333-174554). We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2011, dated March 8, 2012, and that we have no reason to believe that there are any misrepresentations in the information contained in it that was derived from the Report or that is within our knowledge as a result of the services we performed in connection with such Report.

Sincerely,

McDaniel & Associates Consultants Ltd.

/s/ B.J. Wurster, P. Eng.
B.J. Wurster, P.Eng.
Vice President
Calgary, Alberta, Canada
March 8, 2012

Exhibit 31.1

Certification Pursuant to
Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934,
As Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Asim Ghosh, certify that:

1. I have reviewed this annual report on Form 40-F of Husky Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 8, 2012

/s/ Asim Ghosh
Asim Ghosh
President & Chief Executive Officer

Exhibit 31.2

Certification Pursuant to
Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934,
As Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Alister Cowan, certify that:

1. I have reviewed this annual report on Form 40-F of Husky Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 8, 2012

/s/ Alister Cowan
Alister Cowan
Chief Financial Officer

Exhibit 32.1

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Husky Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), **I, Asim Ghosh, President & Chief Executive Officer of the Company**, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date**:** March 8, 2012

/s/ Asim Ghosh
Asim Ghosh
President & Chief Executive Officer

Exhibit 32.2

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Husky Energy Inc. (the "Company") on Form 40-F for the fiscal year ending December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), **I, Alister Cowan, Chief Financial Officer of the Company**, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date**:** March 8, 2012

/s/ Alister Cowan
Alister Cowan
Chief Financial Officer

Exhibit 99.1

Disclosure about Oil and Gas Producing Activities – Accounting Standards Codification 932, "Extractive Activities – Oil and Gas" (unaudited)

The following disclosures have been prepared in accordance with FASB Accounting Standards Codification 932, "Extractive Activities – Oil and Gas". In December 2009, Husky adopted revised oil and gas reserve estimation and disclosure requirements that conformed the definition of proved reserves to the SEC Modernization of Oil and Gas Reporting rules, issued by the SEC in 2008. An accounting standards update revised the definition of proved oil and gas reserves to require that the average, first-day-of-the-month price during the 12-month period before the end of the year rather than the year-end price, must be used when estimating whether reserve quantities are economic to produce. This same 12-month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. The rules also allow for the use of reliable technologies to estimate proved oil, natural-gas, and natural-gas liquids (NGLs) reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes.

The unaudited supplemental information on oil and gas exploration and production activities for 2011, 2010, and 2009 has been presented in accordance with the revised reserve estimation and disclosure rules, which were not applied retrospectively. The December 31, 2008 data is presented in accordance with Financial Accounting Standards Board (FASB) oil and gas disclosure requirements effective at that time.

Husky completed a transition to International Financial Reporting Standards in 2011 and all 2011 and 2010 financial information has been prepared using IFRS. Periods beginning prior to 2010 have not been restated.

Oil and Gas Reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered:(i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Canadian provincial royalties are determined based on a graduated percentage scale, which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and Husky's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause Husky's share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2011, no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of developed or undeveloped reserves as of that date.

Note that the numbers in each column of the tables throughout this exhibit may not add due to rounding.

Results of Operations for Producing Activities [1] **(unaudited)**

	Year Ended December 31, 2011		
($ millions)	**Canada**	**International**	**Total**
Revenues, net of royalties	5,884	241	6,125
Production and operating expenses	1,647	25	1,672
Depreciation, depletion, amortization & impairment	1,976	20	1,996
Exploration & evaluation expenses	372	98	470
Earnings before taxes	1,889	98	1,987
Income taxes	519	26	545
Results of Operations	1,370	72	1,442

	Year Ended December 31, 2010		
($ millions)	**Canada**	**International**	**Total**
Revenues, net of royalties	4,514	252	4,766
Production expenses	1,379	24	1,403
Depreciation, depletion, amortization & impairment	1,504	17	1,521
Exploration & evaluation expenses	249	189	438
Earnings before taxes	1,382	22	1,404
Income tax expense	401	6	407
Results of Operations	981	16	997

(1) The costs in this schedule exclude corporate overhead, interest expense and other operating costs, which are not directly related to producing activities.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (unaudited)

	Canada	**International**	**Total**
		($ millions)	
2011			
Property acquisition			
Proved	792	-	792
Unproved	82	-	82
Exploration	457	266(2)	723
Development	2,389	546(3)	2,935
Total costs incurred	3,720	812	4,532
2010 (1)			
Property acquisition			
Proved	327	-	327
Unproved	62	-	62
Exploration	306	381	687
Development	1,985	63	2,048
Total costs incurred	2,680	444	3,124
2009 (1)			
Property acquisition			
Proved	220	-	220
Unproved	87	2	89
Exploration	323	518	841
Development	1,138	12	1,150
Total costs incurred	1,768	532	2,300

(1) In 2011, the Company revised its definition of costs incurred on exploration and development activities to exclude asset retirement and other environmental reclamation costs. Prior periods have been restated to conform to the current year's presentation.

(2) Total international exploration costs of $266 million pertain to the following countries: China - $233 million, Indonesia - $32 million and USA - $1 million. International exploration costs for Greenland - $2 million are included in the Atlantic Region within Canada exploration costs of $457 million.

(3) Total international development costs of $546 million pertain entirely to China.

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Exploration costs include the costs of geological and geophysical activity, retaining undeveloped properties and drilling and equipping exploration wells.

Develop**m**ent costs include the costs of (i) drilling and equipping development wells; (ii) facilities to extract, treat, gather and store oil and gas;

Exploration and development costs include administrative costs and depreciation of support equipment directly associated with these activities.

The following table sets forth a summary of oil and gas property costs not being amortized at December 31, 2011, by the year in which the costs were incurred:

Withheld Costs (unaudited)	**Total**	**2011**	**2010**	**2009**	**Prior to 2008**
			($ millions)		
Property acquisitions					
Canada	148	148	-	-	-
International	-	-	-	-	-
	148	148	-	-	-
Exploration					
Canada	305	243	62	-	-
International	301	235	66	-	-
	606	478	128	-	-
Development					
Canada	3,090	2,053	436	47	554
International	1,122	539	8	5	570
	4,212	2,592	444	52	1,124
Capitalized interest					
Canada	56	24	16	16	-
International	141	62	79	-	-
	197	86	95	16	-
	5,163	3,304	667	68	1,124

Capitalized Costs Relating to Oil and Gas Producing Activities (unaudited)

	Canada	**International**	**Total**
2011		($ millions)	
Proved properties [1]	32,101	1,539	33,640
Unproved properties	421	325	746
	32,522	1,864	34,386
Accumulated DD&A	(15,586)	(312)	(15,898)
Net Capitalized Costs	16,936	1,552	18,488
2010			
Proved properties [1]	28,247	896	29,143
Unproved properties	252	220	472
	28,499	1,116	29,615
Accumulated DD&A	(13,628)	(287)	(13,915)
Net Capitalized Costs	14,871	829	15,700
2009			
Proved properties [1]	24,306	335	24,641
Unproved properties	1,408	535	1,943
	25,714	870	26,584
Accumulated DD&A	(12,153)	(281)	(12,434)
Net Capitalized Costs	13,561	589	14,150

[1] Capitalized costs related to proved properties include the asset retirement obligations. The asset retirement obligations for the years presented were as follows:

	Canada	**International**	**Total**
		($ millions)	
2011	1,369	20	1,389
2010	836	15	851
2009	482	15	497

Oil and Gas Reserve Information

In Canada, Husky's proved crude oil, natural gas liquids and natural gas reserves are located in the provinces of Alberta, Saskatchewan, British Columbia, and offshore the East Coast. Husky's international proved reserves are located in China and Indonesia.

	Canada		International		Total		
Reserves	**Crude Oil & NGL**	**Natural Gas**	**Crude Oil & NGL**	**Natural Gas**	**Crude Oil & NGL**	**Natural Gas**	**Total Company**
	(mmbbls)	(bcf)	(mmbbls)	(bcf)	(mmbbls)	(bcf)	(mmboe)
Net proved reserves [1] [2] [3] [4]							
End of year 2008	464	1,912	6	-	470	1,912	789
Revisions [5]	60	(315)	5	-	65	(315)	12
Purchases	10	16	-	-	10	16	12
Sales	-	-	-	-	-	-	-
Improved recovery	6	-	-	-	6	-	6
Discoveries and extensions	81	67	-	-	81	67	93
Production	(63)	(167)	(3)	-	(66)	(167)	(94)
End of year 2009	558	1,513	8	-	566	1,513	818
Revisions	(6)	(41)	1	-	(5)	(41)	(12)
Purchases	2	161	-	-	2	161	28
Sales	-	(1)	-	-	-	(1)	-
Improved recovery	4	1	-	-	4	1	4
Discoveries and extensions	87	129	5	147	92	277	139
Production	(63)	(175)	(3)	-	(66)	(175)	(95)
End of year 2010	582	1,587	11	147	593	1,734	882
Revisions	(1)	35	(1)	(10)	(2)	24	2
Purchases	37	342	-	-	37	342	94
Sales	(2)	(2)	(1)	(29)	(3)	(31)	(8)
Improved recovery	13	1	-	-	13	1	13
Discoveries and extensions	87	75	-	-	87	75	99
Production	(65)	(213)	(2)	-	(67)	(213)	(102)
End of year 2011	651	1,824	7	108	658	1,932	980
Net proved developed reserves [1] [2] [3] [4]							
End of year 2008	357	1,524	6	-	363	1,524	617
End of year 2009	360	1,265	8	-	368	1,265	579
End of year 2010	335	1,327	6	-	341	1,327	562
End of year 2011	370	1,567	3	-	373	1,567	635
Net proved undeveloped reserves [1] [2] [3] [4]							
End of year 2008	107	388	-	-	107	388	172
End of year 2009	198	248	-	-	198	248	239
End of year 2010	247	260	5	147	252	407	320
End of year 2011	281	257	4	108	285	365	345

(1) Net reserves are the Company's lesser royalty, overriding royalty and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.

(2) Reserves are the estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

(3) Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

(4) Proved developed oil and gas reserves are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(5) Included in revisions is a reduction of 38 net mmboe of proved reserves as a result of the revised SEC guidelines for the method of determining prices on which the economics of the reserves are based.

(6) The Company's reserve replacement ratio[a] for the last three years was as follows:

Net proved oil and gas reserves	2011	2010	2009
Excluding acquisition & divestiture	112%	138%	118%
Including acquisition & divestiture	196%	167%	130%

(a) Reserve replacement ratio calculated as net reserve additions during the period divided by total production during the period. Net reserve additions include: revisions, purchases, sales, improved recovery and discoveries and extensions.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (unaudited)

The following information has been developed utilizing procedures prescribed by FASB Accounting Standards Codification 932, "Extractive Activities – Oil and Gas" and based on crude oil and natural gas reserve and production volumes estimated by our reserves evaluation staff. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating Husky or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of Husky's reserves.

The future cash flows presented below are based on 2011 average sales prices and cost rates, and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2011 was based on the NYMEX 2011 average natural gas cash market price of U.S. $4.15/mmbtu (2010 average – U.S. $4.45/mmbtu; 2009 average – U.S. $3.87/mmbtu) and on crude oil prices computed with reference to the 2011 average WTI spot price of U.S. $95.95/bbl (2010 average – U.S. $79.43/bbl; 2009 average – U.S. $61.18/bbl).

	Canada [1]			International [1]			Total [1]		
Standardized Measure (unaudited) ($ millions)	2011	2010	2009	2011	2010	2009	2011	2010	2009
Future cash inflows	50,824	40,840	34,528	1,510	1,582	593	52,334	42,422	35,121
Future production costs	18,342	14,682	12,749	503	576	119	18,845	15,258	12,868
Future development costs	7,932	7,605	6,487	161	182	21	8,093	7,787	6,508
Future income taxes	6,286	4,752	3,989	282	255	144	6,568	5,007	4,133
Future net cash flows	18,264	13,801	11,303	564	570	309	18,828	14,371	11,612
Annual 10% discount factor	8,217	6,010	4,781	199	216	39	8,416	6,226	4,820
Standardized measure of discounted future net cash flows	10,047	7,791	6,522	365	354	270	10,412	8,145	6,792

(1) The schedules above are calculated using year average prices and year-end costs, statutory income tax rates and existing proved oil and gas reserves for 2009, 2010 and 2011. The value of exploration properties and probable reserves, future exploration costs, future change in oil and gas prices and in production and development costs are excluded.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (unaudited)

	Canada [1]			International [1]			Total [1]		
($ millions)	2011	2010	2009	2011	2010	2009	2011	2010	2009
Present value at January 1	7,791	6,522	6,250	354	270	109	8,145	6,792	6,359
Sales and transfers, net of production costs	(4,239)	(3,129)	(2,913)	(216)	(227)	(215)	(4,455)	(3,356)	(3,128)
Net change in sales and transfer prices, net of development and production costs	3,281	2,982	1,918	266	99	187	3,547	3,081	2,105
Development cost incurred that reduced future development costs	2,500	2,697	1,518	7	6	5	2,507	2,703	1,523
Changes in estimated future development costs	(1,921)	(2,639)	(2,985)	26	(1)	(10)	(1,895)	(2,640)	(2,995)
Extensions, discoveries and improved recovery, net of related costs	1,601	1,235	1,881	10	169	23	1,611	1,404	1,904
Revisions of quantity estimates	156	(68)	313	(47)	43	241	109	(25)	554
Accretion of discount	908	911	863	55	39	16	963	950	879
Sale of reserves in place	(28)	(4)	—	(59)	—	—	(87)	(4)	—
Purchase of reserves in place	1,096	247	268	—	—	—	1,096	247	268
Changes in timing of future net cash flows and other	(358)	(579)	(388)	(20)	—	(6)	(378)	(579)	(394)
Net change in income taxes	(740)	(384)	(203)	(11)	(44)	(80)	(751)	(428)	(283)
Net increase (decrease)	2,256	1,269	272	11	84	161	2,267	1,353	433
Present value at December 31	10,047	7,791	6,522	365	354	270	10,412	8,145	6,792

[1] The schedules above are calculated using year-end average prices and year-end costs, statutory income tax rates and existing proved oil and gas reserves for 2009, 2010, and 2011. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.

Exhibit 99.2

CODE OF BUSINESS CONDUCT

1. PURPOSE

Husky and its employees will conduct themselves in accordance with the Husky Code of Business Conduct. Husky, its Directors, and its employees are expected to not only meet these expectations, but demonstrate them as necessary to ensure their clients, business associates, shareholders and fellow employees are adhering to this Code of Business Conduct.

The business Conduct Policy seeks to deter wrongdoing and to promote honest and ethical conduct, including the ethical handling of actual and apparent conflicts of interest between personal and professional relationships.

Section One: Husky's Statement of Principles

Husky believes that generally:

- we can make a positive difference within our sphere of influence
- the business sector should show ethical leadership, and take a leadership role through establishment of ethical business principles
- while reflecting cultural diversity and differences, we should do business throughout the world that respects the beliefs and values of this policy
- open, honest and transparent relationships/practices are critical to our success
- the perspective of local communities need to be considered in decision-making for issues that may affect them
- multi-stakeholder processes need to be initiated to seek effective solutions.

Husky values:

- human rights and social justice
- wealth optimization for all stakeholders
- operation of a free market economy
- equal opportunity
- a defined code of ethics and business practice protection of environmental quality and sound environmental stewardship
- good relationships with all stakeholders
- stability and continuous improvement within our operating environment
- employees who endeavour to incorporate these values into their ongoing duties
- health, safety, and well being of its employees.

Concerning community participation and environmental protection, Husky will:

- strive within our sphere of influence to ensure a fair share of benefits to stakeholders impacted by our activities
- ensure meaningful and transparent consultation with all stakeholders and attempt to integrate our corporate activities with local communities as good corporate citizens
- ensure our activities are consistent with sound environmental management and conservation practices
- provide meaningful opportunities for technology transfer by training within the host nation.

Concerning human rights, Husky will support and promote the protection of international human rights within our sphere of influence.

Section Two: Employee's Business Conduct Policy

1. GENERAL GUIDELINE FOR APPROPRIATE CONDUCT

Employees are expected to accept certain responsibilities, adhere to acceptable legal business principles, and exhibit a high degree of personal integrity at all times. You are expected to refrain from behaviour that might be harmful to you, your co-workers, our business associates or the company. The intent of this policy is not to place unreasonable restrictions on your personal actions, but to set out the standards you are expected to meet in your capacity as a Husky employee. The policies which follow are specific policies applicable to employees but do not limit the general nature of this Code of Business Conduct.

Husky will strive to ensure employees', contractors', suppliers' and agents' activities are consistent with these principles.

An employee who engages in any conduct contrary to this Employee's Business Conduct Policy may be terminated summarily for just cause.

If you have any questions relating to this Code of Business Conduct, you are to seek the advice of your Department Manager or respective executive.

2. COMPLIANCE WITH LAWS

All employees should recognize, be familiar with, and comply with applicable government laws, rules, and regulations.

As an employee, if you have any questions about the application or interpretation of laws, regulations and standards governing corporate operations and activities, seek the advice of your Department Manager or respective executive.

3. CONFLICT OF INTEREST

Avoid all situations in which your personal interests conflict with your duties to Husky, or the interests of Husky.

The purpose of this Business Conduct Policy is to outline Husky's position regarding potential conflict of interest situations and the related guidelines with respect to proper business conduct and decision-making.

The expectation is that we not only do "the right thing", but that we do so in a transparent manner.

CONFLICT OF INTEREST DEFINITION

A conflict of interest arises when you are in a position or situation which could:

- benefit you, a member of your family, or someone with whom you are associated, and that benefit is at the expense of Husky, or results in lost opportunity for Husky
- interfere with your objectivity or effectiveness in performing your company duties and responsibilities.

Such activities include but are not limited to:

- outside work, employment, or other endeavours (a) in areas similar to those in which Husky is involved; (b) for clients, suppliers, vendors or competitors of Husky; or (c) that otherwise have the potential to affect your objectivity and work performance
- performing outside work or soliciting outside business on Husky's premises or in Husky's time
- using Husky's equipment or services, materials, resources or proprietary information for outside work
- activities that could reflect negatively on the reputation of Husky and its employees
- holding a financial interest in, or taking a loan from, a business concern that is a supplier, client or competitor of Husky. This constitutes a conflict of interest under certain conditions more fully described below.

In most situations, common sense and integrity will point to the best course. When in doubt, however, you are responsible for clarifying the situation with your department manager or executive, as appropriate. The department manager or senior management may grant permission to engage in an activity where such activity does not violate the intent of this policy. Individual reputations can best be protected by obtaining permission, in writing, in advance of any actions or situations which could lead to a conflict of interest.

GUIDELINES

Employees must immediately disclose any potential conflict of interest to their department managers or lead officers, as applicable. If the department manager or executive is uncertain whether the situation is contrary to policy, he or she should consult with Husky’s Vice President, Legal or Vice President, Corporate Administration.

Unless there are circumstances which have been reviewed and pre-approved, employees should not:

- influence a corporate decision in a manner that favours another individual or organization in the expectation of realizing personal gain for yourself, a family member, or others with whom you have or have had an association
- have (either directly or indirectly) a significant financial interest in any supplier, client or competitor of Husky. A financial interest is significant if the holding is either:

  i. 5% or more of the stock, assets or other interests of the supplier, client or competitor; or

  ii. 10% or more of your net assets.

  This would include significant investments in oil and gas properties and shares or securities of Husky’s joint ventures.

- have investments at any time if such investments could materially affect your judgment with respect to Husky's business interests
- act as an officer, director, partner, consultant, representative, agent, advisor or employee of any of the following:
  i. A supplier, client or competitor of Husky.
  ii. Any business that is involved in technical areas or product lines that are similar to those of Husky.
  iii. Any business whose customers include the company, its customers or its suppliers.
  iv. An organization having or planning to have business dealings with Husky where there exists (or may appear to exist) an opportunity for special consideration for either the employee or the organization.
- accept any directorship, consulting or advisory appointment or engage in any other activity that could create a conflict of interest and thereby impair Husky's reputation for impartiality and fair dealings. Examples of such activities include the following:
  - Having a financial involvement with an employee or representative of a supplier, vendor, client or competitor of Husky with whom you regularly come into contact while performing Husky business.
  - Accepting personal discounts (on products, services or other items) from an employee or representative of a supplier, vendor, client or competitor of Husky, which are not generally available in the normal course of business.
  - Dealing directly, in the course of normal Husky responsibilities, with a spouse or immediate family member who is employed by a supplier, vendor, client or competitor of Husky.

Offer letters to prospective employees require that they disclose any potential conflict of interest to their new managers prior to the acceptance of employment with Husky.

Any breach of this policy is considered serious and may result in disciplinary action up to and including the immediate termination of employment.

4. PROPER RECORD-KEEPING

Ensure that Husky's books, records and accounts reflect accurately, fairly, in reasonable detail, and in a timely manner all the transactions, acquisitions, and dispositions of assets, and other business affairs of Husky.

Almost every employee is required to report some form of accounting, sales, or operations data. Each employee must ensure that the reporting is done on a timely basis, accurately, and in sufficient detail to ensure the integrity of corporate information and records.

As a Husky employee, do not:

- establish or maintain an unrecorded fund or asset on behalf of Husky
- make a false, artificial, or misleading entry in the books, records and documents of Husky for any reason
- engage in any arrangement that results in such prohibited acts

- Initiate a transaction or make a payment on behalf of Husky with the intention or understanding that the transaction or payment is other than what is described in its documentation.

5. POLITICAL CONTRIBUTIONS

All political contributions are the responsibility of the President & Chief Executive Officer. Any contribution on behalf of Husky should be directed to the C.E.O. fund.

6. COMPANY RESOURCES

Safeguard Company Resources

Do not engage in theft, pilferage, willful damage, or misuse of Husky property. Employees who violate this policy are subject to disciplinary action, up to and including immediate termination for cause. Husky might also report the violation to the appropriate police authority.

Confidential Information and Intellectual Property

Do not disclose, appropriate, or use confidential information or intellectual property which is owned, developed, or otherwise possessed by Husky, except as specifically contemplated or properly authorized.

Confidential information includes, but is not limited to, unless previously published: corporate records, reports, papers, devices, processes, plans, methods, other intellectual property, other inside information, and any other information which is designated as confidential at the time it is made available to you or which, because of the circumstances under which you receive it, would reasonably be considered to be confidential. This rule applies whether the information is owned or developed by Husky, or by third parties and in the possession of Husky.

Intellectual property includes: computer software programs, technical processes, inventions, research devices, reports or articles containing any form of unique or original innovation or development, whether or not protected by patent, trademark, copyright, or otherwise.

Intellectual property that has been created or developed by you within your scope of employment is owned by Husky.

7. FAIR COMPETITION

- If you are in a position to make or influence commitments to goods and services suppliers, you must make all decisions on the basis of quality, service and price.
- Do not enter into any agreement with a competitor to adhere to certain prices, or any element thereof (known as price fixing).
- Do not enter into any agreement to refrain from bidding, or to bid at a certain price, or to submit a bid that is less favourable than a competitor's, for the sole purpose of increasing the competitor's likelihood of being awarded the bid.
- Do not enter into any agreement with a competitor that results in a division, assignment, or apportionment of customers or territories to be served or a limitation on any product sold or services rendered.

These principles apply to all Husky employees, Husky subsidiaries, contractors and agents who participate in Husky corporate and operating activities.

Husky employees who are in a position to make or influence Husky commitments to suppliers of goods and services must not use their positions for the solicitation of funds or goods for charitable or any other purposes not related to their employment.

(Also refer to Purchasing Practices Policy # 1.05)

8. BRIBERY OR OTHER OFFERING OF PAYMENTS

Do not make an illegal or improper payment on behalf of Husky to any government agency, person or entity.

Do not at any time offer, promise, authorize, approve, or condone the use of corporate funds or property for any of the following activities:

- The payment of money or the giving of any thing of value to any:
  - government official(s) in order to influence them to act or fail to act in any official capacity, or to induce them to use their influence with any government official or government agency.
  - political party, any official of a political party, or any candidate for political office in order to influence the political party, official or candidate to act or to fail to act in any official capacity or to induce the political party, official, or candidate to influence any government official or any government agency. (See Policy 1.14 on Community Giving. Only the CEO can authorize a donation to a political party).
  - person who will apply the payment or gift (in whole or in part) directly or indirectly to either of the aforementioned activities.

- The payment of a kickback to obtain business for Husky.

The activities set out in this section are prohibited by Husky even if permitted by the laws, standards, or customs of any country where Husky is doing business, and regardless of any requests or pressures received from any government or the competitive consequences of refusing to comply with such requests or pressures.

This policy does not prohibit:

- any payments to a government official, employee or agency which are specifically required by a law, regulation or decree equally applicable to all similarly situated companies
- the normal extension of those common courtesies and social amenities consistent with ethical business practices, and with the customs of the industry, which are offered and received on a basis of amicable personal relations, provided that this cost is properly identified and disclosed on Husky's books. For example, reasonable expenditures for the entertainment of clients, prospective employees and business associates are permissible for employees whose duties include the provision of such entertainment, provided proper accounting is made. Business lunches, dinners, and sporting or entertainment activities in the normal business locale will likely not contravene this policy.

If you are uncertain of the applicability of this section of the policy to any proposed action, obtain permission from the senior Lead Officer responsible for your operation, or from the VP Legal, before proceeding. No one, however, is authorized to compromise or qualify this policy on behalf of Husky.

9. ACCEPTING PAYMENTS AND ENTERTAINMENT

Officers or employees of Husky cannot accept any funds or assets for assisting a person or entity to obtain business or to ensure special concessions from Husky.

You cannot accept payment of money, substantial gifts, or loans which might influence business decisions or compromise independent judgment. This prohibition includes any accommodation or transportation not directly associated with the execution of Husky business.

You cannot accept payment of a rebate or kickback from a third party in return for their obtaining the business of Husky.

Moderate hospitality is an accepted courtesy of a business relationship but should be accepted only at a level and frequency which could be provided in return, at the company's expense. Entertainment offered to you may be accepted when it is consistent with generally accepted industry business practices and not in contravention of any law or regulation.

If you are uncertain of the applicability of this section of the policy to any proposed action, obtain permission from the Lead Officer responsible for your operation before proceeding. No one, however, is authorized to compromise or qualify this policy on behalf of Husky.

10. NON-COMPLIANCE REPORTING

If you know about a practice, event, or a financial transaction that may not be in compliance with this policy, you have the right and in some circumstances, the obligation to rectify the situation by promptly reporting it to an "authority", which may be done anonymously. The "authority" could be different depending on the item or circumstances.

We prohibit retaliatory action against any employee who, in good faith, reports a possible violation.

Anyone who is concerned about a potential instance of non-compliance by a Husky employee or contractor is encouraged to discuss it with their supervisor, manager or HR advisor. If that is inappropriate, ineffective, or uncomfortable, you may:

- report the potential noncompliance through the Ethics Help Line. The report can be given over the phone or online, and you may remain anonymous; or
- contact one of the following: VP Human and Corporate Resources, VP Legal, CFO, CEO or in exceptional cases, the Chairman of the Audit Committee.

A "bad faith" complaint is when there is either no substance to the complaint, or it is erroneous, and the originator knowingly proceeds with the complaint. When there is a "bad faith" complaint, the company may take disciplinary action with the offending employee.