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, 2005 **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)*	*(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 Each Class: None

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

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
The Registrant is a ''voluntary filer'' and files annual reports on Form 40-F, amendments to such reports and furnishes information on Form 6-K to the securities and Exchange Commission, pursuant to its obligations under its indenture dated June 14, 2002 relating to its 6.25% Notes due 2012 and 6.15% Notes due 2019.

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: 424,125,078.

Common Shares were outstanding as of December 31, 2005

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the ''Exchange Act''). If ''Yes'' is marked, indicate the filing number assigned to the Registrant in connection with such Rule.

Yes ☐ No ☑

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 ☐

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: For Form F-9 File No. 333-117972.

Principal Documents

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

A. Annual Information Form

For the Annual Information Form of Husky Energy Inc. (''Husky'') for the year ended December 31, 2005, see Document A of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For Husky's audited consolidated financial statements for the year ended December 31, 2005 and 2004, including the auditor's report with respect thereto, see Document B of this Annual Report on Form 40-F. For a reconciliation of important differences between Canadian and United States generally accepted accounting principles, see Note 19 of the notes to the audited consolidated financial statements.

C. Management's Discussion and Analysis

For Husky's Management's Discussion and Analysis for the year ended December 31, 2005, see Document C of this Annual Report on Form 40-F.

Controls and Procedures

A. Disclosure Controls and Procedures

Husky maintains disclosure controls and other procedures and internal control over financial reporting designed to ensure that information required to be disclosed in the reports filed under the Exchange Act, as amended, is recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms. Husky's principal executive and acting chief financial officer evaluated the effectiveness of Husky's disclosure controls and procedures as of the end of the period covered by this report and concluded that such disclosure controls and procedures are effective for the purpose for which they were designed as of the end of such period.

It should be noted that while Husky's principal executive and acting chief financial officer believes that Husky's disclosure controls and procedures provide a reasonable level of assurance that they are effective, he does not expect that Husky's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

B. Changes in Internal Control over Financial Reporting

During the fiscal year ended December 31, 2005, there were no changes in Husky's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, Husky's internal control over financial reporting.

Audit Committee Financial Expert

The Board of Directors of Husky has determined that R. Donald Fullerton 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 the New York Stock Exchange listed companies. Mr. Fullerton is a corporate director and is independent under the New York Stock Exchange standard. For a description of Mr. Fullerton's relevant experience in financial matters, see Mr. Fullerton's five year history in the section ''Directors and Officers'' in the Registrant's Annual Information Form for the year ended December 31, 2005, 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 all its employees, and is posted on its website at www.huskyenergy.ca. In the event that, during Husky's most recently completed fiscal year, Husky:

i. amends any provision of its Code of Business Conduct that applies to the Registrant's 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 Husky's 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 as enumerated 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 ''Audit Committee'' in the Annual Information Form for the year ended December 31, 2005, which is included as Document A to this Annual Report on Form 40-F.

Off-balance Sheet Arrangements

See ''Off- balance Sheet Arrangements'' in Husky's Management's Discussion and Analysis for the year ended December 31, 2005, which is filed as Document C to this Annual Report on Form 40-F.

Disclosure of Contractual Obligations

See ''Contractual Obligations and Other Commercial Commitments'' in Husky's Management's Discussion and Analysis for the year ended December 31, 2005, which is included as Document C to this Annual Report on Form 40-F.

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 registered pursuant to Form 40-F; 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

Forms F-X signed by Husky and its agent for service of process have been filed with the Commission together with Forms F-9 in connection with its 6.25% Notes due 2012 and 6.15% Notes due 2019.

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 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 14th day of March, 2006.

Husky Energy Inc.

By: /s/ JOHN C. S. LAU

Name: John C.S. Lau
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, 2005

Husky Energy Inc.

Annual Information Form

For the Year Ended December 31, 2005

March 14, 2006

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Unless otherwise indicated, all financial information is in accordance with accounting principles generally accepted in Canada. Unless otherwise indicated, 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. Natural gas volumes are converted to a boe basis using the ratio of six mcf of natural gas to one bbl of oil and natural gas liquids. Unless otherwise indicated, oil and gas commodity prices are quoted after the effect of hedging gains and losses. Natural gas volumes are stated at the official temperature and pressure basis of the area in which the reserves are located. The calculation of barrels of oil equivalent (boe) and thousands of cubic feet equivalent (mcfge) are based on a conversion rate of six thousand cubic feet to one barrel of oil.

Boe or mcfge may be misleading, particularly if used in isolation. A boe conversion ratio of six mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Refer to page 73 ''Special Note Regarding Forward-Looking Statements''.

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/United States rate of exchange or the cost of a U.S. dollar in Canadian currency for the three years indicated.

	Year ended December 31		
	2005	2004	2003
Year end	1.166	1.203	1.292
Low	1.151	1.178	1.292
High	1.210	1.397	1.575
Average	1.211	1.302	1.386

Notes:

(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 month.

DISCLOSURE OF EXEMPTION UNDER NATIONAL INSTRUMENT 51-101

Husky believes that comparability of its disclosures with those required in its major capital market, the United States, is important to many of the investors and prospective investors in its securities. Accordingly, we applied for and were granted an exemption by the Canadian securities regulators under the provisions of National Instrument 51-101 ''Standards of Disclosures for Oil and Gas Activities'' (''NI 51-101''). The exemption, under Section 8.4 of the Companion Policy to NI 51-101, permits us to substitute disclosures required by and consistent with those of the Securities and Exchange Commission of the United States (''SEC'') and the Financial Accounting Standards Board in the United States (''FASB'') in place of much of the disclosure expected by NI 51-101. In accordance with the exemption, proved oil and gas reserves data and certain other disclosures with respect to our oil and gas activities in this AIF are presented in accordance with the following requirements:

- The FASB Statement No. 69 ''Disclosure about Oil and Gas Producing Activities — an amendment of FASB Statements No.'s 19, 25, 33 and 39'' (''FAS 69'');
- FASB Current Text Section Oi5, ''Oil and Gas Producing Activities'' paragraph .103, .106, .107, .108, .112, .160 through .167, .174 through .184 and .401 through .408;
- SEC Industry Guide 2;
- SEC Item 102 of regulation S-K (17 CFR 229.102);
- SEC Item 302(b) of Regulation S-K (17 CFR 229.302(b)); and
- The definitions and disclosures required by SEC Regulation S-X (CFR 210.4-10).

Proved oil and gas reserves information and other disclosures about oil and gas activities in this AIF following SEC requirements may differ from corresponding information otherwise required by NI 51-101. Proved reserves disclosed in this Annual Information Form are in accordance with the SEC definitions.

NI 51-101 specifies that proved reserves be determined in accordance with the Canadian Oil and Gas Evaluation Handbook (''COGEH'') definitions. There were no material differences between the oil and gas reserves determined using the SEC definitions and the COGEH definitions. In addition, NI 51-101 requires the inclusion of probable reserves and their associated future net revenue. The SEC does not normally permit the disclosure of probable reserves in documents filed with them.

The SEC requires the evaluation of oil and gas reserves to be based on prices, costs, fiscal regimes and other economic and operating conditions in effect at the time the evaluation is made (''constant prices''). NI 51-101 also requires the evaluation of oil and gas reserves on this basis but also requires an evaluation of oil and gas reserves to be based on a forecast of economic conditions. In establishing the constant prices for bitumen NI 51-101 provides for a different interpretation of the phrase ''price will be the posted price of oil and the spot price of gas, after historical adjustments for transportation, gravity and other factors''. On January 20, 2005 the Canadian Securities Administrators issued Staff Notice 51-315 ''Guidance Regarding the Determination of Constant Prices for Bitumen Reserves under NI 51-101 ''Standards of Disclosure for Oil and Gas Activities''. Bitumen is very heavy crude oil that is 10 degrees

API and lower. This guidance stipulates that for establishing the constant prices for bitumen companies should use the posted price for WTI and apply the average annual adjustment for transportation, gravity and other factors that create the difference in price between WTI and bitumen. This method was developed primarily in response to the fluctuations in bitumen prices that, for various reasons, tend to experience the lowest prices at the end of the calendar year. Under the FASB/SEC rules the determination of constant price for bitumen does not permit the use of annual average differentials between WTI and bitumen. These rules require the differentials prevailing on the last day of the period to be used to calculate the constant price. As a result on December 31, 2004 the price for bitumen as established under the FASB/SEC formula was lower than the price established under NI 51-101. There is no difference in determining the constant prices for crude oil classified as heavy oil, lighter than 10 degrees API and up to and including 20 degrees API, under NI 51-101 and FASB/SEC although heavy oil experiences the same pricing patterns as bitumen.

Husky believes that its reserves evaluators are qualified and that it has a well established reserves evaluation process that is at least as rigorous as would be the case were we to rely upon independent reserves evaluators. Husky has adopted written evaluation practices and procedures using the COGEH modified to the extent necessary to reflect the definitions and standards under SEC disclosure requirements. In addition, Husky engages a firm of independent qualified reserves evaluators to conduct an audit of the reserves estimates and respective present worth value of the reserves as at December 31, 2005. They conducted their audit in accordance with the standards described in the COGEH and the auditing standards generally accepted in the United States.

NI 51-101 prescribes a relatively comprehensive set of disclosures in respect of oil and gas reserves and other disclosures about oil and gas activities. In comparison, the SEC prescribes a minimum set of disclosures and advises reporting companies not to approach the SEC rules and regulations as merely a blank form but encourages them to provide such additional information that is necessary to further an investor's understanding of their business.

In either jurisdiction, information to further an investor's understanding is specifically encouraged to be included in 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 Canadian Securities Administrators, 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 the FORM 40-F which is filed in accordance with the Securities and Exchange Commission (United States) on the 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. (''Husky Energy'') was incorporated under the *Business Corporations Act* (Alberta) on June 21, 2000. From the date of its incorporation until August 25, 2000, Husky Energy did not carry on any business. On August 25, 2000, Husky Energy was a party to a plan of arrangement under the *Business Corporations Act* (Alberta) (the ''Arrangement'') pursuant to which Husky Oil Limited (''Husky Oil''), Husky Oil Operations Limited (a subsidiary of Husky Oil) and Renaissance Energy Ltd. (''Renaissance'') were amalgamated under the *Business Corporations Act* (Alberta) and continued as one corporation under the name ''Husky Oil Operations Limited'' (''HOOL'') and the security holders of Renaissance and Husky Oil exchanged their securities for securities of Husky Energy. Under the Arrangement, Husky Energy acquired 100 percent of the common shares of HOOL.

Husky Energy 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.

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

Intercorporate Relationships

The principal subsidiaries of Husky and place of incorporation, continuance or place of organization, as the case may be, are as follows. All of the following companies are directly or indirectly 100 percent owned.

Name	Jurisdiction
Subsidiaries of Husky Energy Inc.	
Husky Oil Operations Limited	Nova Scotia
Subsidiaries of Husky Oil Operations Limited	
Husky Oil Limited	Nova Scotia
Husky Energy Marketing Inc.	Alberta
Husky (U.S.A.) Inc.	Delaware
HOI Resources Co.	Nova Scotia
Husky Energy International Sulphur Corporation	Alberta
Canterra Resources Canada Ltd. (formerly 147212 Canada Ltd.)	Canada
Subsidiaries of Husky (U.S.A.) Inc.	
Husky Gas Marketing Inc.	Delaware
Subsidiaries of HOI Resources Co.	
Husky Energy International Corporation	British Columbia
Subsidiaries of Husky Energy International Corporation	
Husky Oil China Ltd.	Alberta
Husky Oil (Madura) Ltd.	British Virgin Islands
Husky Oil Overseas Ltd.	Alberta

GENERAL DEVELOPMENT OF HUSKY

Three Year History

Effective October 1, 2003, Husky purchased all of the outstanding common shares of Marathon Canada Limited (''Marathon'') and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. The total purchase price was U.S.$588 million. In a separate concurrent transaction Husky sold certain of the Marathon properties to another unrelated company for total proceeds of U.S. $320 million. The properties retained by Husky are located throughout western Alberta and northeastern British Columbia. The acquisition added approximately 39.8 mmboe of gross proved reserves, of which 75 percent was natural gas, and 729,000 acres of undeveloped lands in Alberta, British Columbia and the Northwest Territories.

In November 2003, Husky announced that it had signed a contract with CNOOC for the 04/35 exploration block in the East China Sea. The block comprises 4,835 square kilometres and requires one well to be drilled within the first three years of the contract. CNOOC has the right to participate up to a 51 percent interest in any subsequent development.

In November 2003, we established a securitization program to sell, on a revolving basis, up to $250 million of its accounts receivable to a third party. The agreement includes a program fee based on Canadian commercial paper rates.

On June 18, 2004 Husky issued U.S. $300 million of 6.15 percent notes due June 15, 2019. The notes were priced to yield 6.194 percent and are redeemable at the option of the Company at any time subject to a make-whole provision. The notes are unsecured and unsubordinated and rank equally with all its other unsecured and unsubordinated indebtedness.

In August 2004 Husky filed a base shelf prospectus that permits issue of up to U.S. $1 billion of debt securities or the equivalent in other currencies during the 25 months that the prospectus is in effect.

Effective July 15, 2004, Husky acquired Temple Exploration Inc. for a cash purchase of $101.5 million plus the assumption of $13.5 million working capital deficit. The acquisition added 21.1 bcf of natural gas and 1.4 million barrels of natural gas liquids to proved reserves as well as undeveloped land.

On August 16, 2004 we signed a production sharing agreement with the CNOOC for the 3,900 square kilometre 29/26 block in the South China Sea. The agreement requires us to drill one exploration well with the option to drill two

additional exploration wells before 2011. CNOOC has the right to participate in subsequent development up to 51 percent.

On October 26, 2004 we announced an agreement to acquire our co-venturer's interest in the Madura Strait production sharing agreement in Indonesia. Husky now holds a 100 percent interest in the 2,794 square kilometre exploration block, which contains two discoveries with commercial quantities of recoverable natural gas and natural gas liquids.

In November 2004, Husky acquired three exploration licenses in the Jeanne d'Arc Basin offshore Newfoundland. We acquired a 50 percent working interest in 225,100 acres, a 100 percent working interest in 128,800 acres and a 100 percent working interest in 208,200 acres. All three parcels are near Husky's White Rose oilfield currently under development.

In September 2005, Husky announced that its Prince George refinery was now capable of producing gasoline that meets the Government of Canada's new environmental specifications thereby completing the first of two phases of a ''Clean Fuel'' refinery modification project. Completion of the second phase in 2006 will enable the refinery to produce diesel fuel in compliance with the Federal Government's environmental specifications.

On November 12, 2005 first oil was produced at the White Rose oilfield offshore Newfoundland. Husky holds a 72.5 percent interest in White Rose, which is expected to reach plateau production of 100 mbbls/day (72.5 mbbls/day Husky working interest) by mid 2006. Production from White Rose is 31 degrees API light crude oil and will supply markets both in Canada and the United States.

Subsequent Event

In January 2006, Husky acquired two additional Exploration Licences (''EL'') in the Jeanne d'Arc Basin of the Grand Banks Region offshore Newfoundland. Husky holds 100 percent working interest in the 33,320 acre EL 1094 and the 5,260 acre EL 1096. Husky has committed to spend a total of $37 million evaluating the prospects of these ELs.

On February 1, 2006 Husky redeemed its 8.45 percent senior secured bonds for U.S. $85 million.

Events Expected to Occur During 2006

Husky's in-situ oil sands project at Tucker, Alberta is expected to commence and ramp up to a plateau production of approximately 30 mbbls/day within a three to six month period. In addition Husky expects to commence front end engineering and design with respect to the extraction process for the first phase of the Sunrise in-situ oil sands project in 2006 as well as develop alternatives for upgrading and marketing. The extraction plans for Sunrise were approved by the Alberta Energy and Utilities Board in December 2005. Husky holds 100 percent working interest in both oil sands projects.

Husky expects construction of its 130 million litre per year ethanol plant at Lloydminster, Saskatchewan to be completed by mid 2006 and its second 130 million litre per year ethanol plant at Minnedosa, Manitoba to be well on its way to a scheduled mid 2007 completion date.

Business Environment Trends

There are a number of trends that are developing, which may have both long and short-term effects on the oil and gas industry in Canada. Conventional production of crude oil in the Western Canada Sedimentary Basin (''WCSB'') has been in decline since 2000 and will, according to industry forecasts[(1)], continue to decline. Since 2000 increased crude oil production from the WCSB has come from mining and in-situ production of bitumen and heavy crude oils. Non-conventional production of crude oil is forecast[(1)] to increase overall crude oil production from the WCSB beyond current production levels. Natural gas discoveries in the WCSB have, in the past few years, been made in smaller reservoirs. Natural gas exploration efforts in the WCSB are focused on the traditionally less accessible areas in the overthrust belt along the eastern slope of the Rocky Mountains, in the Northwest Territories, offshore the east coast of Canada, smaller shallow gas deposits and coal bed methane.

The trend of volatile commodity prices continues and is expected to continue. Natural gas prices are sensitive to regional supply/demand imbalances, regional industrial activity levels, weather patterns and access to cheaper sources

(1) ''Canadian Crude Oil Production and Supply forecast'', July 2004, Canadian Association of Petroleum Producers ''Oil Sands Technology Roadmap'', January 30, 2004, Alberta Chamber of Resources.

of energy. Oil prices are dependent on the world economy and stable supply. As a result of numerous supply disruptions and increased demand from China and India oil prices have remained historically high.

DESCRIPTION OF HUSKY'S BUSINESS

General

Husky is a publicly held integrated energy and energy related company headquartered in Calgary, Alberta. Our operations include the exploration for and development of crude oil and natural gas properties, as well as the production, purchase, transportation, storage and marketing of crude oil, natural gas, natural gas liquids, sulphur and petroleum coke, and the upgrading and refining of crude oil and marketing of refined petroleum products, including gasoline, diesel, alternative fuels and asphalt products.

Upstream Operations

Husky's portfolio of assets includes properties with reserves classified as light (30 degrees API and lighter), medium (between 20 degrees and 30 degrees API), heavy (20 degrees and heavier but lighter than 10 degrees API) and bitumen (10 degrees API and heavier) crude oil, natural gas liquids, natural gas and sulphur. As operator of the majority of its properties Husky exercises a high degree of control in its upstream operations. We have production, gathering and processing facilities throughout the WCSB. In the Lloydminster heavy oil prone area Husky has a well established position with concentrated landholdings, production, gathering and processing facilities, as well as heavy crude oil pipeline, upgrading and refining facilities.

Reserves and Land Position

At December 31, 2005, our gross proved oil and gas reserves totalled 985 mmboe comprised of 273 mmbbls of light crude oil and NGL, 91 mmbbls of medium crude oil, 291 mmbbls of heavy crude oil, 48 mmbbls of bitumen and 2.1 bcf of natural gas. At December 31, 2005, our gross proved plus probable oil and gas reserves totalled 2,260 mmboe comprised of 462 mmbbls of light crude oil and NGL, 105 mmbbls of medium crude oil, 291 mmbbls of heavy crude oil, 951 mmbbls of bitumen and 2.7 bcf of natural gas. Our undeveloped landholdings in the Western Canada Sedimentary Basin totalled 7.1 million gross acres or 40 percent of our total gross undeveloped land holdings at December 31, 2005.

Properties

In the foothills deep basin areas in Alberta, we operate the Ram River gas plant and have interests in properties that supply this plant including: Blackstone, Ricinus, Limestone, Clearwater, Benjamin, Brown Creek and Stolberg. We also have an interest in the Caroline gas plant and field. Further north we have interests in the Valhalla and Wapiti crude oil and natural gas fields near Grand Prairie and properties in the Galloway, Ansell and Edson area. In northeastern British Columbia, we hold natural gas interests in the Sikanni and Federal area as well as Boundary Lake.

In the plains region of northwest Alberta, we operate the Rainbow Lake Plant, miscible floods and properties in surrounding areas. We have interests in the Peace River Arch, Boyer, Sloat Creek, Marten Hills, Cherpeta and Simons Lake areas. In the east central region of Alberta, we have property holdings east of Calgary and around Red Deer and Edmonton including major properties at Hussar and Provost.

In southern Alberta and Saskatchewan we have extensive property holdings around Taber and Brooks in southern Alberta and throughout southwest Saskatchewan at Shackleton/Lacadena, Cantaur, Fosterton and Carnduff.

On the east coast of Canada we hold a 12.51 percent working interest in the Terra Nova oilfield, which began producing light crude oil in January 2002, and a 72.5 percent working interest in the White Rose oilfield, which was sanctioned by the co-venturers in March 2002 and produced first oil on November 12, 2005. We also hold interests in several exploration and significant discovery licenses in the Jeanne d'Arc Basin.

We hold a 40 percent working interest in the Wenchang oilfields located offshore in the South China Sea. Production at the Wenchang oilfields began in July 2002. We also hold interests in five exploration blocks in the South China Sea with an aggregate areal extent of approximately 17,800 square kilometres and one exploration block in the East China Sea of approximately 4,800 square kilometres.

Husky also holds an interest in a production sharing contract located in the Madura strait offshore Java, Indonesia. We are currently negotiating a natural gas sales contract and, upon execution of this sales contract and acquiring an

extension of the production sharing agreement, we expect to commence field development of the BD field. We also hold a small non-operator interest in the Sirte Basin in Libya

Midstream Operations

Husky's midstream operations include upgrading of heavy crude oil feedstock into synthetic crude oil, pipeline transportation and processing of heavy crude oil, storage of crude oil, diluent and natural gas, and cogeneration of electrical and thermal energy, and marketing of Husky's and third party produced crude oil, natural gas, natural gas liquids, sulphur and petroleum coke.

Refined Products

Husky's refined products operations include refining of heavy and light crude oil, marketing of refined petroleum products, including asphalt and alternate fuels, and processing of grain primarily for ethanol production. Husky sells and distributes transportation fuels including ethanol blended fuels through independently operated Husky and Mohawk branded petroleum outlets, including service stations, truck stops and bulk distribution facilities located from the west coast of Canada to the eastern border of Ontario, some of which include 24 hour restaurants, convenience stores, service bays, car washes, fast food sales, bank machines and propane sales.

Social and Environmental Policy

Husky's environmental policy requires regular environmental audits to be conducted at its sites and facilities. Husky has established procedures designed to anticipate and minimize adverse effects of its operations on the environment, for continued compliance with environmental legislation and to minimize future and current costs. Husky's environmental policies apply equally to employees, subsidiaries and contractors.

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 our 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 capacity for heavy crude oil is limited. As a result, wider price differentials could have adverse effects on financial performance and condition and could reduce the value and quantities of our heavier crude oil reserves and could delay or cancel projects that involve the development of heavier crude oil resources.

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 the Organization of Petroleum Exporting Countries (''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.

During 2005 and to the date of this report Husky did not have any commodity price hedges in-place.

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 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 Husky's pipeline and processing capacity.

Husky's ability to replace reserves

Husky's future cash flow and cost of capital are dependent on its ability to replace its proved oil and gas reserves in a cost effective manner. Without economic reserve additions through exploration and development or acquisition Husky's production and, therefore, cash flow will decline. Without adequate proved reserves Husky's ability to fund development and other capital expenditures with external sources of funds is diminished.

Competition

The energy industry is currently experiencing high levels of activity, which is being driven by high commodity prices. The 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 additional 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 and to gain access to and retain adequate markets for Husky's products and services. Husky's ability to successfully complete development projects could be adversely affected by our inability to acquire economic supplies and services. Subsequent increases in the cost of supplies and services 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.

Husky's operations are susceptible to business interruption

Our operations are subject to various risks with respect to normal operating conditions. These risks comprise, but are not limited to, explosions, blowouts, cratering, fires, severe storms and adverse weather, all forms of marine perils, release of toxic, combustible or explosive substances all of which could cause loss of life, injury and destruction of public and Husky owned property.

The occurrence of any of the above listed events or others not listed could result in adverse financial performance and condition that may not be fully recoverable from our insurers.

Foreign exchange risk

Our results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of our 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. The majority of our expenditures are in Canadian dollars. 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, 2005, 84 percent or $1.6 billion of our long-term debt was denominated in U.S. dollars.

Environmental risks

All phases of the oil and natural gas business are subject to environmental regulation pursuant to a variety of federal, provincial and municipal 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 cannot be certain that the costs of complying with environmental legislation in the future will not have a material adverse effect on Husky's financial condition and results of operations.

Husky anticipates that changes in environmental legislation may require, among other things, 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 Husky's financial condition and results of operations.

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol, which requires the reduction of greenhouse gas emissions. On December 16, 2002, Canada ratified the Kyoto Protocol. This initiative may require Husky to significantly reduce emissions of green house gases such as carbon dioxide at its operations, which may increase capital expenditures. Details regarding the implementation of the Kyoto Protocol remain unclear.

Uncertainty of oil and gas proved reserves estimates

There are numerous uncertainties inherent in estimating quantities of oil and natural gas reserves, including many factors beyond Husky's control. The reserves information included in and incorporated by reference in this Annual Information Form are Husky's estimates. In general, estimates of economically recoverable oil and natural gas reserves and the estimated future net cash flow therefrom are based on a number of variables in effect as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the actual effects of regulation by governmental agencies and the actual future commodity prices and operating costs, all of which may vary considerably from those in effect at the date the reserves were determined. The estimated quantities of reserves expected to be recovered are uncertain and the classification of reserves as proved is only an attempt to define the degree of certainty involved. For these reasons, estimates of economically recoverable oil and natural gas attributable to a particular group of properties, the classification of such reserves as proved and the resultant future net cash flow therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Husky's actual production, revenues, taxes and development, abandonment, and operating expenditures with respect to its estimated oil and natural gas reserves may vary from such estimates, and such variances could be material.

Estimates with respect to reserves that may be developed and produced in the future (proved developed reserves) are often based on volumetric calculations and upon analogy to similar types of reservoirs, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history may result in variations in the estimated reserves, which may be material.

Upstream Operations — Disclosures for Oil and Gas Activities

In the tables that follow, light crude oil has an API gravity of 30 degrees or more: medium crude oil has an API gravity of above 20 degrees and less than 30 degrees: heavy crude oil has an API gravity of 20 degrees to 10 degrees API.

Production

	2005					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *(mbbls/day)*						
Light crude oil and NGL	64.6	31.3	17.2	48.5	16.0	0.1
Medium crude oil	31.1	31.1	—	31.1	—	—
Heavy crude oil	106.0	106.0	—	106.0	—	—
Total gross	201.7	168.4	17.2	185.6	16.0	0.1
Total net	175.7	146.0	15.1	161.1	14.5	0.1
Natural Gas *(mmcf/day)*						
Gross	680.0	680.0	—	680.0	—	—
Net	488.5	488.5	—	488.5	—	—

Production (continued)

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *(mbbls/day)*						
Light crude oil and NGL	66.2	32.7	13.7	46.4	19.7	0.1
Medium crude oil	35.0	35.0	—	35.0	—	—
Heavy crude oil	108.9	108.9	—	108.9	—	—
Total gross	210.1	176.6	13.7	190.3	19.7	0.1
Total net	183.9	153.0	13.2	166.2	17.6	0.1
Natural Gas *(mmcf/day)*						
Gross	689.2	689.2	—	689.2	—	—
Net	524.0	524.0	—	524.0	—	—

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *(mbbls/day)*						
Light crude oil and NGL	71.6	32.2	16.8	49.0	22.4	0.2
Medium crude oil	39.2	39.2	—	39.2	—	—
Heavy crude oil	99.9	99.9	—	99.9	—	—
Total gross	210.7	171.3	16.8	188.1	22.4	0.2
Total net	186.8	149.5	16.7	166.2	20.4	0.2
Natural Gas *(mmcf/day)*						
Gross	610.6	610.6	—	610.6	—	—
Net	473.7	473.7	—	473.7	—	—

Note:

(1) Gross volumes are Husky's lessor royalty, overriding royalty and working interest share of production before deduction of royalties. Net volumes are Husky's gross volumes, less royalties.

Revenue

	2005					
	Total	Western Canada	East Coast	Canada	China	Libya
			($ millions)			
Crude Oil						
Light crude oil and NGL	1,450	686	392	1,078	369	3
Medium crude oil	493	493	—	493	—	—
Heavy crude oil	1,203	1,203	—	1,203	—	—
Total gross	3,146	2,382	392	2,774	369	3
Total net	2,713	2,020	355	2,375	335	3
Natural Gas						
Gross	2,000	2,000	—	2,000	—	—
Net	1,594	1,594	—	1,594	—	—
Processing/Transportation	61	58	3	61	—	—

Revenue (continued)

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
	($ millions)					
Crude Oil						
Light crude oil and NGL	967	474	148	622	343	2
Medium crude oil	462	462	—	462	—	—
Heavy crude oil	757	757	—	757	—	—
Total gross	2,186	1,693	148	1,841	343	2
Total net	1,824	1,375	139	1,514	308	2
Natural Gas						
Gross	1,596	1,596	—	1,596	—	—
Net	1,248	1,248	—	1,248	—	—
Processing	48	48	—	48	—	—

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
	($ millions)					
Crude Oil						
Light crude oil and NGL	879	300	238	538	338	3
Medium crude oil	556	556	—	556	—	—
Heavy crude oil	943	943	—	943	—	—
Total gross	2,378	1,799	238	2,037	338	3
Total net	2,082	1,539	233	1,772	307	3
Natural Gas						
Gross	1,346	1,346	—	1,346	—	—
Net	1,058	1,058	—	1,058	—	—
Processing	46	46	—	46	—	—

Sales Prices

	2005					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil and NGL	61.56	60.15	62.60	61.02	63.15	69.23
Medium crude oil	43.44	43.44	—	43.44	—	—
Heavy crude oil	31.09	31.09	—	31.09	—	—
Total crude oil and NGL	42.75	38.77	62.60	40.97	63.15	69.23
Natural Gas *($/mcf)*	7.96	7.96	—	7.96	—	—

Sales Prices (continued)

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil and NGL	48.34	49.35	47.87	49.64	47.66	57.88
Medium crude oil	36.13	36.13	—	36.13	—	—
Heavy crude oil	28.66	28.66	—	28.66	—	—
Total crude oil and NGL (before hedging)	36.07	33.85	47.87	34.90	47.66	57.88
Total crude oil and NGL (after hedging)	28.43	26.19	29.45	26.42	47.66	57.88
Natural Gas *($/mcf)*						
Before hedging	6.25	6.25	—	6.25	—	—
After hedging	6.24	6.24	—	6.24	—	—

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil and NGL	39.53	38.28	38.91	38.49	41.45	40.44
Medium crude oil	31.42	31.42	—	31.42	—	—
Heavy crude oil	25.87	25.87	—	25.87	—	—
Total crude oil and NGL (before hedging)	31.54	29.48	38.91	30.32	41.45	40.44
Total crude oil and NGL (after hedging)	30.93	28.96	36.96	29.67	41.45	40.44
Natural Gas *($/mcf)*						
Before hedging	5.86	5.86	—	5.86	—	—
After hedging	5.94	5.94	—	5.94	—	—

Capital Expenditures

	2005						
	Total	Western Canada	East Coast/ Frontier	Canada	China	Indonesia	Libya
				($ millions)			
Property acquisition	133	133	—	133	—	—	—
Exploration	445	324	66	390	55	—	—
Development	2,152	1,550	579	2,129	14	8	1
	2,730	2,007	645	2,652	69	8	1

	2004						
	Total	Western Canada	East Coast/ Frontier	Canada	China	Indonesia	Libya
				($ millions)			
Property acquisition[1]	116	54	—	54	—	62	—
Exploration	313	271	24	295	18	—	—
Development	1,728	1,208	515	1,723	5	—	—
	2,157	1,533	539	2,072	23	62	—

Capital Expenditures (continued)

	2003						
	Total	Western Canada	East Coast/ Frontier	Canada	China	Indonesia	Libya
	($ millions)						
Property acquisitions[2]	76	76	—	76	—	—	—
Exploration	324	274	24	298	26	—	—
Development	1,378	845	533	1,378	—	—	—
	1,778	1,195	557	1,752	26	—	—

Notes:
(1) Does not include the acquisition of Temple Exploration Inc.
(2) Does not include the acquisition of Marathon Canada Limited.

Oil and Gas Netbacks

Netbacks reflect the results of operations for leases classified as oil or natural gas. Co-products, such as natural gas produced at an oil property or natural gas liquids produced at a natural gas property, have been converted to equivalent units of oil or natural gas depending on the lease product classification.

	2005					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil						
Sales revenue	61.86	60.74	62.60	61.41	63.15	69.23
Royalties	7.22	8.66	5.91	7.67	5.93	—
Operating costs	6.88	9.86	5.14	8.16	2.92	22.73
Netback	47.76	42.22	51.55	45.58	54.30	46.50
Medium crude oil						
Sales revenue	43.67	43.67	—	43.67	—	—
Royalties	7.77	7.77	—	7.77	—	—
Operating costs	10.97	10.97	—	10.97	—	—
Net back	24.93	24.93	—	24.93	—	—
Heavy crude oil						
Sales revenue	31.22	31.22	—	31.22	—	—
Royalties	3.75	3.75	—	3.75	—	—
Operating costs	9.90	9.90	—	9.90	—	—
Netback	17.57	17.57	—	17.57	—	—
Total crude oil						
Sales revenue	42.83	38.91	62.60	41.08	63.15	69.23
Royalties	5.49	5.41	5.91	5.45	5.93	—
Operating costs	9.13	10.10	5.14	9.65	2.92	22.73
Netback	28.21	23.40	51.55	25.98	54.30	46.50
Natural Gas *($/mcf)*						
Sales revenue	8.02	8.02	—	8.02	—	—
Royalties	1.76	1.76	—	1.76	—	—
Operating costs	1.04	1.04	—	1.04	—	—
Netback	5.22	5.22	—	5.22	—	—
Equivalent Unit *($/boe)*						
Sales revenue	44.56	42.53	62.60	43.69	63.15	69.23
Royalties	7.29	7.45	5.91	7.36	5.93	—
Operating costs	8.12	8.59	5.14	8.39	2.92	22.73
Netback	29.15	26.49	51.55	27.94	54.30	46.50

Oil and Gas Netbacks (continued)

	2004					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil						
Sales revenue	46.95	46.12	47.87	46.63	47.66	57.88
Royalties	5.71	7.76	1.80	6.03	4.91	—
Operating costs	5.82	8.94	3.28	7.29	2.16	16.47
Netback before hedging	35.42	29.42	42.79	33.31	40.59	41.41
Medium crude oil						
Sales revenue	36.20	36.20	—	36.20	—	—
Royalties	6.10	6.10	—	6.10	—	—
Operating costs	10.07	10.07	—	10.07	—	—
Netback before hedging	20.03	20.03	—	20.03	—	—
Heavy crude oil						
Sales revenue	28.73	28.73	—	28.73	—	—
Royalties	3.38	3.38	—	3.38	—	—
Operating costs	9.33	9.33	—	9.33	—	—
Netback before hedging	16.02	16.02	—	16.02	—	—
Total crude oil						
Sales revenue	35.72	33.48	47.87	34.50	47.66	57.88
Royalties	4.58	4.75	1.80	4.54	4.91	—
Operating costs	8.36	9.41	3.28	8.97	2.16	16.47
Netback before hedging	22.78	19.32	42.79	20.99	40.59	41.41
Netback after hedging	15.64	12.25	24.37	13.11	40.59	41.41
Natural Gas *($/mcf)*						
Sales revenue	6.25	6.25	—	6.25	—	—
Royalties	1.44	1.44	—	1.44	—	—
Operating costs	0.89	0.89	—	0.89	—	—
Netback before hedging	3.92	3.92	—	3.92	—	—
Netback after hedging	3.91	3.91	—	3.91	—	—
Equivalent Unit *($/boe)*						
Sales revenue	36.34	35.01	47.87	35.60	47.66	57.88
Royalties	5.96	6.22	1.80	6.03	4.91	—
Operating costs	7.32	7.85	3.28	7.66	2.16	16.47
Netback	23.06	20.94	42.79	21.91	40.59	41.41

Oil and Gas Netbacks (continued)

	2003					
	Total	Western Canada	East Coast	Canada	China	Libya
Crude Oil *($/bbl)*						
Light crude oil						
Sales revenue	40.17	39.91	38.91	39.55	41.45	40.44
Royalties	4.55	7.28	0.81	4.93	3.80	—
Operating costs	5.41	9.27	3.16	7.05	1.94	15.43
Netback before hedging	30.21	23.36	34.94	27.57	35.71	25.01
Medium crude oil						
Sales revenue	31.57	31.57	—	31.57	—	—
Royalties	5.28	5.28	—	5.28	—	—
Operating costs	9.53	9.53	—	9.53	—	—
Netback before hedging	16.76	16.76	—	16.76	—	—
Heavy crude oil						
Sales revenue	25.98	25.98	—	25.98	—	—
Royalties	2.76	2.76	—	2.76	—	—
Operating costs	9.09	9.09	—	9.09	—	—
Netback before hedging	14.13	14.13	—	14.13	—	—
Total crude oil						
Sales revenue	31.70	29.52	38.91	30.53	41.45	40.44
Royalties	3.83	4.14	0.81	3.84	3.80	—
Operating costs	7.97	9.23	3.16	8.68	1.94	15.43
Netback before hedging	19.90	16.15	34.94	18.01	35.71	25.01
Netback after hedging	19.32	15.63	32.99	17.36	35.71	25.01
Natural Gas *($/mcf)*						
Sales revenue	5.79	5.79	—	5.79	—	—
Royalties	1.29	1.29	—	1.29	—	—
Operating costs	0.79	0.79	—	0.79	—	—
Netback before hedging	3.71	3.71	—	3.71	—	—
Netback after hedging	3.79	3.79	—	3.79	—	—
Equivalent Unit *($/boe)*						
Sales revenue	32.69	31.58	38.91	32.01	41.45	40.44
Royalties	5.11	5.48	0.81	5.21	3.80	—
Operating costs	6.92	7.56	3.16	7.30	1.94	15.43
Netback	20.66	18.54	34.94	19.50	35.71	25.01

Producing Wells

	Oil Wells		Natural Gas Wells		Total	
	Gross[1][2]	Net[1]	Gross[1][2]	Net[1]	Gross[1][2]	Net[1]
Canada						
Alberta	4,308	3,341	4,658	3,794	8,966	7,135
Saskatchewan	4,567	3,644	922	826	5,489	4,470
British Columbia	224	78	183	122	407	200
Newfoundland and Labrador	17	4	—	—	17	4
Northwest Territories	5	1	5	1	10	2
	9,121	7,068	5,768	4,743	14,889	11,811
International						
China	24	10	—	—	24	10
Libya	2	1	—	—	2	1
	26	11	—	—	26	11
As at December 31, 2005	9,147	7,079	5,768	4,743	14,915	11,822
Canada						
Alberta	4,477	3,525	4,219	3,367	8,696	6,892
Saskatchewan	4,628	3,689	763	672	5,391	4,361
British Columbia	223	78	133	74	356	152
Manitoba	1	1	—	—	1	1
Newfoundland and Labrador	10	2	—	—	10	2
Northwest Territories	1	—	2	—	3	—
	9,340	7,295	5,117	4,113	14,457	11,408
International						
China	17	8	—	—	17	8
Libya	2	1	—	—	2	1
	19	9	—	—	19	9
As at December 31, 2004	9,359	7,304	5,117	4,113	14,476	11,417

Notes:

(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. Producing wells were producing or capable of producing at December 31.

(2) 2005 includes 331 gross, 312 net oil wells and 566 gross, 459 net natural gas wells and 2004 includes 482 gross, 411 net oil wells and 538 gross, 337 net natural gas wells which were completed in two or more formations and from which the production is not commingled. For the purposes of this table, multiple completions are counted as single wells. Where one of the completions in a given well is an oil completion, the well is classified as an oil well.

(3) The above table does not include wells in which Husky holds a royalty interest. At December 31, 2005 Husky had royalty interests in 3,679 wells of which 1,370 were oil producers and 2,309 were natural gas producers.

Landholdings

	Developed Acreage	
	Gross	Net
	(thousands of acres)	
As at December 31, 2005		
Western Canada		
Alberta	3,146	2,633
Saskatchewan	577	517
British Columbia	182	112
Manitoba	—	—
	3,905	3,262
Northwest Territories and Arctic	7	1
Eastern Canada	35	4
	3,947	3,267
China	17	7
Libya	7	2
	3,971	3,276
As at December 31, 2004		
Western Canada		
Alberta	3,200	2,687
Saskatchewan	567	506
British Columbia	186	110
Manitoba	—	—
	3,953	3,303
Northwest Territories and Arctic	7	1
Eastern Canada	35	4
	3,995	3,308
China	17	7
Libya	7	2
	4,019	3,317

	Undeveloped Acreage	
	Gross	Net
	(thousands of acres)	
As at December 31, 2005		
Western Canada		
Alberta	4,518	3,998
Saskatchewan	1,715	1,577
British Columbia	862	615
Manitoba	2	2
	7,097	6,192
Northwest Territories and Arctic	664	180
Eastern Canada	3,722	2,927
	11,483	9,299
International	6,280	3,429
	17,763	12,728

Landholdings (continued)

	Undeveloped Acreage	
	Gross	Net
	(thousands of acres)	
As at December 31, 2004		
Western Canada		
Alberta	4,983	4,449
Saskatchewan	1,831	1,669
British Columbia	787	544
Manitoba	7	7
	7,608	6,669
Northwest Territories and Arctic	924	254
Eastern Canada	3,154	2,104
	11,686	9,027
International	6,280	3,429
	17,966	12,456

Drilling Activity

	Year ended December 31					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
Western Canada Drilling						
Exploration						
Oil	89	85	45	39	12	11
Gas	392	196	234	180	147	124
Dry	36	36	34	33	22	21
	517	317	313	252	181	156
Development						
Oil	466	433	552	499	520	490
Gas	610	551	807	740	540	518
Dry	42	39	57	53	60	57
	1,118	1,023	1,416	1,292	1,120	1,065
	1,635	1,340	1,729	1,544	1,301	1,221

Present Activities

	Exploratory		Development	
Wells Drilling[1]	Gross	Net	Gross	Net
Western Canada	12	8.1	17	14.5
East Coast	—	—	2	0.9
China	—	—	—	—
	12	8.1	19	15.4

Note:

(1) Denotes wells that were drilling at December 31, 2005.

Reserves Data and Other Oil and Gas Information

Husky's oil and gas reserves as of December 31, 2005 are based on prices and costs in effect on that date and remain constant in future periods in accordance with the Financial Accounting Standards Board and the Securities and Exchange Commission (U.S.) as prepared internally by Husky's reserves evaluation staff. Husky uses a formalized process for determining, approving and booking reserves. This process provides for all reserves evaluation to be done on a consistent basis using established definitions and guidelines. Approval of any significant reserve additions and changes requires review by an internal panel of qualified reserves evaluators.

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 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 in the United States and as set out in the COGEH.

Oil and Gas Reserves Data

The following table presents in summary Husky's gross and net proved developed reserves, gross and net proved undeveloped reserves and associated future net cash flows as at December 31, 2005. Future revenues, based on prices and costs in effect on that date and remain constant in future periods, are presented net of royalties. Estimated future net revenues assume continuation of year end economic conditions including market demand and government policy, which are subject to uncertainty and may differ materially in the future. It should not be assumed that the discounted value of estimated future net reserves is representative of the fair market value of the reserves.

Proved Reserves

	Crude Oil & NGL[1]		Natural Gas[1]		Future Net Cash Flows Before Tax[1][4]	
	Gross[2]	Net[2]	Gross[2]	Net[2]	0%	10%
	(mmbbls)		(bcf)		($ millions)	
Proved developed[3]	446	399	1,710	1,413	22,512	13,782
Proved undeveloped[3][5]	183	166	426	358	5,001	2,923
Proved total[3]	629	565	2,136	1,771	27,513	16,705

Notes:

(1) Husky applied for and was granted an exemption from National Instrument 51-101 ''Standards of Disclosure for Oil and Gas Activities'' to provide oil and gas reserves disclosures in accordance with the U.S. Securities and Exchange Commission guidelines and the U.S. Financial Accounting Standards Board disclosure standards. The information disclosed may differ from information prepared in accordance with National Instrument 51-101. Husky's internally generated oil and gas reserves data was audited by an independent firm of qualified reserves evaluators.

(2) Gross reserves are Husky's lessor royalty, overriding royalty and working interest share of reserves, before deduction of royalties. Net reserves are gross reserves, less royalties.

(3) These reserve categories have the same meanings as those set out in SEC Regulation S-X.

(4) The discounted future net cash flows at December 31, 2005 were based on the year-end spot NYMEX natural gas price of U.S. $9.52/mmbtu and on a spot WTI crude oil price of U.S. $61.06/bbl.

(5) Estimated future capital expenditures required to gain access to proved undeveloped reserves as at December 31, 2005 and 2004 were as follows:

	As at December 31, 2005						
	Total	2006	2007	2008	2009	2010	Thereafter
	($ millions undiscounted)						
Western Canada	1,428	545	353	191	116	56	167
Eastern Canada	109	87	—	—	—	—	22
	1,537	632	353	191	116	56	189

	As at December 31, 2004						
	Total	2005	2006	2007	2008	2009	Thereafter
Western Canada	651	218	210	107	34	13	69
Eastern Canada	352	390	19	9	11	4	(81)
	1,003	608	229	116	45	17	(12)

(6) On December 31, 2005, the date our oil and gas reserves were evaluated, the calculated price of Lloydminster heavy crude oil was $28.57 per barrel. Our heavy crude oil reserves were economic at that price and no negative price revision resulted.

Reconciliation of Gross Proved Reserves

	Canada						International		Total	
	Western Canada					East Coast				
Proved Reserves, Before Royalties[1]	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural Gas	Bitumen[2]	Light Crude Oil	Light Crude Oil & NGL	Natural Gas	Crude Oil & NGL	Natural Gas
	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(mmbbls)	(mmbbls)	(bcf)	(mmbbls)	(bcf)
End of 2002	166	108	227	1,952		31	37	143	569	2,095
Revisions	5	1	6	(132)		1	(5)	(143)	8	(275)
Purchases	9		3	184					12	184
Sales	(1)	(3)	(1)	(23)					(5)	(23)
Discoveries and extensions	5	2	29	300					36	300
Improved recovery	1			1					1	1
Production	(12)	(14)	(37)	(223)		(6)	(8)		(77)	(223)
End of 2003	173	94	227	2,059		26	24		544	2,059
Revisions	1	1	(114)	(23)		(1)	3		(110)	(23)
Purchases	1			23					1	23
Sales			(1)	(14)					(1)	(14)
Discoveries and extensions	7	2	32	372		24			65	372
Improved recovery	1	2	1	4		3			7	4
Production	(12)	(13)	(40)	(252)		(5)	(7)		(77)	(252)
End of 2004	171	86	105	2,169		47	20		429	2,169
Revisions	3	9	121	(65)		9	2		144	(65)
Purchases			7	3					7	3
Sales		(3)	(4)	(9)					(7)	(9)
Discoveries and extensions	4	3	27	277	48	16	1		99	277
Improved recovery	1	7		9		23			31	9
Production	(12)	(11)	(39)	(248)		(6)	(6)		(74)	(248)
End of 2005	167	91	217	2,136	48	89	17		629	2,136

Notes:

(1) Proved reserves are the estimated quantities of crude oil, natural gas and NGL which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

(2) Bitumen is very heavy crude oil that is 10 degrees API and lower.

Gross Reserves and Production by Principal Area

Crude Oil and NGL[1]	Proved Reserves (mmbbls)	Production (mbbls/day)
Canada		
Western Canada		
British Columbia and Foothills		
Alberta and BC Plains area	29	6
Foothills Deep Gas area	24	6
Ram River and Kaybob areas	7	2
Northwest Alberta Plains		
Rainbow Lake area	83	8
Peace River Arch area	10	4
East Central Alberta		
North area	2	1
South area	7	3
Provost area	29	15
Southern Alberta and Saskatchewan		
South Alberta area	25	9
South Saskatchewan area	69	17
Lloydminster Area		
Primary production	124	79
Thermal production	66	18
Oil Sands	48	—
Other[2]	—	1
	523	169
East Coast Canada		
Terra Nova	21	12
White Rose	68	5
	89	17
China		
Wenchang	17	16
	629	202

Notes:

(1) Gross crude oil and NGL reserves as at December 31, 2005 and average 2005 daily gross production of crude oil and NGL.

(2) Other is comprised primarily of royalty interests, which are not considered to be reserves.

Natural Gas[1]	Proved Reserves (bcf)	Production (mmcf/day)
Canada		
Western Canada		
British Columbia and Foothills		
Alberta and BC Plains area	174	56
Foothills Deep Gas area	278	92
Ram River and Kaybob areas	249	76
Northwest Alberta Plains		
Rainbow Lake area	381	56
Peace River Arch	47	25
Northern Alberta area	246	89
East Central Alberta		
Provost area	73	22
North area	177	54
South area	197	57
Southern Alberta and Saskatchewan		
South Alberta area	52	32
South Saskatchewan area	188	58
Lloydminster Area	74	56
Other[2]	—	7
	2,136	680

Notes:

(1) Gross natural gas reserves as at December 31, 2005 and average 2005 daily gross production of natural gas.

(2) Other is comprised primarily of royalty interests, which are not considered to be reserves.

Gross Probable Oil and Gas Reserves[1]

Crude Oil & NGL

	Canada				
	Western Canada				
	Conventional	Bitumen	East Coast	International	Total
			(mmbbls)		
2005	146	903	118	13	1,180
2004	113	79	156	13	361
2003	167	79	182	7	435

Natural Gas

	Canada		
	Western Canada		
	Conventional	International	Total
	(bcf)		
2005	407	167	574
2004	388	167	555
2003	381	67	448

Barrels of Oil Equivalent

	Canada				
	Western Canada				
	Conventional	Bitumen	East Coast	International	Total
			(mmboe)		
2005	213	903	118	41	1,275
2004	177	79	156	41	453
2003	231	79	182	18	510

Notes:

(1) The probable reserves presented have been prepared, using constant prices and costs, in accordance with NI 51-101.

(2) Probable bitumen reserves were based on constant prices calculated in accordance with the Canadian Securities Administrators Staff Notice 51-315 ''Guidance Regarding the Determination of Constant Prices for Bitumen Reserves under National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (the ''Staff Notice''). Bitumen reserves at December 31, 2004 remain classified as probable reserves because the pricing formula in the Staff Notice results in an economically viable price as at that date whereas 37 mmbbls of heavy oil reserves were subtracted from probable reserves due to low December 31, 2004 heavy oil prices under the constant pricing calculation applicable to heavy oil, which differed from the bitumen calculation. See ''Disclosure of Exemption under National Instrument 51-101'' for further discussion.

(3) Proved and probable bitumen reserves are included under the caption Western Canada.

(4) The SEC generally permits oil and gas registrants to disclose only reserves that meet the standards for proved reserves. Due to the higher uncertainty associated with probable reserves, disclosure or reference to probable reserves does not meet the standards for the inclusion in a document filed with the SEC. The disclosure of probable reserves is included herein in accordance with certain undertakings made in an exemption order granted to Husky pursuant to Part 8 of the Companion Policy to NI 51-101.

Disclosure about Oil and Gas Producing Activities — Statement of Financial Accounting Standards No. 69

The following disclosures have been prepared in accordance with FASB Statement No. 69 ''Disclosures about Oil and Gas Producing Activities'' (''FAS 69''):

Oil and Gas Reserves

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

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 our estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause our share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2005, no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

Results of Operations for Producing Activities

Results of Operations for Producing Activities[1][2]	Canada			International			Total		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
	($ millions except per boe amounts)								
Oil and gas production revenue	4,085	2,866	2,917	337	310	310	4,422	3,176	3,227
Operating costs									
Lease operating expenses	925	874	794	18	17	17	943	891	811
Production taxes	56	56	41	—	—	—	56	56	41
Asset retirement obligation accretion	28	23	18	—	—	—	28	23	18
	1,009	953	853	18	17	17	1,027	970	870
Depreciation, depletion and amortization	1,102	1,018	852	42	59	66	1,144	1,077	918
Earnings before taxes	1,974	895	1,212	277	234	227	2,251	1,129	1,439
Income tax	730	349	491	106	92	91	836	441	582
Results of operations	1,244	546	721	171	142	136	1,415	688	857
Operating costs per gross boe[3]	8.39	7.66	7.30	3.06	2.25	2.04	8.12	7.32	6.92
Operating costs per net boe[4]	11.09	10.02	9.32	3.24	2.81	2.31	10.64	9.55	8.78
Amortization rate per gross boe	10.10	9.11	8.05	7.21	8.19	8.00	9.95	9.06	8.04
Amortization rate per net boe	12.45	10.97	9.51	7.96	9.13	8.81	12.19	10.85	9.46

Notes:

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

(2) Under U.S. GAAP, the depreciation, depletion and amortization for Canadian producing activities for 2005 amounted to $1,036 million (2004 — $981 million; 2003 — $772 million). Income taxes for Canadian producing activities under U.S. GAAP for 2005 amounted to $755 million (2004 — $364 million; 2003 — $511 million).

(3) Unit operating costs are field operating expenses divided by gross production.

(4) Unit operating costs include field operating costs, direct administrative expenses and production taxes divided by net production.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities[1]

	Canada	International	Total
		($ millions)	
2005			
Property acquisition			
Proved	68	—	68
Unproved	65	—	65
Exploration	390	55	445
Development	2,042	23	2,065
Capitalized interest	112	—	112
Total costs incurred	2,677	78	2,755
Less: Proved acquisitions	68	—	68
Capitalized interest	112	—	112
Finding and development costs	2,497	78	2,575
2004			
Property acquisition			
Proved	101	—	101
Unproved	91	62	153
Exploration	295	18	313
Development	1,712	4	1,716
Capitalized interest	75	—	75
Total costs incurred	2,274	84	2,358
Less: Proved acquisitions	101	—	101
Capitalized interest	75	—	75
Finding and development costs	2,098	84	2,182
2003			
Property acquisition			
Proved	541	—	541
Unproved	106	—	106
Exploration	298	26	324
Development	1,402	2	1,404
Capitalized interest	52	—	52
Total costs incurred	2,399	28	2,427
Less: Proved acquisitions	541	—	541
Capitalized interest	52	—	52
Finding and development costs	1,806	28	1,834

Notes:

(1) Development costs incurred exclude actual retirement expenditures and include asset retirement obligation incurred.

(2) Property acquisition costs related to corporate acquisitions for proved properties were $98 million.

(3) Property acquisition costs related to corporate acquisitions for unproved properties were $40 million.

(4) Property acquisition costs related to corporate acquisitions for proved properties were $517 million.

(5) Property acquisition costs related to corporate acquisitions for unproved properties were $54 million.

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.

Development costs include the costs of drilling and equipping development wells, facilities to extract, treat and gather and store oil and gas and settle the related asset retirement obligations.

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, 2005, by the year in which the costs were incurred:

Withheld Costs	Total	2005	2004	2003	Prior to 2003
		($ millions)			
Property acquisitions					
Canada	301	54	—	56	191
International	75	—	62	—	13
	376	54	62	56	204
Exploration					
Canada	417	279	96	42	—
International	37	22	13	2	—
	454	301	109	44	—
Development					
Canada	1,213	826	294	93	—
International	15	6	1	1	7
	1,228	832	295	94	7
Capitalized interest					
Canada	385	112	75	52	146
	2,443	1,299	541	246	357

Capitalized Costs Relating to Oil and Gas Producing Activities

	Canada	International	Total
		($ millions)	
2005			
Proved properties	16,195	528	16,723
Unproved properties	2,317	127	2,444
	18,512	655	19,167
Accumulated DD&A	6,729	354	7,083
Net Capitalized Costs[2]	11,783	301	12,084
2004			
Proved properties	13,624	458	14,082
Unproved properties	2,399	129	2,528
	16,023	587	16,610
Accumulated DD&A	5,722	311	6,033
Net Capitalized Costs[2]	10,301	276	10,577
2003			
Proved properties	12,017	449	12,466
Unproved properties	1,814	54	1,868
	13,831	503	14,334
Accumulated DD&A	4,718	252	4,970
Net Capitalized Costs[2]	9,113	251	9,364

Notes:

(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
2005	377	6	383
2004	314	6	320
2003	223	7	230

(2) The net capitalized costs for Canadian oil and gas exploration, development and producing activities under U.S. GAAP for 2005 was $11,290 million (2004 — $9,721 million, 2003 — $8,518 million). The net capitalized costs for International property oil and gas exploration, development and producing activities under U.S. GAAP for 2005 was $300 million (2004 — $274 million, 2003 — $249 million). Please refer to note 19 to the Consolidated Financial Statements for an explanation of the differences between Canadian and U.S. GAAP for oil and gas activities.

Oil and Gas Reserve Information

In Canada, our proved crude oil, natural gas liquids and natural gas reserves are located in the provinces of Alberta, Saskatchewan and British Columbia, and offshore the East Coast. Our international proved reserves are located in China and Libya.

	Canada		International		Total	
Reserves	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)	Crude Oil & NGL (mmbbls)	Natural Gas (bcf)
Net proved reserves[(1)(2)(3)(4)]						
End of 2002	468	1,612	33	101	501	1,713
Revisions	19	(89)	(3)	(101)	16	(190)
Purchases	9	146	—	—	9	146
Sales	(4)	(16)	—	—	(4)	(16)
Discoveries and extensions	31	245	—	—	31	245
Improved recovery	1	1	—	—	1	1
Production	(61)	(182)	(8)	—	(69)	(182)
End of 2003	463	1,717	22	—	485	1,717
Revisions	(105)	(54)	2	—	(103)	(54)
Purchases	1	17	—	—	1	17
Sales	(1)	(12)	—	—	(1)	(12)
Discoveries and extensions	55	309		—	55	309
Improved recovery	6	3	—	—	6	3
Production	(62)	(192)	(6)	—	(68)	(192)
End of 2004	357	1,788	18	—	375	1,788
Revisions	129	(75)	2	—	131	(75)
Purchases	6	2	—	—	6	2
Sales	(7)	(7)	—	—	(7)	(7)
Discoveries and extensions	94	230	1	—	95	230
Improved recovery	29	6	—	—	29	6
Production	(59)	(173)	(5)	—	(64)	(173)
End of 2005	549	1,771	16	—	565	1,771
Net proved developed reserves,[(1)(2)(3)(4)]						
End of year 2002	361	1,273	28	—	389	1,273
End of year 2003	372	1,423	23	—	395	1,423
End of year 2004	299	1,436	18	—	317	1,436
End of year 2005	327	1,413	15	—	342	1,413

Notes:

(1) Net reserves are the Company's lessor 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 quantities of crude oil, natural gas and related substances anticipated from geological and engineering data to be recoverable from known accumulations from a given date forward, by known technology, under existing operating conditions and prices in effect at year end.

(3) Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

(4) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

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

The following information has been developed utilizing procedures prescribed by FAS 69 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.

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.

	Canada[1]			International[1]			Total[1]		
Standardized Measure	2005	2004	2003	2005	2004	2003	2005	2004	2003
				($ millions)					
Future cash inflows	40,066	22,681	24,003	999	979	928	41,065	23,660	24,931
Future production and development costs	13,430	9,353	8,645	122	148	146	13,552	9,501	8,791
Future income taxes	9,000	4,871	5,696	272	266	247	9,272	5,137	5,943
Future net cash flows	17,636	8,457	9,662	605	565	535	18,241	9,022	10,197
Annual 10 percent discount factor	7,115	3,712	4,242	123	105	117	7,238	3,817	4,359
Standardized measure of discounted Future net cash flows	10,521	4,745	5,420	482	460	418	11,003	5,205	5,838

Changes in Standardized Measure

	Canada[1]			International[1]			Total[1]		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
					($ millions)				
Present value at January 1	4,745	5,420	6,347	460	418	839	5,205	5,838	7,186
Sales and transfers, net of production costs	(3,101)	(1,952)	(2,097)	(320)	(294)	(293)	(3,421)	(2,246)	(2,390)
Net change in sales and transfer prices, net of development and production costs	5,585	555	(1,379)	155	197	(376)	5,740	752	(1,755)
Extensions, discoveries and improved recovery, net of related costs	2,027	958	541	24	—	—	2,051	958	541
Revisions of quantity estimates	2,310	(1,318)	76	110	85	(97)	2,420	(1,233)	(21)
Accretion of discount	762	877	1,055	68	61	130	830	938	1,185
Sale of reserves in place	(62)	(20)	(47)	—	—	—	(62)	(20)	(47)
Purchase of reserves in place	36	45	304	—	—	—	36	45	304
Changes in timing of future net cash flows and other	826	(233)	(237)	(13)	17	(49)	813	(216)	(286)
Net change in income taxes	(2,607)	413	857	(2)	(24)	264	(2,609)	389	1,121
Net increase (decrease)	5,776	(675)	(927)	22	42	(421)	5,798	(633)	(1,348)
Present value at December 31	10,521	4,745	5,420	482	460	418	11,003	5,205	5,838

Note:

(1) The schedules above are calculated using year-end prices, costs, statutory income tax rates and existing proved oil and gas reserves. 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.

The future cash flows presented are based on sales prices, 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.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2005 was based on the NYMEX year-end natural gas spot price of U.S. $9.52/mmbtu (2004 — U.S. $6.02/mmbtu; 2003 — U.S. $5.96/mmbtu) and on crude oil prices computed with reference to the year-end WTI price of U.S. $61.06/bbl (2004 — U.S. $43.36/bbl; 2003 — U.S. $32.51/bbl).

INDEPENDENT ENGINEER'S AUDIT OPINION

January 23, 2006

Husky Energy Inc.
707 – 8th Avenue S.W.
Calgary, Alberta
T2P 3G7

Gentlemen:

Pursuant to Husky's request we have conducted an audit of the reserves estimates and the respective present worth value of these reserves of Husky Energy Inc., as at December 31, 2005. The Company's detailed reserves information was provided to us for this audit. Our responsibility is to express an independent opinion on the reserves and respective present worth value estimates, in aggregate, based on our audit tests and procedures.

We conducted our audit in accordance with Canadian generally accepted standards as described in the Canadian Oil and Gas Evaluation Handbook (COGEH) and auditing standards generally accepted in the United States of America. 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 reserve 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 sufficient number of Company properties as considered necessary 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 in the United States and as set out in the Canadian Oil and Gas Evaluation Handbook.

Sincerely,

McDaniel & Associates
Consultants Ltd.

/s/ P.A. Welch

P.A. Welch
President & Managing Director

REPORT ON RESERVES DATA BY QUALIFIED RESERVES EVALUATOR

To the Board of Directors of
HUSKY ENERGY INC. (the ''Company''):

1. Our staff has evaluated the Company's reserves data as at December 31, 2005. The reserves data consists of the following:
   (a) proved oil and gas reserve quantities estimated as at December 31, 2005 using constant prices and costs; and
   (b) the related standardized measure of discounted future net cash flows.
2. The oil and gas reserves data are the responsibility of the Company's management. As the Corporate Representatives 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.
3. 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 ''COGEH'') with the necessary modifications to reflect definitions and standards under the applicable U.S. Financial Accounting Standards Board standards (the ''FASB Standards'') and the legal requirements of the U.S. Securities and Exchange Commission (''SEC Requirements''). Our internal reserves evaluators are not independent of the Company, within the meaning of the term ''independent'' under those standards.
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the oil and gas reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGEH as modified or replaced by the FASB standards and SEC requirements.
5. The following sets forth the estimated standardized measure of discounted future net cash flows (before deducting income taxes) attributed to proved oil and gas reserve quantities, estimated using constant prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2005:

Location of Reserves (country or foreign geographic area)	**Discounted Future Net Cash Flows (Before Income Taxes, 10% Discount Rate)** ($ millions)
Canada	16,005
China	688
Libya	12
	16,705

We have filed the Company's oil and gas reserves disclosures in accordance with Financial Accounting Standards Board Statement No. 69 ''Disclosures about Oil and Gas Producing Activities'' concurrently with this form.

6. In our opinion, the oil and gas reserves data evaluated by us have, in all material respects, been determined in accordance with principles and definitions presented in the COGEH as modified or replaced by the FASB Standards and SEC Requirements.
7. We have no responsibility to update our evaluation for events and circumstances occurring after the date of this report.
8. Oil and gas reserves are estimates only, and not exact quantities. In addition, the oil and gas reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Calgary, Alberta
January 19, 2006

/s/ Preston Kraft P. Eng

Preston Kraft P. Eng
Manager of Reservoir Engineering

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

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 oil and gas reserves data, which consist of the following:

(1) proved oil and gas reserve quantities estimated as at December 31, 2005 using constant prices and costs; and

(2) the related standardized measure of discounted future net cash flows.

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 the U.S. Securities and Exchange Commission (''SEC'') and the applicable provisions of the U.S. Financial Accounting Standards Board Statement of Financial Accounting Standards No. 69 (collectively, the ''Oil and Gas Reserves Data Process''). 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 the Reserves Data Process has been followed. The Report on Reserves Data of the Manager of Reservoir Engineering 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 and external qualified oil and gas reserves evaluators;

(b) met with the internal and, if applicable, external qualified oil and gas reserves evaluator(s) to determine whether any restrictions placed by management affect the ability of the internal qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the internal qualified oil and gas reserves evaluator.

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 the reserves data and other oil and gas information;

(b) the filing of the Report on Reserves Data of the Manager of Reservoir Engineering; 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 reserves evaluators or auditors. Notwithstanding this exemption, Husky involve independent qualified reserve auditors as part of Husky's corporate governance practices. Their involvement helps assure that Husky's internal oil and gas reserves estimates are materially correct.

In Husky's view, the reliability of its 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. Husky is therefore relying on an exemption, which it sought and was granted by securities regulatory authorities, from the requirement under securities legislation to involve independent qualified reserves evaluators or independent qualified reserves auditors.

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.

Husky's view is based in large part on the following. Husky's reserves data were developed in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook. Husky's procedures, records and controls relating to the accumulation of source data and preparation of reserves data by Husky's internal reserves evaluation staff have been established, refined and documented over many years. Husky's internal reserves evaluation staff includes

133 individuals, including support staff, of whom 64 individuals are qualified reserves evaluators as defined in the Canadian Oil and Gas Evaluation Handbook, with an average of 8 years of relevant experience in evaluating reserves. Husky's internal reserves evaluation management personnel includes 24 individuals with an average of 12 years of relevant experience in evaluating oil and gas and managing the evaluation process.

Reserves data are estimates only, and are not exact quantities. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

/s/ JOHN C.S. LAU	March 14, 2006
John C. S. Lau President & Chief Executive Officer	
/s/ JAMES D. GIRGULIS	March 14, 2006
James D. Girgulis Vice President Legal & Corporate Secretary	
/s/ R. DONALD FULLERTON	March 14, 2006
R. Donald Fullerton Director	
/s/ WAYNE E. SHAW	March 14, 2006
Wayne E. Shaw Director	

Description of Major Properties and Facilities

Husky's portfolio of assets includes properties with reserves of light (30 degrees API and lighter), medium (between 20 degrees and 30 degrees API) heavy (20 degrees API and heavier but lighter than 10 degrees API) and bitumen (10 degrees API and heavier) gravity crude oil, NGL, natural gas and sulphur.

Lloydminster Heavy Oil and Gas

Husky's heavy oil assets are concentrated in a large producing area covering more than 14,800 square kilometres in the Lloydminster area in the Canadian provinces of Saskatchewan and Alberta. Approximately 80 percent of Husky's proved reserves in the region are contained in the heavy crude oil producing fields of Pikes Peak, Edam, Tangleflags, Celtic, Bolney, Westhazel, Big Gully, Hillmond, Mervin, Marwayne, Lashburn, Gully Lake 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. We maintain a land position of approximately 1.6 million acres in the Lloydminster area, of which approximately 70 percent is undeveloped.

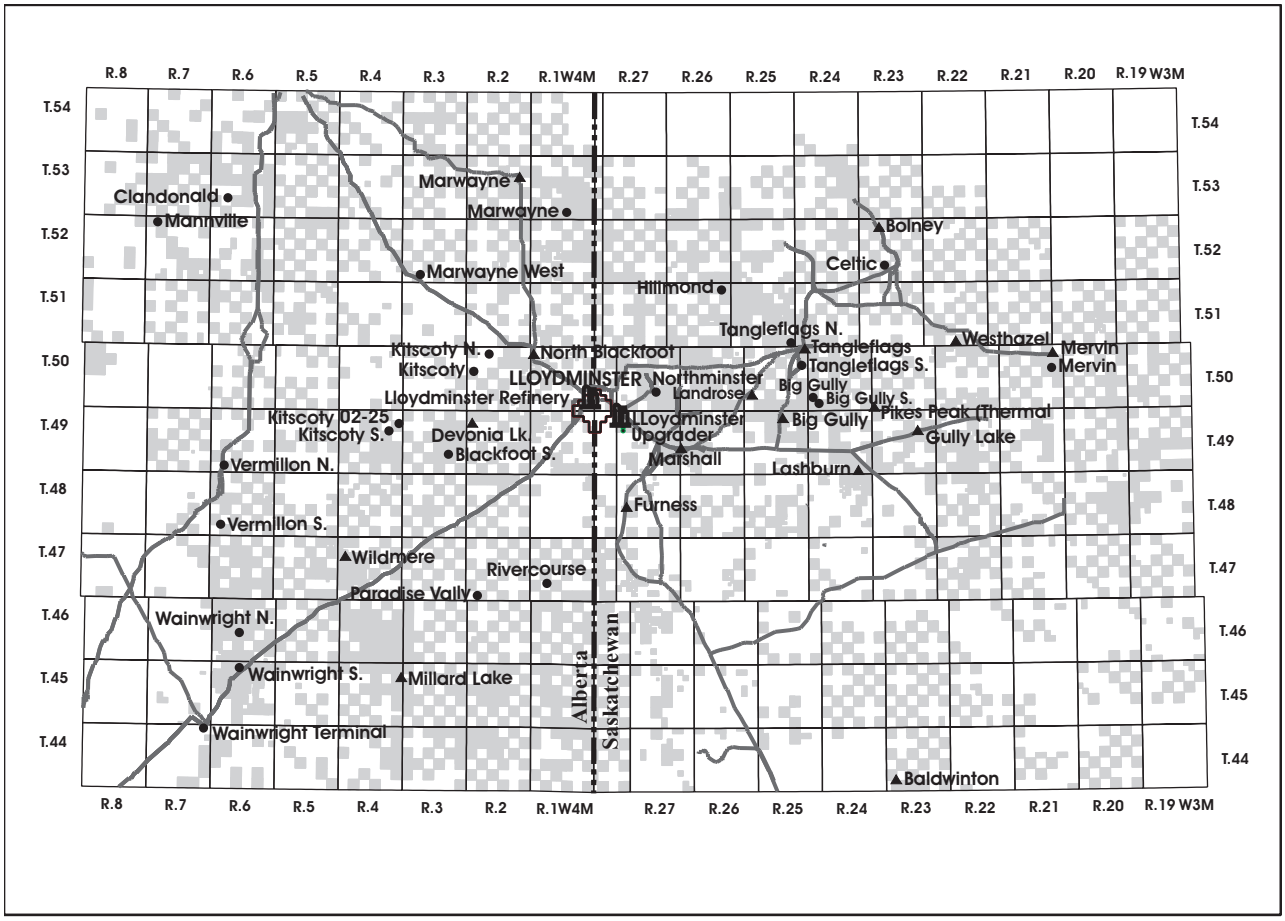
We currently produce from oil and gas wells ranging in depth from 450 to 650 metres and hold a 100 percent working interest in the majority of these wells. We produce heavy oil from the Lloydminster area using a variety of techniques, including standard primary production methods, as well as steam injection, horizontal well technology and steam assisted gravity drainage (''SAGD''). We have 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. Our net heavy and medium crude oil production from the area totalled 97.4 mbbls/day in 2005. Of the total production, 76.2 mbbls/day was primary production of heavy crude oil, 18.0 mbbls/day was production from our thermal operations at Pikes Peak (cyclic steam), Bolney/Celtic (SAGD) and the Lashburn pilot (SAGD), and 3.2 mbbls/day was from the medium gravity waterflooded fields in the Wainwright and Wildmere areas. We believe that the future growth from this area will be driven by primary heavy oil production and new thermal projects.

In the Lloydminster area we own and operate 16 oil treating facilities, all of which are tied into our heavy oil pipeline systems. These pipeline systems transport heavy crude oil from the field locations to our Lloydminster asphalt refinery, to the Husky Lloydminster Upgrader and to the Enbridge Pipeline and Express Pipeline systems at Hardisty, Alberta.

We are focused on increasing our heavy oil production and believe that our undeveloped land position in the Lloydminster area, coupled with the application of improved technologies, a reduced cost structure and increased upgrading capacity, will provide strong growth opportunities for heavy oil production.

We also produce natural gas from numerous small shallow natural gas pools in the Lloydminster area (approximately 73 bcf of proved reserves). Our total gross natural gas production from the area during 2005 was 55.8 mmcf/day.

Lloydminster Area



British Columbia Foothills/Northwest Plains

Rainbow Lake Area

Rainbow Lake, located approximately 700 kilometres northwest of Edmonton, Alberta, is the site of our largest light oil production operation in Western Canada. Husky operates a number of crude oil pools in the Rainbow basin, with an average working interest of 54 percent. Our production in this area is derived from more than 50 oil and gas pools extending over 1,300 square kilometres.

We use secondary and tertiary oil recovery methods extensively in the Rainbow Lake area. These methods include injecting water, natural gas and NGL into the oil reservoirs to enhance crude oil recovery. The use of tertiary recovery programs, such as the miscible flood used at Rainbow Lake, has increased the estimated amount of recoverable crude oil-in-place from 50 to 70 percent of the original crude oil-in-place in certain pools. As a consequence of implementing these natural gas and NGL re-injection programs, historically only small volumes of gas and NGL have been marketed from the Rainbow Lake area prior to 2002. In 2003, we initiated the recovery of natural gas from several pools. NGL recovery is forecast to begin in the 2008-2010 timeframe and is expected to generate revenues as the crude oil production from the pools is completed. We use horizontal drilling techniques, including the re-entry of existing well bores, to maintain the level of crude oil production and to increase recovery rates. We plan to continue exploration efforts to supplement our development initiatives in the Rainbow Lake area. Husky's gross production from this area averaged 7.8 mbbls/day of light crude oil and NGL and 34.1 mmcf/day of natural gas during 2005.

We hold a 50 percent interest in, and operate, the Rainbow Lake processing plant. The processing design rate capacity of the plant is 69 mbbls/day of crude oil and water and 230 mmcf/day of raw gas. The extraction design capacity is 17 mbbls/day of NGL.

During the winter of 2005, Husky installed a dew point facility and compressor at Bivouac to eliminate a pipeline restriction to the Rainbow Lake plant which limited production to 4 mmcf/day. With completion of this facility in May 2005, production from Bivouac increased to 14 mmcf/day. Plans for 2006 are to drill sufficient wells to fill the facility capacity of 20 mmcf/day.

We hold an interest in two significant non-operated properties in the Rainbow area. They include the Ekwan/Sierra property in northeastern British Columbia and the Bistcho/Cameron Hills property straddling the Alberta and Northwest Territories border. Our gross production from these properties currently averages 11.0 mmcf/day of natural gas and 143 bbls/day of liquid hydrocarbons. We also hold a working interest in the Encana Sierra gas plant and the Paramount Bistcho gas plant. We are active in both these areas with development and exploration drilling. In these two areas we hold in excess of 200,000 acres of undeveloped land.

Slave Lake Area

The Slave Lake area of northern Alberta, which includes the Slave Lake, Sawn Lake, Red Earth, Lubicon, Nipisi, Utikuma and other properties, has been primarily a light oil producing area located approximately 370 kilometres northwest of Edmonton. We operate and hold an average 80 percent working interest in several properties in this area. Gross production from our properties was 3.7 mbbls/d of crude oil and 25 mmcf/d natural gas in 2005. The average working interest in these lands is 80 percent. Infrastructure includes a 100 percent working interest in a 30 mmcf/day sour gas plant and three oil batteries. We plan to continue development drilling and waterflood optimization for both crude oil and natural gas targets in this area. In addition, we will assess oil sands deposits for potential primary production.

High Level Area

The High Level area of Alberta is approximately 600 kilometres northwest of Edmonton, Alberta. We are the operator and hold close to 100 percent working interest in our properties. The area holds shallow Bluesky gas reservoirs that are characterized as low deliverability and low decline that are being developed with a drilling density of three wells per section. We intend to continue to develop this area by drilling undeveloped sections, infill drilling, land acquisitions and step out exploration. Gross production from this area in 2005 averaged 32.3 mmcf/day of natural gas. Our plans in 2006 are to drill new wells and recompletions to fully utilize facilities and optimize operating costs.

Athabasca Area

The Athabasca area is located approximately 200 kilometres northeast of Edmonton, Alberta. Natural gas is produced from the Clearwater, Colony, McMurray and Wabasca or combination of these zones that lie at a depth of approximately 600 metres. Gross natural gas production from this district was 49.4 mmcf/day in 2005. The largest asset in the area is at Amadou which consists of a 22 mmcf/day dehydration facility, 5,800 horsepower of compression and a gathering system which collects natural gas from an area four townships in size. Amadou produced 13.4 mmcf/day in 2005. Our plans for 2006 are to continue with development drilling, recompletions and facility optimizations to keep existing infrastructure fully utilized and optimize unit operating costs. In 2006 we also plan to evaluate the existing oil sands leases and prospective oil sands leases for primary production potential.

Ram River Area

The Ram River area is located in west central Alberta and includes the large Blackstone, Ricinus and Clearwater/Limestone natural gas fields.

The Blackstone field is the most prolific of these fields and contains four high deliverability natural gas wells, capable of combined raw gas production of 60 mmcf/day. We hold a 34 percent interest in two unitized wells, a 24 percent and a 50 percent interest, respectively, in two non-unit wells, and act as the contract operator of the Blackstone wells. Production from these wells is processed at the Ram River gas plant.

We hold an average 72 percent interest in, and are the operator of, the Ram River sour gas plant and related processing facilities. The Ram River plant has the capacity to process 622 mmcf/day of sour gas, resulting in sales gas capacity of 525 mmcf/day. The plant also has the capacity to produce in excess of 2.8 mlt/day of sulphur from raw gas. During 2005, the plant operated at approximately 90 percent of its design rate capacity. The Ram River plant processes in excess of 10 percent of our total gross natural gas production, which includes an average of 44 mmcf/day of our gross production from the Blackstone, Brown Creek, Cordel and Stolberg fields and an average of 20.6 mmcf/day of our gross production from Ricinus and Clearwater/Limestone and Benjamin fields, in addition to processing third-party

volumes. In addition, gross production from the Ferrier area, which is processed at other gas plants, averaged 5.1 mmcf/day of natural gas, bringing our total gross production of natural gas from the Ram River area to 65 mmcf/day in 2005. Our 2006 plans for the Ram River area include continued exploration and development along the Mississippian trend and evaluating deeper targets.

Our sour gas pipeline network supports the Ram River plant. We operate a network of 845 kilometres of sour gas pipelines in the Ram River area and hold a 30 percent interest in 684 kilometres of this pipeline system. The sour gas processed at the Ram River plant is produced from 18 sour gas fields located as far as 145 kilometres from the Ram River plant.

We believe that the Ram River plant and the extensive infrastructure of gathering pipelines, transmission systems and rail lines, which support the plant, represents a strategic base for the natural gas exploration and development planned by us in this part of the foothills region. In addition, this region is an active exploration and production area for other producers and provides additional opportunities for generating revenue by processing third party natural gas. In 2005, with the addition of Shell Tay River gas volumes and continued success along the Chungo Mississippian trend, net processing income was $25.3 million.

Kaybob Area

The Kaybob area consists of land located in the Fox Creek area of Alberta. The Kaybob area consists of four main areas. The Kaybob South Beaverhill Lake Unit 1 (35.6 percent working interest), Kaybob South Triassic Unit 1 (40.5 percent working interest), Kaybob South Triassic Unit 2 (26.8 percent working interest), and non-unit lands (various working interests from gross overriding royalty to 100 percent working interest).

We have a 17.8 percent working interest in the sour portion and a 20.4 percent working interest in the sweet gas portion of the plant. We also have various working interests in sweet gas gathering and compression facilities in the area. Our gross production from the area during 2005 was 390 bbls/day of oil, 463 bbls/day of NGL and 11 mmcf/day of natural gas.

Alberta/British Columbia Plains

Boundary Lake Area

We hold a 50 percent working interest in the Boundary Lake Gas Unit and a 34 percent and 19 percent interest in the Boundary Lake oil unit 1 and 2, respectively, in northeast British Columbia. Our natural gas production from this area is derived from five Belloy sour gas pools, and is processed at the nearby Boundary Lake processing plant. Our gross production from this area was 12 mmcf/day of natural gas and 1.6 mbbls/day crude oil and NGL from the Boundary Lake units during 2005.

Valhalla and Wapiti Area

We hold an approximate 30 percent interest in three Valhalla oil units, a 100 percent interest in the Valhalla non-unit waterflood wells and a 100 percent interest in the Wapiti property. Production is primarily from the Doe Creek and Cardium zones and consists of light crude oil, NGL and natural gas. Our gross production from these properties averaged 3.3 mbbls/day of crude oil and NGL and 8.5 mmcf/day of natural gas in 2005.

Kakwa Area

We hold an average 60 percent working interest in oil and gas processing facilities and associated oil and gas gathering systems in the Kakwa area. Our gross production from this area was 14.8 mmcf/day of natural gas, 491 bbls/day NGL and 307 bbls/day of oil in 2005.

Lynx and Copton Area

Husky has had a significant focus on exploration activity in the Lynx/Copton area of western Alberta drilling and tie-in of four net wells in the area, increasing production from 12 mmcf/d to 16 mmcf/d. We plan to continue to develop this immature asset in 2006 to maintain Husky production at 15 mmcf/d.

Foothills West

Caroline Area

We hold an 11 percent working interest in the 32,000 acre Caroline natural gas field located approximately 97 kilometres northwest of Calgary. The field has a high proportion of NGL and as a result the economics of this field are enhanced.

We also hold an 11 percent interest in the Caroline sour gas processing facility. The plant is presently running at a license limit of 113 percent of design capacity and is processing approximately 124 mmcf/day of total plant sales gas and 39 mbbls/day of NGL. Husky's gross production was 3.3 mbbls/day NGL and 11.9 mmcf/day natural gas in 2005.

Edson Area

We hold an average 85 percent working interest in two gas processing facilities and associated gas gathering systems in the Edson area. We operate these properties that had average gross production of 34.0 mmcf/day of natural gas and 1.4 mbbls/day of NGL in 2005. Husky had a significant development program of 20 development in 2005 with plans to drill 20 wells in 2006 to increase production to 40 mmcf/day.

Sikanni Area

We hold interests in properties in the Sikanni and Federal areas of northeast British Columbia, which averaged gross production of 9.8 mmcf/day of natural gas from four wells in 2005. The production flows through our gathering systems for processing at third party plants at Sikanni and McMahon. In December 2005 Husky's gross production increased by 6 mmcf/day with the payout of a reversionary working interest on a farmout well in the Lily area.

Graham Area

We hold a 40 percent working interest in lands in the Graham area of northeastern British Columbia. Our gross production from this area averaged 8.3 mmcf/day of gross natural gas sales in 2005. Production from the property is from one Halfway and seven Baldonnel pools. We also hold an interest in two 1,500 horsepower compressor stations and the non-operated Cypress gas plant. Plant capacity is 45 mmcf/day and the plant is currently operating at full capacity. We hold a 33.2 percent interest in the gas treating unit, 28.2 percent interest in the amine unit and 28 percent interest in the sulphur unit.

East Central Alberta

Craigend Area

The Athabasca area extends approximately 175 kilometres north of Edmonton, and from the Alberta-Saskatchewan border in the east, to the Alberta foothills in the west. The area target is predominantly shallow gas, ranging from 450-900 metres in the multi-zone Palaeozoic Mannville formation. The main producing areas are Athabasca, Craigend and Cold Lake. We operate 32 facilities with a pipeline system and an average working interest of 90 percent in the producing wells. We intend to continue to develop this area with infill, step out and exploratory wells to optimize recovery and develop new pools in order to keep the facilities operating at capacity. Our gross production from this area averaged 54.3 mmcf/day of natural gas and 635 bbls/day of crude oil in 2005.

Red Deer and Hussar Area

The core of the Red Deer and Hussar area is between Calgary, Drumheller and Sylvan Lake. Husky operates 21 facilities with gas gathering systems in this area. Our gross production from this area averaged 57.3 mmcf/day of natural gas and crude oil and NGL of 2.4 mmbbls/day in 2005. We intend to continue to develop the natural gas potential of this area with infill, step out and exploratory wells to optimize gas recovery and develop new pools in order to operate the facilities at capacity. We are involved in coal bed methane development in this area, and by year-end 2005 had drilled 300 wells and built extensive infrastructure. There were 120 wells tied-in by year-end that were producing gross 10 mmcf/day of natural gas. In 2006, we plan to drill 300 more wells to reach an expected gross 35 mmcf/day of natural gas.

Provost Area

The centre of the Provost area is approximately 240 kilometres southeast of Edmonton. It is predominantly a medium crude oil area that averaged gross production of 15.4 mbbls/day of crude oil and 22.2 mmcf/day of natural gas

in 2005. We intend to selectively drill lower risk oil locations and focus on managing operating costs and improving oil recovery, as well as increasing our focus on natural gas exploration and development. In 2006, we intend to continue to develop several of our 2004 and 2005 natural gas discoveries. There is significant competition in the area for land as well as infrastructure. We have a large land position and maintain close to a 100 percent working interest in most of our facilities.

Southern Alberta and Southern Saskatchewan

Southern Saskatchewan Area

Husky is a prominent operator in southern Saskatchewan primarily producing medium gravity crude oil, with some natural gas and light crude oil. Gross production from our properties in this area averaged 16.7 mbls/day of crude oil and 58.2 mmcf/day of natural gas during 2005.

We operate 31 oil batteries and six gas facilities in the southern Saskatchewan area. The oil pools in this area are exploited using pressure maintenance and waterflood recovery operations.

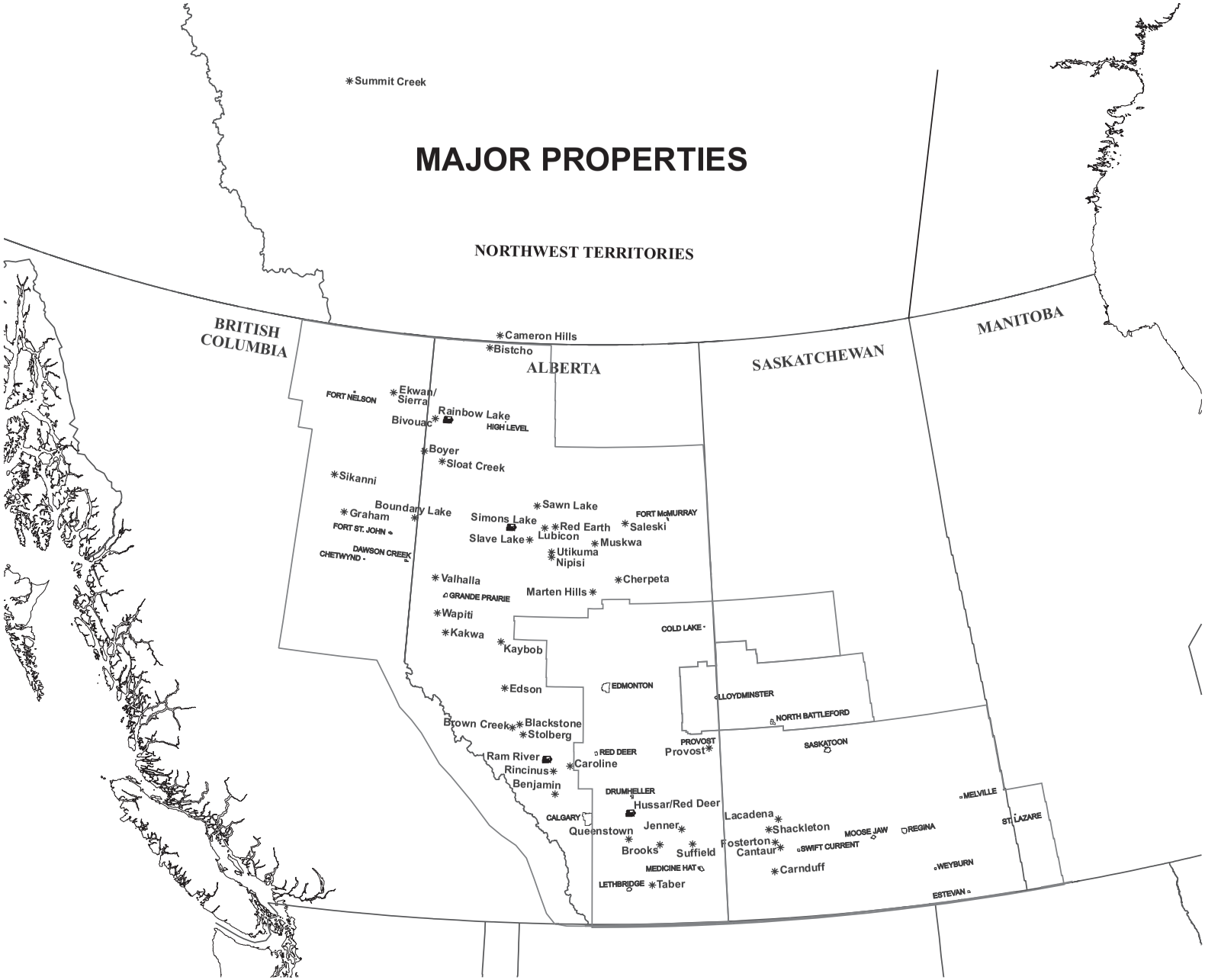
At the Shackleton/Lacadena Milk River shallow gas project, 132 wells were drilled and tied-in in 2005. The project was producing at a rate of 48.8 mmcf/day of natural gas at December 31, 2005 from a total of 330 wells. In 2006, we plan to drill between 65 and 100 additional step out and infill wells and add two 8 mmcf/day sales gas plants.

Southern Alberta Area

Taber and Brooks are our two major centres in southern Alberta. We operate 27 oil facilities and three natural gas facilities with an average working interest of 95 percent. Oil production is mainly medium gravity crude with the majority of reserves being supported by waterfloods or active aquifers. Natural gas production is from a mixture of deep and shallow formations. At Etzikom, near Taber, we operate an alkaline-polymer flood to increase recovery from the Cretaceous Mannville reservoir and we are currently implementing additional floods at Warner and Crowsnest for 2006, and 2007 respectively. Our gross production from this area averaged 10.2 mbbls/day of crude oil and 32.1 mmcf/day of natural gas during 2005.

During 2005 we divested of approximately 1,100 bbls/day of heavy crude production at Jenner, which had very high operating costs, and minimal upside.

MAJOR PROPERTIES



Oil Sands

Athabasca, Cold Lake and Peace River

Husky currently holds interests in 433,610 net acres, including 7,680 acres of petroleum and natural gas rights, in the bitumen prone areas of Athabasca, Cold Lake and Peace River.

In addition to interests in the 353,930 net acres in the Cold Lake and Athabasca regions in northeastern Alberta, Husky holds an interest in 79,680 net acres in the Peace River region of northern Alberta.

Tucker

In May of 2004 we received approval from the Alberta Energy and Utilities Board to develop the Tucker in-situ oil sands project. Tucker is located 30 kilometres northwest of Cold Lake, Alberta. The Tucker project will utilize SAGD technology and will have a design rate capacity of 30 mbbls/day. Construction commenced in late 2004 and as of year-end 2005 drilling operations were 85 percent complete and facility construction was approximately 65 percent complete. The project remains on schedule and on budget and we expect to commission the facility in the third quarter of 2006 with first oil production before year-end 2006.

Sunrise

The Sunrise in-situ oil sands project is located in the Athabasca region of Alberta. Stratigraphic delineation drilling over the last four years has confirmed a large recoverable resource base with original bitumen-in-place under Husky lands estimated at 10.6 billion barrels. The commercial project application submitted to the Alberta Energy and Utilities Board (AEUB) and Alberta Environment envisioned development to 200 mbbls/day in 50 mbbls/day phases. The application was approved by the AEUB in December 7, 2005. Husky worked closely with local stakeholders including several First Nations and the local environmental coalition and obtained regulatory approval approximately 15 months after submission. During 2006 Husky will conduct front end engineering and design for the extraction aspects of the project and will develop optimal transportation and product marketing plans.

Caribou

Our Caribou oil sands lands are located in the Cold Lake Air Weapons Range and comprise 35,840 acres. Pilot testing was conducted in the early 1990s. Further stratigraphic drilling in 2005 yielded encouraging results, confirming that the Clearwater reservoirs being developed to the south by other operators extend onto Husky's Caribou lands. In 2006 Husky will drill 15 additional stratigraphic (resource assessment) wells and begin preparation of the development project application.

Saleski

Our largest bitumen deposit, with original bitumen-in-place estimated at 16.8 billion barrels is located approximately 120 kilometres west of Fort McMurray, Alberta. The bitumen is contained in the Grosmont carbonate formation. During 2005 Husky examined available geological data and the results of previous pilot projects. A 20 well program will be conducted in 2006 to provide additional geological data. Since there are no existing operations producing bitumen from the Grosmont carbonate, piloting of various technologies will be required over the coming years to identify commercial development approaches.

Oil Sands Leases

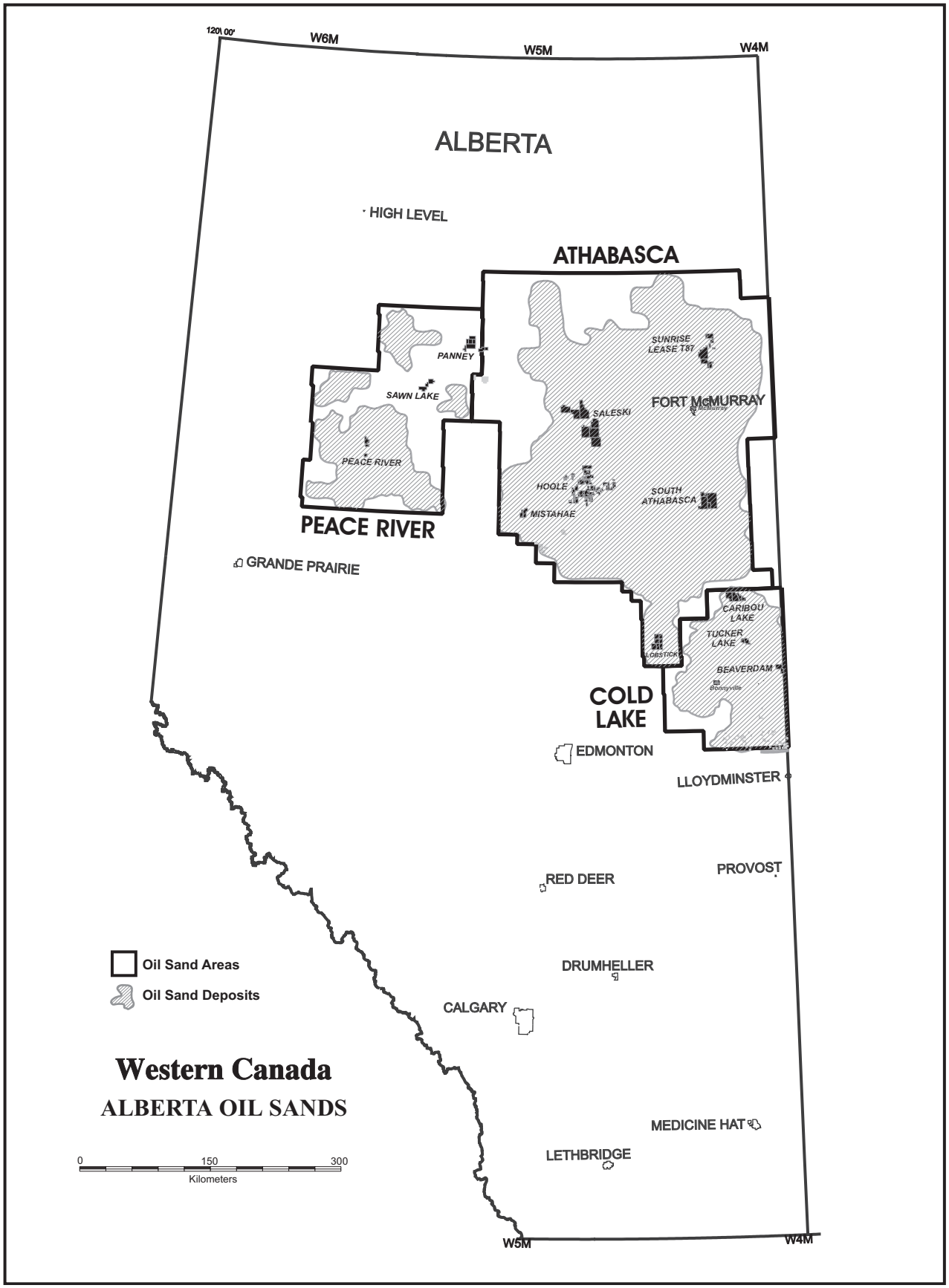
General Location Name	Oil Sands Area	Gross Acres	Net Acres	Husky Operator
South Athabasca — overriding royalty	Athabasca	35,601	—	No
South Athabasca	Athabasca	22,032	11,016	Yes
Sunrise — In situ[1]	Athabasca	57,634	57,634	Yes
Misthae (Drowned, Martin Hills W. & Spur)	Athabasca	28,160	28,160	Yes
Saleski	Athabasca	154,880	154,880	Yes
Hoole — overriding royalty	Athabasca	47,040	—	No
Beaverdam	Cold Lake	11,520	11,520	Yes
Caribou[2]	Cold Lake	35,840	35,840	Yes
Lobstick	Cold Lake	37,120	37,120	Yes
Tucker[3]	Cold Lake	10,080	10,080	Yes
Panny (Senex & Welstead)	Peace River	47,360	47,360	Yes
Peace River (Cadotte Lake)	Peace River	11,840	11,840	Yes
Sawn Lake (Loon)	Peace River	20,480	20,480	Yes
		519,587	425,930	

Notes:

(1) Not included in the gross and net amounts are an additional 6,400 acres of petroleum and natural gas rights held as protection acreage for gas over bitumen issues. In 2003, the Alberta regulatory authority issued General Bulletin GB 2003-28 that required natural gas wells within certain bitumen prone areas to be shut-in. The production of natural gas where natural gas reservoirs were believed to be in pressure contact with bitumen reserves was deemed to present an unacceptable risk to future in-situ bitumen production. Sunrise was formerly named Kearl.

(2) Husky also has the exclusive right to acquire an additional 65,280 acres in the Caribou area.

(3) Not included in the gross and net amounts are an additional 1,280 acres of petroleum and natural gas rights held as protection acreage for gas over bitumen issues.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ATHABASCA
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PEACE RIVER
SUNRISE LEASE 187
SALESKI
FORT McMURRAY
HOOLE
MISTAHAE
SOUTH ATHABASCA
GRANDE PRAIRIE
CARIBOU LAKE
TUCKER LAKE
LOBSTICK
BEAVERDAM
COLD LAKE
EDMONTON
LLOYDMINSTER
PROVOST
RED DEER
DRUMHELLER
CALGARY
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Oil Sand Deposits
Western Canada
ALBERTA OIL SANDS
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Offshore East Coast — Canada

Husky's offshore East Coast exploration and development program is focused in the Jeanne d'Arc Basin on the Grand Banks offshore the coast of Newfoundland, which contains the Hibernia, Terra Nova and White Rose oilfields. We hold ownership interests in the Terra Nova and White Rose oilfields as well as in a number of smaller undeveloped fields in the central part of the basin. We presently hold working interests ranging from 5.33 to 72.5 percent in 15 Significant Discovery License (''SDL'') areas in the Jeanne d'Arc Basin. We are also the operator of 10 exploration licenses (''EL'') on the Grand Banks and also hold an interest in one non-operated EL on-shore in the province of Nova Scotia. In 2005, we acquired 2 ELs. One of the licenses, EL 1096, totalling 5,263 acres is directly north of the Terra Nova oilfield and the other, EL 1094, totalling 33,321 acres is directly west of the Hebron significant discovery area. Husky holds 100 percent of the two licences and operates both. We believe that there is exploration potential in the area, and that our position off the East Coast of Canada will provide growth opportunities for light crude oil production in the medium to long-term.

We will continue technical evaluation of our East Coast exploration acreage. In 2006, we plan to acquire 3-D seismic over several license areas in the Northern Jeanne d'Arc Basin as well as south of the White Rose oilfield. Depending on drilling rig availability, we plan on drilling several delineation/exploration wells in 2006.

In January 2006, we relinquished two ELs following the drilling of the Lewis Hill G-85 exploration well, which was plugged and abandoned.

Terra Nova Oilfield

The Terra Nova oilfield is located approximately 350 kilometres southeast of St. John's, Newfoundland and Labrador, 35 kilometres southeast of the Hibernia oilfield, in 91 to 100 metres of water. The Terra Nova oilfield is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Our current pooled interest in the Terra Nova field is 12.51 percent. This interest is subject to change, pending re-determination once the field has been further delineated. Production at Terra Nova commenced in January 2002. Husky's gross share of production in 2005 from the Terra Nova field was 4.5 mmbbls based on an average of 12.4 mbbls/day annual production rate.

As at December 31, 2005, there were 12 development wells drilled in the Graben area, eight production wells and four injection wells. In the East Flank area there were 11 development wells including six production wells and five injection wells. Drilling operations are expected to continue in 2006 based on a 36 well depletion plan for the Graben and East Flank areas. An extended reach well was drilled from the East Flank subsea template to the Far East Central area in 2005 and production will commence during the first quarter of 2006. Husky continues to promote drilling additional delineation wells in the Far East area and a Far East South well location, PF8, will be included in the 2006 drilling program. As at December 31, 2005, we had booked 13.7 mmbbls of gross light crude oil in the proved developed category and 6.7 mmbbls of proved undeveloped. These reserves are estimated to be capable of being produced using primary and secondary (waterflood and gasflood) production techniques.

White Rose Oilfield

The White Rose oilfield, which we operate, is located 354 kilometres off the coast of Newfoundland approximately 48 kilometres east of the Hibernia oilfield on the eastern section of the Jeanne d'Arc Basin. Husky holds a 72.5 percent interest in the White Rose oilfield. At plateau production, the oilfield is estimated to produce approximately 100,000 barrels per day and Husky's share is expected to average 67,500 barrels per day on an annual basis. Husky's share of proven and probable reserves for the field is estimated at 173 million barrels including the currently undeveloped West Avalon pool.

In August 2005, the *SeaRose FPSO* (floating production, storage and offloading vessel) arrived at the White Rose oilfield, 350 kilometres east of St. John's, Newfoundland and Labrador, following a 48-hour journey from Marystown, Newfoundland and Labrador. The *SeaRose FPSO* had arrived in Marystown in April 2004, where topsides fabrication, installation and commissioning were carried out. The *SeaRose FPSO* departed Marystown on August 20, 2005. The vessel connected to a subsea production system and then underwent approximately three months of offshore hook-up and commissioning in preparation for first oil.

In November, 2005 first oil production was achieved marking the successful completion of the third offshore oil development for Newfoundland and Labrador. Oil was introduced into the process stream on the *SeaRose FPSO* on November 12, 2005. The White Rose field is expected to reach plateau production of 100,000 barrels per day in the first half of 2006. Husky has chartered two shuttle tankers, the *Heather Knutsen* and the *Jasmine Knutsen,* to transport

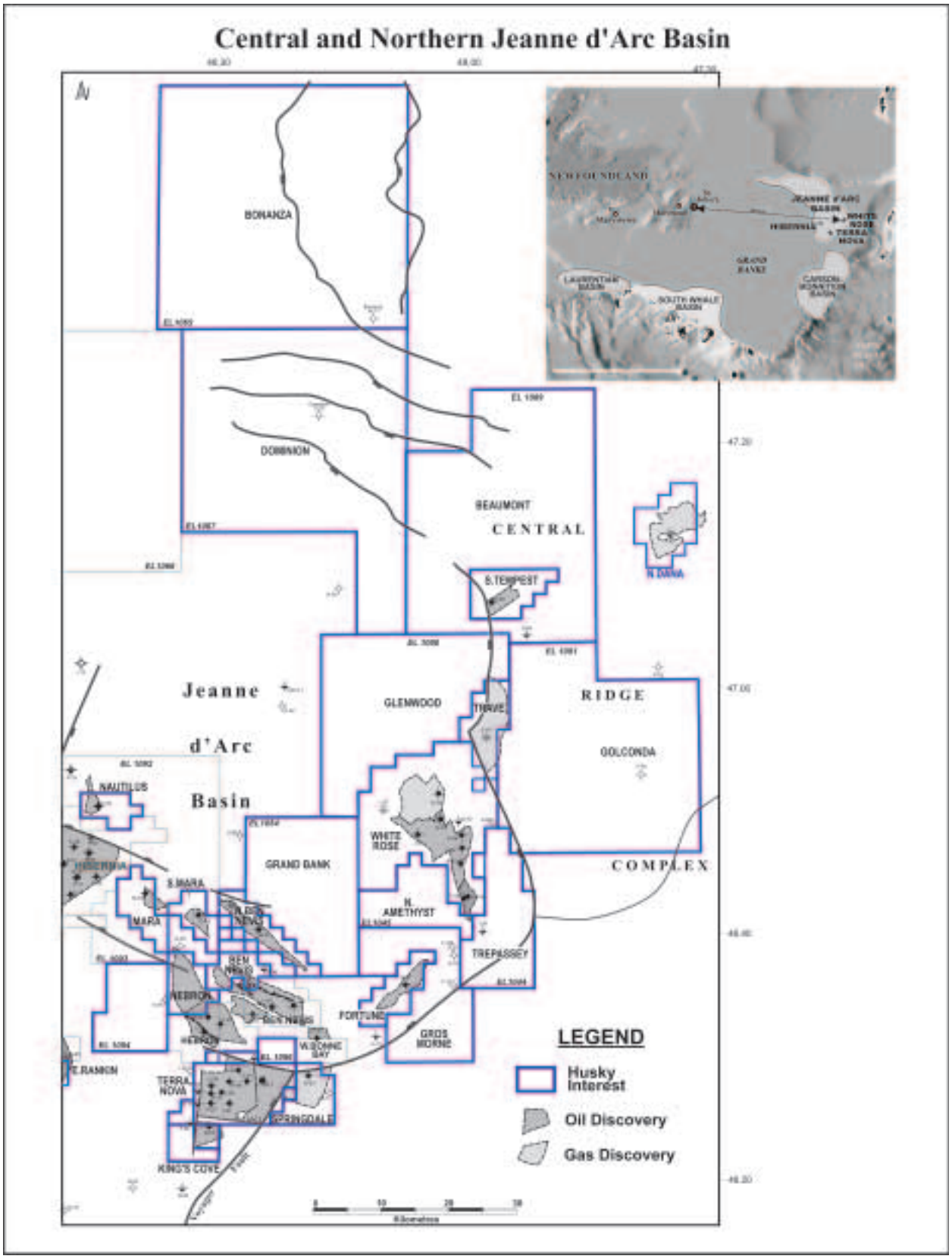
White Rose crude oil to market. The Samsung-designed double-hulled tankers each have a crude oil capacity of one million barrels. In December 2005, Husky offloaded three shipments of crude oil from the *SeaRose FPSO*. Approximately 2.4 million barrels of oil were produced from the White Rose field in 2005, with 1.74 million net to Husky.

Development drilling activity at the field is on schedule with 10 wells drilled as at the end of 2005, including three production wells, one gas injection well and six water injection wells. All well results were as predicted, or better. Initial production from the field supports an average oil production per well of 25,000 bbls/day.

In 2005, three pre-front end engineering and design studies relating to East Coast Natural Gas development were completed. The studies were undertaken by Husky to evaluate the viability of producing and transporting natural gas from White Rose. The studies commissioned focused on screening assessment of compressed natural gas (CNG) as one potential development option. During 2005 the scope was widened to consider and rank all technical options for development of the east coast natural gas resource. Husky also entered into a Memorandum of Understanding with other east coast operators to explore potential synergies and a regional solution.

Husky intends to progress technical screening to a shortlist of solutions complete with high level cost estimates. In parallel, delineation drilling will improve estimates of the reserve base ahead of future development. We will also continue to work closely with the Government of Newfoundland and Labrador as they work to develop a suitable fiscal regime during 2006.

East Coast


Central and Northern Jeanne d'Arc Basin
BONANZA
DOMINION
BEAUMONT
CENTRAL
S.TEMPEST
N.DANA
Jeanne
d'Arc
Basin
GLENWOOD
THAVE
RIDGE
GOLCONDA
NAUTILUS
WHITE ROSE
GRAND BANK
COMPLEX
S.MARA
MARA
N. AMETHYST
TREPASSEY
HEBRON
FORTUNE
GROS MORNE
TERRA NOVA
SPRINGDALE
KING'S COVE
LEGEND
Husky Interest
Oil Discovery
Gas Discovery

International

Our international exploration and development program is focused on Southeast Asia. In China, we have a 40 percent interest in one producing oilfield and interests in six exploration blocks. The bulk of these interests are in the South China Sea. In Indonesia, we have a 100 percent interest in the Madura block.

South China Sea

Wenchang

The Wenchang oilfield is located in the western Pearl River Mouth Basin, approximately 400 kilometres south of Hong Kong and 100 kilometres east of Hainan Island. We hold a 40 percent working interest in the oilfields, which commenced production in July 2002. The Wenchang 13-1 and 13-2 oilfields are producing from 24 wells in 100 metres of water into a FPSO (floating production, storage and offloading vessel) stationed between fixed platforms located in the fields. The blended crude oil from the two fields averages approximately 35 degree API, similar to the benchmark Minas blend. At December 31, 2005, our gross proved reserves at Wenchang were 17.3 mmbbls of crude oil and NGL. Our gross production averaged 16.0 mbbls/day during 2005. Two near field wildcat exploration wells were drilled in 2005 with no economic success.

Block 39/05

We executed a production sharing contract with China National Offshore Oil Corporation (''CNOOC'') for the 5,700 square kilometres 39-05 exploration block surrounding the Wenchang fields with a commencement date of October 1, 2001. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. In January 2003, the Qionghai 18-1-3 exploration type stratigraphic well on the block was plugged and abandoned without testing and in February 2003, the Wenchang 8-1-1 exploration type stratigraphic well was plugged and abandoned without testing. In 2004, we relinquished 25 percent of Block 39-05. Husky will relinquish an additional 25 percent of 39-05 in 2006. Husky is continuing to evaluate the geological information for the remainder of this block and expects to undertake additional exploration drilling in 2007.

Blocks 23/15 and 23/20

Husky executed production sharing contracts with CNOOC for the 23-15 and 23-20 exploration blocks with a commencement date of December 1, 2002. Both contract areas are located in the South China Sea north of Hainan, within 80 kilometres of the Weizhan oilfields. The 23-15 block is approximately 1,325 square kilometres and the 23-20 Block is 1,543 square kilometres. The work program requires Husky to drill a single exploration well on each block within three years. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. In 2003, we completed a 1,000 square kilometre 3-D seismic survey shot over a portion of block 23-15. Husky fulfilled its Phase I commitments on Block 23-15 with the drilling of Wushi 17-1-1 in 2005. Husky is currently evaluating the results of WS17-1-1 and expects to announce its intentions with respect to Phase II commitments in 2006. Husky fulfilled its Phase I commitments on Block 23-20 with drilling of Wushi 32-1-1 in 2005. Husky is currently evaluating the results of WS32-1-1 and its intentions with respect to Phase II commitments in 2006.

Block 29/26

Husky executed a production sharing contract with CNOOC for the 29-26 exploration block with a commencement date of October 1, 2004. The block is located in the South China Sea approximately 300 kilometres southeast of Hong Kong and 65 kilometres southeast of the Panyu gas discovery. The block covers an area of approximately 3,965 square kilometres. The production sharing contract requires the drilling of one exploration well within three years and has a minimum work commitment of U.S.$8 million. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. Husky has contracted a deep-water drill ship and plans to spud the first exploratory well in the first quarter of 2006.

Block 40/30

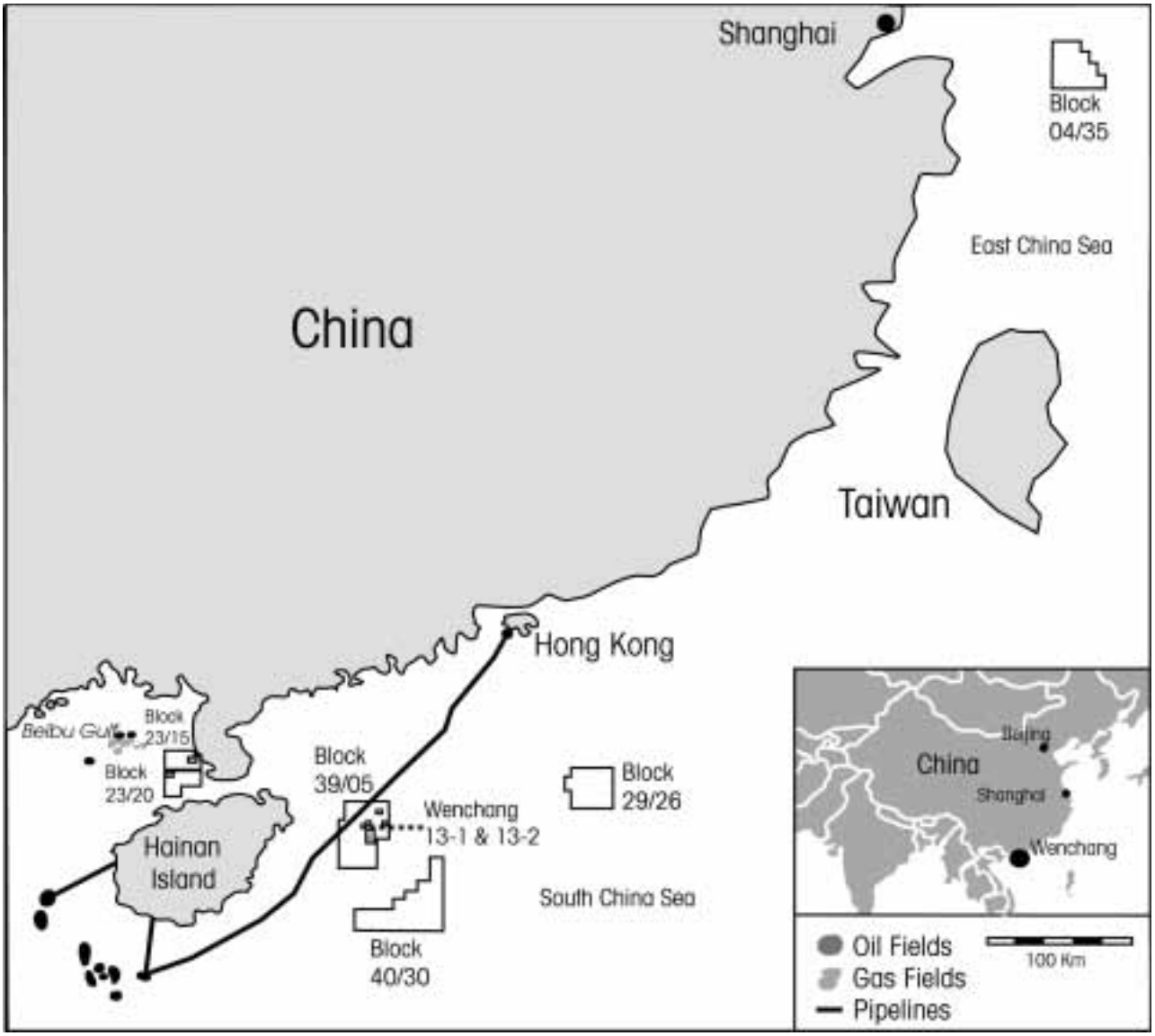
We executed a production sharing contract with CNOOC for the 40-30 exploration block with a commencement date of February 1, 2003. The block is located in the South China Sea approximately 100 kilometres south of the Wenchang 13-1 and 13-2 oilfields. The block covers an area of approximately 6,705 square kilometres. The production sharing contract requires the drilling of one exploration well within three years and has a minimum work commitment of U.S.$10 million. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. We fulfilled our Phase I obligations of the petroleum contract with the drilling of ChangChang (''CC'') 12-1-1. The CC 12-1-1 is the deepest-water well in the South China Sea to date. The CC12-1-1 well was plugged and abandoned without testing.

East China Sea

Block 04/35

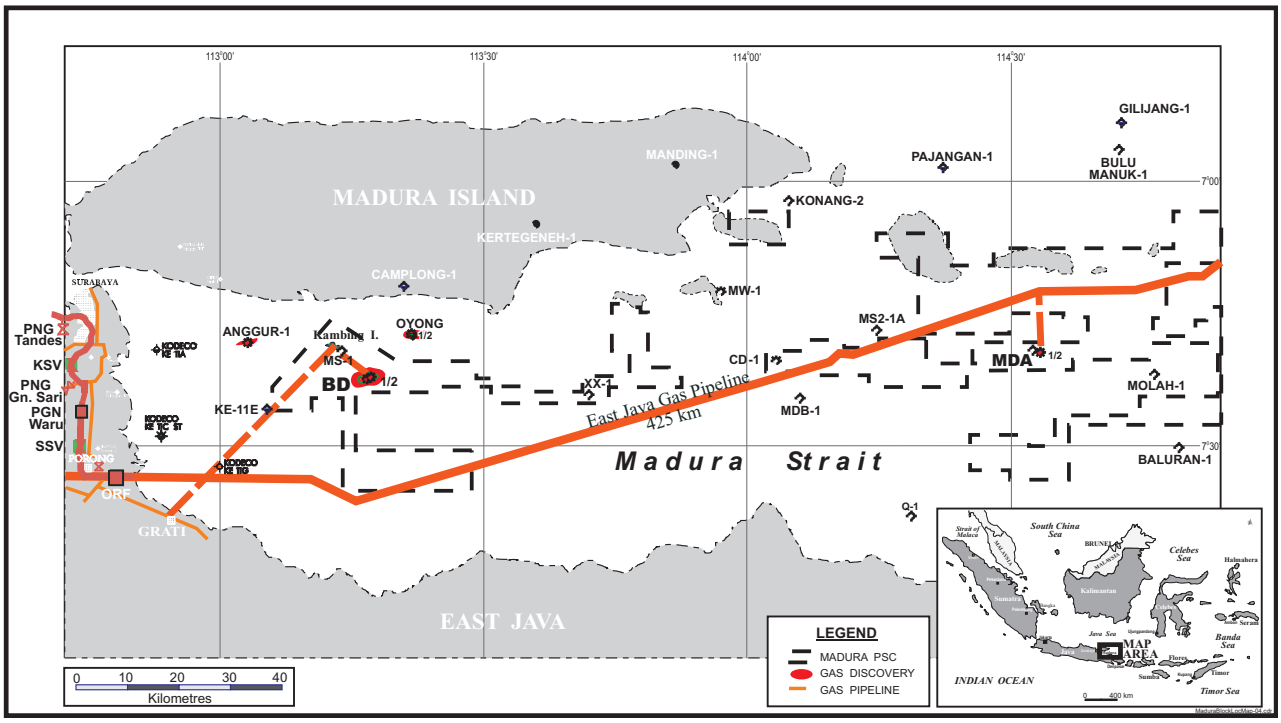
We executed a production sharing contract with CNOOC for the 04-35 exploration block with a commencement date of December 1, 2003. The block is located in the East China Sea approximately 350 kilometres east of the city of Shanghai and covers an area of approximately 4,835 square kilometres. The production sharing contract requires the drilling of a single exploration well in the first exploration phase to a depth of 2,500 metres within three years and a minimum work commitment of U.S.$3 million. Technical evaluations of the hydrocarbon potential are complete and we expect to fulfill our first phase commitments early in 2006. CNOOC has the right to participate in development of any discoveries up to a 51 percent working interest. Husky has completed its preliminary geological evaluation and expects to begin exploration drilling in 2006.

China



Madura Strait, Indonesia

We have a 100 percent interest in the approximately 2,795 square kilometre Madura Strait production sharing contract (''PSC''), offshore East Java, Indonesia. There have been two natural gas fields discovered on the block. The larger of these is the Madura BD field, which has been granted commercial status and had a plan of development approved by the Indonesian state oil company in 1997. The field was to supply natural gas to a new proposed independent power plant, however construction of the power plant did not proceed due to economic issues that occurred in Indonesia. Husky has begun discussions to establish a new natural gas sales contract for Madura production and in addition, the development engineering re-validation work commenced in 2005 for the production facilities. In 2006, we expect to complete negotiation of the gas sales contract, submit a revised Plan of Development to the Indonesian regulatory authority for approval and negotiate an extension to the PSC term. Production is expected to come on stream approximately three years after these agreements are negotiated.



Shatirah, Libya

Husky has a non-operated interest in a small crude oil production operation in the Shatirah field, onshore Libya.

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. The combined dry crude feedstock requirements of the upgrader and asphalt refinery are equal to approximately 75 percent of Husky's heavy crude oil production from the Lloydminster area. 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. Natural gas liquids are sold to local petrochemical end users, retail and wholesale distributors and to 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:

	Years ended December 31,		
	2005	2004	2003
	(mmcf/day)		
Sales to end users			
United States	357	407	382
Canada	212	187	156
	569	594	538
Sales to aggregators	31	34	43
Internal use[1]	80	61	30
	680	689	611

Note:

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

We also market third party natural gas production in addition to our own production.

Delivery Commitments

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

	Fixed Price		Market Price
	Bcf	$/mmbtu	Bcf
2006	25.9	3.98	19.7
2007	20.4	4.51	19.7
2008	20.4	4.75	11.8
2009	20.4	5.00	0.9
2010	20.4	5.28	0.5
2011	20.4	5.57	—
2012	20.0	5.47	—
2013	20.0	3.67	—
2014	6.2	3.67	—

Midstream Operations

Overview

The midstream operations include:

- Upgrading — the upgrading of heavy crude oil into synthetic light crude oil;
- 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.

Upgrading Operations

Husky owns and operates the Husky Lloydminster Upgrader (''Upgrader''), which is 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 feedstock for the refining of premium transportation fuels in Canada and the

United States. In addition, the Upgrader recovers the diluent, which facilitates pipeline transportation of heavy crude oil, and returns it to the field to be reused.

The Upgrader provides heavy crude oil access to a new market, which we believe has facilitated, and will continue to stimulate heavy oil production in the area. The market for heavy crude oil previously was either as feedstock for asphalt production or it was sold as blended heavy crude oil for feedstock for specific refineries designed to process or upgrade heavier crude oils. The Upgrader was commissioned in 1992 with an original design capacity of 46 mbbls/day of synthetic crude oil. Actual production has ranged considerably higher than the original design rate capacity as a result of throughput modifications and improved reliability. The Upgrader's current rated capacity exceeds 67 mbbls/day of synthetic crude oil. Production at the Upgrader averaged 56.7 mbbls/calendar day of synthetic crude oil and 9.9 mbbls/day of diluent in 2005 compared with 55.2 mbbls/day of synthetic crude oil and 9.4 mbbls/day of diluent in 2004. Throughput at the Upgrader in 2005 was higher than 2004 due to improved plant reliability. In addition to synthetic crude oil and diluent, the Upgrader also produced, as by-products of its upgrading operations, approximately 312 lt/day of sulphur and 755 lt/day of petroleum coke during 2005. These products are sold in local and international markets. By the end of 2006 it is anticipated that the Upgrader will also be producing 2,500/bbls per day of low sulphur diesel. The profitability of our upgrading operations is primarily dependent upon the differential between the price of synthetic crude oil and the price of heavy crude oil. The Upgrader shipped its 250 millionth barrel of Husky Synthetic Blend in May 2005.

The Upgrader is currently undergoing a number of debottleneck projects. These projects, upon completion in late 2006, are expected to increase upgrading capacity to 82 mbbls/day of synthetic crude oil and diluent.

Infrastructure

Heavy Oil Pipeline Systems and Processing Facilities

Husky has been involved in the gathering, transporting and storage of heavy crude oil in the Lloydminster area since the early 1960s. Our crude oil pipeline systems include approximately 2,050 kilometres of pipeline and are capable of transporting in excess of 575 mbbls/day of blended heavy crude oil, diluent and synthetic crude oil. The pipeline systems transport blended heavy crude oil to Lloydminster, accessing markets through the Upgrader and our asphalt refinery in Lloydminster. Blended heavy crude oil from the field and synthetic crude oil from the upgrading operations are moved south to Hardisty, Alberta to a connection of the Enbridge Pipeline system and the Express Pipeline system. The crude oil is transported to eastern and southern markets on these pipelines. Our crude oil pipeline systems also have feeder pipeline interconnections with the Cold Lake Partnership Pipeline, the Enbridge Athabasca Pipeline and the Talisman Chauvin Pipeline.

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

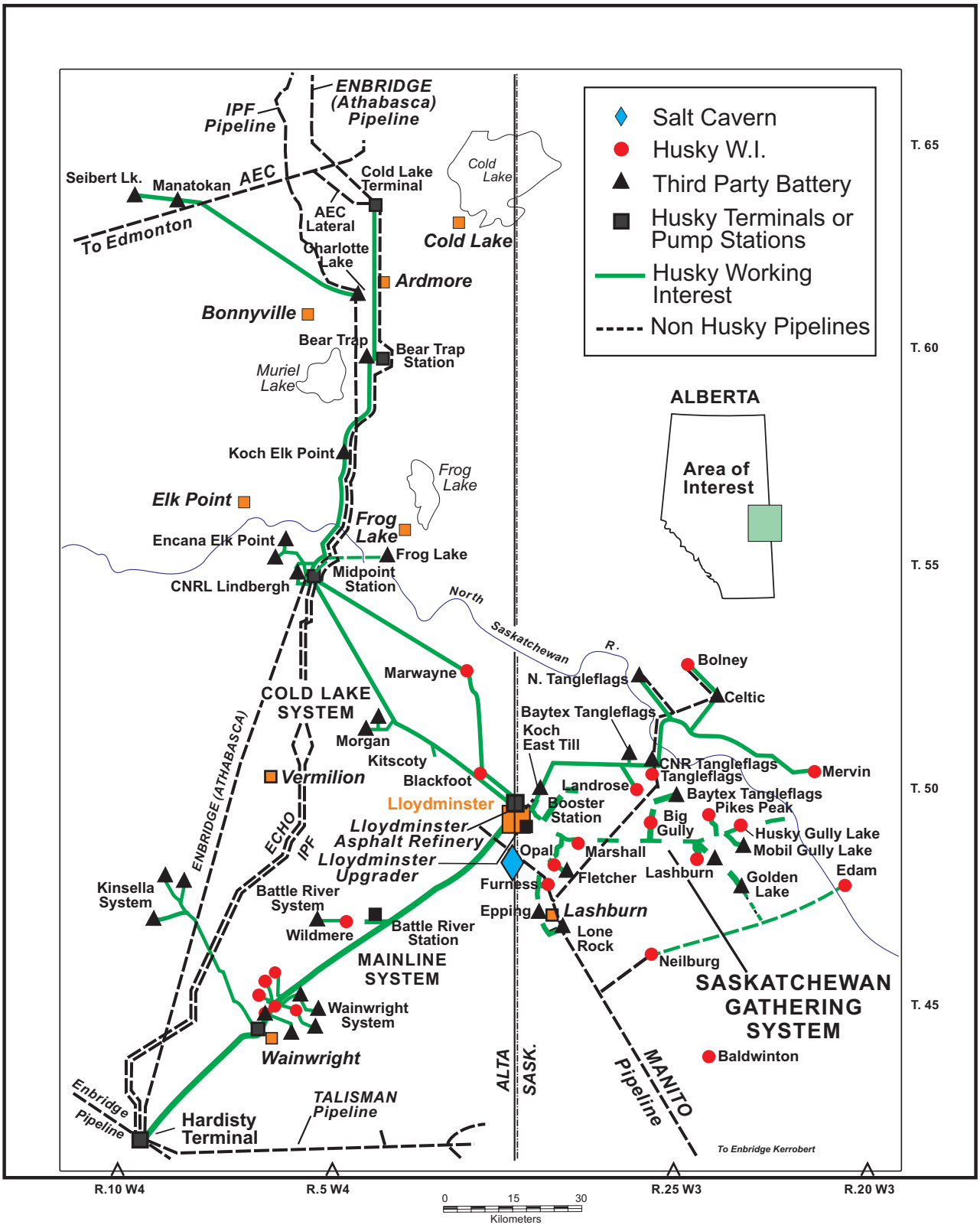
	Years ended December 31,		
	2005	2004	2003
		(mbbls/day)	
Combined pipeline throughput	474	492	484

In recent years Husky has expanded and expects to further expand its heavy crude pipeline systems to capitalize on anticipated increases in heavy oil production from the Lloydminster and Cold Lake areas.

We consider the expansion and optimization of our pipeline systems in the Lloydminster area to be necessary to further our own development objectives in the area. As a result of recent expansion of mainline pipeline systems in the area, competition for throughput volumes has increased.

We operate 16 heavy crude oil processing facilities located throughout the Lloydminster area. These facilities process Husky's and other producers' raw heavy crude oil from the field by removing sand, water and other impurities to produce clean dry heavy crude oil. The heavy crude oil is then blended with a diluent to meet pipeline specifications for transportation.

Heavy Oil Pipeline Systems



Cogeneration

Husky has a 50 percent interest in a 215 MW natural gas fired cogeneration facility at the site of the Upgrader. The plant was commissioned in December 1999. Electricity produced at the facility is being sold to Saskatchewan Power Corporation under a 25 year power purchase agreement effective in 1999. Thermal energy (steam) is sold to the Upgrader.

Husky has a 50 percent interest in a 90 MW natural gas fired cogeneration facility adjacent to Husky's Rainbow Lake processing plant. The cogeneration plant produces electricity for the Alberta Power Pool and thermal energy (steam) for the Rainbow Lake processing plant. It provides power directly to the Alberta Power Pool under an agreement with the Alberta Transmission Administrator 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. Husky is the operator of the facility.

Natural Gas Storage Facilities

Husky has been operating a natural gas storage facility at Hussar, Alberta since April 2000. The facility has a working storage capacity of 17 bcf of natural gas. Husky 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. We also market petroleum coke, a by-product from the Lloydminster Upgrader. We supply feedstock to our Upgrader and asphalt refinery from our own and third party heavy oil production sourced from the Lloydminster and Cold Lake areas. We also sell blended heavy crude oil directly to refiners based in the United States and Canada. Our extensive infrastructure in the Lloydminster area supports its heavy crude oil refining and marketing operations.

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

We market natural gas sourced from our own production and third party production. We are currently committed to gas sales contracts with third parties, which in aggregate do not exceed amounts forecast to be deliverable from our reserves. Our contracts are with customers located in eastern Canada/northeastern United States (28 percent), mid-west United States (23 percent), Western Canada (46 percent) and west coast United States (3 percent). The natural gas volumes sales contracted are primarily at market prices (90 percent). The terms of the contracts remaining at December 31, 2004 are up to one year (74 percent), one year to five years (18 percent) and over five years (8 percent). Husky has acquired rights to firm pipeline capacity to transport the natural gas to most of these markets.

We have developed our commodity marketing operations to include the acquisition of third party volumes in order to increase volumes and enhance the value of our midstream assets. We plan to expand our marketing operations by continuing to increase marketing activities. We believe that this increase will generate synergies with the marketing of our own production volumes and the optimization of our assets.

Refined Products

Overview

Husky's refined products operations include refining of light crude oil, manufacturing of fuel and industrial grade ethanol, manufacturing of asphalt products from heavy crude oil and retail, commercial and wholesale marketing of refined petroleum products. Our retail network provides a platform for substantial non-fuel related businesses.

Light oil refined products are produced at our 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 and are marketed directly or through Husky's eight emulsion plants, four of which are also asphalt terminals located throughout Western Canada.

Branded Petroleum Product Outlets and Commercial Distribution

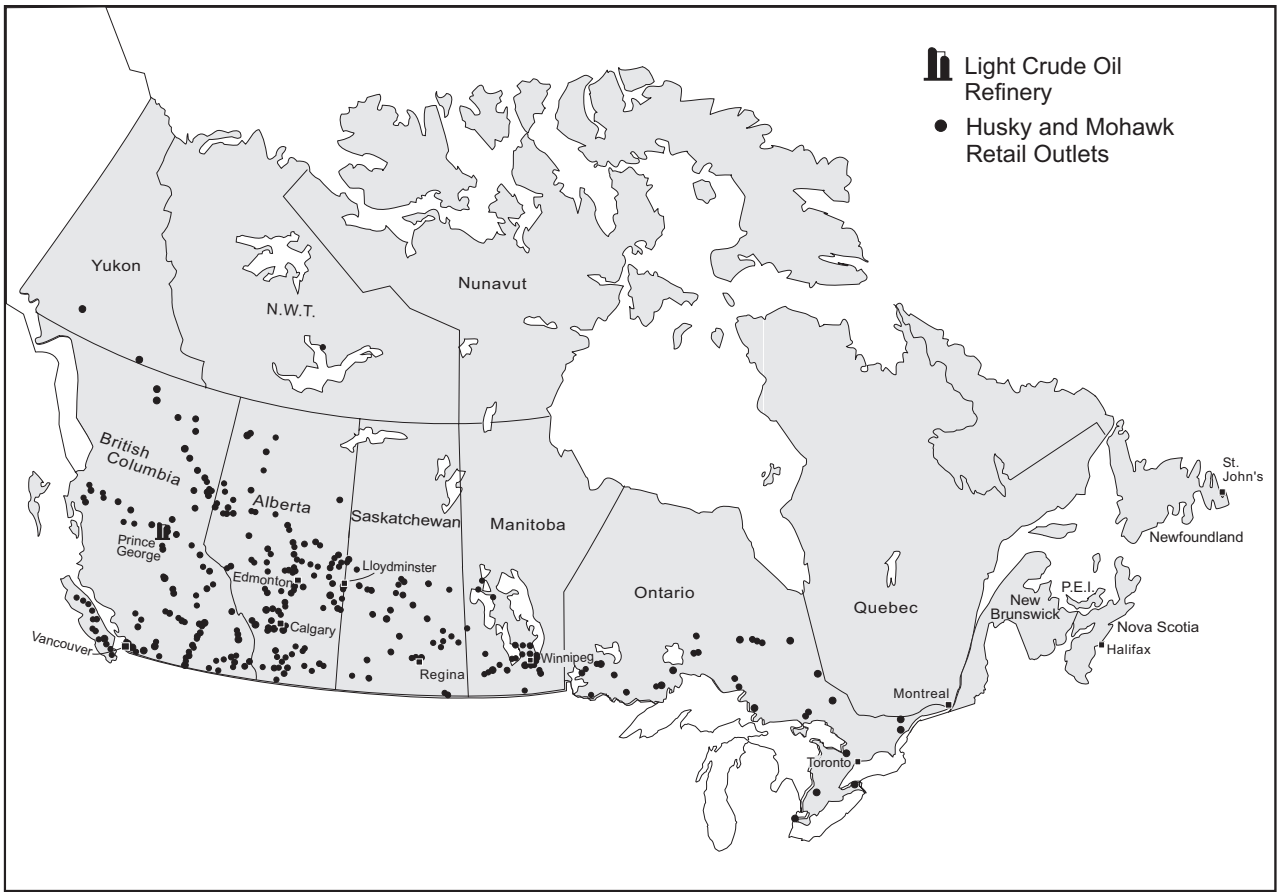
Distribution

As of December 31, 2005, there were 515 independently operated Husky and Mohawk branded petroleum product outlets. These petroleum product outlets include service stations, travel centres 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 24 hours per day, 365 days a year 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 will electronically process transactions and provide detailed billing, sales tax and other information. A variety of full and self serve retail locations under the Mohawk and Husky brand names serve urban and rural markets, while Husky and Mohawk bulk distributors offer direct sales to commercial and farm markets in Western Canada.

Retail Marketing System

Branded Petroleum Product Outlets

Branded Petroleum Outlets



Independent retailers or agents operate all Husky and Mohawk branded petroleum product outlets. Branded outlets feature varying services such as 24 hour service, convenience stores, service bays, car washes, Husky House full service family style restaurants, proprietary and co-branded quick serve restaurants, bank machines and alternate fuels such as propane and compressed natural gas. In addition to conventional gasolines, ethanol blended fuels branded as ''Mother Nature's Fuel'' and additive enhanced ''Diesel Max'' are offered in all markets 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 the Husky Snowstars Program, various national and university athletic sponsorships 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 class of trade and by province as of December 31, 2005:

Retail Outlets	British Columbia & Yukon	Alberta	Sask.	Manitoba	Ontario	Total	2004 Total
Travel Centres	9	8	4	2	13	36	36
Full Serve	10	15	2	2	2	31	37
Full/Self Serve	16	25	6	11	3	61	59
Self Serve	18	12	1	1	1	33	34
Bulk Distributor	1	7	4	1	1	14	14
Card/Key Locks	2	7	0	0	1	10	10
	56	74	17	17	21	185	190
Leased							
Travel Centres	1	0	0	0	0	1	1
Full Serve	3	8	5	4	0	20	24
Full/Self Serve	14	22	4	6	0	46	46
Self Serve	31	22	0	1	0	54	52
Bulk Distributor	3	0	0	0	0	3	3
Card/Key Locks	3	2	0	3	2	10	9
	55	54	9	14	2	134	135
Independent Retailers							
Travel Centres	1	1	0	0	4	6	6
Full Serve	22	15	8	14	7	66	77
Full/Self Serve	17	5	5	1	1	29	28
Self Serve	29	45	4	3	2	83	85
Bulk Distributor	2	4	1	0	0	7	7
Card/Key Locks	1	1	0	0	3	5	3
	72	71	18	18	17	196	206
Total							
Travel Centres	11	9	4	2	17	43	43
Full Serve	35	38	15	20	9	117	138
Full/Self Serve	47	52	15	18	4	136	133
Self Serve	78	79	5	5	3	170	171
Bulk Distributor	6	11	5	1	1	24	24
Card/Key Locks	6	10	0	3	6	25	22
	183	199	44	49	40	515	531
Cardlocks[1]	24	18	4	6	21	73	74
Convenience Stores[1]	178	183	39	46	33	479	484
Restaurants	11	12	4	2	16	45	45

Note:

(1) All of these are located at branded petroleum outlets.

We also market 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 our average daily sales volumes of light refined petroleum products for the periods indicated:

	Years ended December 31,		
	2005	2004	2003
	(mbbls/day)		
Gasoline	28.3	28.3	28.5
Diesel fuel	26.5	23.9	22.1
Liquefied petroleum gas	0.9	1.1	1.2
	55.7	53.3	51.8

Our strategy in respect of our petroleum product outlets includes continuing to increase profits and sales through the strategic location of new outlets, the enhancement of ancillary non-fuel income streams, the modernization, automation and upgrading of existing petroleum product outlets, expanding customer loyalty programs and the sale of non-core locations. We also plan to continue to enter into strategic alliances with third parties to sell various consumer products at Husky and Mohawk branded petroleum outlets in order to generate revenue and increase demand for other products and services provided at those outlets. We are pursuing acquisitions and joint venture opportunities to further enhance our existing distribution network.

Supply

Prince George Refinery

In 2005 Husky completed the upgrade at its Prince George Refinery to produce low sulphur gasoline fuels that meet the Government of Canada's new fuel specification. The cost of the upgrade is expected to be $92 million and with this upgrade refinery nameplate productive capacity was increased 20 percent to 12,000 bbls/day. Upgrades to produce ultra low sulphur diesel will continue into 2006. The Prince George refinery production makes up 22 percent of the Refined Products — Light Oil's fuel supply as it is the lowest cost supply source. The refinery produces all grades of unleaded gasoline, seasonal diesel fuels, a mixed propane and butane stream, and heavy oil products.

Lloydminster Asphalt Refinery

Our Lloydminster refinery processes heavy crude into asphalt products used in road construction and maintenance, manufactured building products, locomotive blendstock and specialty oilfield products. The refinery has a total nameplate throughput capacity of 25,000 barrels per day of heavy crude oil. It also produces a distillate stream used by the Upgrader, and a condensate stream used to blend with heavy oil production.

Ethanol Manufacturing

Husky currently produces 10 million litres per year of fuel and industrial ethanol at our plant in Minnedosa, Manitoba. A second ethanol facility in Lloydminster, Saskatchewan is currently under construction, at a cost of approximately $130 million. This plant, which is scheduled to be operational in the second quarter 2006, will have an annual capacity of 130 million litres, making it the largest ethanol plant in Western Canada. Minnedosa will be further expanded in 2007 to reach a production level of 130 million litres per year.

Husky's ethanol production supports our ''Mother Nature's Fuel'' ethanol-blended gasoline marketing program. When added to gasoline, ethanol improves fuel combustion, raises octane levels and prevents fuel line freezing, and carbon monoxide emissions, ozone precursors and net emissions of greenhouse gases. Environment Canada has designated ethanol-blended gasoline as an Environmental Choice product.

Husky's Refined Products group continues to position themselves as the leaders in ethanol-blended fuels in Western Canada.

Other Supply Arrangements

In addition to the refined petroleum products supplied by the Prince George refinery, Husky has established processing arrangements with major refiners. Processing arrangements allow us to participate in industry refining margins. Primarily Husky crude oil production and some third party purchased crude oil is delivered to major refiners, who process the crude oil into refined products, which are then marketed by us through our retail networks and to our wholesale customers. During 2005, these refiners processed an average of approximately 38.2 mbbls/day of crude oil

for us, yielding approximately 34.7 mbbls/day of refined petroleum products. During 2005, we also purchased approximately 11.2 mbbls/day of refined petroleum products from refiners and acquired approximately 6.2 mbbls/day of refined petroleum products pursuant to exchange agreements with third party refiners.

Asphalt Products

Husky produces asphalt and residual products at our 10,000 bbls/day asphalt refinery at Lloydminster and markets these products to customers across Western Canada and the northwestern and midwestern United States.

Husky has 37 percent of the market for paving asphalt sold in Western Canada our Pounder Emulsions division has a 50 percent market share in Western Canada for road application emulsion products and additional non-asphalt based road maintenance products are marketed and distributed through the Western Road Management division. We have increased sales to the United States and Eastern Canada, with 40 percent of production in 2005 exported to the United States and products shipped as far as Texas, Florida and New Brunswick. Husky plans to expand asphalt production, improve distribution, improve quality and reduce cost.

Husky also sells in excess of 5 mmbbls of asphalt cements per year. In addition, we produce and sell straight run distillates, and residuals. The distillates are a hydrogen deficient and are sold directly to the Upgrader and blended into the Husky Synthetic Blend stream. The cut is removed and re-circulated into the heavy oil pipeline network as pipeline diluent. Residuals are a blend of medium and light gas oil streams which we sell directly to customers.

Husky's asphalt distribution network consists of four emulsion/asphalt terminals located at Kamloops, British Columbia; Lethbridge, Alberta; Yorkton, Saskatchewan; and Winnipeg, Manitoba and four emulsion plants located at Edmonton, Alberta; Watson Lake, Yukon; Lloydminster and Saskatoon, Saskatchewan. Husky also utilizes an independently operated terminal at Langley, British Columbia.

All of our asphalt requirements are supplied by our Lloydminster, Alberta asphalt refinery. The refinery was designed specifically to produce asphalt from heavy crude oil at a rate of 25 mbbls/day. Debottlenecking has allowed us to increase that to 26.9 mbbls/day. The crude oil feedstock for the Lloydminster refinery is supplied through Husky's pipeline systems from the supply of heavy crude oil in the region, including Husky's heavy crude oil.

The following table shows our average daily sales volumes of products produced at the Lloydminster refinery, for the years indicated:

	Years ended December 31,		
	2005	2004	2003
	(mbbls/day)		
Asphalt	13.8	14.0	12.9
Residual and other	8.7	8.8	9.1
	22.5	22.8	22.0

Refinery throughput averaged 25.5 mbbls/day of blended heavy crude oil feedstock during 2005. Total production of asphalt at the refinery for 2005 was down due to a planned maintenance and repair turnaround in July as well as other repairs that limited production.

Due to the seasonal demand for asphalt products the refinery historically has operated at full capacity only during the normal paving season in Canada and the northern United States. We have implemented various plans to increase refinery throughput during the other months of the year, such as producing low sulphur diesel, entering into custom processing arrangements and developing other U.S. and international markets for asphalt products. This has allowed us to run at or near full capacity year round.

Our strategy with respect to our asphalt marketing business is to increase sales volumes by increasing asphalt supply and developing new product streams, to enhance margins by soliciting industry for Husky ideal specifications, to minimize costs and expand our income base through new products and new markets and to pursue mergers, acquisitions, brokering and processing opportunities within our niche markets.

Some of the focus areas in 2006 will include identifying acquisition, merger, brokering, terminalling, and processing opportunities, increasing residual sales relative to diluents and tops to enhance margins, focusing on sales of higher quality products with larger margins, developing new sales tools and programs to improve customer service and satisfaction and developing new products and improving existing products.

Human Resources

The number of employees in each business segment was as follows:

	December 31,	
	2005	2004
Upstream	2,019	1,822
Midstream	367	347
Refined Products	385	358
Corporate and business support	518	505
	3,289	3,032

DIVIDENDS

The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31:

	2005	2004	2003
Cash dividends declared per common share	$1.65	$1.00	$1.38

Dividend Policy and Restrictions

The Board of Directors of Husky have established a dividend policy that pays quarterly dividends. From August 2000 to July 2003, Husky paid a quarterly dividend of $0.09 ($0.36 annually) per common share. From August 2003 to July 2004, Husky paid $0.10 ($0.40 annually) per common share. The dividend policy was reviewed by the Board in April 2004 and the quarterly dividend was increased to $0.12 ($0.48 annually) per common share. The dividend policy was again reviewed in April 2005 and increased to $0.14 ($0.56 annually) and again in October 2005 when it was increased to $0.25 ($1.00 annually). The Board declared special cash dividends in the amount of $1.00 per common share in July, 2003 and $0.54 per common share in November, 2004. In October 2005 the Board declared a special dividend amounting to $1.00 per common share. Husky's dividend policy will continue to be reviewed and there can be no assurance that further dividends will be declared.

The declaration and payment of dividends will be at the discretion of the Board, 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.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

Husky is authorized to issue an unlimited number of common shares. Holders of common shares are entitled to one vote per share at meetings of shareholders of Husky, to receive such dividends as declared by the Board of Directors on the common shares and to receive pro-rata the remaining property and assets of Husky upon its dissolution or winding up, subject to any rights having priority over the common shares.

Preferred Shares

Husky is authorized to issue an unlimited number of preferred shares. Holders of preferred shares shall not be entitled to vote at meetings of Husky, are entitled to receive such dividends as and when declared by the Board of Directors in priority to common shares and shall be entitled to receive pro-rata in priority to holders of common shares the remaining property and assets of Husky upon its dissolution or winding up. There are no preferred shares currently outstanding.

Credit Ratings Summary

	Rating	Last Review	Last Rating Change
Moody's:			
Outlook	Stable	August 29, 2005	—
Senior Unsecured Debt	Baa2	August 29, 2005	April 25, 2001
U.S. Senior Secured Bonds	Baa2	April 30, 2004	April 25, 2001
Capital Securities	Ba1	August 29, 2005	April 25, 2001
Standard and Poor's:			
Outlook	Positive	September 12, 2005	October 3, 2002
Senior Unsecured Debt	BBB	September 12, 2005	—
U.S. Senior Secured Bonds	BBB	August 24, 2005	—
Capital Securities	BB+	September 12, 2005	—
Dominion Bond Rating Service:			
Trend	Stable	May 13, 2005	—
Senior Unsecured Debt	BBB(high)	May 13, 2005	—
Capital Securities	BBB	May 13, 2005	
Fitch:			
Outlook	Stable	July 22, 2005	—
Senior Unsecured Debt	BBB+	July 22, 2005	—
U.S. Senior Secured Bonds	A–	July 22, 2005	
Capital Securities	BBB–	July 22, 2005	—

Credit ratings are intended to provide investors with an independent measure of credit quality of any issue 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 appears 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 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.

Dominion Bond Rating Service

Dominion Bond Rating Service's credit rating system ranges from AAA (highest) to D (lowest). Debt securities rated within the BBB category are considered to be of adequate 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.

Fitch

Fitch's credit rating system ranges from AAA (highest) to D (lowest). Debt securities rated within the BBB category indicate that there is currently a low expectation of credit risk. The capacity for timely payment of financial commitments is considered adequate, but adverse changes in circumstances or in economic conditions are more likely to impair this capacity. The addition of the modifier + or – indicates the debt is positioned above (+) or below (–) the mid range of the general category. The A category denotes that the debtor's capacity with regard to the rated debt is strong rather than adequate.

MARKET FOR SECURITIES

Husky's common shares are listed and posted for trading on the Toronto Stock Exchange under the trading symbol ''HSE''.

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, 2005:

	High	Low	Volume (000's)
January	34.90	32.50	11,845
February	37.65	32.30	20,225
March	40.49	35.89	14,300
April	38.84	35.12	16,441
May	42.30	36.65	12,283
June	50.75	42.00	18,264
July	53.35	47.37	11,386
August	62.00	53.50	11,413
September	69.95	59.00	11,722
October	65.79	50.50	15,936
November	59.95	53.63	11,028
December	61.60	55.58	11,767

DIRECTORS AND OFFICERS

The following are the names and municipalities of residence of the directors and officers of Husky, their positions and offices with Husky and their principal occupations during the past five years. The directors shall hold office until the next annual meeting of Husky shareholders or until their respective successors have been duly elected or appointed.

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
Li, Victor T.K. Hong Kong	Co-Chairman and Director	August 25, 2000	Managing Director of Cheung Kong (Holdings) Limited (an investment holding and project management company) since 1999 and Deputy Chairman since 1994. Mr. Li has also been Deputy Chairman of Hutchison Whampoa Limited (an investment holding company) since 1999 and Executive Director since 1995. Mr. Li has been a Director and Chairman of CK Life Sciences Int'l., (Holdings) Inc. (a biotechnology company) since 2002 and has held the following positions for more than five years: a Director and Chairman of Cheung Kong Infrastructure Holdings Limited (an infrastructure development company), an Executive Director of Hongkong Electric Holdings Limited (a holding company). Mr. Li is also a Director of The Hongkong and Shanghai Banking Corporation Limited. Mr. Li is a member of the Standing Committee of the 10th 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 Executive Committee of the Commission on Strategic Development and the Economic and Employment Council of the Hong Kong Special Administrative Region. Mr. Li holds a Bachelor of Science degree in Civil Engineering and a Master of Science degree in Structural Engineering.
Fok, Canning K.N. Hong Kong	Co-Chairman and Director	August 25, 2000	Group Managing Director of Hutchison Whampoa Limited since 1993 and Executive Director since 1984. Mr. Fok has been a Director and Chairman of Hutchison Telecommunications International Limited (an investment holding company) since 2004. Mr. Fok has held the following positions for more than five years: a Director and since 2002, Chairman of Hutchison Harbour Ring Limited (an investment holding company), a Director and Chairman of Hutchison Telecommunications (Australia) Limited (a telecommunications company), and Partner Communications Company Ltd. (a telecommunications company), Deputy

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
			Chairman and a Director of Cheung Kong Infrastructure Holdings Limited and a Director, and since November 2005 Chairman of Hongkong Electric Holdings Limited. Mr. Fok is also a director of Cheung Kong (Holdings) Limited and Hutchison Whampoa Finance (CI) Limited (a finance company). Mr. Fok is also a Non Executive Director of Panvas Gas Holdings Limited. Mr. Fok was a director of Voice Stream Wireless Corporation from 1998 - 2001 and Hanny Holdings Limited from 1992 - 2005. Mr. Fok holds a Bachelor of Arts degree and is a member of the Australian Institute of Chartered Accountants.
Fullerton, R. Donald Toronto, Ontario Canada	Director	May 1, 2003	Corporate Director. Mr. Fullerton has been a Director of Asia Satellite Telecommunications Holdings Limited since 1996. Mr. Fullerton was a director of George Weston Limited (a holding company) from 1991 to 2005, of Partner Communications Ltd. from 2003 to 2005, of CIBC from 1974 to 2004, of Hollinger Inc. from 1992 to 2003, of Westcoast Energy Inc. from 1993 to 2003 and of IBM Canada Ltd. from 1982 to 2001.
Glynn, Martin J.G. New York, New York U.S.A.	Director	August 25, 2000	President and Chief Executive Officer of HSBC Bank USA N.A. since 2003 and a director since 2000. Mr. Glynn has been a director of HSBC Bank Canada since 1999 and was President and Chief Executive Officer from 1999 to 2003. From 1982 Mr. Glynn held various senior executive positions with HSBC Bank Canada (formerly Hongkong Bank of Canada). Mr. Glynn is also a director of Wells Fargo HSBC Trade Bank N.A. and Group General Manager of HSBC Holdings plc.
Hui, Terence C.Y. Vancouver, British Columbia Canada	Director	August 25, 2000	President & Chief Executive Officer, Concord Pacific Group Inc. (a real estate development company) since 1997, Director and President of Adex Securities Inc. (a financial services company) since 1992 and Director and Chairman of Maximizer Software Inc. (formerly Multiactive Software Inc.) and Multiactive Technologies Inc. (computer software companies) since 1995 and of Coopers Park Real Estate Corporation since 2005. Mr. Hui was President and Chief Executive Officer of Pacific Place Developments Corp. (a real estate

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
			development company) from 1992 to 2001. Mr. Hui has been a director of abc Multiactive Limited (a software company) since 1995.
Kinney, Brent D. Dubai, United Arab Emirates	Director	August 25, 2000	Mr. Kinney has been a director and Chief Executive Officer of Sky Petroleum Inc. since 2005. Mr. Kinney has been a director of Dragon Oil plc since 2001, of Western Silver Corporation (a mineral exploration company) since 2005 and of Benchmark Energy Ltd. since 2005. Mr. Kinney was also a director of Aurado Energy Inc. from 2003 to 2004.
Kluge, Holger Toronto, Ontario Canada	Director	August 25, 2000	Corporate Director. Mr. Kluge has been a director of Hongkong Electric Holdings Limited since 1999, of Hutchison Whampoa Limited since 2004 and of Shoppers Drug Mart since 2006. Mr. Kluge was a director of Hutchison Telecommunications (Australia) Limited from 1999 to 2005, of TOM Group Limited (formerly TOM.COM LIMITED) from 2000 to 2005, and of Loring Ward International Limited (a financial planning company) from 2004 to 2005. Mr. Kluge holds a Bachelor of Commerce degree and a Master's degree in Business Administration.
Koh, Poh Chan Hong Kong	Director	August 25, 2000	Finance Director, Harbour Plaza Hotel Management (International) Ltd. since 1998.
Kwok, Eva L. Vancouver, British Columbia Canada	Director	August 25, 2000	Chairman, a director and Chief Executive Officer of Amara International Investment Corp. (an investment holding company) since 1992 and President from 1992 to 1996. Mrs. Kwok has been a director of Bank of Montreal Group of Companies since 1999, of CK Life Sciences Int'l., (Holdings) Inc. since 2002, Cheung Kong Infrastructure Holdings Limited and Shoppers Drug Mart since 2004 and of the Li Ka Shing (Canada) Foundation since 2005. Mrs. Kwok was a director of Air Canada from 1998 to 2003 and of Telesystem International Wireless Inc. from 2002 to 2003.
Kwok, Stanley T.L. Vancouver, British Columbia Canada	Director	August 25, 2000	President, Stanley Kwok Consultants (an architecture, planning and development company) since 1993. Mr. Kwok has been a director since 1997 and President since 1999 of Amara International Investment Corp. Mr. Kwok is a director of Cheung Kong (Holdings) Limited and CTC Bank of Canada.

Name and Municipality of Residence	Office or Position	Director Since	Principal Occupation During Past 5 Years
Lau, John C.S. Calgary, Alberta Canada	President & Chief Executive Officer and Director	August 25, 2000	President & Chief Executive Officer of Husky Energy Inc. since August 2000.
Shaw, Wayne E. Toronto, Ontario Canada	Director	August 25, 2000	Senior Partner, Stikeman Elliott LLP, Barristers and Solicitors.
Shurniak, William Limerick, Saskatchewan Canada	Deputy Chairman and Director	August 25, 2000	Director and chairman of Northern Gas Networks Limited (a distributor of natural gas in Northern England) since 2005 and a director of Hutchison Whampoa Limited since 1984. Mr. Shurniak 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 and CitiPower Pty Ltd. (a utility company) since 2002, a director of Envestra Limited (a natural gas distributor) since 2000, CrossCity Motorways Pty Ltd. (an infrastructure and transportation company) since 2002, and of Lane Cove Tunnel Company Pty Ltd. (an infrastructure and transportation company) since 2004. Mr. Shurniak holds an Honorary Doctor of Laws degree from the University of Saskatchewan and from The University of Western Ontario.
Sixt, Frank J. Hong Kong	Director	August 25, 2000	Group Finance Director of Hutchison Whampoa Limited since 1998 and Executive Director since 1991. Mr. Sixt has been the Chairman and Director of TOM Online Inc., and a Director of Hutchison Telecommunications International Limited since 2004. Mr. Sixt has held the following positions for more than five years: Chairman and Director of TOM Group Limited, Executive Director of Cheung Kong Infrastructure Holdings Limited and Hongkong Electric Holdings Limited and a Director of Cheung Kong (Holdings) Limited, Hutchison Whampoa Finance (CI) Limited, Hutchison Telecommunications (Australia) Limited, and Partner Communications Company Ltd. Mr. Sixt was also a director of VoiceStream Wireless Corp. from 2000 to 2001. Mr. Sixt holds a Master's degree in Arts and a Bachelor's degree in Civil Law and is a member of the Bar and of the Law Society of the Provinces of Quebec and Ontario, Canada.

Name and Municipality of Residence	Office or Position	Principal Occupation During Past 5 Years
Ingram, Donald R. Calgary, Alberta	Senior Vice President, Midstream & Refined Products	Senior Vice President, Midstream and Refined Products of Husky since August 2000.
Girgulis, James D. Calgary, Alberta	Vice President, Legal & Corporate Secretary	Vice President, Legal & Corporate Secretary of Husky since August 2000.

The Board of Directors has an Audit Committee (as required by the *Business Corporations Act* (Alberta)) currently consisting of R.D. Fullerton (Chair), M.J.G. Glynn, T.C.Y. Hui, and W.E. Shaw, a Compensation Committee currently consisting of C.K.N. Fok (Chair), H. Kluge, E.L. Kwok and F.J. Sixt, a Health, Safety and Environment Committee currently consisting of H. Kluge (Chair), B. D. Kinney, and S.T.L. Kwok and a Corporate Governance Committee currently consisting of H. Kluge (Chair), E.L. Kwok and W.E. Shaw. Husky does not have an Executive Committee.

As at February 28, 2006, the directors and officers of Husky, as a group, owned beneficially, directly or indirectly, or exercised control or direction over 397,108 common shares of Husky representing less than 1 percent of the issued and outstanding common shares.

Conflicts of Interest

Certain officers and directors of Husky are also officers and/or directors of other companies engaged in the oil and gas business generally and which, in certain cases, own interests in oil and gas properties in which Husky holds or may in future hold an interest. As a result, situations 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 officers of the Company is or has been within the past ten years, a director or officer of any company, including the Company, 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 was subject to an event that resulted, after the director or officer ceased to be a director or officer, in the company being 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 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 Eva Kwok who was a director of Air Canada in 2003 at the time it became subject to creditor protection under the *Companies Creditors Arrangement Act* (Canada). In addition, Holger Kluge and Frank Sixt were directors until April 12, 2002 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. Mr. Fok acted as a non-executive director of Peregrine Investments Holdings Limited (an investment bank) which was put into compulsory liquidation on March 18, 1998.

Individual Penalties, Sanctions or Bankruptcies

None of the persons who are directors or officers of the Company have, within the past ten years 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 manager or trustee appointed to hold his assets.

None of the persons who are directors or officers of the Company have been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has 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 are R.D. Fullerton (Chair), M.J.G. Glynn, T.C.Y. Hui and W.E. Shaw. Each of the members of the Company's Audit Committee (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 board of directors of Husky (the ''Board''), reasonably interfere with the exercise of a member's independent judgment.

The Committee's Charter 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.

R.D. Fullerton (Chair) — Before his retirement Mr. Fullerton served as Chief Executive Officer of CIBC and also served as a director and/or an Audit Committee member of 16 major domestic and international public companies as well as director of a number of affiliates of CIBC.

T.C.Y. Hui — Mr. Hui is the President and Chief Executive Officer of Concord Pacific Group Inc. which three years ago was a public company.

M.J.G. Glynn — Mr. Glynn is currently the Chief Executive Officer of HSBC Bank USA and prior thereto served as Chief Executive Officer of HSBC Bank Canada.

W.E. Shaw — Mr. Shaw is a senior partner of a major Canadian law firm and in that capacity has developed general business knowledge.

Husky's Audit Committee Charter 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 fiscal years indicated:

	Aggregate Fees Billed by the External Auditor	
	2005	**2004**
	($ thousands)	
Audit fees	447	805
Audit-related fees	27	207
Tax fees	160	144
All other fees	476	45
	1,110	1,201

Audit Fees. 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.

Audit-Related Fees. Audit-related services included attest services not required by statute or regulation and services with respect to acquisitions and dispositions.

Tax Fees. Tax fees included tax planning and various taxation matters.

All Other Fees. Other services provided by the Company's external auditor, other than audit, audit-related and tax services, included advisory services associated with various aspects of the Sarbanes-Oxley Act of 2002.

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 approved all of the audit-related, tax and other services provided by KPMG LLP in 2005.

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 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 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 directly or indirectly, or exercise control or direction over, more than 10 percent 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 materially affect the Company except as follows.

Up to and effective July 13, 2004, the Company leased its head office space located in Western Canadian Place in Calgary, Alberta from Western Canadian Place Ltd., which is indirectly controlled by the Company's principal shareholders. The Company's President & Chief Executive Officer is also a director and officer of Western Canadian Place Ltd. The Vice President, Corporate Administration of the Company's subsidiary, Husky Oil Operations Limited, is also a director and officer of Western Canadian Place Ltd. The Company entered into an amended and restated lease for a term ending August 31, 2013 with Western Canadian Place Ltd. on commercial terms consistent with those for leases of comparable space in Class A office buildings in Calgary. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party.

The Company has entered into a management agreement effective July 15, 2004 with Western Canadian Place Ltd. for general management of Western Canadian Place Ltd.'s leasehold interest in office space at 635 – 8th Avenue S.W., Calgary, Alberta. The Company was paid fees of $129,547.03 in 2005 for providing such management services.

TRANSFER AGENTS 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 shares are maintained by Computershare Trust Company of Canada at its principal offices in the cities of Calgary and Toronto. 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, 2005 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 reserve engineering. The partners of McDaniel as a group beneficially own, directly or indirectly, less than 1 percent of the Company's securities of any class.

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 is contained in Husky's Management Information Circular dated March 14, 2006, prepared in connection with the annual and special meeting of shareholders to be held on April 19, 2006.

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, 2005, contained in Husky's 2005 Annual Report.

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

ABBREVIATIONS AND GLOSSARY OF TERMS

As 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
mbbls/day	— thousand barrels per calendar day
boe	— barrels of oil equivalent
boe/day	— barrels of oil equivalent per calendar day
mcf	— thousand cubic feet
mmcf	— million cubic feet
bcf	— billion cubic feet
mmcf/day	— million cubic feet per calendar day
mcfge	— thousand cubic feet of gas equivalent
lt	— long ton
mlt	— thousand long tons
lt/day	— long tons per calendar day
mlt/day	— thousand long tons per calendar day
mmbtu	— million British thermal units
MW	— megawatts

Acronyms

API	— American Petroleum Institute
COGEH	— Canadian Oil and Gas Evaluation Handbook
FASB	— Financial Accounting Standards Board
FPSO	— floating production, storage and offloading vessel
LLB	— Lloydminster Blend
NGL	— natural gas liquids
NYMEX	— New York Mercantile Exchange
OPEC	— Organization of Petroleum Exporting Countries
PSC	— production sharing contract
SAGD	— steam assisted gravity drainage
SEC	— Securities and Exchange Commission of the United States
SEDAR	— System for Electronic Document Analysis and Retrieval
WTI	— West Texas Intermediate crude oil

Barrel

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

Bitumen

A highly viscous oil which is too thick to flow in its native state, and which cannot be produced without altering its viscosity. The density of bitumen is generally less than 10 degrees API.

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 (CH(4)). Coal bed methane is methane found and recovered from the coal bed seams. The methane is normally trapped in the 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.

Debottlenecking

To remove restrictions thus improving flow rates and productive capacity.

Degrees 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.

Delineation Well

A well in close proximity to an oil or gas well that helps determine the areal 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, which 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

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

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.

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.

Liquefied Petroleum Gas

Liquefied propanes and butanes, separately or in mixtures.

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 run inside the casing, each of which carry hydrocarbons from a separate and distinct producing formation.

Natural Gas Liquids (''NGL'')

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 includes 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 additional 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

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 therefrom of liquefiable hydrocarbons or other substances contained therein.

Recoverable Oil-in-place

The total original oil-in-place which can be expected to be recovered. This quantity is dependent upon recovery efficiency and the economics of operation.

Secondary Recovery

Oil or gas recovered by injecting water or gas into the reservoir to force additional oil 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

A licence with respect to the Canadian offshore or the Northwest Territories or Yukon 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 other provisions of the relevant legislation, the exclusive right to obtain a production 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, where the weight of water is assigned a value of one (1). However, the specific gravity of oil is normally expressed in degrees of API gravity as follows:

$$\text{Degrees API} = \frac{141.5}{\text{Specific gravity @ F60 degrees}} - 13.5$$

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

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.

Straight Run

A term used to describe any refined product that emerges from the initial distillation of crude oil.

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-D Seismic (Survey)

Three dimensional seismic imaging which uses a grid of numerous cable 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 shut down for the duration.

Undeveloped Area

An area in which it 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 of 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 sub surface 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 or information, (collectively ''forward-looking statements''), within the meaning of applicable Canadian securities legislation, and Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The Company is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in forward-looking statements made in this Annual Information Form. 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 result,'' ''are expected to,'' ''will continue,'' ''is anticipated,'' ''estimated,'' ''intend,'' ''plan,'' ''projection'' ''could''; ''vision''; ''goals''; ''objective'' and ''outlook'') are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. In particular, our construction plans for the Tucker in-situ oil sands project, Lloydminster Ethanol Plant and the Minnedosa Ethanol Plant; our plans to debottleneck the Lloydminster Upgrader; our plans to expand our oil pipeline systems; our design plans for the Sunrise in-situ oil sands project; our exploration and development drilling plans for Western Canada and the Northwest Territories; our South and east China Seas exploration drilling plans; our estimates of the productive capacity for White Rose, Tucker and Sunrise; our production forecasts; our plans to develop our Madura Stait PSC; and statements relating to declining production in the Western Canada Sedimentary Basin and increasing non-conventional production, are forward-looking statements.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Company made by or on behalf of the Company, 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. The risks, uncertainties and other factors, many of which are beyond our control, that could influence actual results include, but are not limited to:

- fluctuations in commodity prices
- the accuracy of our oil and gas reserve estimates and estimated production levels as they are affected by our success at exploration and development drilling and related activities and estimated decline rates
- the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures
- changes in general economic, market and business conditions
- fluctuations in supply and demand for our products
- fluctuations in the cost of borrowing
- our use of derivative financial instruments to hedge exposure to changes in commodity prices and fluctuations in interest rates and foreign currency exchange rates
- political and economic developments, expropriations, royalty and tax increases, retroactive tax claims and changes to import and export regulations and other foreign laws and policies in the countries in which we operate
- our ability to receive timely regulatory approvals
- the integrity and reliability of our capital assets
- the cumulative impact of other resource development projects
- the maintenance of satisfactory relationships with unions, employee associations and joint venturers
- competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy
- actions by governmental authorities, including changes in environmental and other regulations that may impose restriction in areas where we operate
- the ability and willingness of parties with whom we have material relationships to fulfill their obligations

- the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us and that may or may not be financially recoverable
- such other risks, uncertainties and other factors described from time to time in Husky's reports and filings with Canadian securities authorities and with the SEC.

Further, 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 or statements 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 statements.

Schedule A

AIF

HUSKY ENERGY INC.

Audit Committee Charter

The Audit Committee (the ''Committee'') of the Board of Directors (the ''Board'') of Husky Energy Inc. (the ''Company'') will have the oversight responsibility, authority and specific duties as described below.

Composition

The Committee will be comprised of three or more directors as determined by the Board, each of whom shall satisfy the independence and financial literacy requirements of applicable securities regulatory requirements. In addition, one of the members of the Committee will be an audit committee financial expert as defined in applicable securities regulatory requirements. The members of the Committee will be elected annually at the organizational meeting of the full Board on the recommendation of the Corporate Governance Committee to the Co-Chairmen and will be listed in the annual report to shareholders. One of the members of the Committee will be elected Committee Chair by the Board.

Responsibility

The Committee is a part of the Board. Its primary function is to assist the Board in fulfilling its oversight responsibilities with respect to:

(i) the quarterly and annual financial statements and quarterly and annual MD&A be provided to shareholders and the appropriate regulatory agencies;

(ii) earnings press releases before the Company publicly discloses this information;

(iii) the system of internal controls that management has established;

(iv) the internal and external audit process;

(v) the appointment of qualified reserves evaluators or auditors; and

(vi) the filing of statements and reports with respect to the Company's oil and gas reserves.

In addition, the Committee provides an avenue for communication between the Board and each of internal audit, the external auditors, financial management, external qualified reserves evaluators or auditors and internal qualified reserves evaluators. The Committee should 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.

The Committee will make regular reports to the Board concerning its activities.

While the Audit Committee has the responsibilities and powers set forth in this Charter, the role of the Audit committee is oversight. The members of the Committee are not full time employees of the Company 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 Audit Committee to plan or conduct audits or to determine that the Company's financial statements are complete and accurate and are in accordance with generally accepted accounting 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 shall also have the responsibility to conduct investigations and to assure compliance with laws and regulations and the Company's business conduct guidelines.

Authority

Subject to the prior approval of 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 Company and the reporting of the Company's reserves and oil and gas activities.

The Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to set and pay the compensation for any advisors employed by the Committee.

In recognition of the fact that the independent auditors are ultimately accountable to the Committee, the Committee shall have the authority and responsibility to nominate for shareholder approval, evaluate and, where appropriate, replace the independent auditors and shall approve all audit engagement fees and terms and all non-audit engagements with the independent auditors. The Committee shall consult with management and the internal audit group but shall not delegate these responsibilities.

Meetings

The Committee is to meet at least four times annually and as many additional times as the Committee deems necessary. Committee members will strive to be present at all meetings either in person or by telephone. 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. Likewise, as necessary or desirable, but in any case at least annually, the Committee shall meet the management and representatives of the external reserve 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.

Specific Duties

In carrying out its oversight responsibilities, the Committee will:

1. Review and reassess the adequacy of this Charter annually and recommend any proposed changes to the Board for approval.
2. (a) Review with the Company's management, internal audit and external auditors and recommend to the Board for approval the Company's annual financial statements and annual MD&A which is to be provided to shareholders and the appropriate regulatory agencies, including any financial statement contained in a prospectus, information circular, registration statement or other similar document.

   (b) Review with the Company's management, internal audit and external auditors and approve the Company's quarterly financial statements and quarterly MD&A which is to be provided to shareholders and the appropriate regulatory agencies.
3. Review with the Company's management and approve earnings press releases before the Company publicly discloses this information.
4. Recommend to the Board the external auditors to be nominated for the purpose of preparing or issuing an audit report or performing other audit, review or attest services and the compensation to be paid to the external auditors. The external auditors shall report directly to the Committee.
5. Be directly responsible for the oversight of the work of the external auditors, including the resolution of disagreements between management of the Company and the external auditors regarding financial reporting.
6. Review with the Company's management, internal audit and external auditors the Company's accounting and financial reporting controls. Obtain annually in writing from the external auditors their observations, if any, on significant weaknesses in internal controls as noted during the course of their work.
7. Review with the Company's management, internal audit and external auditor's significant accounting and reporting principles, practices and procedures applied by the Company in preparing its financial statements. Discuss with the external auditors their judgements about the quality, not just the acceptability, of the Company'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 auditors and how management is addressing the conditions reported.
9. Review the scope and general extent of the external auditors' annual audit. The Committee's review should include an explanation from the external auditors of the factors considered in determining the audit scope, including the major risk factors. The external auditors should confirm to the Committee 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

Company as contemplated by Independence Standards Board Standard No. 1, Independence Discussions with Audit Committees.

11. Have a predetermined arrangement with the external auditors that they will advise the Committee, through its Chair and management of the Company, of any matters identified through procedures followed for the review of interim quarterly financial statements of the Company, and that such notification is to be made prior to the related press release. Also receive a written confirmation provided by the external auditors 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. At the completion of the annual audit, review with management, internal audit and the external auditors the following:

    - The annual financial statements and related footnotes and financial information to be included in the Company's annual report to shareholders.
    - 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.
    - Significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit. Inquire about the cooperation received by the external auditors during their audit, including access to all requested records, data and information.
    - 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 Company's financial statements.

13. Discuss with the external auditors, without management being present, (a) the quality of the Company's financial and accounting personnel, and (b) the completeness and accuracy of the Company's financial statements. Also, elicit the comments of management regarding the responsiveness of the external auditors to the Company'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. The Committee should review responses of management to the Letter of Comments and Recommendations from the external auditors and receive follow-up reports on action taken concerning the aforementioned recommendations.

15. Have 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, in connection therewith, to approve all fees and other terms of engagement. The Committee shall also review and approve disclosures required to be included in periodic reports filed with Canadian securities regulators and the Securities and Exchange Commission with respect to non-audit services performed by external auditors.

16. Be satisfied that adequate procedures are in place for the review of the Company's disclosure of financial information extracted or derived from the Company'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 Company regarding accounting, internal accounting controls or auditing matter, and (b) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

18. Review and approve the Company'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 Company's policies with respect to unethical or illegal activities by Company employees that may have a material impact on the financial statements.

21. Generally as part of the review of the annual financial statements, receive a report(s), at least annually, from the Company's general counsel concerning legal, regulatory and compliance matters that may have a material impact on the financial statements.
22. Review, with reasonable frequency, the Company's procedures relating to the disclosure of information with respect to the Company's oil and gas reserves, including the Company's procedures for complying with the disclosure requirements and restrictions of applicable regulations.
23. Review with management the appointment of 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 the appointed external qualified reserves evaluators or auditors, and management.
24. Review, with reasonable frequency, the Company'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 laws.
25. Before the approval and the release of the Company's reserves data and the report of the qualified reserve evaluators or auditors thereon, meet with 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.
26. Recommend to the Board for approval the content and filing of required statements and reports relating to the Company's disclosure of reserve data as prescribed by applicable regulations.
27. Review and approve (a) any change or waiver in the Company's Code of Business Conduct for the chief executive officer and senior financial officers and (b) any public disclosure made regarding such change or waiver.

Calgary, Alberta, Canada
February 16, 2005

Document B
Form 40-F

CONSOLIDATED FINANCIAL STATEMENTS AND AUDITORS' REPORT TO SHAREHOLDERS

For the Year Ended December 31, 2005

MANAGEMENT'S REPORT

The management of Husky Energy Inc. is responsible for the financial information and operating data presented in this Annual Report.

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. 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 Annual Report has been prepared on a basis consistent with that in the consolidated financial statements.

Husky Energy Inc. 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. 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, as well as the external auditors, to discuss auditing (external, internal and joint venture), internal controls, accounting policy, financial reporting matters and 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 consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with Canadian generally accepted auditing standards on behalf of the shareholders. KPMG LLP has full and free access to the Audit Committee.

/s/ JOHN C. S. LAU

John C. S. Lau
President & Chief Executive Officer

Calgary, Alberta, Canada
February 6, 2006

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Husky Energy Inc., as at December 31, 2005, 2004 and 2003 and the consolidated statements of earnings, retained earnings, and cash flows for each of the years in the three-year period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

/s/ KPMG LLP

KPMG LLP
Chartered Accountants

Calgary, Alberta, Canada
February 6, 2006

COMMENTS BY AUDITOR FOR US READERS ON CANADA/US REPORTING DIFFERENCES

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's financial statements, such as the change described in Note 11, Long-term debt — to the Company's consolidated financial statements as at December 31, 2005, 2004 and 2003, and for each of the years in the three-year period ended December 31, 2005. Our report to the shareholders dated February 6, 2006 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

/s/ KPMG LLP

KPMG LLP
Chartered Accountants

Calgary, Alberta, Canada
February 6, 2006

CONSOLIDATED BALANCE SHEETS

	As at December 31		
	2005	2004	2003
	(millions of dollars)		
ASSETS			
Current assets			
Cash and cash equivalents	$ 249	$ 7	$ 3
Accounts receivable *(note 4)*	856	446	618
Inventories *(note 5)*	471	274	198
Prepaid expenses	40	52	33
	1,616	779	852
Property, plant and equipment, net *(notes 1, 6)*	13,959	12,193	10,862
Goodwill *(note 7)*	160	160	120
Other assets *(note 11)*	62	108	115
	$15,797	$13,240	$11,949
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Bank operating loans *(note 9)*	$ —	$ 49	$ 71
Accounts payable and accrued liabilities *(note 10)*	2,391	1,498	1,136
Long-term debt due within one year *(note 11)*	274	56	259
	2,665	1,603	1,466
Long-term debt *(note 11)*	1,612	2,047	1,730
Other long-term liabilities *(note 12)*	730	632	519
Future income taxes *(note 13)*	3,270	2,758	2,621
Commitments and contingencies *(note 14)*			
Shareholders' equity			
Common shares *(note 15)*	3,523	3,506	3,457
Retained earnings	3,997	2,694	2,156
	7,520	6,200	5,613
	$15,797	$13,240	$11,949

On behalf of the Board:

/s/ JOHN C. S. LAU
John C. S. Lau
Director

/s/ R.D. FULLERTON
R.D. Fullerton
Director

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2004 and 2003 amounts as restated (notes 3 and 11).

CONSOLIDATED STATEMENTS OF EARNINGS

	Year ended December 31		
	2005	2004	2003
	(millions of dollars, except per share amounts)		
Sales and operating revenues, net of royalties	$10,245	$8,440	$7,658
Costs and expenses			
Cost of sales and operating expenses *(note 12)*	5,917	5,706	4,847
Selling and administration expenses	138	135	119
Stock-based compensation *(note 15)*	171	67	—
Depletion, depreciation and amortization *(notes 1, 6)*	1,256	1,179	1,021
Interest — net *(note 11)*	32	60	102
Foreign exchange *(note 11)*	(31)	(120)	(282)
Other — net	(50)	8	3
	7,433	7,035	5,810
Earnings before income taxes	2,812	1,405	1,848
Income taxes *(note 13)*			
Current	297	302	147
Future	512	97	331
	809	399	478
Net earnings	$ 2,003	$1,006	$1,370
Earnings per share *(note 15)*			
Basic	$ 4.72	$ 2.37	$ 3.26
Diluted	$ 4.72	$ 2.37	$ 3.25

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

	Year ended December 31		
	2005	2004	2003
	(millions of dollars)		
Beginning of year	$ 2,694	$2,156	$1,366
Net earnings	2,003	1,006	1,370
Dividends on common shares *(note 15)*			
Ordinary	(276)	(195)	(160)
Special	(424)	(229)	(420)
Stock-based compensation — retroactive adoption *(note 15)*	—	(44)	—
End of year	$ 3,997	$2,694	$2,156

The accompanying notes to the consolidated financial statements are an integral part of these statements. 2004 and 2003 amounts as restated (notes 3 and 11).

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31		
	2005	2004	2003
	(millions of dollars)		
Operating activities			
Net earnings	$ 2,003	$ 1,006	$ 1,370
Items not affecting cash			
Accretion *(note 12)*	33	27	22
Depletion, depreciation and amortization	1,256	1,179	1,021
Future income taxes	512	97	331
Foreign exchange	(37)	(124)	(309)
Other	18	12	(5)
Settlement of asset retirement obligations	(41)	(40)	(34)
Change in non-cash working capital *(note 8)*	(72)	169	113
Cash flow — operating activities	3,672	2,326	2,509
Financing activities			
Bank operating loans financing — net	(49)	(22)	71
Long-term debt issue	3,235	2,200	598
Long-term debt repayment	(3,401)	(1,937)	(971)
Settlement of cross currency swap	—	—	(32)
Debt issue costs	—	(5)	—
Proceeds from exercise of stock options	6	18	51
Proceeds from monetization of financial instruments	39	8	44
Dividends on common shares	(700)	(424)	(580)
Other	(1)	—	—
Change in non-cash working capital *(note 8)*	255	337	48
Cash flow — financing activities	(616)	175	(771)
Available for investing	3,056	2,501	1,738
Investing activities			
Capital expenditures	(3,068)	(2,349)	(1,868)
Corporate acquisitions	—	(102)	(809)
Asset sales	74	36	511
Other	(31)	(19)	5
Change in non-cash working capital *(note 8)*	211	(63)	120
Cash flow — investing activities	(2,814)	(2,497)	(2,041)
Increase (decrease) in cash and cash equivalents	242	4	(303)
Cash and cash equivalents at beginning of year	7	3	306
Cash and cash equivalents at end of year	$ 249	$ 7	$ 3

The accompanying notes to the consolidated financial statements are an integral part of these statements.
2004 and 2003 amounts as restated (notes 3 and 11).

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Except where indicated and per share amounts, all dollar amounts are in millions.

Note 1

***Segmented Financial Information*[1]**

	Upstream			Midstream					
				Upgrading			Infrastructure and Marketing		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
Year ended December 31									
Sales and operating revenues, net of royalties	$ 4,367	$ 3,120	$ 3,186	$1,488	$1,058	$1,013	$7,383	$6,126	$4,946
Costs and expenses									
Operating, cost of sales, selling and general	1,050	967	873	1,018	884	901	7,084	5,914	4,747
Depletion, depreciation and amortization	1,144	1,077	918	21	19	20	21	21	21
Interest — net	—	—	—	—	—	—	—	—	—
Foreign exchange	—	—	—	—	—	—	—	—	—
	2,194	2,044	1,791	1,039	903	921	7,105	5,935	4,768
Earnings (loss) before income taxes	2,173	1,076	1,395	449	155	92	278	191	178
Current income taxes	215	211	95	16	—	1	(14)	31	27
Future income taxes	434	152	233	120	43	20	110	32	37
Net earnings (loss)	$ 1,524	$ 713	$ 1,067	$ 313	$ 112	$ 71	$ 182	$ 128	$ 114
Capital employed — As at December 31	$ 8,697	$ 7,600	$ 6,607	$ 510	$ 480	$ 456	$ 359	$ 402	$ 450
Property, plant and equipment — As at December 31									
Cost									
Canada	$18,512	$16,023	$13,831	$1,205	$1,084	$1,023	$ 683	$ 647	$ 622
International	655	587	503	—	—	—	—	—	—
	$19,167	$16,610	$14,334	$1,205	$1,084	$1,023	$ 683	$ 647	$ 622
Accumulated depletion, depreciation and amortization									
Canada	$ 6,729	$ 5,722	$ 4,718	$ 430	$ 409	$ 391	$ 247	$ 226	$ 203
International	354	311	252	—	—	—	—	—	—
	$ 7,083	$ 6,033	$ 4,970	$ 430	$ 409	$ 391	$ 247	$ 226	$ 203
Net									
Canada	$11,783	$10,301	$ 9,113	$ 775	$ 675	$ 632	$ 436	$ 421	$ 419
International	301	276	251	—	—	—	—	—	—
	$12,084	$10,577	$ 9,364	$ 775	$ 675	$ 632	$ 436	$ 421	$ 419
Capital expenditures — Year ended December 31 (3)	$ 2,730	$ 2,157	$ 1,778	$ 120	$ 62	$ 25	$ 37	$ 31	$ 18
Total assets — As at December 31 (4)									
Canada	$12,559	$10,771	$ 9,583	$ 844	$ 708	$ 650	$ 866	$ 746	$ 804
International	328	275	264	—	—	—	—	—	—
	$12,887	$11,046	$ 9,847	$ 844	$ 708	$ 650	$ 866	$ 746	$ 804

(1) 2004 and 2003 amounts as restated (notes 3 and 11).

(2) 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.

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

(4) Includes goodwill on corporate acquisitions related to Upstream.

	Refined Products			Corporate and Eliminations (2)			Total		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
Year ended December 31									
Sales and operating revenues, net of royalties	$2,345	$1,797	$1,502	$(5,338)	$(3,661)	$(2,989)	$10,245	$ 8,440	$ 7,658
Costs and expenses									
Operating, cost of sales, selling and general	2,169	1,694	1,426	(5,145)	(3,543)	(2,978)	6,176	5,916	4,969
Depletion, depreciation and amortization	47	38	26	23	24	36	1,256	1,179	1,021
Interest — net	—	—	—	32	60	102	32	60	102
Foreign exchange	—	—	—	(31)	(120)	(282)	(31)	(120)	(282)
	2,216	1,732	1,452	(5,121)	(3,579)	(3,122)	7,433	7,035	5,810
Earnings (loss) before income taxes	129	65	50	(217)	(82)	133	2,812	1,405	1,848
Current income taxes	(3)	11	9	83	49	15	297	302	147
Future income taxes	50	13	9	(202)	(143)	32	512	97	331
Net earnings (loss)	$ 82	$ 41	$ 32	$ (98)	$ 12	$ 86	$ 2,003	$ 1,006	$ 1,370
Capital employed — As at December 31	$ 475	$ 354	$ 315	$ (635)	$ (484)	$ (155)	$ 9,406	$ 8,352	$ 7,673
Property, plant and equipment — As at December 31									
Cost									
Canada	$1,063	$ 878	$ 773	$ 257	$ 232	$ 205	$21,720	$18,864	$16,454
International	—	—	—	—	—	—	655	587	503
	$1,063	$ 878	$ 773	$ 257	$ 232	$ 205	$22,375	$19,451	$16,957
Accumulated depletion, depreciation and amortization									
Canada	$ 476	$ 432	$ 392	$ 180	$ 158	$ 139	$ 8,062	$ 6,947	$ 5,843
International	—	—	—	—	—	—	354	311	252
	$ 476	$ 432	$ 392	$ 180	$ 158	$ 139	$ 8,416	$ 7,258	$ 6,095
Net									
Canada	$ 587	$ 446	$ 381	$ 77	$ 74	$ 66	$13,658	$11,917	$10,611
International	—	—	—	—	—	—	301	276	251
	$ 587	$ 446	$ 381	$ 77	$ 74	$ 66	$13,959	$12,193	$10,862
Capital expenditures — Year ended December 31 (3)	$ 191	$ 106	$ 58	$ 21	$ 23	$ 23	$ 3,099	$ 2,379	$ 1,902
Total assets — As at December 31 (4)									
Canada	$ 834	$ 625	$ 540	$ 366	$ 115	$ 108	$15,469	$12,965	$11,685
International	—	—	—	—	—	—	328	275	264
	$ 834	$ 625	$ 540	$ 366	$ 115	$ 108	$15,797	$13,240	$11,949

Note 2

Nature of Operations and Organization

Husky Energy Inc. (''Husky'' or ''the Company'') is a publicly traded, integrated energy and energy-related company headquartered in Calgary, Alberta, Canada.

Management has segmented the Company's business based on differences in products and services and management strategy and responsibility. The Company's business is conducted predominantly through three major business segments — upstream, midstream and refined products.

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

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

Refined products include refining of crude oil and marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products.

Note 3

Significant Accounting Policies

a) Principles of Consolidation and the Preparation of Financial Statements

These financial statements are prepared in accordance with Canadian generally accepted accounting principles (''GAAP'') which, in the case of the Company, differ in certain respects from those in the United States. These differences are described in note 19, Reconciliation to Accounting Principles Generally Accepted in the United States.

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

The consolidated financial statements include the accounts of the Company and its subsidiaries.

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 flow from these activities.

b) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and deposits with a maturity of less than three months at the time of purchase.

c) Inventory Valuation

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 and supplies are valued at the lower of average cost or net realizable value. Cost consists of raw material, labour, direct overhead and transportation. Intersegment profits are eliminated.

d) Property, Plant and Equipment

i) Oil and Gas

The Company employs 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 are capitalized and accumulated within cost centres on a country-by-country basis. Such costs include land acquisition, geological and geophysical activity, drilling of productive and non-productive wells, carrying costs directly related to unproved properties and administrative costs directly related to exploration and development activities.

The provision for depletion of oil and gas properties and depreciation of associated production facilities is calculated using the unit of production method, based on gross proved oil and gas reserves as estimated by the Company's engineers, for each cost centre. Depreciation of gas plants and certain other oil and gas facilities is provided using the straight-line method based on their estimated useful lives. Costs subject to depletion and depreciation include both the estimated costs required to develop proved undeveloped reserves and the associated addition to the asset retirement obligations. In the normal course of operations, retirements of oil and gas interests are accounted for by charging the asset cost, net of any proceeds, to accumulated depletion or depreciation. Gains or losses on the disposition of oil and gas properties are not recognized unless the gain or loss changes the depletion rate by 20 percent or more.

Costs of acquiring and evaluating significant unproved oil and gas interests are excluded from costs subject to depletion and depreciation until it is determined that proved oil and gas reserves are attributable to such interests or until impairment occurs. Costs of major development projects are excluded from costs subject to depletion and depreciation until proved developed reserves have been attributed to a portion of the property or the property is determined to be impaired.

Impairment losses are recognized when the carrying amount of a cost centre exceeds the sum of:

- the undiscounted cash flow expected to result from production from proved reserves;
- the costs of unproved properties, less impairment; and
- the costs of major development projects, less impairment.

The amount of impairment loss is determined to be the amount by which the carrying amount of the cost centre exceeds the sum of:

- the fair value of proved and probable reserves; and
- the cost, less impairment, of unproved properties and major development projects that do not have probable reserves attributed to them.

ii) Other Plant and Equipment

Depreciation for substantially all other plant and equipment, except upgrading assets, is provided using the straight-line method based on estimated useful lives of assets which range from five to 25 years. Depreciation for upgrading assets is provided using the unit of production method, based on the plant's estimated productive life. Repairs and maintenance costs, other than major turnaround costs, are charged to earnings as incurred. Major turnaround costs are deferred to other assets when incurred and amortized over the estimated period of time to the next scheduled turnaround. At the time of disposition of plant and equipment, accounts are relieved of the asset values and accumulated depreciation and any resulting gain or loss is reflected in earnings.

iii) Asset Retirement Obligations

The recognition of the fair value of obligations associated with the retirement of tangible long-lived assets is recorded in the period that the asset is put into use, with a corresponding increase to the carrying value of the related asset. The obligations recognized are legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion which is included in cost of sales and operating expenses. The liability will also be adjusted to reflect revisions to the previous estimates of the undiscounted obligation. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion, depreciation and amortization of the underlying asset. Retirement expenditures are charged to the accumulated liability as incurred.

iv) Capitalized Interest

Interest is capitalized on certain major capital projects based on the Company's long-term cost of borrowing.

e) Impairment or Disposal of Long-lived Assets

An impairment loss is recognized when the carrying value of a long-lived asset is not recoverable and exceeds its fair value. Testing for recoverability uses the undiscounted cash flows expected from the asset's use and disposition. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent.

A long-lived asset that meets the conditions as held for sale is measured at the lower of its carrying amount or fair value less costs to sell. Such assets are not amortized while they are classified as held for sale. The results of operations of a component of an entity that has been disposed of, or is classified as held for sale, are reported in discontinued operations if: i) the operations and cash flows of the component have been or will be eliminated as a result of the disposal transaction; and, ii) the entity will not have a significant continuing involvement in the operations of the component after the disposal transaction.

f) Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net assets acquired. Goodwill is subject to impairment tests on at least an annual basis or sooner if there are indicators of impairment. The Company tests impairment annually in the fourth quarter of each year. To assess impairment, the fair value of the reporting unit is compared with its carrying amount. If any potential impairment is indicated, then it is quantified by comparing the carrying value of goodwill to its fair value determined, based on the fair value of the assets and liabilities of the reporting unit. Impairment losses would be recognized in current period earnings.

g) Derivative Financial Instruments

Derivative financial instruments are utilized by the Company to manage market risk against the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative financial instruments for speculative purposes. The Company may choose to designate derivative financial instruments as hedges.

When applicable, at the inception of the hedge, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between hedged items and hedging items and the method for testing the effectiveness of the hedge which must be reasonably assured over the term of the hedge. 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 on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

The Company may enter into commodity price contracts to hedge anticipated sales of oil and natural gas production to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream oil and gas revenues as the related sales occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers in order to retain market prices while meeting customer or supplier pricing requirements. Gains and losses from these contracts are recognized in midstream revenues or cost of sales as the related sales or purchases occur.

The Company may enter into interest rate swap agreements to hedge its fixed and floating interest rate mix on long-term debt. Gains and losses from these contracts are recognized as an adjustment to the interest expense on the hedged debt instrument. The related amount payable or receivable from the counterparties is recorded as an adjustment to accrued interest.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments are accrued under other current, or non-current, assets or liabilities on the balance sheet and recognized in foreign exchange 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 forward premium or discount on the foreign exchange contract is amortized as an adjustment to interest expense over the term of the contract.

The Company may enter into foreign exchange forwards and foreign exchange collars to hedge anticipated U.S. dollar denominated oil and natural gas sales. Gains and losses on these instruments are recognized as an adjustment to upstream oil and gas revenues when the sale is recorded.

Realized and unrealized gains or losses associated with derivative financial instruments which have been terminated or cease to be effective as a hedge prior to maturity are deferred under current or non-current assets or liabilities on the balance sheet and recognized into income in the period in which the underlying hedged transaction is recognized in income. In the event that a designated hedged item is sold, extinguishes or matures prior to the termination of the related derivative financial instrument, any realized or unrealized gain or loss is recognized in earnings.

h) Employee Future Benefits

The Company provides a defined contribution pension plan and a post-retirement health and dental care plan 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. The cost of the pension benefits earned by employees in the defined contribution pension plan is paid and expensed when incurred. The cost of the benefits earned by employees in the post-retirement health and dental care plan and defined benefit pension plan is charged to earnings as services are rendered using the projected benefit method prorated on service. The cost of the post-retirement health and dental care plan and defined benefit pension plan reflects a number of assumptions that affect the 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 plan assets are valued at fair value for the purposes of calculating the expected return on plan assets.

Adjustments arising out of plan amendments, changes in assumptions and experience gains and losses are normally amortized over the expected remaining average service life of the employee group.

i) Future Income Taxes

The Company follows the liability method of accounting for income taxes. Future income tax assets and liabilities are recognized at expected tax rates in effect when temporary differences between the tax basis and the carrying value of the Company's assets and liabilities reverse. The effect of a change to the tax rate on the future tax assets and liabilities is recognized in earnings when substantively enacted.

j) Non-monetary Transactions

Non-monetary transactions are measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business.

k) Revenue Recognition

Revenues from the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recorded on a gross basis when title passes to an external party. Sales between the business segments of the Company are eliminated from sales and operating revenues and cost of sales. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

l) Foreign Currency Translation

Results of foreign operations, all of which are considered financially and operationally integrated, are translated to Canadian dollars at the monthly average exchange rates for revenue and expenses, except for depreciation and depletion which are translated at the rate of exchange applicable to the related assets. Monetary assets and liabilities are translated at current exchange rates and non-monetary assets and liabilities are translated using historical rates of exchange. Gains or losses resulting from these translation adjustments are included in earnings.

m) Stock-based Compensation

Effective January 1, 2004, the Company adopted the Canadian Institute of Chartered Accountants (''CICA'') section 3870, ''Stock-based Compensation and Other Stock-based Payments'', retroactively without restatement of prior periods. In accordance with the Company's stock option plan, common share options may be granted to directors, officers and certain other employees. The recommendations require the Company to record compensation expense over the vesting period based on the fair value of options granted.

Effective June 1, 2004, the Company amended its stock option plan to 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 expected cash settlements is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares. The liability is revalued to reflect changes in the market price of the Company's common shares and the net change is recognized in 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. Accrued compensation for an option that is forfeited is adjusted to earnings by decreasing the compensation cost in the period of forfeiture.

n) Earnings per Share

Basic common shares outstanding are the weighted average number of common shares outstanding for each period. The calculation of basic earnings per common share is based on net earnings divided by the weighted average number of common shares outstanding.

Diluted common shares outstanding are calculated using the treasury stock method, which assumes that any proceeds received from in-the-money options would be used to buy back common shares at the average market price for the period. However, since the Company has a tandem stock option plan and accrues a liability for expected cash settlements, the potential common shares issuable upon exercise associated with the stock options are not included in diluted common shares outstanding. Shares potentially issuable on the settlement of the capital securities have not been included in the determination of diluted earnings per common share, as the Company has neither the obligation nor intention to settle amounts due through the issuance of shares.

o) Reclassification

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

Note 4

Accounts Receivable

	2005	2004	2003
Trade receivables	$854	$448	$568
Investment tax credit	—	—	48
Allowance for doubtful accounts	(10)	(10)	(12)
Other	12	8	14
	$856	$446	$618

Sale of Accounts Receivable

As at December 31, 2005, the Company's ceiling on its securitization program to sell, on a revolving basis, accounts receivable to a third party was $350 million. As at December 31, 2005, $350 million (2004 — $350 million; 2003 — $250 million) in outstanding accounts receivable had been sold under the program. The agreement includes a program fee. The average effective rate for 2005 was approximately 3.0 percent (2004 — 2.6 percent; 2003 — 2.8 percent).

The Company has retained the responsibility for servicing, administering and collecting accounts receivable sold. The servicing liability at December 31, 2005 was not significant.

Proceeds from revolving sales between the third party and the Company in 2005 totalled approximately $3.4 billion (2004 — $2.5 billion).

Note 5

Inventories

	2005	2004	2003
Crude oil and refined petroleum products	$241	$159	$115
Natural gas	207	100	69
Materials, supplies and other	23	15	14
	$471	$274	$198

Note 6

Property, Plant and Equipment

Refer to note 1, Segmented Financial Information, which presents the Company's property, plant and equipment by segment.

General and administrative costs capitalized in 2005 were $61 million (2004 — $40 million; 2003 — $28 million).

Costs of oil and gas properties, including major development projects, excluded from costs subject to depletion and depreciation at December 31 were as follows:

	2005	2004	2003
Canada	$2,317	$2,399	$1,814
International	127	129	54
	$2,444	$2,528	$1,868

The prices used in the ceiling test evaluation of the Company's crude oil and natural gas reserves at December 31, 2005 were:

Canada	2006	2007	2008	2009	2010	Price increase from 2010 to 2025
						(percent)
Crude oil *($/bbl)*	$50.08	$46.57	$39.13	$37.12	$36.83	30
Natural gas *($/mcf)*	10.23	8.97	7.40	6.82	6.69	26

Note 7

Corporate Acquisitions

Effective July 15, 2004, the Company acquired all of the issued and outstanding shares of Temple Exploration Inc. (''Temple'') for total cash consideration of $102 million.

Effective October 1, 2003, the Company acquired all of the issued and outstanding shares of Marathon Canada Limited and the Western Canadian assets of Marathon International Petroleum Canada, Ltd. (''Marathon Canada'') for cash consideration of U.S. $611 million (Cdn $831 million).

In conjunction with the above acquisition of Marathon Canada, the Company sold certain of the Marathon Canada oil and gas properties to a third party for cash consideration of U.S. $320 million (Cdn $431 million).

The results of Temple and Marathon Canada are included in the consolidated financial statements of the Company from their acquisition dates.

The allocation of the aggregate purchase price based on the estimated fair values of the net assets of Temple and Marathon Canada on their acquisition dates was as follows:

	Temple	Marathon Canada
Net assets acquired		
Working capital (1)	$ (17)	$ (15)
Property, plant and equipment	138	1,008
Goodwill (2)	20	140
Asset retirement obligations	—	(38)
Future income taxes	(39)	(264)
	$102	$ 831

(1) Working capital of Marathon Canada acquired included cash of $22 million.

(2) Allocated to the Company's upstream segment and not deductible for income tax purposes. Refer to note 1, Segmented Financial Information.

Note 8

Cash Flows — Change in Non-cash Working Capital

a) Change in non-cash working capital was as follows:

	2005	2004	2003
Decrease (increase) in non-cash working capital			
Accounts receivable	$(410)	$ 209	$ (7)
Inventories	(197)	(77)	28
Prepaid expenses	17	(12)	(10)
Accounts payable and accrued liabilities	984	323	270
Change in non-cash working capital	394	443	281
Relating to:			
Financing activities	255	337	48
Investing activities	211	(63)	120
Operating activities	$ (72)	$ 169	$113

b) Other cash flow information:

	2005	2004	2003
Cash taxes paid	$154	$213	$ 69
Cash interest paid	$147	$143	$165

Note 9

Bank Operating Loans

At December 31, 2005, the Company had unsecured short-term borrowing lines of credit with banks totalling $195 million (2004 and 2003 — $195 million). As at December 31, 2005, $0.4 million (2004 — $49 million; 2003 — $71 million) had been used for bank operating loans and $18 million (2004 — $23 million; 2003 — $18 million) had been used for letters of credit. Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates. During 2005, the weighted average interest rate on short-term borrowings was approximately 3.9 percent (2004 — 3.4 percent; 2003 — 3.7 percent).

Note 10

Accounts Payable and Accrued Liabilities

	2005	2004	2003
Trade payables	$ 88	$ 110	$ 58
Accrued liabilities	1,247	760	804
Dividend payable	530	280	42
Commodity contract settlements	—	50	8
Stock-based compensation	130	49	—
Current income taxes	164	119	117
Other	232	130	107
	$2,391	$1,498	$1,136

Note 11

Long-term Debt

	Maturity	Cdn $ Amount 2005	Cdn $ Amount 2004	Cdn $ Amount 2003	U.S. $ Denominated 2005	U.S. $ Denominated 2004	U.S. $ Denominated 2003
Long-term debt							
Syndicated credit facility		$ —	$ 70	$ —	$ —	$ —	$ —
Bilateral credit facilities		—	40	—	—	—	—
7.125% notes	2006	175	181	194	150	150	150
6.25% notes	2012	467	481	517	400	400	400
7.55% debentures	2016	233	241	258	200	200	200
6.15% notes	2019	350	361	—	300	300	—
Private placement notes		—	18	41	—	15	32
8.45% senior secured bonds	2006	99	140	188	85	117	145
Medium-term notes		—	—	200	—	—	—
Medium-term notes	2007	100	100	100	—	—	—
Medium-term notes	2009	200	200	200	—	—	—
8.90% capital securities	2028	262	271	291	225	225	225
Total long-term debt		1,886	2,103	1,989	$1,360	$1,407	$1,152
Amount due within one year		(274)	(56)	(259)			
		$1,612	$2,047	$1,730			

Interest — net for the years ended December 31 was as follows:

	2005	2004	2003
Long-term debt	$ 144	$133	$158
Short-term debt	4	3	2
	148	136	160
Amount capitalized	(114)	(75)	(52)
	34	61	108
Interest income	(2)	(1)	(6)
	$ 32	$ 60	$102

Foreign exchange for the years ended December 31 was as follows:

	2005	2004	2003
Gain on translation of U.S. dollar denominated long-term debt	$(51)	$(150)	$(382)
Cross currency swaps	14	27	73
Other losses	6	3	27
	$(31)	$(120)	$(282)

As at December 31, 2005, other assets included $21 million (2004 — $24 million; 2003 — $22 million) of deferred debt issue costs.

Credit Facilities

The revolving syndicated credit facility allows the Company to borrow up to $1 billion in either Canadian or U.S. currency from a group of banks on an unsecured basis. The facility is structured as a three-year committed revolving credit facility. 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.

The Company's $150 million revolving bilateral credit facilities have substantially the same terms as the syndicated credit facility.

Notes and Debentures

The 7.125 percent notes and the 7.55 percent debentures represent unsecured securities issued under a trust indenture dated October 31, 1996. These securities mature in 2006 and 2016, respectively. The 7.125 percent notes are not redeemable prior to maturity. Interest is payable semi-annually.

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

On August 12, 2004, the Company filed a base shelf prospectus with securities regulatory authorities in Canada and the United States. The prospectus permits Husky to offer for sale, from time to time, up to U.S. $1 billion of debt securities during the 25-month period from August 12, 2004. No notes have been issued under the base shelf prospectus as of December 31, 2005.

The 8.45 percent senior secured bonds represent securities issued by a subsidiary under a trust indenture dated July 20, 1999. These securities amortize semi-annually. Such securities were issued in connection with the financing of the Company's share of the costs for the exploration and development of the Terra Nova oilfield located off the East Coast of Canada. Interest is payable semi-annually. The Company has the option of delaying the repayment schedule by one year. The Company, through a wholly owned partnership, owns 12.51 percent of the Terra Nova oilfield and associated facilities. The repayment of the securities is contracted to be made solely from revenue from the Terra Nova oilfield. There is also a charge created by the partnership on its interest in the assets of the Terra Nova oilfield and associated facilities in favour of the security holders. Certain related financial obligations require collateral of letters of credit and/or cash equivalents. As at December 31, 2005, letters of credit totalling $41 million (2004 and 2003 — $54 million) were outstanding. The Company redeemed these bonds in full on February 1, 2006.

The medium-term notes Series B represent unsecured securities issued under a trust indenture dated February 3, 1997 and the Series E notes represent unsecured securities issued under a trust indenture dated May 4, 1999. The amounts, rates and maturities are as follows:

Issue	Amount	Interest Rate	Maturity Date
Series B	$100	6.85%	February 2007
Series E	$200	6.95%	July 2009

Interest is payable semi-annually on all series.

The 8.90 percent capital securities represent unsecured securities under an indenture dated August 10, 1998. Such securities rank junior to all senior debt and other financial debt of the Company. The 8.90 percent interest is payable semi-annually until August 15, 2008. The capital securities mature in 2028. They are redeemable, in whole or in part, by the Company at any time prior to August 15, 2008 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 plus an applicable spread. They are redeemable at par, in whole but not in part, by the Company on or after August 15, 2008. If not redeemed in whole, commencing on August 15, 2008, the interest rate changes to a floating rate equal to U.S. LIBOR plus 5.50 percent payable semi-annually. The Company has the right at any time prior to maturity, subject to certain conditions, to defer payment of interest for up to five years. The Company also has the unrestricted ability to settle its deferred interest, principal and redemption obligations through the issuance of common or preferred shares.

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.

Capital Securities Restatement

In November 2003, the Accounting Standards Board revised recommendations in CICA section 3860, ''Financial Instruments — Disclosure and Presentation'', on the classification of obligations that must or could be settled with an entity's own equity instruments. The new recommendations were effective January 1, 2005 and resulted in the Company's capital securities being classified as liabilities instead of equity. The accrued return on the capital securities and the issue costs are classified outside of shareholders' equity. The return on the capital securities is a charge to earnings. The revision was applied retroactively effective January 1, 2005 and resulted in the following changes to the Company's financial statements:

	2004			2003		
	As Reported	Change	As Restated	As Reported	Change	As Restated
Consolidated Balance Sheets						
Assets						
Other assets	$ 106	$ 2	$ 108	$ 112	$ 3	$ 115
Liabilities and Shareholders' Equity						
Accounts payable and accrued liabilities	1,489	9	1,498	1,126	10	1,136
Long-term debt	1,776	271	2,047	1,439	291	1,730
Capital securities and accrued return	278	(278)	—	298	(298)	—
Consolidated Statements of Earnings						
Interest — net	$ 33	$ 27	$ 60	$ 73	$ 29	$ 102
Foreign exchange	(99)	(21)	(120)	(215)	(67)	(282)
Future income taxes	103	(6)	97	329	2	331
Net earnings	1,006	—	1,006	1,334	36	1,370

Note 12

Other Long-term Liabilities

	2005	2004	2003
Asset retirement obligations	$557	$509	$432
Cross currency swaps	40	68	41
Interest rate swaps	42	18	26
Employee future benefits	27	23	20
Stock-based compensation	46	14	—
Other	18	—	—
	$730	$632	$519

Asset Retirement Obligations

At December 31, 2005, the estimated total undiscounted inflation adjusted amount required to settle the asset retirement obligations was $3.3 billion. These obligations will be settled at the end of the useful lives of the underlying assets, which currently extend up to 50 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2 percent to 6.4 percent.

Changes to the asset retirement obligations were as follows:

	2005	2004	2003
Asset retirement obligations at beginning of year	$509	$432	$286
Liabilities incurred	63	13	158
Liabilities disposed	(7)	—	—
Liabilities settled	(41)	(40)	(34)
Revisions	—	77	—
Accretion	33	27	22
Asset retirement obligations at end of year	$557	$509	$432

Note 13

Income Taxes

The provision for income taxes in the Consolidated Statements of Earnings reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31 were accounted for as follows:

	2005	2004	2003
Earnings before income taxes			
Canadian	$2,553	$1,165	$1,625
Foreign jurisdictions	259	240	223
	2,812	1,405	1,848
Statutory income tax rate *(percent)*	38.4	39.3	40.2
Expected income tax	1,080	552	743
Effect on income tax of:			
Royalties, lease rentals and mineral taxes payable to the crown	105	153	175
Resource allowance on Canadian production income	(133)	(156)	(183)
Rate benefit on partnership earnings	(69)	(42)	(23)
Change in statutory tax rate	(4)	(40)	(161)
Non-deductible capital taxes	15	20	22
Capital gains and losses	(140)	(23)	(58)
Foreign jurisdictions	(14)	(13)	(16)
Other — net	(31)	(52)	(21)
Income tax expense	$ 809	$ 399	$ 478

The future income tax liability at December 31 comprised the tax effect of temporary differences as follows:

	2005	2004	2003
Future tax liabilities			
Property, plant and equipment	$3,487	$2,949	$2,826
Foreign exchange gains taxable on realization	60	56	32
Other temporary differences	2	5	2
	3,549	3,010	2,860
Future tax assets			
Asset retirement obligations	195	180	160
Loss carry forwards	—	11	2
Provincial royalty rebates	7	14	52
Other temporary differences	77	47	25
	279	252	239
	$3,270	$2,758	$2,621

Note 14

Commitments and Contingencies

Certain former owners of interests in the upgrading assets retained a 20-year upside financial interest expiring in 2014 which requires payments to them when the average differential between heavy crude oil feedstock and synthetic crude oil exceeds $6.50 per barrel. The calculation is based on a two-year rolling average of the differential. During 2005, the Company capitalized $68 million (2004 — $27 million; 2003 — $10 million) of payments under this arrangement.

At December 31, 2005, the Company had commitments for non-cancellable operating leases and other long-term agreements that require the following minimum future payments:

	2006	2007	2008	2009	2010	After 2010	Total
Operating leases	$ 81	$ 82	$ 76	$ 68	$ 63	$132	$ 502
Firm transportation agreements	169	133	110	68	50	149	679
Unconditional purchase obligations	616	656	565	127	44	9	2,017
Lease rentals and exploration work agreements	50	54	44	44	81	154	427
Engineering and construction commitments	365	154	12	—	—	—	531
	$1,281	$1,079	$807	$307	$238	$444	$4,156

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity. In 2005 a lawsuit was settled with proceeds received and the resulting gain was recognized in earnings and recorded in other — net.

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 future income taxes.

Note 15

Share Capital

The Company's authorized share capital is as follows:

Common shares — an unlimited number of no par value.

Preferred shares — an unlimited number of no par value, none outstanding.

Common Shares

Changes to issued share capital were as follows:

	Number of Shares	Amount
December 31, 2002	417,873,601	$3,406
Options and warrants exercised	4,302,141	51
December 31, 2003	422,175,742	3,457
Stock-based compensation — adoption	—	23
Options and warrants exercised	1,560,672	26
December 31, 2004	423,736,414	3,506
Options and warrants exercised	388,664	17
December 31, 2005	424,125,078	$3,523

Stock Options

At December 31, 2005, 20.4 million common shares were reserved for issuance under the Company stock option plan. As described in note 3 m), on June 1, 2004, the Company modified its stock option plan to a tandem plan that provides the stock option holder with the right to exercise the option or surrender the option for a cash payment. The exercise price of the option is equal to the average market price of the Company's common shares during the five trading days prior to the date of the award. When the option is surrendered for cash, the cash payment is the difference between the average market price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option. Under the stock option plan the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year.

A downward adjustment of $0.55 was made to the exercise price of all outstanding stock options effective December 1, 2005, pursuant to the terms of the stock option plan under which the options were issued as a result of the special $1.00 per share dividend that was declared in November 2005. Similar downward adjustments of $0.48 in 2004 and $0.82 in 2003 were made to the exercise price of all outstanding stock options as a result of a special dividend declared in each of those years.

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

	Number of Options	Weighted Average Exercise Prices	Weighted Average Contractual Life	Options Exercisable
	(thousands)		(years)	(thousands)
December 31, 2002	7,920	$13.91	3	4,822
Granted	591	$19.17	5	
Exercised for common shares	(3,789)	$13.45	2	
Forfeited	(125)	$14.71	2	
December 31, 2003	4,597	$13.88	2	3,564
Granted	8,200	$25.10	4	
Exercised for common shares	(1,350)	$13.11	1	
Surrendered for cash	(1,269)	$13.32	1	
Forfeited	(214)	$22.73	4	
December 31, 2004	9,964	$22.61	4	1,417
Granted	670	$48.14	5	
Exercised for common shares	(359)	$15.84	1	
Surrendered for cash	(2,443)	$19.05	2	
Forfeited	(547)	$24.10	3	
December 31, 2005	7,285	$25.81	3	1,533

Range of Exercise Price	As at December 31, 2005				
	Outstanding Options			Options Exercisable	
	Number of Options	Weighted Average Exercise Prices	Weighted Average Contractual Life	Number of Options	Weighted Average Exercise Prices
	(thousands)		(years)	(thousands)	
$13.67 — $14.99	187	$14.32	2	144	$14.17
$15.00 — $22.99	234	$19.44	3	116	$19.98
$23.00 — $23.99	5,977	$23.83	3	1,252	$23.83
$24.00 — $39.99	392	$32.11	4	21	$30.60
$40.00 — $55.14	495	$52.12	5	—	$ —
	7,285	$25.81	3	1,533	$22.72

Warrants

In 2000, the Company granted 1.4 million Renaissance Energy Ltd. (''Renaissance'') replacement options to purchase common shares of Husky in exchange for certain share purchase options to purchase common shares of Renaissance previously held by employees of Renaissance. The former shareholders of Husky Oil Limited were also granted warrants to acquire, for no additional consideration, 1.86 common shares of the Company for each common share issued on the exercise of a Renaissance replacement option. During 2005, 16,000 warrants were exercised (2004 — 113,600; 2003 — 276,500). As at December 31, 2005, there were no Renaissance replacement options or warrants outstanding.

Earnings per Common Share

	2005	2004	2003
Net earnings	$2,003	$1,006	$1,370
Weighted average number of common shares outstanding			
Basic *(millions)*	424.0	423.4	419.5
Effect of dilutive stock options and warrants	—	0.9	2.0
Weighted average number of common shares outstanding			
Diluted *(millions)*	424.0	424.3	421.5
Earnings per share			
Basic	$ 4.72	$ 2.37	$ 3.26
Diluted	$ 4.72	$ 2.37	$ 3.25

Stock-based Compensation

As described in note 3 m), beginning January 1, 2004, stock-based compensation is being recognized in earnings. This change was adopted retroactively without restatement of prior periods and resulted in a decrease to retained earnings of $44 million, an increase to contributed surplus of $21 million and an increase to share capital of $23 million on January 1, 2004. If the Company had applied the fair value method retroactively with restatement of prior periods for all options granted, the Company's net earnings and earnings per share for the year ended December 31, 2003 would have been as follows:

	2003
Compensation cost — all options granted (1)	$ 14
Net earnings available to common shareholders	
As reported	$1,370
As restated	$1,356
Weighted average number of common shares outstanding *(millions)*	
Basic	419.5
Diluted	421.5
Basic earnings per share	
As reported	$ 3.26
As restated	$ 3.23
Diluted earnings per share	
As reported	$ 3.25
As restated	$ 3.22

(1) Includes options modified.

As described in note 3 m), effective June 1, 2004, the Company modified the stock option plan to a tandem plan. Prior to the modification, the fair values of all common share options granted were estimated on the date of grant using the Black-Scholes option-pricing model. The grant date fair values and assumptions used prior to June 1, 2004 were:

	2004	2003
Weighted average fair value per option	$5.67	$4.00
Risk-free interest rate *(percent)*	3.1	3.9
Volatility *(percent)*	21	23
Expected life *(years)*	5	5
Expected annual dividend per share	$0.44	$0.36

As a result of the downward adjustment of $0.82 to the exercise price of all outstanding options effective September 3, 2003, the fair values of all common share options granted prior to that date were revalued on September 3, 2003 using the Black-Scholes option-pricing model. The weighted average fair value of outstanding stock options as at September 3, 2003 and the assumptions used are noted below:

Weighted average fair value per option	$7.14
Risk-free interest rate *(percent)*	2.8
Volatility *(percent)*	20
Expected life *(years)*	2.3
Expected annual dividend per share	$0.40

Dividends

During 2005, the Company declared dividends of $1.65 per common share (2004 — $1.00 per common share; 2003 — $1.38 per common share), including a special dividend of $1.00 per common share (2004 — $0.54 per common share; 2003 — $1.00 per common share).

Contributed Surplus

Changes to contributed surplus were as follows:

	2004
December 31, 2003	$ —
Stock-based compensation — adoption	21
Stock-based compensation cost	1
Stock options exercised	(6)
Modification of stock option plan — June 1, 2004	(16)
December 31, 2004	$ —

Note 16

Employee Future Benefits

The Company currently provides a defined contribution pension plan for all qualified employees. The Company also maintains a defined benefit pension plan, which is closed to new entrants, and all current participants are vested. The Company also provides certain health and dental coverage to its retirees which is accrued over the expected average remaining service life of the employees.

Weighted average long-term assumptions are based on independent historical and projected references and are noted below:

	2005	2004	2003
Discount rate *(percent)*	5.8	6.0	6.0
Long-term rate of increase in compensation levels *(percent)*	5.0	5.0	5.0
Long-term rate of return on plan assets *(percent)*	7.5	8.0	8.0

The discount rate used at the end of 2005 to determine the accrued benefit obligation was 5.0 percent.

The long-term rate of return on the assets was determined based on management's best estimate and the historical rates of return, adjusted periodically. The rate at the end of 2005 was 7.5 percent.

The average health care cost trend used was eight percent, which is reduced by 0.50 percent until 2009. The average dental care cost trend used was four percent, which remains constant.

Defined Benefit Pension Plan

The status of the defined benefit pension plan at December 31 was as follows:

Benefit Obligation

	2005	2004	2003
Benefit obligation, beginning of year	$124	$118	$108
Current service cost	2	2	2
Interest cost	7	7	7
Benefits paid	(6)	(6)	(6)
Actuarial losses	11	3	7
Benefit obligation, end of year	$138	$124	$118

Fair Value of Plan Assets

	2005	2004	2003
Fair value of plan assets, beginning of year	$ 96	$85	$77
Contributions	11	10	8
Benefits paid	(6)	(6)	(6)
Expected return on plan assets	7	7	6
Gain on plan assets	—	1	2
Foreign exchange losses	—	(1)	(2)
Fair value of plan assets, end of year	$108	$96	$85

Funded Status of Plan

	2005	2004	2003
Fair value of plan assets	$108	$ 96	$ 85
Benefit obligation	(138)	(124)	(118)
Excess obligation	(30)	(28)	(33)
Unrecognized past service costs	1	1	1
Unrecognized losses	40	32	32
Accrued benefit asset	$ 11	$ 5	$ —

Husky adheres to a Statement of Investment Policies and Procedures (the ''Policy''). The 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 date of the last actuarial valuation for the Company was January 1, 2005.

The composition of the defined benefit pension plan assets was as follows:

	2005	2004	2003
U.S. common equities	—%	15%	15%
Canadian common equities	29	25	28
International equity mutual funds	28	11	10
Canadian equity mutual funds	—	—	2
Canadian government bonds	18	25	29
Canadian corporate bonds	3	16	12
Canadian fixed income mutual funds	20	—	—
Cash and receivables	2	8	4
Total	100%	100%	100%

During 2005, Husky contributed $11 million to the defined benefit pension plan assets, $9 million of which was in respect of additional contributions as a result of the plan's deficiency. Husky currently plans to contribute $10 million in 2006.

The Company amortizes the portion of the unrecognized actuarial gains or losses that exceed 10 percent of the greater of the accrued benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets. The gains or losses that are in excess of 10 percent are amortized over the expected future years of service, which is currently seven years.

The past service costs are amortized over the expected future years of service.

Post-retirement Health and Dental Care Plan

The status of the post-retirement health and dental care plan at December 31 was as follows:

Benefit Obligation

	2005	2004	2003
Benefit obligation, beginning of year	$ 25	$ 23	$ 21
Current service cost	2	2	2
Interest cost	1	1	1
Benefits paid	—	(1)	(1)
Actuarial losses	5	—	—
Benefit obligation, end of year	$ 33	$ 25	$ 23

Funded Status of Plan

	2005	2004	2003
Benefit obligation	$(33)	$(25)	$(23)
Unrecognized losses	6	2	3
Accrued benefit liability	$(27)	$(23)	$(20)

The assumed health care cost trend can have a significant effect on the amounts reported for Husky's post-retirement health and dental care plan. A one percent increase and decrease in the assumed trend rate would have the following effect:

	1% Increase	1% Decrease
Effect on total service and interest cost components	$ 1	$ —
Effect on post-retirement benefit obligation	$ 6	$ (5)

Pension Expense and Post-retirement Health and Dental Care Expense

The expenses for the years ended December 31 were as follows:

Pension Expense

	2005	2004	2003
Defined benefit pension plan			
Employer current service cost	$ 2	$ 2	$ 2
Interest cost	7	7	7
Expected return on plan assets	(7)	(7)	(6)
Amortization of net actuarial losses	3	2	2
	5	4	5
Defined contribution pension plan	14	12	11
Total expense	$ 19	$ 16	$ 16

Post-retirement Health and Dental Care Expense

	2005	2004	2003
Employer current service cost	$ 2	$ 2	$ 2
Interest cost	1	1	1
Total expense	$ 3	$ 3	$ 3

Future Benefit Payments

The following table discloses the current estimate of future benefit payments:

	Defined Benefit Pension Plan	Post-retirement Health and Dental Care Plan
2006	$ 7	$ 1
2007	7	1
2008	8	1
2009	8	1
2010	8	1
2011 - 2015	46	7

Note 17

Related Party Transactions

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, Husky paid approximately $10 million for office space in Western Canadian Place during 2004 (2003 — $17 million).

Note 18

Financial Instruments and Risk Management

Carrying Values and Estimated Fair Values of Financial Assets and Liabilities

The carrying value of cash and cash equivalents, accounts receivable, bank operating loans, accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of these instruments.

The fair value of the long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates. The estimated fair value of the long-term debt at December 31 was as follows:

	2005		2004		2003	
	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$1,886	$1,995	$2,103	$2,296	$1,989	$2,209

Unrecognized Gains (Losses) on Derivative Instruments

	2005	2004	2003
Commodity price risk management			
Natural gas	$ —	$ (9)	$ (8)
Crude oil	—	—	(109)
Power consumption	—	(1)	2
Interest rate risk management			
Interest rate swaps	7	52	31
Foreign currency risk management			
Foreign exchange contracts	(32)	(30)	(19)
Foreign exchange forwards	—	—	15

Commodity Price Risk Management

Natural Gas Production

During 2005 the impact of hedging was a loss of $17 million (2004 — loss of $1 million; 2003 — gain of $16 million).

Crude Oil Production

The Company did not have a hedge program in 2005. The impact of hedging in 2004 and 2003 was a loss of $560 million and $36 million, respectively.

Power Consumption

The impact of the 2005 hedge program was a gain of $4 million (2004 — gain of $3 million).

Natural Gas Contracts

The Company has a portfolio of fixed and basis price offsetting physical forward purchase and sale natural gas contracts relating to marketing of other producers' natural gas. The objective of these contracts is to ''lock in'' a positive spread between the physical purchase and sale contract prices. At December 31, 2005, the Company had the following offsetting physical purchase and sale contracts:

	Volumes	Unrecognized Gain (Loss)
	(mmcf)	
Physical purchase contracts	35,261	$ 29
Physical sale contracts	(35,261)	$(28)

Interest Rate Risk Management

The majority of the Company's long-term debt has fixed interest rates and various maturities. The Company periodically uses interest rate swaps to manage its financing costs. At December 31, 2005, the Company had entered into interest rate swap arrangements whereby the fixed interest rate coupon on certain debt was swapped to floating rates with the following terms:

Debt	Amount	Swap Maturity	Swap Rate
			(percent)
6.95% medium-term notes	$200	July 14, 2009	CDOR + 175 bps

During 2005 the Company realized a gain of $13 million (2004 — gain of $22 million; 2003 — gain of $17 million) from interest rate risk management activities.

In 2005 and 2003, the Company unwound interest rate swaps for proceeds of $37 million and $44 million, respectively. The proceeds have been deferred and are being amortized to income over the remaining term of the underlying debt.

Foreign Currency Risk Management

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

At December 31, 2005, the Company had the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate
				(percent)
7.125% notes	U.S. $150	$218	November 15, 2006	8.74
6.25% notes	U.S. $150	$212	June 15, 2012	7.41
6.25% notes	U.S. $ 75	$ 90	June 15, 2012	5.65
6.25% notes	U.S. $ 50	$ 59	June 15, 2012	5.67
6.25% notes	U.S. $ 75	$ 88	June 15, 2012	5.61

The Company hedged U.S. dollar revenues for various amounts and maturities through 2005 using foreign exchange forwards. On November 10, 2004, the Company unwound its long-dated forwards, which resulted in a gain of $8 million that was deferred and was recognized into income during 2005 on the dates that the underlying hedged transactions took place.

During 2005 the Company recognized a gain of $1 million (2004 — loss of $13 million; 2003 — loss of $56 million) from foreign currency risk management activities.

Credit Risk

Accounts receivable are predominantly with customers in the energy industry and are subject to normal industry credit risks.

In addition, the Company is exposed to credit related losses in the event of non-performance by counterparties to its derivative financial instruments. The Company's policy is to primarily deal with major financial institutions and investment grade rated entities to mitigate these risks.

Husky did not have any customers that constituted more than 10 percent of total sales and operating revenues during 2005.

Note 19

Reconciliation to Accounting Principles Generally Accepted in the United States

The Company's consolidated financial statements have been prepared in accordance with GAAP in Canada, which differ in some respects from those in the United States. Any differences in accounting principles as they pertain to the accompanying consolidated financial statements were insignificant except as described below:

Consolidated Statements of Earnings

	2005	2004	2003
Net earnings under Canadian GAAP (1)	$2,003	$1,006	$1,370
Adjustments:			
Full cost accounting (a)	66	37	80
Related income taxes	(23)	(13)	(29)
Derivatives and hedging (b)	—	—	(1)
Related income taxes	—	—	1
Energy trading contracts (c)	—	(1)	(15)
Related income taxes	—	—	6
Stock-based compensation (e)	—	2	(46)
Earnings before cumulative effect of change in accounting principle under U.S. GAAP	2,046	1,031	1,366
Cumulative effect of change in accounting principle, net of tax (d)	—	—	9
Net earnings under U.S. GAAP	$2,046	$1,031	$1,375
Weighted average number of common shares outstanding under U.S. GAAP *(millions)*			
Basic	424.0	423.4	419.5
Diluted	424.0	424.3	421.5
Earnings per share before cumulative effect of change in accounting principle under U.S. GAAP			
Basic	$ 4.83	$ 2.44	$ 3.26
Diluted	$ 4.83	$ 2.43	$ 3.24
Earnings per share under U.S. GAAP			
Basic	$ 4.83	$ 2.44	$ 3.28
Diluted	$ 4.83	$ 2.43	$ 3.26

(1) 2004 and 2003 amounts as restated (notes 3 and 11).

Condensed Consolidated Balance Sheets

	2005		2004		2003	
	Canadian GAAP	U.S. GAAP	Canadian GAAP (1)	U.S. GAAP	Canadian GAAP (1)	U.S. GAAP
Current assets (b)(c)	$ 1,616	$ 1,672	$ 779	$ 837	$ 852	$ 911
Property, plant and equipment, net (a)	13,959	13,465	12,193	11,633	10,862	10,264
Other assets (i)	222	223	268	269	235	236
	$15,797	$15,360	$13,240	$12,739	$11,949	$11,411
Current liabilities (b)(c)(i)	$ 2,665	$ 2,766	$ 1,603	$ 1,656	$ 1,466	$ 1,628
Long-term debt (b)	1,612	1,670	2,047	2,124	1,730	1,794
Other long-term liabilities (b)	730	688	632	614	519	493
Future income taxes (a)(b)(c)(d)(i)	3,270	3,089	2,758	2,555	2,621	2,372
Share capital (e)(f)(g)	3,523	3,757	3,506	3,740	3,457	3,737
Retained earnings	3,997	3,431	2,694	2,085	2,156	1,478
Accumulated other comprehensive income						
Cash flow hedges, net of tax (b)	—	(21)	—	(20)	—	(76)
Minimum pension liability, net of tax (i)	—	(20)	—	(15)	—	(15)
	$15,797	$15,360	$13,240	$12,739	$11,949	$11,411

(1) 2004 and 2003 amounts as restated (notes 3 and 11).

Condensed Consolidated Statements of Retained Earnings and Accumulated Other Comprehensive Income

	2005		2004		2003	
	Canadian GAAP	U.S. GAAP	Canadian GAAP (1)	U.S. GAAP	Canadian GAAP (1)	U.S. GAAP
Retained earnings, beginning of year	$2,694	$2,085	$2,156	$1,478	$1,366	$ 683
Net earnings	2,003	2,046	1,006	1,031	1,370	1,375
Dividends on common shares	(700)	(700)	(424)	(424)	(580)	(580)
Stock-based compensation — retroactive adoption (e)	—	—	(44)	—	—	—
Retained earnings, end of year	$3,997	$3,431	$2,694	$2,085	$2,156	$1,478
Accumulated other comprehensive income, beginning of year	$ —	$ (35)	$ —	$ (91)	$ —	$ (17)
Cash flow hedges, net of tax (b)	—	(1)	—	56	—	(69)
Minimum pension liability, net of tax (i)	—	(5)	—	—	—	(5)
Accumulated other comprehensive income, end of year	$ —	$ (41)	$ —	$ (35)	$ —	$ (91)

(1) 2004 and 2003 amounts as restated (notes 3 and 11).

Condensed Consolidated Statements of Earnings and Comprehensive Income

	2005		2004		2003	
	Canadian GAAP	U.S. GAAP	Canadian GAAP (1)	U.S. GAAP	Canadian GAAP (1)	U.S. GAAP
Sales and operating revenues (b)(c)(h)	$10,245	$8,445	$8,440	$7,038	$7,658	$6,823
Costs and expenses (b)(c)(e)(h)	6,112	4,312	5,769	4,366	4,665	3,892
Accretion expense	33	33	27	27	22	22
Depletion, depreciation and amortization (a)	1,256	1,190	1,179	1,142	1,021	941
Interest — net	32	32	60	60	102	102
Earnings before income taxes	2,812	2,878	1,405	1,443	1,848	1,866
Income taxes (a)(b)(c)	809	832	399	412	478	500
Earnings before cumulative effect of change in accounting principle	2,003	2,046	1,006	1,031	1,370	1,366
Cumulative effect of change in accounting principle, net of tax (d)	—	—	—	—	—	9
Net earnings	2,003	2,046	1,006	1,031	1,370	1,375
Other comprehensive income (b)(i)	—	6	—	(56)	—	74
Comprehensive income	$ 2,003	$2,052	$1,006	$ 975	$1,370	$1,449

(1) 2004 and 2003 amounts as restated (notes 3 and 11).

The increases or decreases noted above refer to the following differences between U.S. GAAP and Canadian GAAP:

(a) Under Canadian GAAP the ceiling test is performed by comparing the carrying value of the cost centre based on the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach of proved plus probable reserves using future prices. Under U.S. GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and gas reserves using a discount factor of 10 percent. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable year-end. At December 31, 2001, the Company recognized a U.S. GAAP ceiling test write down of $334 million after tax. Depletion expense for U.S. GAAP is reduced by $62 million (2004 — $76 million; 2003 — $80 million), net of tax of $21 million (2004 — $27 million; 2003 — $30 million).

Under U.S. GAAP, prices used in the reserve determination were those in effect at the applicable year-end. For Canadian GAAP, forecast prices are used in the reserve determination. The different prices result in a lower reserve base for U.S. GAAP. Additional depletion of $39 million, net of taxes of $14 million was recorded under U.S. GAAP in December 2004. As of the first quarter of 2005 these reserves have become economical again and are included in the reserve base resulting in a reduction to depletion expense for U.S. GAAP of $4 million, net of tax of $2 million.

(b) The Company records all derivative instruments as assets and liabilities on the balance sheet based on their fair values as required under FAS 133, ''Accounting for Derivative Instruments and Hedging Activities''. At December 31, 2005, the Company recorded additional assets and liabilities for U.S. GAAP purposes of $7 million (2004 — $52 million; 2003 — $52 million) and $39 million (2004 — $93 million; 2003 — $172 million), respectively, for the fair values of derivative financial instruments. The Company also recorded a gain of less than $1 million, net of tax (2004 — loss of less than $1 million; 2003 — loss of $2 million), in revenue for U.S. GAAP purposes with respect to derivatives designated as fair value hedges relating to commodity price risk. In addition, the amount included in other comprehensive income was increased by $1 million net of tax (2004 — decreased by $51 million; 2003 — increased by $69 million), for changes in the fair values of the derivatives designated as hedges of cash flows relating to commodity price risk, foreign exchange risk and the transfer to income of amounts

applicable to cash flows occurring in 2005. In 2004, the Company unwound its long-dated foreign exchange forwards. The unrealized gain of $5 million, net of tax was deferred in other comprehensive income and recognized in 2005 when the underlying transactions took place. In 2005 and 2003 the Company unwound interest rate swaps that were fair value hedges of debt for proceeds of $37 million and $44 million, respectively. Under Canadian GAAP, the proceeds received have been recorded to current and long-term liabilities and are being deferred over the life of the debt. For U.S. GAAP purposes, the balance in the current and long-term liabilities has been reclassified to long-term debt consistent with fair value hedge treatment. In prior years, the gains net of tax (2003 — $1 million), on foreign currency derivatives and natural gas basis swaps that did not qualify for hedge accounting under FAS 133 were included in income for U.S. GAAP purposes.

(c) Under U.S. GAAP, natural gas purchase and sale contracts related to energy trading activities are recorded at fair value in accordance with Emerging Issues Task Force 02-03, ''Issues Involved in Accounting for Derivative Contracts held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities''. Under Canadian GAAP, the impact of energy trading contracts is recorded as they settle. Under U.S. GAAP, at December 31, 2005 the Company recorded additional assets and liabilities of $49 million (2004 — $4 million; 2003 — $7 million) and $48 million (2004 — $3 million; 2003 — $5 million), respectively, and included the resulting unrealized gain, net of tax of less than $1 million (2004 — loss of $1 million; 2003 — loss of $9 million), in earnings for the year. Under U.S. GAAP, gains and losses on energy trading contracts have been netted against sales and operating revenues.

(d) In 2003, the Company adopted FAS 143, ''Accounting for Asset Retirement Obligations'', which requires the fair value of a liability for an asset retirement obligation to be recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related tangible long-lived asset. The standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and normal use of the asset. The liability is accreted at the end of each period through charges to accretion expense. The change was effective January 1, 2003, and the related cumulative effect of change in accounting principle to net earnings to December 31, 2002 was an increase of $20 million, net of tax of $11 million or $0.02 per share (diluted). Effective January 1, 2004, under Canadian GAAP the Company adopted CICA section 3110, ''Asset Retirement Obligations'', which is substantially the same as the recommendations in FAS 143. CICA section 3110 was adopted retroactively with restatement. The application of asset retirement obligations did not have a material impact on the Company's depletion, depreciation and amortization rate. There was no impact on the Company's cash flow as a result of adopting asset retirement obligations.

(e) On September 3, 2003, the Company modified the exercise price of all outstanding options. Under U.S. GAAP these options are required to be accounted for using variable accounting where the in-the-money portion of the vested stock options outstanding is adjusted through the statement of earnings as compensation expense over the remaining vesting period.

Effective January 1, 2004, under Canadian GAAP, the Company adopted fair value accounting for stock-based compensation retroactively without restatement, which is consistent with the recommendations in FAS 123, ''Accounting for Stock-based Compensation — Transition and Disclosure''. As a result, the compensation expense of $46 million for the year ended December 31, 2003 was reversed through earnings and a compensation expense of $44 million was recognized for the fair value of all stock options.

(f) As a result of the reorganization of the capital structure which occurred in 2000, the deficit of Husky Oil Limited of $160 million was eliminated. Elimination of the deficit would not be permitted under U.S. GAAP.

(g) Until 1997 the Company recorded interest waived on subordinated shareholders' loans and dividends waived on Class C shares as a reduction of ownership charges. Under U.S. GAAP, waived interest and dividends in those years would be recorded as interest on subordinated shareholders' loans and dividends on Class C shares and as capital contributions.

(h) Under U.S. GAAP, transportation costs are included in cost of sales. Effective January 1, 2004, for Canadian purposes, certain transportation costs that were previously netted against revenue are now being recorded as cost of sales on a prospective basis. Transportation costs for 2003 were $112 million.

(i) The Company amortizes the portion of the unrecognized gains or losses that exceed 10 percent of the greater of the projected benefit obligation or the market-related value of pension plan assets. The market-related value of pension plan assets is the fair value of the assets or a calculated value that recognizes changes in fair value over not more than five years. Under U.S. GAAP, an additional minimum liability is recognized if the unfunded accumulated benefit obligation exceeds the unfunded pension cost already recognized. If an additional minimum liability is recognized, an amount equal to the unrecognized prior service cost is recognized as an intangible asset and any excess is reported in other comprehensive income. At December 31, 2005, the additional minimum liability was increased by $6 million (2004 — decrease of $1 million; 2003 — increase of $6 million) with a decrease to other comprehensive income of $5 million (2004 — decrease of less than $1 million; 2003 — decrease of $5 million), net of tax.

Additional U.S. GAAP Disclosures

Corporate Acquisitions

As described in note 7, Corporate Acquisitions, the Company purchased all of the outstanding shares of Temple Exploration Inc. and Marathon Canada Limited. The Company also purchased the Western Canadian assets of Marathon International Petroleum Canada, Ltd. These transactions increased the reserve base and created cost efficiencies, increasing shareholder value.

Accounting for Derivative Instruments and Hedging Activities

Effective January 1, 2001, the Company adopted the provisions of FAS 133, which require that all derivatives be recognized as assets and liabilities on the balance sheet and measured at fair value. Gains or losses, including unrealized amounts, on derivatives that have not been designated as hedges are included in earnings as they arise.

For derivatives designated as fair value hedges, changes in the fair value are recognized in earnings together with equal or lesser amounts of changes in the fair value of the hedged item. No portion of the fair value of the derivatives related to time value has been excluded from the assessment of hedge effectiveness in these hedging relationships.

For derivatives designated as cash flow hedges, the portion of the changes in the fair value of the derivatives that are effective in hedging the changes in future cash flows are recognized in other comprehensive income until the hedged items are recognized in earnings. Any portion of the change in the fair value of the derivatives that is not effective in hedging the changes in future cash flows is included in earnings. No portion of the fair value of the derivatives related to time value has been excluded from the assessment of hedge effectiveness in these hedging relationships.

Stock Option Plan

FAS 123 establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by FAS 123, Husky has elected to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board (''APB'') Opinion 25. Since all options were granted with exercise prices equal to the market price, no compensation expense has been charged to income at the time of the option grants. On September 3, 2003, the Company modified the exercise price of all outstanding options, resulting in the use of variable accounting for these modified stock options. The table below provides pro forma amounts prior to the application of variable accounting which required recognition of compensation expense on September 3, 2003. Effective January 1, 2004, the Company adopted CICA section 3870, which requires the Company to record a compensation expense over the vesting period of the options based on the fair value of the options granted. CICA section 3870 is consistent with the recommendations in FAS 123. Had compensation cost for Husky's stock options been determined based on the fair market value at the grant dates of the awards, and amortized on a straight-line basis over the vesting period, consistent with methodology prescribed by FAS 123, Husky's net earnings and earnings per share for the year ended December 31, 2003 would have been the pro forma amounts indicated below:

	2003	
	As Reported	**Pro Forma**
Net earnings under U.S. GAAP	$1,375	$1,407
Earnings per share — Basic	$ 3.28	$ 3.35
— Diluted	$ 3.26	$ 3.34

The fair values of all common share options granted were estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average fair market value of options granted during 2003 and the assumptions used in their determination are the same as described in note 15.

In December 2004, the Financial Accounting Standards Board (''FASB'') issued FAS 123(R), ''Share-based Payment'', which replaces FAS 123 and supersedes APB Opinion 25. FAS 123(R) requires compensation cost related to share-based payments be recognized in the financial statements and that the cost must be measured based on the fair value of the equity or liability instruments issued. Under FAS 123(R) all share-based payment plans must be valued using option-pricing models. For U.S. GAAP, the liability related to the options issued under the Company's tandem plan will be measured at fair value using an option pricing model. Under Canadian GAAP, the liability will be measured based on the intrinsic value of the option. Over the life of the option the amount of compensation expense recognized will differ under U.S. and Canadian GAAP, creating a temporary GAAP timing difference. At exercise or surrender of the option, the compensation expense to be recorded will be equal to the cash payment which will be identical under U.S. and Canadian GAAP and there will no longer be a GAAP difference. FAS 123(R) is effective for the first quarter of 2006.

Depletion, Depreciation and Amortization

Upstream depletion, depreciation and amortization per gross equivalent barrel is calculated by converting natural gas volumes to a barrel of oil equivalent (''boe'') using the ratio of 6 mcf of natural gas to 1 barrel of crude oil (sulphur volumes have been excluded from the calculation). Depletion, depreciation and amortization per boe as calculated under U.S. GAAP for the years ended December 31 were as follows:

	2005	**2004**	**2003**
Depletion, depreciation and amortization per boe	$9.38	$8.76	$7.35

Accounting for Inventory Costs

In November 2004, the FASB issued FAS 151, which clarifies the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted material as they relate to inventory costing. FAS 151 requires these items to be recognized as current period expenses. Additionally, the allocation of fixed production overheads to the cost of inventory should be based on the normal capacity of the production facilities. FAS 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company does not believe that the application of FAS 151 will have an impact on the financial statements.

Accounting for Exchanges of Nonmonetary Assets

In December 2004, the FASB issued FAS 153, which deals with the accounting for the exchanges of nonmonetary assets. FAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. FAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for nonmonetary exchanges of similar productive assets and introduces a broader exception for exchanges of nonmonetary assets that do not have commercial substance. FAS 153 is effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Company does not believe that the application of FAS 153 will have an impact on the financial statements.

Accounting Changes and Error Corrections

In May 2005, the FASB issued FAS 154, which deals with all voluntary changes in accounting principles and changes required by an accounting pronouncement if that pronouncement does not include specific transition provisions. FAS 154 replaces APB Opinion 20, ''Accounting Changes'' and FAS 3, ''Reporting Accounting Changes in Interim Financial Statements''. This Statement requires retrospective application of a change in accounting principle to prior periods' financial statements, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change, in which case the change in principle is applied as if it were adopted prospectively from the earliest date practicable. Corrections of an error require adjusting previously issued financial statements. FAS 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005.

Document C
Form 40-F

MANAGEMENT'S DISCUSSION AND ANALYSIS

February 16, 2006

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INTRODUCTION

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

This MD&A is intended to provide a wide range of readers with information explaining Husky's financial and operational performance against performance in prior periods and expected or planned performance. It also describes our ability to deliver expected results from our current plans.

Review by the Audit Committee

This MD&A was reviewed by the Audit Committee and approved by Husky's Board of Directors on February 16, 2006. Any events subsequent to that date could conceivably materially alter the veracity and usefulness of the information contained in this document. Husky may, but is not obligated, to provide updates to its forward-looking statements in its subsequent interim MD&A filings or in subsequent news releases filed or furnished to regulatory agencies.

Additional Husky Documents that should be considered by the Reader

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 2005, 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 Securities and Exchange Commission (''SEC''), the U.S. regulatory agency. These documents are available at www.sedar.com and www.sec.gov, respectively.

Use of Pronouns and Other Terms Denoting Husky

In this MD&A the pronouns ''we'', ''our'' and ''us'' and the term ''Husky'' denote the corporate entity, Husky Energy Inc. and its subsidiaries on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the year ended December 31, 2005 are compared with results for the year ended December 31, 2004 and, similarly discussions with respect to Husky's financial position as at December 31, 2005 are compared with its financial position at December 31, 2004.

Reclassifications and Materiality for Disclosures

Certain prior year amounts have been reclassified to conform with 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

The Consolidated Financial Statements and all financial information included and incorporated by reference in this MD&A have been prepared in accordance with Canadian generally accepted accounting principles (''GAAP''). The effect of significant differences between Canadian and United States accounting principles is disclosed in Note 19 of the Consolidated Financial Statements.

All dollar amounts are in millions of Canadian dollars, unless otherwise indicated. Unless otherwise indicated, all production volumes quoted are gross, which represent Husky's working interest share before royalties. Prices quoted include or exclude the effect of hedging as indicated. Crude oil has been classified as the following: light crude oil has an API gravity of 30 degrees or more; medium crude oil has an API gravity of 21 degrees or more and less than 30 degrees; heavy crude oil has an API gravity of less than 21 degrees.

The Company uses the terms barrels of oil equivalent (''boe'') and thousand cubic feet of gas equivalent (''mcfge''), which are 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 terms boe and mcfge 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 well head.

Forward-looking Statements

This MD&A contains forward-looking statements. These statements are based on certain estimates and assumptions and involve risks and uncertainties. Actual results may differ materially. See Section 10. ''Forward-looking Statements'' for additional information.

1. VISION

CORE BUSINESSES

Our operations are organized into three major business segments:

Upstream

The upstream business includes the exploration for and development and production of crude oil, natural gas, natural gas liquids (''NGL'') and sulphur. Our upstream operations are primarily located throughout the Western Canada Sedimentary Basin in the provinces of Alberta, Saskatchewan and British Columbia. We also have significant operations off the East Coast of Canada in the Jeanne d'Arc Basin and we are currently evaluating development potential in the Mackenzie Valley in the Northwest Territories. Outside of Canada, we are involved in China including exploration in the South China Sea near Hainan Island and the East China Sea east of Shanghai and production at Wenchang in the South China Sea. In Indonesia, we are in the early stages of developing a natural gas and NGL property in the Madura Strait offshore Java.

Midstream

The midstream business includes the operation of a heavy oil upgrader with a capacity in excess of 60,000 barrels of synthetic crude oil per day located at Lloydminster, Saskatchewan, pipeline systems with combined capacity in excess of 500,000 barrels per day in the heavy oil producing regions between Cold Lake, Alberta south through Lloydminster to Hardisty, Alberta, crude oil and natural gas storage facilities, cogeneration and commodity marketing activities.

Refined Products

The refined products business includes the operation of a recently upgraded 11,000 barrel per day full slate refinery in Prince George, British Columbia, a 25,000 barrel per day asphalt refinery in Lloydminster, Alberta and a marketing and distribution system with locations from the West Coast of Canada to the eastern border of Ontario. We are also currently at various stages of constructing ethanol plants at Lloydminster, Saskatchewan and Minnedosa, Manitoba.

OPERATING AND FINANCIAL STRATEGIES

Strategic Objective and Measures

Our mission is ''to maximize returns to our shareholders in a socially responsible manner.'' Our strategy is to maintain financial discipline while optimizing our foundation asset base in the Western Canada Sedimentary Basin and expanding into large scale sustainable areas including oil sands, Canada's East Coast and northern basins and high potential basins offshore Southeast Asia.

Strategic Plans

Our ultimate success in achieving our long-term objectives rests on the effective execution of a number of operational and financial strategies. In this regard we employ a planning process that provides critical consideration to our stated strategies and their possible outcomes.

Financial Objective and Strategies

- maintain debt to capitalization ratio of less than 40 percent; and
- maintain debt to cash flow from operations of less than two times.

Upstream Strategies

- increase production through plant and facility optimization, increased property development, property consolidation and decreased tie-in time;
- increase reserves through capital allocation to high-impact areas in the foothills, deep basin and northern plains;
- continue exploration on our large land position in the Jeanne d'Arc Basin and delineation of White Rose satellite prospects;

- continue exploration in China and development of Wenchang satellite prospects;
- development of Indonesian natural gas and NGL property in the Madura Strait and exploration in the area; and
- continue development of oil sands resources starting with first oil at Tucker in 2006.

Midstream Strategies

- debottleneck and enhance performance of upgrader;
- expand upgrader;
- expand pipeline and facilities;
- expand natural gas storage capacity; and
- centralize sulphur handling facilities.

Refined Products Strategies

- continue to enhance retail outlets through automation, remodeling and expanded services;
- expand commercial marketing through application of our cardlock system;
- expand ethanol production capacity;
- continue to expand manufacture and use of ethanol as an oxygenate in gasoline;
- optimize throughput per outlet;
- optimize asphalt product mix by seeking customers with high quality requirements;
- expand asphalt marketing reach and distribution network; and
- continue to debottleneck Lloydminster asphalt refinery and improve operational performance.

We believe that the execution of our current strategic plans as they relate to our current portfolio of assets will attain our mission but we will continue to purse acquisitions and strategic alliances. Our financial objective and strategies are intended to maintain our financial condition to facilitate corporate acquisitions of a size and type that will leverage our core portfolio of assets.

CAPABILITY TO DELIVER RESULTS

We have and will maintain the financial capacity and flexibility to undertake our strategic plans including major growth projects. We have a significant resource in our workforce and will maintain it through increasing investment in training, mentoring, succession and retention programs. Our capital investments must meet an established criterion of providing a return on capital employed.

Upstream Strengths and Challenges

Our upstream business strengths consist primarily of:

- large base of producing properties in Western Canada that generally respond well to increasingly sophisticated exploitation techniques and will continue to provide a large proportion of cash flow from operations necessary to undertake current and future major growth projects;
- significant natural gas potential in the prospective deep basin, foothills and northwest plains;
- longstanding experience in the heavy oil producing areas in the Lloydminster region of Alberta and Saskatchewan combined with an extensive infrastructure;
- substantial long-term growth potential in the oil sands regions of Alberta;
- well established exploration capability in the Jeanne d'Arc Basin off the East Coast of Canada now combined with development experience with the White Rose oilfield;
- well established relationships in Southeast Asia and readily transferable exploitation expertise.

Our upstream business will likely be challenged by the following:

- increasing costs driven by the high level of oil and gas industry activity;
- labour market skills shortages;

- highly competitive environment for materials and services required to undertake large projects;
- increasing difficulty and cost of managing the natural reservoir declines of our properties in the Western Canada Sedimentary Basin;
- increasing resistance from opposing special interest groups; and
- increasing political pressure to implement fiscal regimes that might divert material cash flow available for investment.

Midstream Strengths and Challenges

Our midstream business strengths consist primarily of:

- modern reliable heavy oil upgrading facility located in the Lloydminster heavy oil producing region capable of expansion;
- reliable heavy oil pipeline systems well integrated in the Lloydminster producing region with expansion opportunities; and
- large scale marketer capable of operating as a market balancer, serving the needs of both customer and supplier.

Our midstream business will likely be challenged by the following:

- increasingly heavier crude feedstock requiring expansion and modification of our upgrader; and
- competition for pipeline capacity in heavy crude oil producing regions.

Refined Products Strengths and Challenges

Our refined products business strengths consist primarily of:

- established niche market with good marketing outlet locations and strategic land position;
- growing economies of scale for our ethanol production;
- largest manufacturer of paving asphalt in Western Canada; and
- modern asphalt manufacturing facilities located within the Lloydminster integrated infrastructure.

Our refined products business will likely be challenged by the following:

- limited access to refining margins due to lack of sufficient refining facilities;
- motor fuel and related products are increasingly being offered by other industry retailers; and
- higher transportation costs as a result of plant locations and lack of asphalt distribution network in the U.S. and Eastern Canada.

KEY PERFORMANCE DRIVERS AND MEASURES

In order to achieve our mission of maximizing returns to our shareholders in a socially responsible manner we must, in the medium- and long-term:

- find and develop proved reserves of crude oil and natural gas at a price that is competitive with our peers; and
- acquire developed and undeveloped properties which complement our portfolio and provide enhanced potential for future sustainable growth.

In the short-term we must:

- competitively optimize production through effective exploitation techniques;
- exercise selective acquisition and divestitures;
- maintain costs among the industry's lowest cost quartile performers; and
- continue to progress with the development of our major expansion projects in the Jeanne d'Arc Basin, the Alberta oil sands, the Madura Strait natural gas and NGL project and optimization and expansion assessment of the Lloydminster Upgrader.

In addition to the metrics presented by financial statements, which are prepared in accordance with Canadian GAAP, we prepare a number of additional performance indicators. Although these metrics may not be comparable with other companies they are comparable from period to period within Husky.

The overall corporate performance metrics that we monitor with respect to achieving return to our shareholders' goals are return on equity and return on average capital employed and can be found in Section 2. ''Financial and Operational Overview.''

The individual components of the overall metrics which we can and must influence are as follows:

Revenue Performance

Our revenues are primarily sensitive to changes in the commodity prices we receive for the products we sell, particularly for our production of crude oil and natural gas. Changes in these prices are caused by many factors that are outside of our control. As a result we must focus on increasing the volume of the commodities that we produce. The expected results of all plans to increase production must achieve minimum rates of return before capital is allocated. Production is subsequently measured against expected results.

Cost Performance

Cost of sales and operating expenses comprise many components, a number of which are related to our own business such as energy costs and crude oil feedstock for refining and upgrading operations and refined product purchase costs for the majority of our refined products marketing operations. Our focus is on optimizing our costs to achieve a competitive position in the industry.

Capital Performance

Before capital is allocated to a project its expected benefits must achieve an appropriate rate of return. Capital expenditures are monitored on a project by project basis and requirements for capital supplements are approved only by senior executive management. Upstream capital, which generally accounts for the majority of our capital budget, is monitored in detail to ensure that it achieves the desired result: that of increasing production, optimizing operating expenses or increasing reserves.

People Performance

We are continually investigating the factors that influence the development of a high functioning work environment and strong corporate culture. It is evident that the competitive edge that is measured with numbers is dependent on the quality of an enterprise's value-based culture. To help us foster the development of a value-based culture we monitor attrition rates as well as the results of exit interviews; we monitor training statistics and attendance records. We facilitate and maintain a work place that is respectful, inclusive, safe and socially responsible. We also keep informed of industry trends to ensure that we are well placed in the market with respect to being an employer of choice.

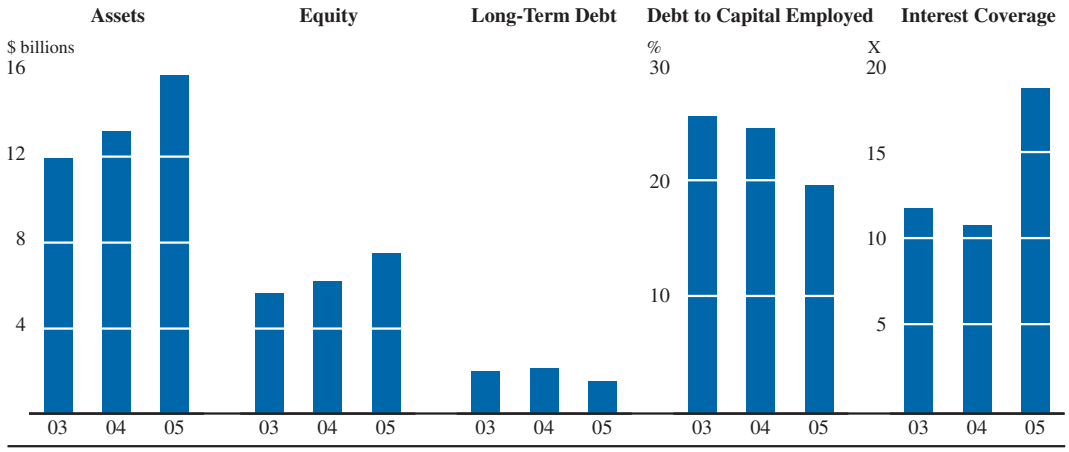
Health, Safety and Environmental Performance

We monitor all recordable accidents and all reportable environmental events that involve our operations. In addition we conduct debriefings subsequent to events and regular audits to ensure full compliance.

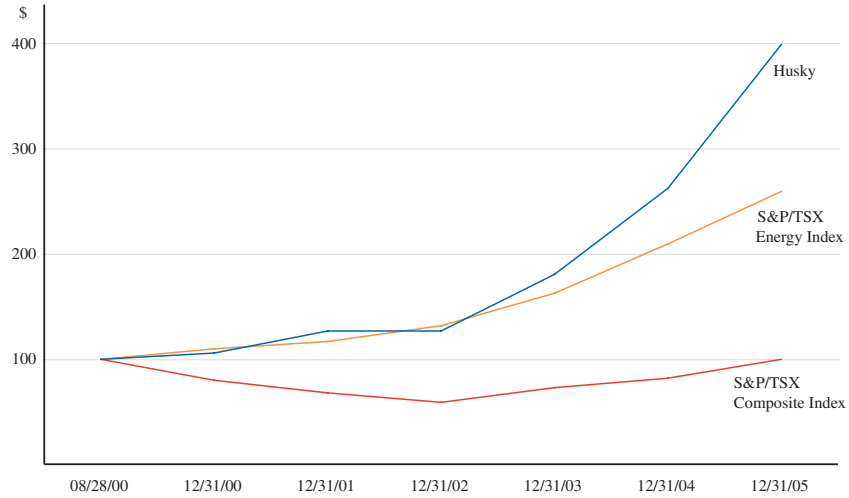
2. FINANCIAL AND OPERATIONAL OVERVIEW

OVERVIEW

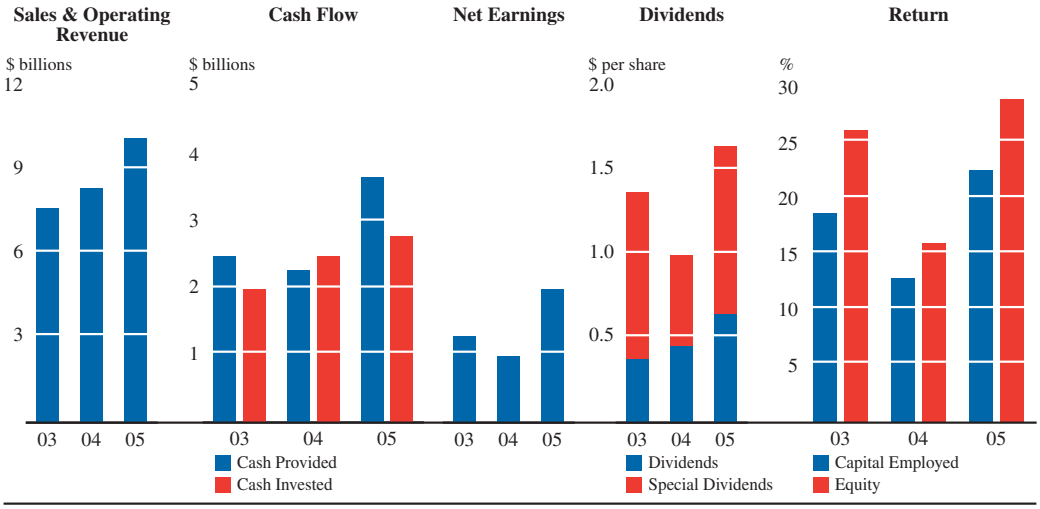
Financial Position



Comparative Shareholder Return



Financial Performance



SELECTED ANNUAL INFORMATION

	Year ended December 31				
	2005	Percent Change	2004[1]	Percent Change	2003[1]
	($ millions, except where indicated)				
Sales and operating revenues, net of royalties	$10,245	21	$ 8,440	10	$ 7,658
Segmented earnings					
Upstream	$ 1,524	114	$ 713	(33)	$ 1,067
Midstream	495	106	240	30	185
Refined Products	82	100	41	28	32
Corporate and eliminations	(98)		12		86
Net earnings	$ 2,003	99	$ 1,006	(27)	$ 1,370
Per share					
Basic	$ 4.72	99	$ 2.37	(27)	$ 3.26
Diluted	$ 4.72	99	$ 2.37	(27)	$ 3.25
Dividends per common share	$ 0.65	41	$ 0.46	21	$ 0.38
Special dividend per common share	$ 1.00	85	$ 0.54	(46)	$ 1.00
Total assets	$15,797	19	$13,240	11	$11,949
Long-term debt excluding current portion	$ 1,612	(21)	$ 2,047	18	$ 1,730
Return on equity *(percent)*	29.2		17.0		26.4
Return on average capital employed *(percent)*	22.8		13.0		18.9

(1) 2004 and 2003 amounts as restated. Refer to Notes 3 and 11 to the Consolidated Financial Statements.

SELECTED QUARTERLY INFORMATION

	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
	($ millions, except where indicated)							
Sales and operating revenues, net of royalties	$ 3,207	$ 2,594	$ 2,350	$ 2,094	$ 2,018	$ 2,191	$ 2,210	$ 2,021
Net earnings	$ 669	$ 556	$ 394	$ 384	$ 225	$ 297	$ 229	$ 255
Per share								
Basic	$ 1.58	$ 1.31	$ 0.93	$ 0.91	$ 0.53	$ 0.70	$ 0.54	$ 0.60
Diluted	$ 1.58	$ 1.31	$ 0.93	$ 0.91	$ 0.53	$ 0.70	$ 0.54	$ 0.60
Share price								
High	$ 65.79	$ 69.95	$ 50.75	$ 40.49	$ 35.65	$ 31.15	$ 28.30	$ 28.04
Low	$ 50.50	$ 47.37	$ 35.12	$ 32.30	$ 30.05	$ 25.42	$ 23.74	$ 22.73
Close (end of period)	$ 59.00	$ 64.57	$ 48.73	$ 36.33	$ 34.25	$ 30.79	$ 25.65	$ 26.20
Shares traded *(thousands)*	38,731	34,521	46,988	46,370	37,417	35,074	26,654	22,824
Dividends declared per common share	$ 0.25	$ 0.14	$ 0.14	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.10
Special dividend per common share	$ 1.00	$ —	$ —	$ —	$ 0.54	$ —	$ —	$ —
Weighted average number of common shares outstanding *(thousands)*								
Basic	424,120	424,049	423,891	423,791	423,708	423,610	423,413	422,711
Diluted	424,120	424,049	423,891	423,791	423,708	423,610	425,169	424,720

THE BUSINESS ENVIRONMENT IN 2005

Husky's financial results are significantly influenced by its business environment. Risks include, but are not limited to:

- crude oil and natural gas prices;
- the price differential and demand related to various crude oil qualities;
- cost to find, develop, produce and deliver crude oil and natural gas;
- prevailing climatic conditions in our operating and marketing locations; and
- the exchange rate between the Canadian and U.S. dollar.

Average Benchmark Prices and U.S. Exchange Rate	2005	2004	2003
WTI crude oil[1] *(U.S. $/bbl)*	$56.56	$41.40	$31.04
Dated Brent *(U.S. $/bbl)*	$54.38	$38.21	$28.94
Canadian par light crude 0.3 percent sulphur *($/bbl)*	$69.28	$52.91	$43.56
Lloyd @ Lloydminster heavy crude *($/bbl)*	$31.07	$28.75	$26.44
NYMEX natural gas[1] *(U.S. $/mmbtu)*	$ 8.62	$ 6.14	$ 5.39
NIT natural gas *($/GJ)*	$ 8.04	$ 6.44	$ 6.35
WTI/Lloyd crude blend differential *(U.S. $/bbl)*	$21.01	$13.65	$ 8.55
U.S./Canadian dollar exchange rate *(U.S. $)*	$0.826	$0.769	$0.716

(1) Prices quoted are near-month contract prices for settlement during the next month.

Our profitability is largely determined by the price we realize for crude oil and natural gas. All of our crude oil production and the majority of our natural gas production receive the prevailing market price. The price for crude oil is determined largely by global factors and is beyond our control. The price for natural gas is determined more by the environment in North America since virtually all natural gas production in North America is consumed by North American customers, predominantly in the United States. The price of natural gas, within its market area, is also subject to the supply and demand equation. Weather conditions may exert a dramatic effect on short-term supply and demand.

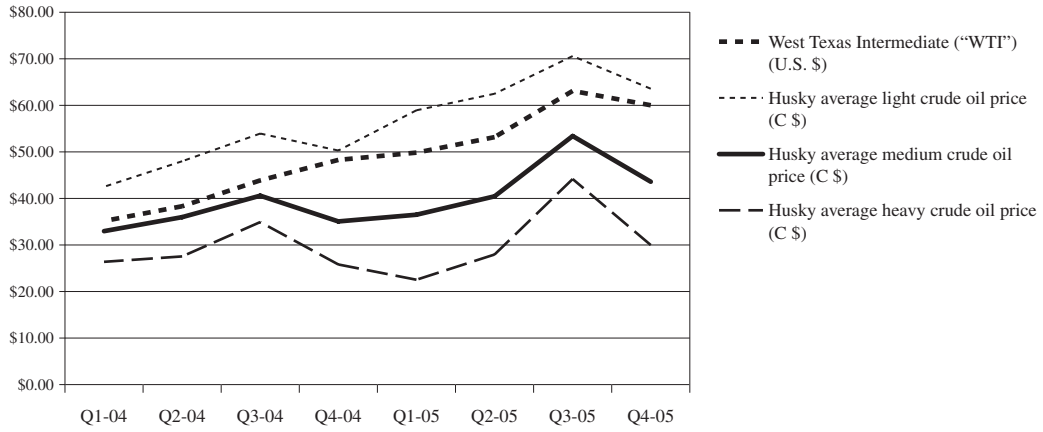
Lately the world supply and demand balance has been edging toward higher demand and as a result prices have increased substantially. This brings with it increased international effort to increase production. Notwithstanding the success of those efforts, any diminishing of global demand could set the stage for price declines.

In addition, the global decline in the supply of lighter crude oil has spawned a surge in the price of heavier grades of crude oil and consequently an increase in the development and production of heavier grades of crude oil. The heavier grades trade at a discount to light crude oil refinery feedstock since they are less suited to the manufacture of motor fuels. The increased supply of heavy crude has caused a widening of the pricing differential between heavy and light crude oil since the capacity to refine heavy crude oil feedstock has not materially increased.

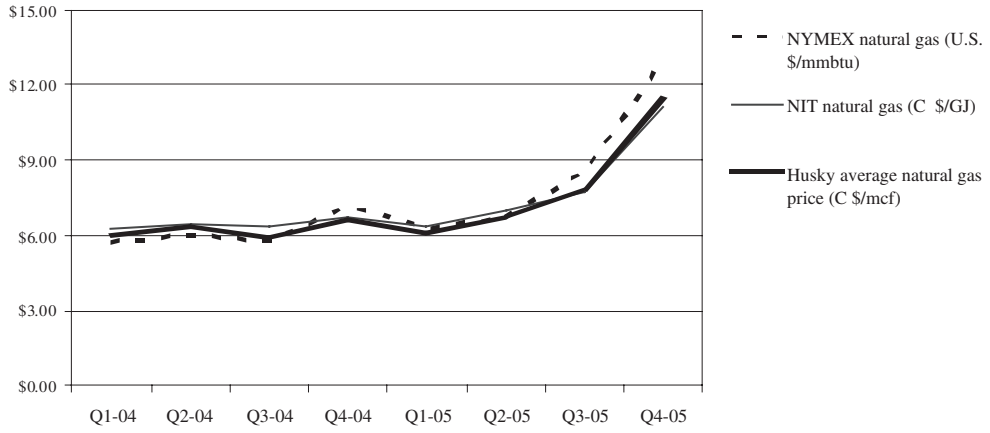
The majority of our crude oil and natural gas production is marketed in North America.

WTI and Husky Average Crude Oil Prices

($/bbl)



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



SENSITIVITIES BY SEGMENT FOR 2005 RESULTS

The following table is indicative of the relative effect on pre-tax cash flow and net earnings from changes in certain key variables in 2005. The analysis is based on business conditions and production volumes during 2005. 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	2005 Average	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
			($ millions)	($/share)[5]	($ millions)	($/share)[5]
Upstream and Midstream						
WTI benchmark crude oil price	$56.56	U.S. $1.00/bbl	77	0.18	50	0.12
NYMEX benchmark natural gas price[1]	$8.62	U.S. $0.20/mmbtu	36	0.08	22	0.05
Upgrading differential[2]	$30.70	Cdn $1.00/bbl	(27)	(0.06)	(17)	(0.04)
Exchange rate (U.S. $ per Cdn $)[3]	$0.826	U.S. $0.01	(58)	(0.14)	(39)	(0.09)
Refined Products						
Light oil margins	$0.039	Cdn $0.005/litre	16	0.04	10	0.02
Asphalt margins	$10.05	Cdn $1.00/bbl	8	0.02	5	0.01
Consolidated						
Year-end translation of U.S. $ debt (U.S. $ per Cdn $)	$0.858[4]	U.S. $0.01	—	—	10	0.02

(1) Includes decrease in earnings related to natural gas consumption.

(2) Includes impact of upstream and upgrading operations only.

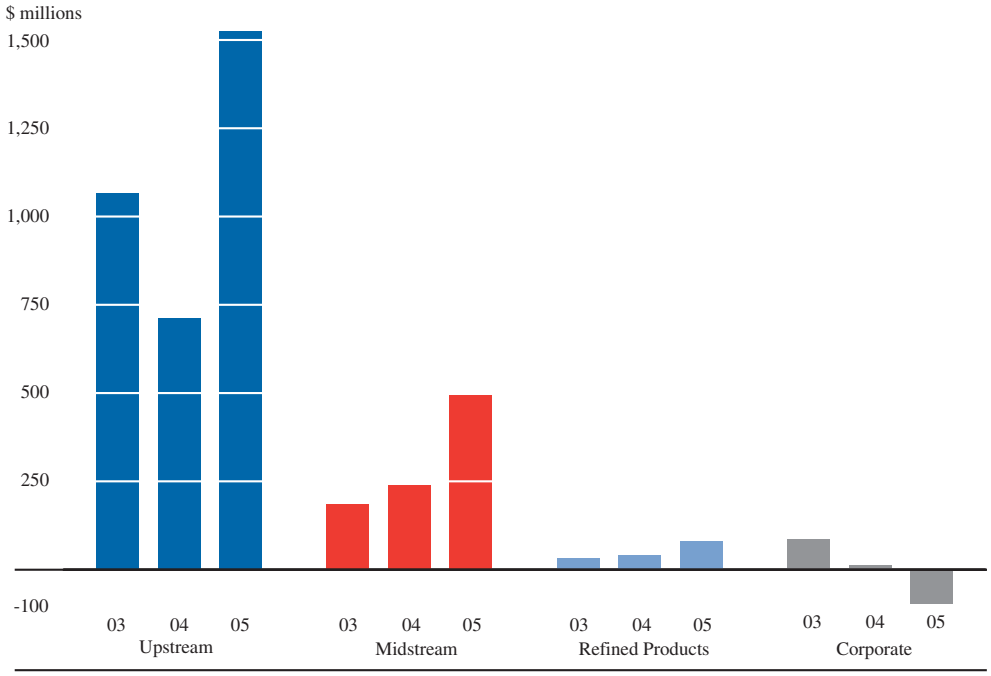
(3) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items.

(4) U.S./Canadian dollar exchange rate at December 31, 2005.

(5) Based on December 31, 2005 common shares outstanding of 424.1 million.

3. RESULTS OF OPERATIONS

Segmented Earnings



UPSTREAM

Earnings Summary and 2005 Variance Analysis

Upstream Earnings Summary	Year ended December 31		
	2005	2004	2003
		($ millions)	
Gross revenues	$5,207	$4,392	$3,796
Royalties	840	711	584
Hedging loss	—	561	26
Net revenues	4,367	3,120	3,186
Operating and administration expenses	1,050	967	873
Depletion, depreciation and amortization	1,144	1,077	918
Income taxes	649	363	328
Earnings	$1,524	$ 713	$1,067

Upstream earnings in 2005 were $811 million higher than in 2004 primarily due to the following factors:

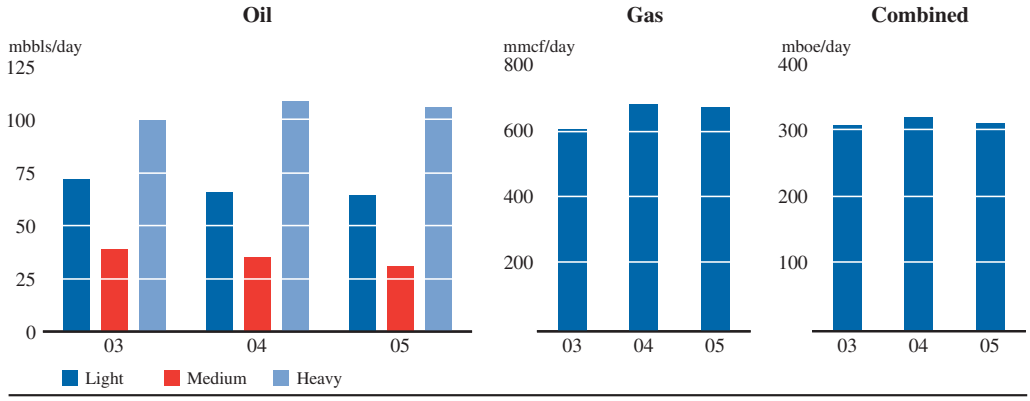
- higher natural gas and crude oil prices increased 2005 revenue by $947 million; and
- absence of commodity price hedging in 2005; 2004 hedging was primarily on 85 mbbls/day of crude oil at a strike price of U.S. $27.46.

Partially offset by:

- higher royalties resulting from higher commodity prices and Terra Nova progressing to a higher royalty rate;
- lower sales volume of crude oil and natural gas, the net effect of which lowered revenue by $145 million in 2005;
- unit operating costs were $0.80/boe higher in 2005 compared with 2004 as a result of:
  - higher fuel and energy related costs;
  - increasing level of field maintenance costs involved in crude oil exploitation activities; and
  - increasing wells and compression for natural gas production.
- higher unit depletion, depreciation and amortization, which was $9.95/boe during 2005 versus $9.06 during 2004 as a result of:
  - start up of operations at the White Rose oilfield offshore the East Coast of Canada; and
  - increasing exploration and exploitation costs in the Western Canada Sedimentary Basin.

Net Revenue Variance Analysis	**Crude Oil & NGL**	**Natural Gas**	**Other**	**Total**
		($ millions)		
Year ended December 31, 2003				
Net revenues	$2,097	$1,024	$65	$3,186
Price changes	359	98	—	457
Volume changes	(36)	172	—	136
Royalties	(67)	(60)	—	(127)
Hedging	(514)	(21)	—	(535)
Processing and sulphur	—	—	3	3
Year ended December 31, 2004				
Net revenues	1,839	1,213	68	3,120
Price changes	1,081	427	—	1,508
Volume changes	(120)	(25)	—	(145)
Royalties	(71)	(58)	—	(129)
Processing and sulphur	—	—	13	13
Year ended December 31, 2005				
Net revenues	**$2,729**	**$1,557**	**$81**	**$4,367**

Production



Daily Production, before Royalties	Year ended December 31 2005	2004	2003
Light crude oil & NGL *(mbbls/day)*	64.6	66.2	71.6
Medium crude oil *(mbbls/day)*	31.1	35.0	39.2
Heavy crude oil *(mbbls/day)*	106.0	108.9	99.9
Total crude oil & NGL *(mbbls/day)*	201.7	210.1	210.7
Natural gas *(mmcf/day)*	680.0	689.2	610.6
Barrels of oil equivalent (6:1) *(mboe/day)*	315.0	325.0	312.5

Average Sales Prices	Year ended December 31 2005	2004	2003
Crude oil *($/bbl)*			
Light crude oil & NGL	$61.56	$48.34	$39.53
Medium crude oil	43.44	36.13	31.42
Heavy crude oil	31.09	28.66	25.87
Total average	42.75	36.07	31.54
Total average after hedging	42.75	28.43	30.93
Natural gas *($/mcf)*			
Average	$ 7.96	$ 6.25	$ 5.86
Average after hedging	7.96	6.24	5.94

Upstream Revenue Mix[1]	Year ended December 31 2005	2004	2003
Percentage of upstream sales revenues, after royalties			
Light crude oil & NGL	29%	27%	29%
Medium crude oil	9%	11%	12%
Heavy crude oil	24%	27%	26%
Natural gas	38%	35%	33%
Total	100%	100%	100%

Effective Royalty Rates[1]	Year ended December 31 2005	2004	2003
Percentage of upstream sales revenues			
Light crude oil & NGL	14%	13%	12%
Medium crude oil	18%	18%	17%
Heavy crude oil	12%	12%	11%
Natural gas	20%	22%	22%
Total	16%	16%	16%

(1) Before commodity hedging.

Operating Netbacks

Western Canada Light Crude Oil Netbacks[1]	Year ended December 31 2005	2004	2003
		(per boe)	
Sales revenues before hedging	$60.74	$46.12	$39.91
Royalties	8.66	7.76	7.28
Operating costs	9.86	8.94	9.27
Netback	$42.22	$29.42	$23.36

Western Canada Medium Crude Oil Netbacks[1]	Year ended December 31		
	2005	2004	2003
		(per boe)	
Sales revenues before hedging	$43.67	$36.20	$31.57
Royalties	7.77	6.10	5.28
Operating costs	10.97	10.07	9.53
Netback	$24.93	$20.03	$16.76

(1) Includes associated co-products converted to boe.

Western Canada Heavy Crude Oil Netbacks[1]	Year ended December 31		
	2005	2004	2003
		(per boe)	
Sales revenues before hedging	$31.22	$28.73	$25.98
Royalties	3.75	3.38	2.76
Operating costs	9.90	9.33	9.09
Netback	$17.57	$16.02	$14.13

Western Canada Natural Gas Netbacks[2]	Year ended December 31		
	2005	2004	2003
		(per mcfge)	
Sales revenues before hedging	$8.02	$6.25	$5.79
Royalties	1.76	1.44	1.29
Operating costs	1.04	0.89	0.79
Netback	$5.22	$3.92	$3.71

Total Western Canada Upstream Netbacks[1]	Year ended December 31		
	2005	2004	2003
		(per boe)	
Sales revenues before hedging	$42.53	$35.01	$31.58
Royalties	7.45	6.22	5.48
Operating costs	8.59	7.85	7.56
Netback	$26.49	$20.94	$18.54

Terra Nova Crude Oil Netbacks	Year ended December 31		
	2005	2004	2003
		(per boe)	
Sales revenues before hedging	$62.19	$47.87	$38.91
Royalties	7.95	1.80	0.81
Operating costs	4.53	3.28	3.16
Netback	$49.71	$42.79	$34.94

White Rose Crude Oil Netbacks	Year ended December 31		
	2005	2004	2003
		(per boe)	
Sales revenues before hedging	$63.68	$ —	$ —
Royalties	0.61	—	—
Operating costs	6.72	—	—
Netback	$56.35	$ —	$ —

Total Canada Netbacks[1]	Year ended December 31		
	2005	2004	2003
		(per boe)	
Sales revenues before hedging	$43.69	$35.60	$32.01
Royalties	7.36	6.03	5.21
Operating costs	8.39	7.66	7.30
Netback	$27.94	$21.91	$19.50

(1) Includes associated co-products converted to boe.

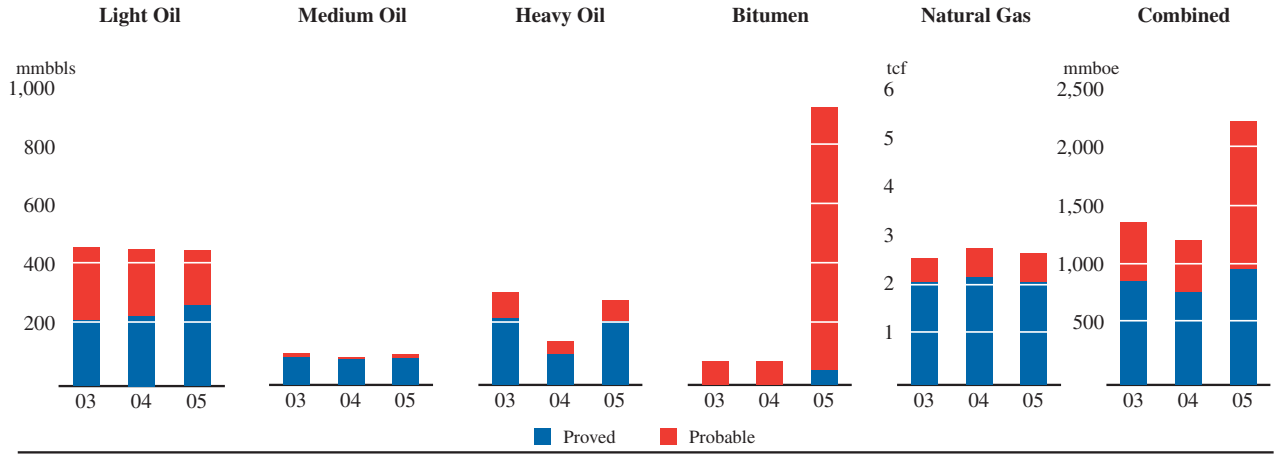
(2) Includes associated co-products converted to mcfge.

Wenchang Crude Oil Netbacks	Year ended December 31		
	2005	2004	2003
		(per boe)	
Sales revenues before hedging	$63.15	$47.66	$41.45
Royalties	5.93	4.91	3.80
Operating costs	2.92	2.16	1.94
Netback	$54.30	$40.59	$35.71

Total Upstream Segment Netbacks[1]	Year ended December 31		
	2005	2004	2003
		(per boe)	
Sales revenues before hedging	$44.56	$36.34	$32.69
Royalties	7.29	5.96	5.11
Operating costs	8.12	7.32	6.92
Netback	$29.15	$23.06	$20.66

(1) Includes associated co-products converted to boe.

Oil and Gas Reserves



Husky applied for and was granted an exemption from Canada's National Instrument 51-101 ''Standards of Disclosure for Oil and Gas Activities'' and provides oil and gas reserves disclosures in accordance with the United States SEC guidelines and the United States Financial Accounting Standards Board (''FASB'') disclosure standards. The information disclosed may differ from information prepared in accordance with National Instrument 51-101.

For more detail on our oil and gas reserves and the disclosures with respect to the FASB's Statement No. 69, ''Disclosures about Oil and Gas Producing Activities'' and the differences between our disclosures and those

prescribed by National Instrument 51-101, refer to our Annual Information Form available at www.sedar.com or our Form 40-F available at www.sec.gov or on our website at www.huskyenergy.ca.

At December 31, 2005, the present value of future net cash flows after tax from Husky's proved oil and gas reserves, based on prices and costs in effect at year-end and discounted at 10 percent, was $11.0 billion compared with $5.2 billion at the end of 2004.

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 in the United States and as set out in the Canadian Oil and Gas Evaluation Handbook.

Crude Oil and Natural Gas Reserves Summary[1]	**Proved Developed**			**Proved Undeveloped**			**Total Proved**			**Proved and Probable**		
	2005	**2004**	**2003**	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**	**2005**	**2004**	**2003**
					(constant price before royalties)							
Crude oil *(mmbbls)*												
Light & NGL	226	191	200	47	47	23	273	238	223	462	465	474
Medium	80	80	86	11	6	8	91	86	94	105	96	108
Heavy	140	91	156	77	14	71	217	105	227	291	150	319
Bitumen	—	—	—	48	—	—	48	—	—	951	79	79
	446	362	442	183	67	102	629	429	544	1,809	790	980
Natural gas *(bcf)* . .	1,710	1,745	1,712	426	424	347	2,136	2,169	2,059	2,709	2,724	2,507
Total *(mmboe)* . . .	731	653	727	254	138	160	985	791	887	2,260	1,244	1,397

(1) Refer to ''Terms and Abbreviations'' in this Annual Report for definitions of reserves.

2005 Reserve Additions

Our oil and gas reserves are estimated in accordance with the regulations and guidance of the SEC and the FASB which, among other things, require reserves to be evaluated using prices in effect on the day the reserves are estimated.

The additions to crude oil and NGL proved reserves from discoveries, extensions, improved recovery and technical revisions in 2005 amounted to 154 million barrels and were primarily from the White Rose oilfield in the Jeanne d'Arc Basin offshore Newfoundland, the Tucker Oil Sands project in the Cold Lake region of Alberta and the Lloydminster heavy oil region.

The additions to natural gas proved reserves from discoveries, extensions and improved recovery amounted to 286 billion cubic feet which was partially offset by net technical revisions of negative 68 billion cubic feet due to well performance. The positive results were primarily related to our drilling program in the foothills and deep basin areas of Alberta and northeastern British Columbia and the negative technical revisions were recorded at properties throughout the Western Canada Sedimentary Basin.

Reconciliation of Proved Reserves	Canada						International		Total		
	Western Canada					East Coast					
	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural gas	Bitumen	Light Crude Oil	Light Crude Oil	Natural Gas	Crude Oil & NGL	Natural Gas	
	(mmbbls)	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(bcf)*	*(mmboe)*
	(constant price before royalties)										
Proved reserves at December 31, 2004	171	86	225	2,172	—	47	20	—	549	2,172	911
Heavy oil price revision	—	—	(120)	(3)	—	—	—	—	(120)	(3)	(120)
Proved reserves at December 31, 2004	171	86	105	2,169	—	47	20	—	429	2,169	791
Technical revisions	3	9	1	(68)	—	9	2	—	24	(68)	13
Heavy oil price revision	—	—	120	3	—	—	—	—	120	3	120
Purchase of reserves in place	—	—	7	3	—	—	—	—	7	3	7
Sale of reserves in place	—	(3)	(4)	(9)	—	—	—	—	(7)	(9)	(9)
Discoveries, extensions and improved recovery	5	10	27	286	48	39	1	—	130	286	178
Production	(12)	(11)	(39)	(248)	—	(6)	(6)	—	(74)	(248)	(115)
Proved reserves at December 31, 2005	**167**	**91**	**217**	**2,136**	**48**	**89**	**17**	**—**	**629**	**2,136**	**985**
Proved and probable reserves											
At December 31, 2005	**225**	**105**	**291**	**2,542**	**951**	**207**	**30**	**167**	**1,809**	**2,709**	**2,260**
At December 31, 2004	229	96	150	2,557	79	203	33	167	790	2,724	1,244

Reconciliation of Proved Developed Reserves	Canada						International	Total		
	Western Canada					East Coast				
	Light Crude Oil & NGL	Medium Crude Oil	Heavy Crude Oil	Natural Gas	Bitumen	Light Crude Oil	Light Crude Oil	Crude Oil & NGL	Natural Gas	
	(mmbbls)	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmbbls)*	*(mmbbls)*	*(mmbbls)*	*(mmbbls)*	*(bcf)*	*(mmboe)*
	(constant price before royalties)									
Proved developed reserves at December 31, 2004	155	80	91	1,745	—	16	20	362	1,745	653
Revision of previous estimate	7	11	71	77	—	27	2	118	77	130
Purchase of reserves in place	—	—	2	2	—	—	—	2	2	3
Sale of reserves in place	(1)	(2)	(3)	(8)	—	—	—	(6)	(8)	(7)
Improved recovery	2	2	18	142	—	22	—	44	142	67
Production	(12)	(11)	(39)	(248)	—	(6)	(6)	(74)	(248)	(115)
Proved developed reserves at December 31, 2005	**151**	**80**	**140**	**1,710**	**—**	**59**	**16**	**446**	**1,710**	**731**

Upstream Capital Expenditures

Capital Expenditures[1]	Year ended December 31		
	2005	2004	2003
		($ millions)	
Upstream			
Exploration			
Western Canada	$ 389	$ 322	$ 326
East Coast Canada and Frontier	66	24	24
International	55	18	26
	510	364	376
Development Western Canada	1,618	1,211	869
East Coast Canada	579	515	533
International	23	67	—
	2,220	1,793	1,402
	$2,730	$2,157	$1,778

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

Western Canada Drilling	Year ended December 31					
	2005		2004		2003	
	Gross	Net	Gross	Net	Gross	Net
			(wells)			
Exploration						
Oil	89	85	45	39	12	11
Gas	392	196	234	180	147	124
Dry	36	36	34	33	22	21
	517	317	313	252	181	156
Development						
Oil	466	433	552	499	520	490
Gas	610	551	807	740	540	518
Dry	42	39	57	53	60	57
	1,118	1,023	1,416	1,292	1,120	1,065
Total	1,635	1,340	1,729	1,544	1,301	1,221

Canada

In 2005, upstream capital spending in Canada amounted to $2,652 million, up from $2,072 million in 2004. Capital spending in 2005 comprised $1,217 million on Western Canada conventional areas, $424 million in the Lloydminster heavy oil region, $366 million in the Alberta oil sands regions, $579 million for East Coast development and $66 million for East Coast and Northwest Territories exploration.

In 2005, spending on exploration activities comprised $213 million in the foothills and deep basin regions, $57 million in the Lloydminster heavy oil region, $24 million in the Alberta oil sands regions and $95 million in the remainder of the conventional Western Canada Sedimentary Basin.

In the Lloydminster heavy oil production region capital spending amounted to $424 million in 2005, $57 million of which was classified as exploration. Spending in this area is primarily focused on steam-assisted gravity drainage (''SAGD''), cyclic steam and cold production techniques that are utilized to produce the 12 to 14 degree API heavy crude oil. Production of heavy crude oil is more capital intensive due to the extensive infrastructure required to produce the large amounts of steam used to heat the crude oil in-situ prior to pumping to the surface.

Exploration spending in the foothills and deep portion of the greater Western Canada Sedimentary Basin amounted to $213 million in 2005, up from $167 million in 2004. Exploration in this region, which extends along the

eastern slopes of the Rocky Mountains in Alberta and into northeastern British Columbia, involves drilling deep wells into high pressure natural gas formations.

Spending on oil sands projects amounted to $366 million in 2005, up from $53 million in 2004. Our Tucker SAGD Oil Sands project is well underway and on-schedule to commence operations before the end of 2006. We spent $342 million on the Tucker project in 2005. The Sunrise Oil Sands project was approved by Alberta regulatory authorities at the end of 2005 and the front-end engineering and design is underway. During 2005 we spent $21 million on Sunrise and $3 million on other oil sands prospects.

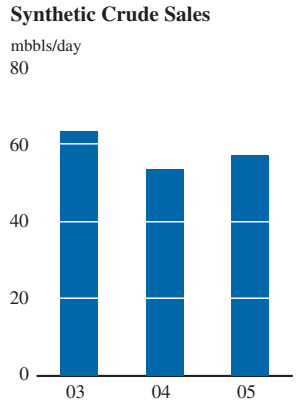
During November 2005, the White Rose oilfield in the Jeanne d'Arc Basin offshore Newfoundland produced first oil. The project will now continue to ramp up production with the drilling of at least nine additional production and injection wells through 2006 and 2007. During 2005, exploration activities involved one exploration well at Lewis Hill in the South Whale Basin, which was abandoned without testing, and a delineation well in the White Rose field. In 2005 capital spending for exploration and development activities in this region amounted to $645 million, up from $539 million in 2004.

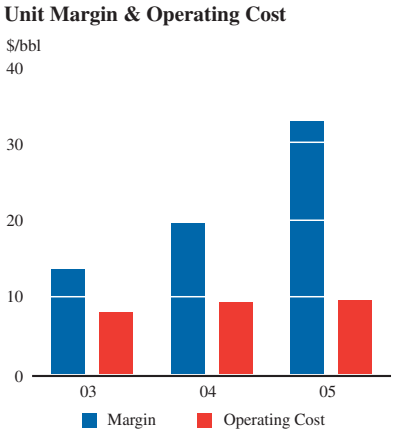
International

Exploration spending in China involved the drilling of two wells in the South China Sea. The first well encountered hydrocarbon and the results are being evaluated; the second well was plugged and abandoned without testing. In Indonesia front-end engineering and design for the Madura Strait natural gas and NGL project is underway. Total capital spending on international activities amounted to $78 million, a similar level compared with 2004.

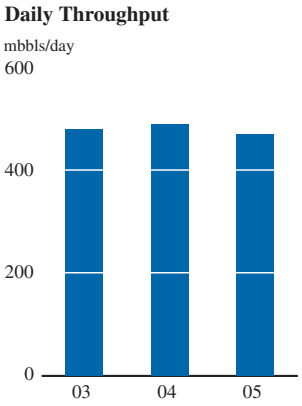
MIDSTREAM

Upgrader





Pipelines



Upgrading Earnings Summary and 2005 Variance Analysis

Upgrading Earnings Summary	Year ended December 31		
	2005	2004	2003
	($ millions, except where indicated)		
Gross margin	$ 692	$ 383	$ 313
Operating costs	228	214	205
Other recoveries	(6)	(5)	(4)
Depreciation and amortization	21	19	20
Income taxes	136	43	21
Earnings	$ 313	$ 112	$ 71
Upgrader throughput[1] *(mbbls/day)*	66.6	64.6	72.5
Synthetic crude oil sales *(mbbls/day)*	57.5	53.7	63.6
Upgrading differential *($/bbl)*	$30.70	$17.79	$12.88
Unit margin *($/bbl)*	$33.01	$19.48	$13.51
Unit operating cost[2] *($/bbl)*	$ 9.38	$ 9.07	$ 7.77

(1) Throughput includes diluent returned to the field.

(2) Based on throughput.

Upgrading earnings increased by $201 million in 2005 primarily due to:

- wider upgrading differential, which averaged $30.70/bbl in 2005 compared with $17.79/bbl in 2004; and
- higher sales volume of synthetic crude oil. The upgrader was down in both 2005 and 2004 for scheduled maintenance.

Partially offset by:

- higher energy and non-energy related unit operating costs.

Upgrading Earnings Variance Analysis	($ millions)
Year ended December 31, 2003	$ 71
Volume	(48)
Differential	118
Operating costs — non-energy related	(9)
Other	1
Depreciation and amortization	1
Income taxes	(22)
Year ended December 31, 2004	112
Volume	25
Differential	284
Operating costs — energy related	(18)
Operating costs — non-energy related	5
Depreciation and amortization	(2)
Income taxes	(93)
Year ended December 31, 2005	**$313**

Upgrading Differential

The profitability of Husky's heavy oil upgrading operations is dependent upon the amount by which revenues from the synthetic crude oil produced exceed the costs of the heavy oil feedstock plus the related operating costs. An increase in the price of blended heavy crude oil feedstock that is not accompanied by an equivalent increase in the sales price of synthetic crude oil would reduce the profitability of our upgrading operations. We have significant crude oil production that trades at a discount to light crude oil, and any negative effect of a narrower differential on upgrading

operations would be more than offset by a positive effect on revenues in the upstream segment from heavy oil production.

Infrastructure and Marketing Earnings Summary and 2005 Variance Analysis

Infrastructure and Marketing Earnings Summary	Year ended December 31		
	2005	**2004**	**2003**
	($ millions, except where indicated)		
Gross margin			
Pipeline	$ 92	$ 84	$ 66
Other infrastructure and marketing	217	136	141
	309	220	207
Other expenses	10	8	8
Depreciation and amortization	21	21	21
Income taxes	96	63	64
Earnings	$182	$128	$114
Aggregate pipeline throughput *(mbbls/day)*	474	492	484

Infrastructure and marketing earnings increased by $54 million in 2005 primarily due to:

- higher income from oil and gas commodity marketing;
- higher heavy crude oil tariffs;
- higher Lloyd blend marketing margins;
- higher crude oil and NGL trading; and
- higher cogeneration income.

Partially offset by:

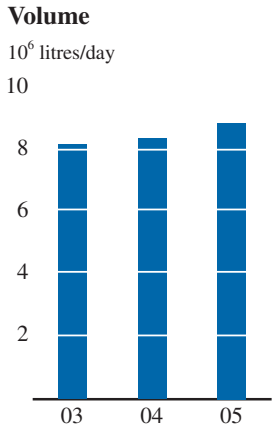
- lower heavy crude oil pipeline throughput; and
- higher operating costs due primarily to higher energy costs.

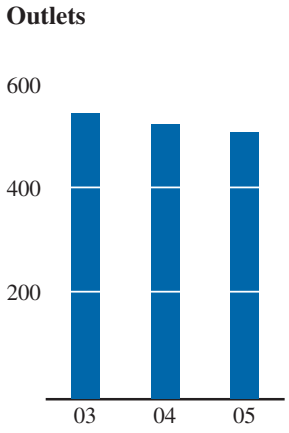
Midstream Capital Expenditures

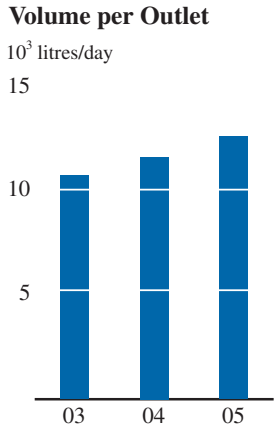
Midstream capital expenditures of $157 million in 2005 were primarily for upgrader debottlenecking and pipeline upgrades compared with $93 million in 2004.

REFINED PRODUCTS

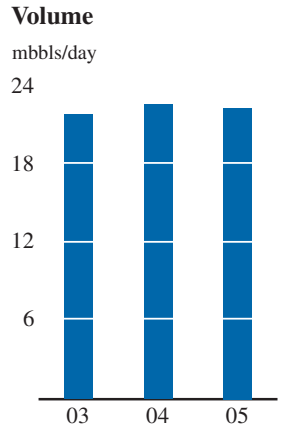
Light Oil Product Marketing







Asphalt Products



Earnings Summary and Variance Analysis

Refined Products Earnings Summary	Year ended December 31		
	2005	**2004**	**2003**
	($ millions, except where indicated)		
Gross margin			
Fuel sales	$126	$ 93	$ 71
Ancillary sales	34	30	28
Asphalt sales	91	51	51
	251	174	150
Operating and other expenses	75	71	74
Depreciation and amortization	47	38	26
Income taxes	47	24	18
Earnings	$ 82	$ 41	$ 32
Number of fuel outlets	515	531	552
Refined products sales volume			
Light oil products *(million litres/day)*	8.9	8.4	8.2
Light oil products per outlet *(thousand litres/day)*	12.7	11.7	10.8
Asphalt products *(mbbls/day)*	22.5	22.8	22.0
Refinery throughput			
Prince George refinery *(mbbls/day)*	9.7	9.8	10.3
Lloydminster refinery *(mbbls/day)*	25.5	25.3	25.7

Refined products earnings increased by $41 million in 2005 primarily due to:

- higher marketing margins and sales volume for gasoline and distillates;
- higher marketing margins of asphalt products; and
- higher restaurant and convenience store income.

Partially offset by:

- slightly lower sales volume of asphalt products; and
- higher depreciation and amortization.

Refined Products Margins

The margins realized by Husky for refined products are affected by crude oil price fluctuations, which affect refinery feedstock costs, and third-party light oil refined product purchases. Husky's ability to maintain refined

products margins in an environment of higher feedstock costs is contingent upon the ability to pass on higher costs to our customers.

Integration

Husky's production of light, medium and heavy crude oil and natural gas and the efficient operation of our upgrader, refineries and other infrastructure provide opportunities to take advantage of any fluctuation in commodity prices while assisting in managing commodity price volatility. Although we are predominantly an oil and gas producer, the nature of our integrated operations is such that the upstream business segment's output provides input to the midstream and refined products segments.

Refined Products Capital Expenditures

Refined products capital expenditures in 2005 of $191 million were primarily for marketing outlet improvements, refinery upgrades and construction of an ethanol plant compared with $106 million in 2004.

CORPORATE

Corporate Earnings Summary[1]	Year ended December 31		
	2005	2004	2003
	($ millions) income (expenses)		
Intersegment eliminations — net	$ (50)	$ (14)	$ 14
Administration expenses	(19)	(27)	(22)
Stock-based compensation	(171)	(67)	—
Accretion	(2)	(2)	—
Other — net	49	(8)	(3)
Depreciation and amortization	(23)	(24)	(36)
Interest on debt	(146)	(135)	(154)
Interest capitalized	114	75	52
Foreign exchange	31	120	282
Income taxes	119	94	(47)
Earnings (loss)	$ (98)	$ 12	$ 86

(1) 2004 and 2003 amounts as restated. Refer to Notes 3 and 11 to the Consolidated Financial Statements.

Corporate expense increased by $110 million in 2005 compared with 2004 primarily due to:

- higher intersegment profit eliminated;
- higher stock-based compensation;
- higher interest costs;
- lower foreign exchange gains on translation of U.S. dollar denominated debt; and
- provision for retrospective insurance premiums in respect of past claims on a mutual insurance consortium.

Partially offset by:

- proceeds from a litigation settlement; and
- higher capitalized interest resulting from a higher capital base for the White Rose and Tucker projects.

Foreign Exchange Summary[1]	Year ended December 31 2005	2004	2003
		($ millions)	
(Gain) loss on translation of U.S. dollar denominated long-term debt			
Realized	$ (13)	$ (10)	$ 11
Unrealized	(38)	(140)	(393)
	(51)	(150)	(382)
Cross currency swaps			
Realized	—	—	32
Unrealized	14	27	41
	14	27	73
Other losses	6	3	27
	$ (31)	$ (120)	$ (282)
U.S./Canadian dollar exchange rates:			
At beginning of year	U.S. $0.831	U.S. $0.774	U.S. $0.633
At end of year	U.S. $0.858	U.S. $0.831	U.S. $0.774

(1) 2004 and 2003 amounts as restated. Refer to Notes 3 and 11 to the Consolidated Financial Statements.

Foreign Exchange Risk

Our results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of our 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. The majority of our expenditures are in Canadian dollars. 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, 2005, 84 percent or $1.6 billion of our long-term debt was denominated in U.S. dollars. The Cdn/U.S. exchange rate at the end of 2005 was $1.1659. The percentage of our long-term debt exposed to the Cdn/U.S. exchange rate decreases to 51 percent when cross currency swaps are included. Refer to the section ''Financial Risk and Risk Management.''

Consolidated Income Taxes

Consolidated income taxes increased in 2005 to $809 million from $399 million in 2004 primarily as a result of higher pre-tax earnings.

In 2004 the indicative income tax rate was higher than in the previous year as a result of the 2003 amendments to the Federal and Alberta income tax acts. During 2004, the enactment of Bill 27-Alberta Corporate Tax Amendment Act, 2004 resulted in a non-recurring benefit of $40 million. During 2003, an amendment to the Federal Income Tax Act reduced the income tax rate on resource income by seven percent, provided for the deduction from income of crown royalties and eliminated the resource allowance deduction. This amendment resulted in a total benefit being recorded in 2003 of $141 million. In addition, in 2003 a non-recurring benefit totalling $20 million was recorded pursuant to Bill 41, the Alberta Corporate Tax Amendment Act, 2003. All benefits reduced future income taxes.

In 2005 current income taxes totalled $297 million and comprised $84 million in respect of the Wenchang oilfield operation, $15 million of capital taxes and $198 million of Canadian income tax.

The following table shows the effect of non-recurring tax benefits for the periods noted:

	2005	2004
	($ millions)	
Income taxes before tax amendments	$813	$439
Canadian federal and provincial tax amendments	4	40
Income taxes as reported	$809	$399

Husky's Canadian Tax Pools	Year ended December 31 2005	2004
	($ millions)	
Canadian exploration expense	$ 78	$ —
Canadian development expense	2,033	1,616
Canadian oil and gas property expense	721	557
Foreign exploration and development expense	240	212
Undepreciated capital costs	4,249	3,269
Other	27	22
	$7,348	$5,676

Corporate Capital Expenditures

Corporate capital expenditures of $21 million in 2005 were primarily for computer hardware and software and office furniture and equipment and compared with $23 million in 2004.

4. LIQUIDITY AND CAPITAL RESOURCES

SUMMARY OF CASH FLOW

	Year ended December 31 2005	2004	2003
Cash flow — operating activities *($ millions)*	$ 3,672	$ 2,326	$ 2,509
— financing activities *($ millions)*	$ (616)	$ 175	$ (771)
— investing activities *($ millions)*	$(2,814)	$ (2,497)	$(2,041)
Debt to capital employed *(percent)*	20.1	25.8	26.9
Corporate reinvestment ratio[1]	0.8	1.1	0.9

(1) Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

Cash Flow from Operating Activities

In 2005 cash generated by operating activities was $3,672 million, an increase of $1,346 million from the $2,326 million recorded in 2004. The higher cash from operating activities in 2005 was primarily due to higher earnings, partially offset by increased non-cash working capital associated with operating activities.

Cash Flow from (used for) Financing Activities

In 2005 cash used in financing activities amounted to $616 million. The cash used was composed of the repayment of long-term debt of $3,401 million and a $49 million repayment of operating lines, dividends of $700 million, including a $1.00 per share special dividend and other costs of $1 million. Cash provided by financing activities in 2005 comprised $3,235 million issuance of long-term debt, $6 million of proceeds from the exercise of stock options, proceeds from monetization of financial instruments totalling $39 million and a change of $255 million in non-cash working capital. Debt issuances and repayments include multiple drawings and repayments under revolving debt facilities.

Husky's long-term debt balances were also reduced by $51 million during 2005 primarily as a result of the narrowing of the exchange rate between Canadian and U.S. currencies.

Cash Flow used for Investing Activities

Cash used in investing activities amounted to $2,814 million in 2005, an increase of $317 million from the $2,497 million in 2004. Cash invested in 2005 was composed of capital expenditures of $3,068 million, partially offset by $74 million of proceeds from asset sales. Change in non-cash working capital and other adjustments amounted to $180 million used in investing activities.

FINANCIAL POSITION

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 proved developed reserves, to acquire strategic oil and gas assets, repay maturing debt and pay dividends. Husky's upstream capital programs are funded principally by cash provided from operating activities. During times of low oil and gas prices part of a capital program can generally be deferred. However, due to the long cycle times and the importance to future cash flow in maintaining our production, it may be necessary to utilize alternative sources of capital to continue our strategic investment plan during periods of low commodity prices. As a result, we continually examine our options with respect to sources of long and short-term capital resources. In addition, from time to time we engage in hedging a portion of our production to protect cash flow in the event of commodity price declines.

The following illustrates the Company's sources and uses of cash during the years ended December 31, 2005, 2004 and 2003:

Sources and Uses of Cash	2005	2004	2003
		($ millions)	
Cash sourced			
Cash flow from operations[1]	$3,785	$2,197	$2,430
Debt issue	3,235	2,200	669
Asset sales	74	36	511
Proceeds from exercise of stock options	6	18	51
Proceeds from monetization of financial instruments	39	8	44
Other	—	—	5
	7,139	4,459	3,710
Cash used			
Capital expenditures	3,068	2,349	1,868
Corporate acquisitions	—	102	809
Debt repayment	3,450	1,959	971
Special dividend on common shares	424	229	420
Ordinary dividends on common shares	276	195	160
Settlement of asset retirement obligations	41	40	34
Settlement of cross currency swap	—	—	32
Other	32	24	—
	7,291	4,898	4,294
Net cash (deficiency)	(152)	(439)	(584)
Increase (decrease) in non-cash working capital	394	443	281
Increase (decrease) in cash and cash equivalents	242	4	(303)
Cash and cash equivalents — beginning of year	7	3	306
Cash and cash equivalents — end of year	$ 249	$ 7	$ 3

(1) Cash flow from operations represents net earnings plus items not affecting cash, which include accretion, depletion, depreciation and amortization, future income taxes and foreign exchange.

Sources and Uses of Cash (continued)

	2005	2004	2003
		($ millions)	
Increase (decrease) in non-cash working capital			
Cash positive working capital change			
Accounts receivable decrease	$ —	$209	$ —
Inventory decrease	—	—	28
Prepaid expense decrease	17	—	—
Accounts payable and accrued liabilities increase	984	323	270
	1,001	532	298
Cash negative working capital change			
Accounts receivable increase	410	—	7
Inventory increase	197	77	—
Prepaid expense increase	—	12	10
	607	89	17
Increase (decrease) in non-cash working capital	$ 394	$443	$281

Capital Structure

	December 31, 2005		
	Outstanding		Available
	(U.S. $)	(Cdn $)	(Cdn $)
		($ millions)	
Short-term bank debt	$ —	$ —	$ 177
Long-term bank debt			
Syndicated credit facility	—	—	1,000
Bilateral credit facility	—	—	150
Medium-term notes	—	300	
Capital securities	225	262	
U.S. public notes	1,050	1,225	
U.S. senior secured bonds	85	99	
Total short-term and long-term debt	$1,360	$1,886	$1,327
Common shares and retained earnings		$7,520	

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2005, our working capital deficiency was $1.0 billion compared with $824 million at December 31, 2004. The increase in the deficiency is primarily due to the $1.00 per share special dividend declared on October 19, 2005 and the increase in payables for capital and commodity purchases. It is not unusual for Husky to have working capital deficits at the end of a reporting period. These working capital deficits are primarily the result of accounts payable related to capital expenditures for exploration and development. Settlement of these current liabilities is funded by cash provided by operating activities and to the extent necessary by bank borrowings. This position is a common characteristic of the oil and gas industry which, by the nature of its business, spends large amounts of capital.

As at December 31, 2005, our outstanding long-term debt totalled $1.9 billion, including amounts due within one year, compared with $2.1 billion at December 31, 2004.

At December 31, 2005, we had no drawings under our $1 billion revolving syndicated credit facility. Interest rates under this facility vary and are 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 rating agencies to our senior unsecured debt. The syndicated credit facility requires Husky to maintain a debt to cash flow ratio of less than three times and a consolidated tangible net worth, as of December 31, 2005, of at least $4.4 billion.

At December 31, 2005, we had no drawings under our $150 million bilateral credit facilities. The terms of these facilities are substantially the same as the syndicated credit facility.

At December 31, 2005, we had borrowed $0.4 million and utilized $18 million in support of letters of credit under our $195 million in short-term borrowing facilities. The interest rates applicable to these facilities vary and are based on Bankers' Acceptance, U.S. LIBOR or prime rates. In addition, we utilized $105 million under our dedicated letter of credit facilities.

Husky has an agreement to sell up to $350 million of net trade receivables on a revolving basis. The agreement calls for purchase discounts, based on Canadian commercial paper rates, plus a program fee to be paid on an ongoing basis. As at December 31, 2005, $350 million in outstanding accounts receivable had been sold under this agreement. The arrangement matures on January 31, 2009.

Based on our 2006 commodity price forecast, we believe that our non-cancellable contractual obligations and other commercial commitments and our 2006 capital program will be funded by cash flow from operating activities and, to the extent required, by available credit facilities. In the event of significantly lower cash flow, we would be able to defer certain of our projected capital expenditures without penalty.

We declared dividends that aggregated $1.65 per share totalling $700 million in 2005, including a special dividend of $1.00 per share. The Board of Directors of Husky has established a dividend policy that pays quarterly dividends of $0.25 ($1.00 annually) per common share. The declaration of dividends will be at the discretion of the Board of Directors, which will consider earnings, capital requirements, our financial condition and other relevant factors.

Cash and cash equivalents at December 31, 2005 totalled $249 million compared with $7 million at the beginning of the year.

On February 1, 2006, we announced the redemption of the 8.45 percent senior secured bonds amounting to U.S. $85 million.

Credit Ratings

Husky's senior debt and capital securities have been rated investment grade by several rating agencies. These ratings are disclosed and explained in detail in our Annual Information Form.

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				
	Total	2006	2007-2008	2009-2010	Thereafter
			($ millions)		
Long-term debt and interest[1]	$2,700	$ 403	$ 565	$350	$1,382
Operating leases	502	81	158	131	132
Firm transportation agreements	679	169	243	118	149
Unconditional purchase obligations[2]	2,017	616	1,221	171	9
Lease rentals and exploration work agreements	427	50	98	125	154
Engineering and construction commitments	531	365	166	—	—
	$6,856	$1,684	$2,451	$895	$1,826

(1) Includes interest on fixed rate debt.

(2) Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums and natural gas purchases.

Estimated Obligations Not Included in the Table

- Asset retirement obligations

  Husky currently includes such obligations in the amortizing base of its oil and gas properties. Effective January 1, 2004 with the adoption of the Canadian Institute of Chartered Accountants (''CICA'') section 3110, ''Asset Retirement Obligations'', Husky records a separate liability for the fair value of its asset retirement obligations. See Note 12 to the Consolidated Financial Statements.

- Employee future benefits

  Husky has a defined contribution pension plan and a post-retirement health and dental care plan for its employees. In addition Husky has a defined benefit pension plan for approximately 200 active employees and 460 retirees and beneficiaries. In 1991 admittance to the defined benefit pension plan ended after the majority of members transferred to the newly created defined contribution pension plan. See Note 16 to the Consolidated Financial Statements.

Other Obligations

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 impact on future liquidity. Such obligations include environmental contingencies, contingent consideration and potential settlements resulting from litigation.

2006 Capital Program

Husky plans to invest capital in the following segments in 2006:

	Year ended December 31, 2006 Estimate ($ millions)
Upstream	
Western Canada	$1,730
East Coast Canada	350
International	140
	2,220
Midstream	340
Refined Products	260
Corporate	30
	$2,850

OFF-BALANCE SHEET ARRANGEMENTS

We do not utilize off-balance sheet arrangements with unconsolidated entities to enhance perceived liquidity.

Accounts Receivable Securitization Program

In the ordinary course of business, we engage in the securitization of accounts receivable. Our receivable securitization program is fully utilized at $350 million. The securitization agreement terminates on January 31, 2009. The accounts receivable are sold to an unrelated third party on a revolving basis. In accordance with the agreement we must provide a loss reserve to replace defaulted receivables.

The securitization program provides us with cost-effective short-term funding for general corporate use. We account for these securitizations as asset sales. In the event the program is terminated our liquidity would not be substantially reduced.

Standby Letters of Credit

In addition, from time to time, we issue letters of credit in connection with transactions in which the counterparty requires such security.

Derivative Instruments

We utilize derivative financial instruments in order to manage unacceptable risk. The derivative financial instruments currently outstanding are listed and discussed in the section ''Financial Risk and Risk Management.''

TRANSACTIONS WITH RELATED PARTIES AND MAJOR CUSTOMERS

Husky, in the ordinary course of business, was party to a lease agreement with Western Canadian Place Ltd. The terms of the lease provided for the lease of office space at Western Canadian Place, management services and operating

costs at commercial rates. Effective July 13, 2004, Western Canadian Place Ltd. sold Western Canadian Place to an unrelated party. Western Canadian Place Ltd. is indirectly controlled by Husky's principal shareholders. Prior to the sale, we paid approximately $10 million for office space in Western Canadian Place during 2004.

We did not have any customers that constituted more than 10 percent of total sales and operating revenues during 2005.

FINANCIAL RISK AND RISK MANAGEMENT

Husky is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. Refer to Section 2. under ''The Business Environment in 2005.'' From time to time, we use derivative instruments to manage our 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.

We implemented a corporate hedging program for 2004 to manage the volatility of natural gas and crude oil prices.

Natural Gas

As a result of a corporate acquisition, we assumed a natural gas derivative contract for a notional 7.5 mmcf/day that matured at the end of 2005. During 2005, we recorded payments totalling $17 million on this contract.

Power Consumption

During 2005, we received payments totalling $4 million on our power consumption hedges.

Foreign Currency Risk Management

At December 31, 2005, Husky had the following cross currency debt swaps in place:

- U.S. $150 million at 7.125 percent swapped at $1.45 to $218 million at 8.74 percent until November 15, 2006.
- U.S. $150 million at 6.250 percent swapped at $1.41 to $212 million at 7.41 percent until June 15, 2012.
- U.S. $75 million at 6.250 percent swapped at $1.19 to $90 million at 5.65 percent until June 15, 2012.
- U.S. $50 million at 6.250 percent swapped at $1.17 to $59 million at 5.67 percent until June 15, 2012.
- U.S. $75 million at 6.250 percent swapped at $1.17 to $88 million at 5.61 percent until June 15, 2012.

At December 31, 2005 the cost of a U.S. dollar in Canadian currency was $1.1659.

In 2005 the cross currency swaps resulted in an offset to foreign exchange gains on translation of U.S. dollar denominated debt amounting to $14 million.

In addition, we entered into U.S. dollar forward contracts, which resulted in realized gains totalling approximately $15 million in 2005. In 2004, Husky unwound its long-dated forwards resulting in a gain of $8 million, which was recognized into income during 2005 on the dates the underlying hedged transactions took place.

Interest Rate Risk Management

In 2005 interest rate risk management activities resulted in a decrease to interest expense of $13 million.

The cross currency swaps resulted in an addition to interest expense of $10 million in 2005.

We have interest rate swaps on $200 million of long-term debt, effective February 8, 2002, whereby 6.95 percent was swapped for CDOR + 175 bps until July 14, 2009. During 2005, these swaps resulted in an offset to interest expense amounting to $5 million.

In May 2005, Husky unwound the interest rate swaps on U.S. $300 million of long-term debt due June 15, 2019. Proceeds of $30 million have been deferred and are being amortized to income over the remaining term of the underlying debt. During 2005, the impact of these swaps before they were unwound was an offset to interest expense amounting to $3 million.

In November 2005, Husky unwound the interest rate swaps on U.S. $200 million of long-term debt due November 15, 2016. Proceeds of $7 million have been deferred and are being amortized to income over the remaining term of the underlying debt. During 2005, the impact of these swaps before they were unwound was an offset to interest expense amounting to $6 million.

The amortization of previous interest rate swap terminations resulted in an additional $9 million offset to interest expense in 2005.

OUTSTANDING SHARE DATA

Authorized:

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

Issued and outstanding: February 21, 2006

- common shares 424,147,746
- preferred shares none
- stock options 7,200,457
- stock options exercisable 1,193,153

At February 21, 2006, 20,045,663 common shares were reserved for issuance under the stock option plan. Options awarded under the stock option plan have a maximum term of five years and vest evenly over the first three years.

5. 2006 OUTLOOK

GENERAL ECONOMY

The factors that produced the supply and demand dynamics affecting 2004 and 2005 are expected to continue into 2006. This belief is, in part, derived from the predictions of the International Monetary Fund which forecast continued global economic growth led by the emerging Asian economies, particularly China. The world's more developed economies are not expected to interfere with this prediction. The largest consumer of petroleum, the United States, is expected to grow and Japan appears to be recovering.

General inflation is expected to continue to rise as higher petroleum costs ripple throughout the cost inputs of virtually all other products and services, including the cost of capital. Although higher petroleum prices are beneficial to creating shareholder value for oil and gas enterprises, they also impact us, since we consume vast amounts of goods and services, not the least of which is energy itself.

UPSTREAM

Production Outlook	2006	2005 Actual
Light crude oil and NGL *(mbbls/day)*	103 - 116	65
Medium crude oil *(mbbls/day)*	29 - 32	31
Heavy crude oil *(mbbls/day)*	115 - 120	106
Total crude oil and NGL *(mbbls/day)*	247 - 268	202
Natural gas *(mmcf/day)*	680 - 730	680
Barrels of oil equivalent (6:1) *(mboe/day)*	360 - 390	315

Western Canada Conventional

Although the conventional production areas of the Western Canada Sedimentary Basin are considered relatively mature, current exploration and development activity is unprecedented. Production from this area is expected to account for less than 80 percent of our production in 2006, down from 90 percent in 2005 but will still be Husky's cash generating foundation. By 2010, we expect conventional production from Western Canada, including heavy oil, to account for less than 60 percent of our total production.

We expect to replace a large portion of our conventional production from development of new areas in Canada, the oil sands, basins off the East Coast and the Northwest Territories and from China and Indonesia.

Capital expenditures for development and exploration on our conventional Western Canada properties are expected to account for 66 percent of the total $2.2 billion in upstream capital expenditures in 2006; up from 60 percent in 2005. This is because of the slowing of White Rose capital spending, which was completed to first oil in 2005, and the slowing of Tucker capital spending, which will reach first oil in 2006. This represents a short dip in spending outside of the Western Canada conventional area prior to the development of the Sunrise Oil Sands and Madura natural gas and NGL projects. We expect that by 2010 capital expenditures on conventional properties in Western Canada will drop to approximately 37 percent of total upstream capital spending.

We will also continue to pursue additional natural gas reserves and production using unconventional production technology from coal beds, shale and tight formations. Based on activity in 2005, production of natural gas from coal beds is encouraging.

Oil Sands

In 2006, we will continue with and complete to first oil the development of Tucker and proceed with the front-end engineering and design of Sunrise, which will be developed in phases to reach total capacity by approximately 2012.

	Cost	Timing	Capacity
Tucker	$ 500 million	2006	30,000 bbls/day
Sunrise	To be finalized	2010-12	200,000 bbls/day

Canada — East Coast and Northwest Territories

On the East Coast we will continue with the development and extension of the White Rose field, including monitoring the economics and technical feasibility of natural gas developments off the East Coast, in particular the natural gas resources in the north section of the White Rose field. In addition, we will continue to identify and evaluate new prospects off the East Coast with an emphasis on the Jeanne d'Arc Basin where we recently acquired additional exploration rights on 38,600 acres, with a minimum work program commitment of $36.5 million.

In 2006, we will proceed with delineation and evaluation of the Summit Creek B-44 discovery which confirmed several productive intervals within a 180 metre zone. We and our partners hold over one million acres covering the central extent of this play.

China and Indonesia

In China, we will continue to pursue offshore prospects.

In Indonesia, we expect to conclude negotiating a natural gas sales contract and an extension to the production sharing agreement. We will continue to validate previous engineering work and make appropriate modifications during 2006. We expect that development construction will take approximately three years following project sanction.

MIDSTREAM

In 2006, we will maintain and optimize infrastructure to capitalize on increasing activity in the bitumen corridor, which extends from Lloydminster north to Fort McMurray, Alberta. We will also pursue expansion of ancillary businesses including transportation, storage, cogeneration and upgrading. In particular, we will continue the debottlenecking projects and operating performance initiatives at the Lloydminster Heavy Oil Upgrader.

REFINED PRODUCTS

In 2006, we will complete the Prince George Refinery modification, which will permit production of fuels that meet Federal requirements and we will complete the Lloydminster Ethanol Plant. We will also continue with construction of a second ethanol plant at Minnedosa, Manitoba, which will replace a small existing plant and is expected to be operational by mid-2007. We will continue to improve technology, appearance and product offerings at our marketing outlets. We will also continue to optimize the number and location of our retail outlets.

6. APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

Husky's Consolidated Financial Statements have been prepared in accordance with Canadian GAAP. The significant accounting policies we use are disclosed in Note 3 to the Consolidated Financial Statements. Certain accounting policies require that we make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The following discusses such

accounting policies and is included in MD&A to aid you in assessing the critical accounting policies and practices of Husky and the likelihood of materially different results being reported. We review our estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies is not meant to be exhaustive. Husky might realize different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

FULL COST ACCOUNTING FOR OIL AND GAS ACTIVITIES

The indicated change in the following estimates will result in a corresponding increase in the amount of depletion, depreciation and amortization (''DD&A'') expense charged to income in a given period:

An increase in:

- estimated costs to develop the proved undeveloped reserves;
- estimated fair value of the asset retirement obligation related to the oil and gas properties; and
- estimated impairment of costs excluded from the DD&A calculation.

A decrease in:

- previously estimated proved oil and gas reserves; and
- estimated proved reserves added compared to capital invested.

DEPLETION EXPENSE

Husky uses the full cost method of accounting for exploration and development activities as recommended by the CICA. In accordance with this method of accounting, all costs associated with exploration and development are capitalized on a country by country basis. The aggregate of capitalized costs, net of accumulated DD&A, plus the estimated future costs required to develop the proved undeveloped oil and gas reserves less estimated equipment salvage values is charged to income using the unit of production method based on estimated proved oil and gas reserves.

WITHHELD COSTS

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

FULL COST ACCOUNTING

Effective January 1, 2004, we adopted Accounting Guideline 16, ''Oil and Gas Accounting — Full Cost''. The new guideline modified the ceiling test, which requires, for each cost centre, capitalized costs be tested for recoverability. The test uses the estimated undiscounted future net cash flows from proved oil and gas reserves based on forecast prices and costs. When the carrying amount of a cost centre is not recoverable, the cost centre is written down to its fair value. Fair value is estimated using present value techniques which incorporate risks and other uncertainties as well as the future value of reserves when determining estimated cash flows.

IMPAIRMENT OF LONG-LIVED ASSETS

We are required to review the carrying value of all property, plant and equipment, including the carrying value of oil and gas assets, for potential impairment. Impairment is indicated if the carrying value of the long-lived asset or oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings.

FAIR VALUE OF DERIVATIVE INSTRUMENTS

Periodically we utilize financial derivatives to manage market risk. The purpose of the derivative is to provide an element of stability to our cash flow in a volatile environment. We disclose the estimated fair value of open hedging contracts as at the end of a reporting period. Effective January 1, 2004 Husky adopted CICA Accounting Guideline 13,

''Hedging Relationships'' (''AcG-13''). AcG-13 has essentially the same criteria to be satisfied before the application of hedge accounting is permitted as the corresponding requirements of the FASB Statement No. 133, ''Accounting for Derivative Instruments and Hedging Activities'' (''FAS 133''). Refer to the description of FAS 133 in Note 19 to the Consolidated Financial Statements.

The estimation of the fair value of certain hedging derivatives requires considerable judgement. The estimation of the fair value of commodity price hedges requires sophisticated financial models that incorporate forward price and volatility data and which when compared with Husky's open hedging contracts, produce cash inflow or outflow variances over the contract period. The estimate of fair value for interest rate and foreign currency hedges is determined primarily through quotes from financial institutions.

Accounting rules for transactions involving derivative instruments are complex and subject to a range of interpretation. The FASB has established the Derivative Implementation Group task force, which, on an ongoing basis, considers issues arising from interpretation of these accounting rules. The potential exists that the task force may promulgate interpretations that differ from those of Husky. In this event our policy would be modified.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, we adopted the recommendations of CICA section 3110, ''Asset Retirement Obligations'' (''ARO''), which is essentially identical to the United States accounting requirements of FAS 143.

We have significant obligations to remove tangible assets and restore land after operations cease and we retire or relinquish the asset. The ARO relates to all of our business operations, however, approximately 90 percent of the liability relates to the upstream business. The retirement of upstream assets consists primarily of plugging and abandoning wells, removing and disposing of surface and sub-sea equipment and facilities and restoration of land to a state required by regulation or contract. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often require interpretation. Restoration technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

The new ARO rules require that an asset retirement obligation associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying cost of the associated asset. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the initial fair value of the ARO is recognized over the useful life of the asset. The initial fair value of the ARO is accreted to its expected settlement date. The accretion amount is expensed as a cost of operating and is added to the ARO liability. The fair value of the ARO is measured using expected future cash outflows discounted at our credit adjusted risk free interest rate.

Inherent in the present value calculation 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. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the tangible asset balance.

LEGAL, ENVIRONMENTAL REMEDIATION AND OTHER CONTINGENT MATTERS

We are required to both determine whether a loss is probable based on judgement and interpretation of laws and regulations and determine that the loss can reasonably be estimated. When the loss is determined it is charged to earnings. The Company's management must continually monitor known and potential contingent matters and make appropriate provisions by charges to earnings when warranted by circumstances.

INCOME TAX ACCOUNTING

The determination of our 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

Over recent years Husky has grown considerably through combining with other businesses. Husky acquired Temple Exploration Inc. in 2004 and Marathon Canada Limited in 2003. These transactions were accounted for using what is now the only accounting method available, the purchase method. Under the purchase method, the acquiring company includes the fair value of the assets of the acquired entity on its balance sheet. The determination of fair value necessarily involves many assumptions. The valuation of oil and gas properties primarily relies on placing a value on the oil and gas reserves. The valuation of oil and gas reserves entails the process described in Section 3. ''Results of Operations — Upstream'' under the caption ''Oil and Gas Reserves'' but in contrast incorporates the use of economic forecasts that estimate future changes in prices and costs. In addition, this methodology is used to value unproved oil and gas reserves. The valuation of these reserves, by their nature, is less certain than the valuation of proved reserves.

GOODWILL

The process of accounting for the purchase of a company, described above, results in recognizing the fair value of the acquired company's assets on the balance sheet of the acquiring company. Any excess of the purchase price over fair value is recorded as goodwill. Since goodwill results from the culmination of a process that is inherently imprecise the determination of goodwill is also imprecise. In accordance with the issuance of FASB Statement No. 142 and CICA section 3062, ''Goodwill and Other Intangible Assets'', goodwill is no longer amortized but assessed periodically for impairment. The process of assessing goodwill for impairment necessarily requires Husky to determine the fair value of its assets and liabilities. Such a process involves considerable judgement.

7. NEW ACCOUNTING STANDARDS

LIABILITIES AND EQUITY

In November 2004, the Accounting Standards Board (''AcSB'') revised recommendations in CICA section 3860, ''Financial Instruments — Disclosure and Presentation'', on the classification of obligations that must or could be settled with an entity's own equity instruments. The new recommendations were effective January 1, 2005 and resulted in Husky's capital securities being classified as liabilities instead of equity. The accrued return on the capital securities and the issue costs are classified outside of shareholders' equity. The return on the capital securities is a charge to earnings. The revision was applied retroactively effective January 1, 2005.

NON-MONETARY TRANSACTIONS

In June 2005 the AcSB issued CICA section 3831, ''Non-monetary Transactions'' which replaced section 3830 of the same name. The new recommendations require that all non-monetary transactions are measured based on fair value unless the transaction lacks commercial substance or is an exchange of product or property held for sale in the ordinary course of business. The guidance is effective for all non-monetary transactions initiated in periods beginning on or after January 1, 2006.

8. PENDING ACCOUNTING STANDARDS

In April 2005, the CICA released three new Handbook sections which deal with the recognition and measurement of financial instruments:

- Section 1530, Comprehensive Income;
- Section 3855, Financial Instruments — Recognition and Measurement; and
- Section 3865, Hedges.

The new standards are an attempt to harmonize Canadian GAAP with U.S. GAAP. Initial measurement of all financial instruments is to be based on their fair values. The subsequent measurement of the financial instrument will depend on whether it is classified as a loan or receivable; held to maturity investment; available for sale financial asset; held for trading asset or liability; or, other financial liability. Available for sale financial assets and held for trading assets or liabilities are measured at fair value on an ongoing basis. The other financial instruments are recognized at amortized cost using the effective interest method. The gains and losses on held for trading financial instruments are recognized immediately in net income. The gains and losses on available for sale financial assets will be recognized in other comprehensive income and are transferred to net income when the asset is derecognized.

Other comprehensive income is a new equity category where revenues, expenses, gains and losses are temporarily presented outside of net income but included in comprehensive income. Unrealized gains or losses on qualifying hedging instruments and available for sale financial assets are included in other comprehensive income and reclassified to net income when realized.

Hedge accounting continues to be an option and the new Handbook section provides detailed guidance on the application of hedge accounting and the required disclosures.

These new standards are effective for fiscal years beginning on or after October 1, 2006.

9. SUMMARY OF VARIANCES FOR 2004 COMPARED WITH 2003

Net earnings in 2004 were $1,006 million compared with $1,370 million in 2003. The decrease of $364 million was attributable to the following:

Upstream — decrease of $354 million

- hedging losses;
- higher operating costs and DD&A;
- higher royalties; and
- higher income taxes.

Partially offset by:

- higher crude oil and natural gas prices; and
- higher sales volume of heavy crude oil and natural gas.

Midstream — increase of $55 million

- wider upgrading differential;
- higher heavy crude oil pipeline throughput and tariffs;
- higher crude oil and NGL trading; and
- higher income taxes.

Partially offset by:

- lower upgrader throughput and sales volume;
- higher unit operating costs, which were primarily energy related; and
- lower cogeneration income.

Refined Products — increase of $9 million

- higher light oil product margins; and
- higher restaurant and convenience store income.

Partially offset by:

- higher depreciation and amortization; and
- higher income taxes.

Corporate — decrease of $74 million

- lower foreign exchange gains;
- stock-based compensation first recorded in June 2004;
- higher intersegment profit eliminated; and
- higher administration expenses.

Partially offset by:

- lower depreciation and amortization;
- lower interest expense resulting from lower rates; and
- higher capitalized interest resulting from a higher capital base for the White Rose project.

10. FORWARD-LOOKING STATEMENTS

This MD&A contains certain forward-looking statements relating, but not limited, to Husky's operations, anticipated financial performance, levels of production, business prospects and strategies and which are based on our expectations, estimates, projections and assumptions and were made by us in light of experience and perception of historical trends. All statements that address expectations or projections about the future, including statements about strategy for growth, expected expenditures, commodity prices, costs, production volumes and operating or financial results, are forward-looking statements. Some of our forward-looking statements may be identified by words like ''expects'', ''anticipates'', ''plans'', ''intends'', ''believes'', ''projects'', ''could'', ''vision'', ''goal'', ''objective'' and similar expressions. In addition, our production forecast and our estimate of productive capacity for White Rose, Tucker and Sunrise and plans associated with our exploration programs are forward-looking statements. Our business is subject to risks and uncertainties, some of which are similar to other energy companies and some of which are unique to Husky. Our actual results may differ materially from those expressed or implied by Husky's forward-looking statements as a result of known and unknown risks, uncertainties and other factors.

The reader is cautioned not to place undue reliance on Husky's 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. The risks, uncertainties and other factors, many of which are beyond our control, that could influence actual results include, but are not limited to:

- fluctuations in commodity prices;
- the accuracy of our oil and gas reserve estimates and estimated production levels as they are affected by our success at exploration and development drilling and related activities and estimated decline rates;
- the uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- changes in general economic, market and business conditions;
- fluctuations in supply and demand for our products;
- fluctuations in the cost of borrowing;
- our use of derivative financial instruments to hedge exposure to changes in commodity prices and fluctuations in interest rates and foreign currency exchange rates;
- political and economic developments, expropriations, royalty and tax increases, retroactive tax claims and changes to import and export regulations and other foreign laws and policies in the countries in which we operate;
- our ability to receive timely regulatory approvals;
- the integrity and reliability of our capital assets;
- the cumulative impact of other resource development projects;
- the maintenance of satisfactory relationships with unions, employee associations and joint venturers;
- competitive actions of other companies, including increased competition from other oil and gas companies or from companies that provide alternate sources of energy;
- actions by governmental authorities, including changes in environmental and other regulations that may impose restriction in areas where we operate;
- the ability and willingness of parties with whom we have material relationships to fulfill their obligations; and
- the occurrence of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us and that may or may not be financially recoverable.

11. OIL AND GAS RESERVE REPORTING

DISCLOSURE OF PROVED OIL AND GAS RESERVES AND OTHER OIL AND GAS INFORMATION

Husky's disclosure of proved oil and gas reserves and other information about its oil and gas activities has been made based on reliance of an exemption granted by the Canadian Securities Administrators. The exemption permits Husky to make these disclosures in accordance with requirements in the United States. These requirements and, consequently, the information presented may differ from Canadian requirements under National Instrument 51-101, ''Standards of Disclosure for Oil and Gas Activities''. The proved oil and gas reserves disclosed in this MD&A have been evaluated using the United States standards contained in Rule 4-10 of Regulation S-X of the Securities Exchange Act of 1934. The probable oil and gas reserves disclosed in this MD&A have been evaluated in accordance with the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101.

Husky uses the terms barrels of oil equivalent (''boe'') and thousand cubic feet of gas equivalent (''mcfge''), which are 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 terms boe and mcfge 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 well head.

Cautionary note to U.S. Investors — The United States Securities and Exchange Commission permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. Husky uses certain terms in this MD&A, such as probable that the SEC's guidelines strictly prohibit from inclusion in filings with the SEC.

12. NON-GAAP MEASURES

DISCLOSURE OF CASH FLOW FROM OPERATIONS

This MD&A contains 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 GAAP as an indicator of the Company's financial performance. The Company'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:

	2005	2004	2003
		($ millions)	
Non-GAAP			
Cash flow from operations	$3,785	$2,197	$2,430
Settlement of asset retirement obligations	(41)	(40)	(34)
Change in non-cash working capital	(72)	169	113
GAAP			
Cash flow — operating activities	$3,672	$2,326	$2,509

13. EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Husky's Chief Executive Officer, acting also in his capacity as Acting Chief Financial Officer, has concluded, based on his evaluation as of a date within 90 days prior to the filing of this MD&A (the ''evaluation date''), that Husky's disclosure controls and procedures are effective to ensure that information required to be disclosed by it in reports filed or submitted by it under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by it in such reports is accumulated and communicated to Husky's management, including its chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

There have been no significant changes to Husky's disclosure controls or in other factors that could significantly affect these controls subsequent to the evaluation date and the filing date of this MD&A.

PUBLIC SECURITIES FILINGS

You may access additional information about our Company, including our Annual Information Form, which is filed with the Canadian Securities Administrators at www.sedar.com and the Form 40-F, which is filed with the United States Securities and Exchange Commission at www.sec.gov.

EXHIBIT INDEX

Exhibit No.	Description
23.1	Consent of KPMG LLP, independent accountants.
23.2	Consent of McDaniel and Associates Consultants Ltd., independent engineers.
31.1	Certification of Chief Executive Officer and Acting Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934.
32.1	Certification of Chief Executive Officer and Acting Chief Financial Officer pursuant to Rule 13(a)-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Husky Energy Inc.

We consent to the incorporation by reference in the Registration Statement (No. 333-117972) on Form F-9 of Husky Energy Inc. (the ''Company'') of our report dated February 6, 2006 relating to the consolidated balance sheets of the Company as at December 31, 2005, 2004 and 2003, and the related consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2005, which report appears in the 2005 annual report on Form 40-F of Husky Energy Inc. for the fiscal year ended December 31, 2005 and further consent to the use of such report in such annual report on Form 40-F, and to the inclusion of our comments for US Readers on Canada-US Reporting Differences which appears in the Registration Statement.

/s/ KPMG LLP

KPMG LLP
Chartered Accountants

Calgary, Alberta, Canada
February 6, 2006

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, 2005 (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-9 (File No. 333-117972). We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2005 dated March 14, 2006 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/ P.A. Welch

P.A. Welch
President & Managing Director
Calgary, Alberta, Canada
March 14, 2006

Exhibit 31.1

CERTIFICATION

I, John C.S. Lau, President & Chief Executive Officer and in my capacity as Acting Chief Financial Officer of Husky Energy Inc., 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. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the issuer and have:

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

   (b) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report my 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

   (c) 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; and

5. I have disclosed, based on my 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 functions):

   (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 14, 2006

/s/ John C.S. Lau

John C.S. Lau
President, Chief Executive Officer and
in my capacity as Acting 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, 2005 as filed with the Securities and Exchange Commission on the date hereof (the ''Report''), I, John C.S. Lau, President & Chief Executive Officer and in my capacity as Acting 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 14, 2006

/s/ John C.S. Lau

John C.S. Lau
President & Chief Executive Officer and
In my capacity as Acting Chief Financial Officer