



Canadian Oil Sands

CANADIAN OIL SANDS TRUST

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2006

March 15, 2007

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GLOSSARY

"AENV" means Alberta Environment;

"AEPEA" means Alberta Environmental Protection and Enhancement Act;

"AEUB" means Alberta Energy Utilities Board, the successor to the ERCB;

"AOSII" means Athabasca Oil Sands Investments Inc.;

"AOST" means Athabasca Oil Sands Trust;

"bitumen" in its raw state, is a black oil; it is a naturally occurring viscous tar-like mixture, mainly containing hydrocarbons heavier than pentane, which is not recoverable at a commercial rate in its naturally occurring viscous state through a well without using enhanced recovery methods; when extracted, bitumen can be upgraded into crude oil and other petroleum products;

"bucketwheel reclaimer" means a very large machine that scoops up mined oil sand and places it on conveyors;

"CRA" means Canada Revenue Agency;

"CO" means carbon monoxide;

"CO₂" means carbon dioxide;

"Canadian Oil Sands", "us" or "we" mean collectively the Trust, the Corporation and all subsidiaries of the Trust;

"capacity" means maximum output that can be achieved from a facility in ideal operating conditions in accordance with engineering design specifications;

"coker" means vessels in which bitumen is cracked into light fractions and coke is withdrawn to start the conversion process of bitumen to upgraded crude oil;

"Corporation" means Canadian Oil Sands Limited, the continuing corporation resulting from the amalgamation of AOSII, COSII and COSL on January 1, 2003;

"COSII" means Canadian Oil Sands Investments Inc.;

"COSL" means Canadian Oil Sands Limited, prior to the amalgamation with AOSII and COSII;

"COST" means the former Canadian Oil Sands Trust, which was merged with the Trust;

"conventional crude oil" means crude oil produced through wells by standard industry recovery methods for the production of crude oil;

"cracking" means a process which breaks large, complex hydrocarbon molecules into smaller, simpler compounds by means of heat (as in the case of a coker) or by means of catalytic hydrogen addition (as in the case of the LC Finer);

"Crown Royalty" or "Crown Royalties" means the payments to be made to the Province of Alberta pursuant to the Alberta Crown Agreement or under the generic crown royalty scheme;

"crude oil" means unrefined liquid hydrocarbons, excluding natural gas liquids;

"double roll crusher" means a large unit which crushes the oil sand and deposits the crushed oil sand on to a conveyor;

"dragline" means a large machine which digs oil sand from the mine pit and places it into elongated piles (windrows);

"ERCB" means the Energy Resources Conservation Board of Alberta, a governmental body that oversaw the exploration and development of natural resources in Alberta, now succeeded by the AEUB;

"EnCana" means EnCana Corporation, formerly PanCanadian Energy Corporation;

"Executive Officers" means the five highest remunerated officers of the Corporation and includes the President and Chief Executive Officer and the Chief Financial Officer;

"extraction" means the process of separating the bitumen from the oil sand;

"fines (fine tailings)" means, essentially, muddy water, which is about 85 per cent water and 15 per cent fine clay particles by volume that is produced as a result of extraction of bitumen from oil sand;

"joint venture" means an economic activity resulting from a contractual arrangement whereby two or more venturers jointly control the economic activity;

"LP" means Canadian Oil Sands Limited Partnership;

"MD&A" means our management's discussion and analysis for the year ended December 31, 2006;

"Manager" means, prior to January 1, 2003, AOSII and COSII and, on and after January 1, 2003, the Corporation;

"naphtha" means a light fraction of crude oil used to make gasoline;

"oil sand(s)" is comprised of sand, bitumen, mineral rich clays and water;

"overburden" means material overlying oil sand that must be removed before mining; consists of muskeg, glacial deposits and sand;

"residuum" means the fraction of bitumen that remains after the light ends have been distilled;

"SCL" means Syncrude Canada Ltd., the operator of the Syncrude Project which is owned by the Syncrude Participants;

"SERP" means the Syncrude emission reduction project;

"SSB" means Syncrude™ Sweet Blend;

"SSP" means Syncrude™ Sweet Premium;

"synbit" is a blend of bitumen and synthetic crude oil;

"Syncrude" means, collectively, the Syncrude Joint Venture and the Syncrude Project;

"Syncrude Joint Venture" means the joint venture formed by the Syncrude Participants for the purpose of exploiting the Athabasca oil sands, which includes the Syncrude Plant and leases acquired or developed in connection therewith;

"Syncrude Participants" or "Participants" means ConocoPhillips Oilsands Partnership II (9.03 per cent), Imperial Oil Resources (25 per cent), Mocal Energy Limited (5 per cent), Murphy Oil Company Ltd. (5 per cent), Nexen Oil Sands Partnership (7.23 per cent) and Petro-Canada Oil and Gas (12 per cent), and, prior to January 2, 2007, Canadian Oil Sands Limited Partnership (5 per cent), the Corporation (31.74 per cent), and effective January 2, 2007, Canadian Oil Sands Limited (36.74 per cent), as the corporations or partnerships that own the undivided interests in the Syncrude Project and their respective successors and assigns in interest from time to time;

"Syncrude Plant" means the plant and facilities owned by the Syncrude Participants and operated by Syncrude Canada Ltd. located at Mildred Lake, approximately 40 kilometres north of Fort McMurray, Alberta, where upgrading of bitumen occurs;

"Syncrude Project" means (a) the scheme for recovery of oil sands, crude bitumen or products derived therefrom originally approved in Approval No. 1920 of the ERCB and currently approved in Approval Nos. 8573 and 8250, as issued by the AEUB (as successor of the ERCB), as such scheme may be amended or superseded from time to time, (b) all property now owned or hereafter acquired or developed by the owners participating from time to time in such scheme or by Syncrude Canada Ltd. on their behalf in connection with such scheme, (c) the oil sands leases, and (d) any other scheme or schemes implemented for the purpose of recovering oil sands, crude bitumen or products derived from those oil sands leases related to such scheme or schemes and all property acquired or developed in connection with such scheme or schemes;

"Trust" means Canadian Oil Sands Trust, which prior to the merger with COST, was known as Athabasca Oil Sands Trust;

"trust royalty" means the net royalty paid by the Manager on the production of synthetic crude oil and associated products, attributable to the Manager's working interest in Syncrude;

"Unitholders" means the holders of the units of the Trust; and

"upgrading" means the conversion of heavy bitumen into a lighter crude oil by increasing the hydrogen to carbon ratio, either through the removal of carbon (coking) or the addition of hydrogen (hydroprocessing).

UNITS

API	A measure of specific gravity
bbl	Barrel
bbls/d	barrels per day
gj or GJ	Giga Joule
MW	Mega Watt

Notes: Unless otherwise specified:

- (1) all information is as at December 31, 2006;
- (2) all dollar amounts are expressed in Canadian dollars, all references to "dollars" or "\$" are to Canadian dollars and all references to "US\$" are to United States dollars; and
- (3) Unit information has been adjusted to reflect the 5:1 Unit split that occurred on May 3, 2006.

NON-GAAP FINANCIAL MEASURES

In our MD&A and this Annual Information Form ("AIF"), we refer to net income before unrealized foreign exchange and future income taxes. This is a measurement that is not defined by Canadian generally accepted accounting principles ("GAAP"). The Trust also reports funds from operations, free cash flow and Unitholder distributions on both a total and per Unit basis, as well as cash from operating activities per Unit, which are all measures that do not have any standardized meaning under Canadian GAAP. Funds from operations is calculated on the Trust's consolidated statement of cash flows as cash from operating activities before changes in operating cash working capital. Free cash flow is now calculated as cash from operating activities less capital expenditures and reclamation trust contributions in the period. As a result, net income before unrealized foreign exchange and future income taxes, funds from operations and free cash flow may not be directly comparable to similar measures presented by other companies or trusts. Starting on January 29, 2007, Canadian Oil Sands discusses "cash from operating activities", as per the Trust's Consolidated Statements of Cash Flows, as our measure of the Trust's ability to generate cash from operations. Previously, Canadian Oil Sands reported "funds from operations" as such a measure. "Funds from operations" did not include changes in non-cash working capital from operating activities and was not considered a GAAP measure. Cash from operating activities provides similar information to funds from operations and better comparability to other reporting entities as it is a GAAP measure.

FORWARD-LOOKING INFORMATION ADVISORY

In the interest of providing Canadian Oil Sands (or "we" or "us") Unitholders and potential investors with information regarding Canadian Oil Sands, including the Corporation's assessment of Canadian Oil Sands' future plans and operations, certain statements throughout this AIF contain "forward-looking statements". Forward-looking statements are typically identified by words such as "anticipate", "expect", "believe", "plan", "intend" or similar words suggesting future outcomes, or statements regarding an outlook with respect to: the energy consumption levels for 2007 and beyond; the expected impact on the Trust from the announced proposed changes to the Federal Government's taxation of income trusts, including without limitation, the negative impact on net income, cash from operating activities and Unitholder distributions; the expected increased reliability and other benefits from the Management Services Agreement between Syncrude Canada Ltd. and Imperial Oil Resources; the anticipated timing to reach full production rates from Coker 8-3 and to modify the FGD unit and hydrogen plant; the expected impact that increased supplies of synthetic crude oil will have on the net realized selling price that Canadian Oil Sands receives for its product; the expectation not to enter into crude oil hedges in the future; the expected realized selling price for Canadian Oil Sands' product as expressed as a differential to WTI; the level of natural gas consumption; the anticipated capital expenditures for 2007 including the amount attributable to the Syncrude Emissions Reduction Project ("SERP"); the expected timing to produce SSP; the net sales proceeds of the disposition of the remainder of Canada Southern Petroleum Ltd.'s conventional assets; the expected impact of any future environmental legislation, the Kyoto

Protocol or changes to the Crown royalties regime; the expected level of production and operating costs at Syncrude for 2007 and beyond, and the resulting oil production per day for Canadian Oil Sands; the anticipated impact that certain factors such as natural gas and crude oil prices, foreign exchange and operating costs have on Canadian Oil Sands' cash from operating activities and net income; the estimated value and amount of reserves recoverable and the time frame to recover such reserves; the estimated resources both at Syncrude and in the Arctic Islands licenses; and the anticipated maintenance work at Syncrude and the impact such maintenance will have on Canadian Oil Sands' financial results. You are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Although Canadian Oil Sands believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this AIF include, but are not limited to: the impact of technology on operations and processes and how new complex technology may not perform as expected; labour shortages and the productivity achieved from labour in the Fort McMurray area; the supply and demand metrics for oil and natural gas; the impact that pipeline capacity and refinery demand have on prices for our products; the variances of stock market activities generally; normal risks associated with litigation, regulatory changes and sanctions; volatility of crude oil and natural gas prices; market competition; Canadian Oil Sands' ability to either generate sufficient cash flow from operations to meet our current and future obligations or obtain external sources of debt and equity capital; changes in environmental and other regulations; general economic, business and market conditions, and such other risks and uncertainties described from time to time in our MD&A, in the risk factors section of this AIF, and in the reports and filings made with securities regulatory authorities by Canadian Oil Sands as well as those assumptions outlined in Canadian Oil Sands' guidance document being correct. You are cautioned that the foregoing list of important factors is not exhaustive. The discussion on proposed tax changes in trust tax legislation is based solely on the general information found in the background paper issued by the Department of Finance at the time of the October 31, 2006 announcement (which is not legislation), the guidelines issued by Finance on December 15, 2006, and the draft amendments to the *Income Tax Act* (Canada) released on December 21, 2006. No assurance can be given that the final legislation implementing the 2006 proposed tax changes will be consistent with the foregoing or that Canadian federal income tax law respecting income trusts and other flow-through entities will not be further changed in a manner which adversely affects the Trust and its Unitholders. To the extent that changes, including the 2006 proposed tax changes, are implemented, such changes could result in the income tax considerations described in this AIF being materially different in certain respects. Furthermore, the forward-looking statements contained in this AIF are made as of the date of this AIF, and unless required by law, Canadian Oil Sands does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

THE TRUST AND ITS STRUCTURE

Name, Address and Formation

The Trust is an open-ended investment trust formed in October 1995 under the laws of the Province of Alberta pursuant to an amended and restated trust indenture created upon the merger of the Athabasca Oil Sands Trust ("AOST") and the former Canadian Oil Sands Trust ("COST"). On July 5, 2001, AOST acquired all the assets of COST and assumed all the liabilities of COST in exchange for

AOST units equal to the number of COST units issued and outstanding as of such date. AOST then changed its name to Canadian Oil Sands Trust. The trust indenture was further amended and restated on June 1, 2005 to reflect the adoption of amendments passed at the 2003 and 2005 Unitholders' meetings and effective December 20, 2005 to allow for a change in how distributions were paid. Commencing in the fourth quarter of 2005 distributions are recorded in the quarter declared and paid to Unitholders on the last business day of February, May, August and November. The current trustee of the Trust is Computershare Trust Company of Canada (the "Trustee").

The registered and head office of the Trust is located at 2500 First Canadian Centre, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

Intercorporate Relationships

The following table provides the name, the percentage of voting securities owned and the jurisdiction of incorporation, continuance or formation of the Trust's subsidiaries as at March 15, 2007.

	Percentage of Voting Securities (directly or indirectly)	Jurisdiction of Incorporation/ Formation
Canadian Oil Sands Limited ⁽¹⁾⁽²⁾⁽⁴⁾	100%	Alberta
Canadian Oil Sands Marketing Inc. ⁽³⁾	100%	Alberta
Canadian Arctic Gas Ltd.	100%	Alberta

Notes:

- (1) Total assets and total revenues of this entity constituted more than 10 per cent of the consolidated assets and consolidated revenues of the Trust at December 31, 2006.
- (2) Holds a direct 36.74 per cent working interest in Syncrude.
- (3) Markets the SSB production for the Trust and its subsidiaries outside of Canada.
- (4) Prior to January 2, 2007, Canadian Oil Sands Limited also acted as general partner and held 75 per cent of the limited partnership units in Canadian Oil Sands Limited Partnership ("LP") with Talisman Energy Inc. ("Talisman") holding 25 per cent of LP. When Canadian Oil Sands Limited purchased Talisman's interest in the LP on January 2, 2007, the LP was dissolved with the 5 per cent working interest that had been held by the LP now held directly by Canadian Oil Sands Limited.

GENERAL DEVELOPMENT OF THE BUSINESS

Summary

We are the largest energy trust in Canada, based on market capitalization as at March 15, 2007 of approximately \$13 billion, and the only public investment vehicle that provides a non-diversified ownership in Syncrude, the largest open mining sands project in the world. Syncrude is located near Fort McMurray, Alberta, Canada and operates large oil sands mines, bitumen extraction plants, an upgrading complex that processes bitumen into a light sweet crude oil, and electrical power utility plants. The Syncrude operation is comprised of four major operating areas: mining, extraction, upgrading and utilities. Syncrude's principal product is a high quality, light, sweet synthetic crude oil blend, referred to as "Syncrude™ Sweet Blend" ("SSB"), which has an average gravity of about 32° API and low sulphur content of less than 0.2 per cent. The Trust's business is its indirect ownership of Syncrude and the marketing and sales of SSB derived from such ownership as well as other products related to such Syncrude interest.

On July 5, 2001, the Trust was created by the merger of AOST and COST, which trusts held an 11.74 per cent and 10 per cent working interest, respectively, in Syncrude. Following the merger, the Trust's indirect 21.74 per cent working interest in Syncrude was administered by PanCanadian Petroleum Limited (now EnCana) pursuant to an administrative services agreement. In August 2001, Canadian Oil Sands hired Mr. Marcel Coutu as President and Chief Executive Officer to oversee the Trust's working interests and assume a more active management role in relation to the Trust's assets. This internalization of management continued, when in the fall of 2002, the Corporation terminated the administrative services agreement with EnCana and hired its own staff.

In 2003, Canadian Oil Sands acquired an additional 13.75 per cent working interest in Syncrude from EnCana for total consideration of approximately \$1.5 billion, which acquisition was financed through a combination of debt and equity issuances. Due to the tax considerations of the vendor, we acquired the additional interest in a manner which created a more complex organizational structure. In 2004, the Corporation obtained a tax ruling from the CRA which enabled the Corporation to consolidate three royalties into one royalty. On December 31, 2004, the Trust and its subsidiaries undertook a reorganization which simplified the corporate structure and enabled all of its working interests in Syncrude to be consolidated under the Corporation.

In 2006, Canadian Oil Sands acquired Canada Southern Petroleum Ltd. ("CSP") for cash proceeds of approximately \$223 million. The objective of the acquisition was the Arctic Island's natural gas interests. These assets are estimated to contain approximately 927 billion cubic feet equivalent of natural gas ("bcfe"), net to CSP, based on available information and third party and internal estimates. Following the acquisition of about 78 per cent of the issued and outstanding common shares of CSP over the summer of 2006 through a take over bid process, Canadian Oil Sands acquired the remainder of the common shares on October 25, 2006. Concurrent with this final purchase, CSP was amalgamated with two wholly-owned subsidiaries of the Corporation to form Canadian Arctic Gas Ltd. ("Canadian Arctic"). Following the acquisition, we proceeded to sell CSP's conventional oil and natural gas reserves in B.C., Alberta and Saskatchewan and are currently in the process of selling the remaining conventional assets in the Yukon.

Canadian Oil Sands views the acquisition of CSP as a strategic acquisition that provides Canadian Oil Sands with a unique opportunity to secure a large, long-life natural gas resource to reduce the risk of significant future natural gas price increase impacts on its Syncrude oil sands production. On a macro-basis, the estimate of 927 bcfe of natural gas resource represents the Trust's expected natural gas requirements to produce its share of light, sweet crude oil at post Stage 3 productive capacity rates for approximately 25 years, thereby providing a long-term financial hedge against any significant increases in natural gas prices in the long-term. Canadian Oil Sands financed the acquisition with bank debt and cash from operating activities.

On November 29, 2006, the Corporation entered into an agreement with Talisman Energy Inc. ("Talisman") to acquire the 1.25 per cent indirect working interest in Syncrude that Talisman held through its ownership of units of Canadian Oil Sands Limited Partnership. This acquisition, which closed on January 2, 2007, was for \$475 million, half of which Canadian Oil Sands paid in cash and half through the issuance of 8,189,655 Units. Immediately following the acquisition, the Corporation dissolved Canadian Oil Sands Limited Partnership, resulting in the 36.74 per cent working interest in Syncrude being held directly by the Corporation.

On November 1, 2006, Canadian Oil Sands announced that the Syncrude Participants had approved Syncrude Canada Ltd. ("SCL") entering into a comprehensive management services agreement and secondment agreement with Imperial Oil Resources ("Imperial Oil"). Under the agreement, Imperial

Oil, with the support of ExxonMobil, will provide global practices in several areas including: maintenance and reliability, energy management, procurement, safety, health, and environmental performance with the expectation of delivering further sustainable improvement in Syncrude's operating performance. The agreement is effective November 1, 2006 and has an initial term of 10 years with renewal provisions. Imperial Oil, ExxonMobil, SCL and the other Syncrude participants have formed a team which is conducting a comprehensive onsite assessment of the Syncrude operations with a view to making specific recommendations in the second quarter of 2007 in respect of the services to be provided by Imperial Oil. The mandate of this opportunity assessment team ("OAT") is to better understand, prioritize and define best approaches for implementing potential opportunities at Syncrude. If the recommendations are not approved to the reasonable satisfaction of Imperial Oil, the management services agreement can be terminated by Imperial Oil. Either Syncrude or Imperial Oil has the option to cancel the agreement on 24 months' notice for any reason. Canadian Oil Sands will pay its pro-rata share of annual fixed service fees equivalent to about \$17 million (\$47 million gross to SCL) plus its share of the direct costs that Imperial Oil incurs in providing the services. Following the initial 10 year term, the annual fixed service fees drop to \$33 million gross to Syncrude or approximately \$12 million net to Canadian Oil Sands based on its 36.74 per cent share of Syncrude. In years four through 10, performance fee incentives similar in magnitude to the fixed fees also will apply if certain targets are achieved. Through higher production levels, savings in energy efficiency, lower sustaining capital costs, reduced maintenance and operating costs, and other efficiencies from new business control systems, we believe that the value to be captured should be a multiple of the fees paid. The agreement does not change the existing Ownership and Management Agreement between SCL and the Syncrude Participants - SCL remains the operator and employer of Syncrude's personnel. Ownership in the Syncrude Joint Venture remains unchanged, as does the proportionate ownership in SCL. The oversight and strategic direction for Syncrude continues to come from the Syncrude Participants' Management Committee, which is comprised of senior representatives from each Syncrude Participant, and is currently chaired by Canadian Oil Sands.

The Corporation is responsible for the management of the Trust. Specific responsibilities are: (i) to devise, manage and execute a long-term strategy aimed at optimizing Unitholders' value in the Trust; (ii) to ensure compliance by the Trust with continuous disclosure obligations under all applicable securities legislation; (iii) to provide investor relations services; (iv) to provide, or cause to be provided to Unitholders, all information to which Unitholders are entitled under the amended and restated trust indenture; (v) to call, hold and distribute material including notices of meetings and information circulars in respect of all necessary meetings of Unitholders; (vi) to determine the amounts payable from time to time to Unitholders and to arrange for distribution to Unitholders of distributable income; and (vii) to determine the timing and terms of future financings, including offerings of Units, if any.

Canadian Oil Sands is responsible for funding our share of Syncrude's operations, maintenance, expansions, and our own administrative costs. Sources of funding include cash from operating activities generated from the sale of our SSB production and, as required, debt and equity financing. In the opinion of the Corporation's management, cash from operating activities is a key performance indicator of the Trust's ability to generate cash to fund capital expenditures. Free cash flow, which is calculated as cash from operating activities less capital expenditures and mining reclamation trust contributions, is a key indicator of the Trust's ability to repay debt and pay Unitholder distributions. The Trust makes distributions to its Unitholders after it receives trust royalties and debt and interest payments from its subsidiaries and pays its expenses.

The Syncrude Joint Venture is owned as various undivided interests by the Syncrude Participants and has produced synthetic crude oil for 28 years. The assets of the Syncrude Joint Venture are operated and managed by SCL, which is owned by the Syncrude Participants in the same proportions as their interest in

the Syncrude Joint Venture. SCL is a single purpose company with no significant tangible or capital assets with the exception of its workforce and retirement plan assets. The Syncrude Management Committee governs the Syncrude Joint Venture and each Participant nominates a representative to the committee, which is charged with setting the strategic direction for and making decisions regarding the operation of the Syncrude Joint Venture. Our President and Chief Executive Officer is the Chairman of the Syncrude Management Committee. He is also Chairman of the Board of Directors of SCL and chairs the CEO Committee of the Board of SCL. Our Chief Financial Officer is the Chairman of the Audit and Pension Committee of the Board of SCL as well as the Chair of the Business Controls project at Syncrude. None of the representatives of the Syncrude Joint Venture Participants on the Board and committees of SCL receive compensation as directors of that corporation. Each Participant receives its share of production *in kind* and is responsible for the subsequent marketing of such share of the production. Syncrude commenced production in 1978 and has, through capital investment and technological and efficiency improvements, increased annual production. With the start up of Stage 3 in the fall of 2006, Syncrude production reached 94.3 million barrels in 2006 compared to 78 million barrels in 2005 and 87 million barrels in 2004. This significant increase from 18 million barrels in 1979 and 3.6 million barrels in 1978, which was a partial operating year, shows the incredible growth and potential of Syncrude. The focus in 2007 and beyond is to line out the Stage 3 to achieve more reliable and efficient operations that will allow Syncrude to reach annual productive capacity of 128 million barrels gross to Syncrude. We believe that the implementation of the management services agreement between SCL and Imperial Oil is a significant step towards achieving this goal.

Production volumes reflect the capacity of the Syncrude facility and the reliability of its operations. Our proved plus probable reserves life index, estimated at more than 35 years, provides a secure, long-term source of bitumen for the production of SSB. However, the process of mining, extracting and upgrading bitumen is a highly technical and complex manufacturing operation that requires regular maintenance of the various operating units, which can affect production volumes and consequently revenues. Production volumes have a significant impact on per barrel operating costs as a large proportion of the costs are fixed and, if the plant is not operating, repair costs typically also are being incurred. One of the most significant production cost inputs is natural gas. Therefore, operating costs are also sensitive to changes in natural gas prices and usage.

Canadian Oil Sands' cash from operating activities is highly dependent on the net selling price received for our SSB product, production and sales volumes, and the operating costs and other expenses of producing SSB, including Crown royalties. In 2005, consistent with our increased focus on the stewardship of our business, we elected not to renew our marketing agreement with EnCana and in August 2006, we internalized the marketing function at the Corporation. As the markets are changing with new supply being added from various oil sands operators in Western Canada, new pipelines, new refineries and refinery re-configurations, and new feedstock choices for refiners, we decided to have increased influence over that landscape. Establishing our own marketing capability should result in more direct control over our marketing processes, a better understanding of our customers' needs, and enhancement of our connection with rapidly changing market dynamics. We expect these insights will assist us in making better long-term strategic decisions about markets and products, both for our interest in Syncrude and as we consider other oil sands investments. Additionally, focusing on ensuring we obtain space on pipelines to move our product is expected to be a cornerstone of the marketing department's activities over the next few years until various announced pipeline projects are completed.

As part of such internalization of the marketing department, we created a wholly-owned subsidiary of the Corporation, called Canadian Oil Sands Marketing Inc. ("COSMI"). COSMI is the entity which markets Canadian Oil Sands' crude oil to customers with title transfer points in the United States as opposed to the Corporation which sells to customers with title transfer points within Canada.

COSMI purchases SSB from the Corporation for resale to the customers in the United States and enters into pipeline and other transportation and marketing arrangements in the United States. COSMI has no staff or officers of its own and instead is allocated a portion of the overhead costs of the Corporation.

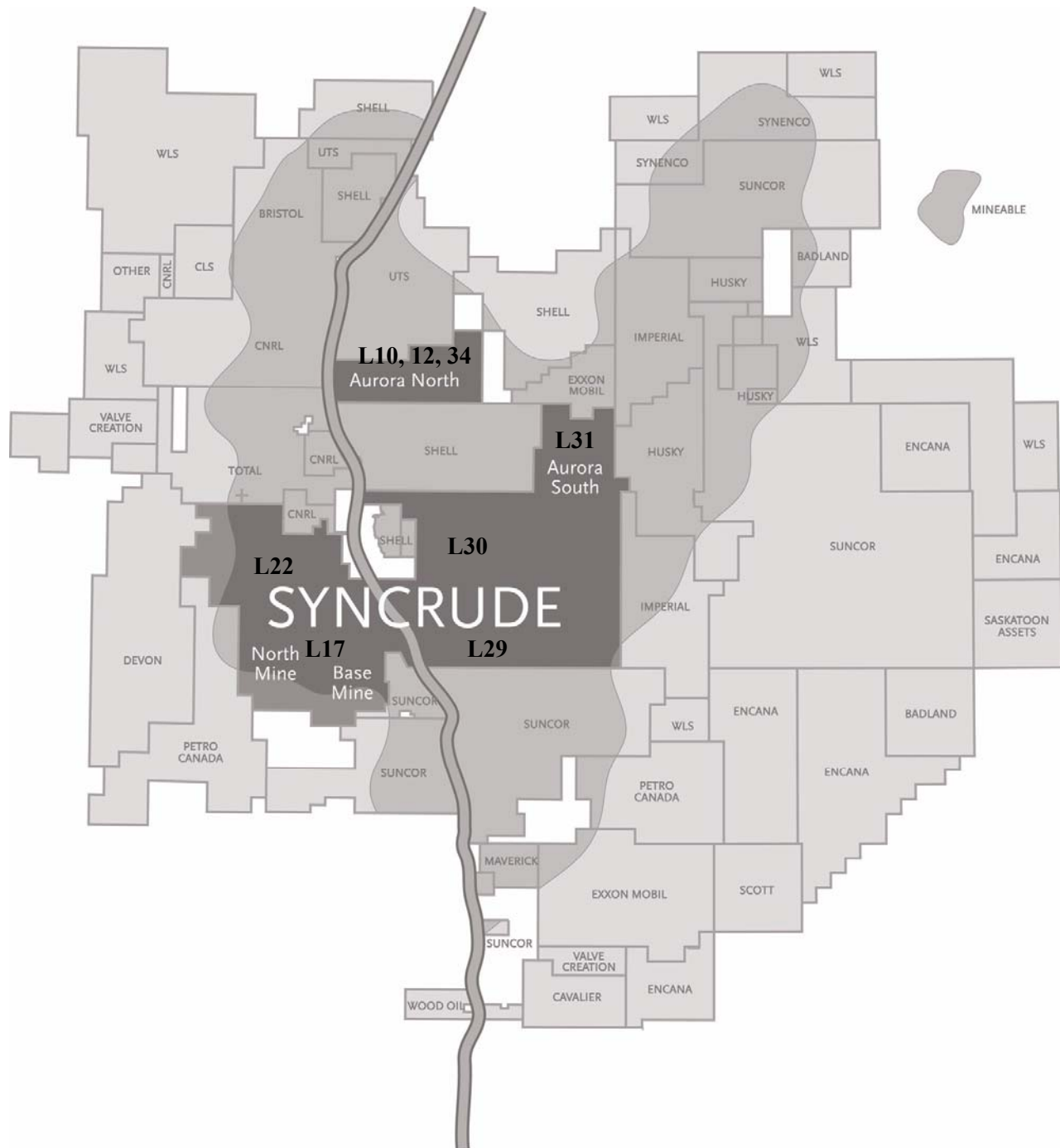
In 2006, Syncrude completed the largest expansion project in its history, known as Stage 3. The expansion is designed to increase annual Syncrude productive capacity to about 128 million barrels and enhance the product quality of SSB to a new level known as SSP. While Syncrude started up Coker 8-3 and the related units, which are the main components of Stage 3, at the end of May 2006, Syncrude had to shut down Stage 3 operations due to odorous emissions from the plant. Upon further investigation, Syncrude determined that the source of the odor was from the flue gas desulphurization unit ("FGD") primarily as a result of contaminated ammonia which was produced on-site and required as feedstock to the FGD and additional retrofit work was undertaken. Coker 8-3 was restarted in August 2006 with the use of imported ammonia and is expected to operate using this imported ammonia until such time as additional changes to the FGD unit can be undertaken. The total project cost for Stage 3 is estimated at \$8.55 billion, or \$3.1 billion net to the Trust based on its 36.74 per cent ownership. See the discussion below under "Syncrude".

Historically, the price we have received for our SSB product has correlated closely to the U.S. West Texas Intermediate ("WTI") benchmark oil price, and is also impacted by movements in U.S./Canadian foreign exchange rates. Crude oil prices can be volatile, reflecting world events and supply and demand fundamentals. In addition, supply and demand impacts the price differential of our SSB product relative to Canadian dollar WTI prices. The differential can move from a premium to a discount depending on the supply/demand dynamics in the market. During the past three years, WTI daily closing prices have fluctuated from a low of approximately US\$32.50 per barrel to a high of approximately US\$77.00 per barrel.

Syncrude

Syncrude produces light, sweet synthetic crude oil from the Athabasca oil sands deposits by surface mining the oil sands, extracting the bitumen from the sands, upgrading the recovered bitumen into lighter oil fractions, and combining those component fractions into a single product called Syncrude™ Sweet Blend or SSB. Syncrude produces a single product type of crude oil, rather than a slate of different heavy, light, sweet and sour crude oils. Bitumen, in its raw state, is a thick, tar-like, black crude oil that requires upgrading in order to make it transportable by pipeline and more useable to refineries across North America.

The Athabasca oil sands deposits are vast and the Syncrude leases contained in such deposits are illustrated in the following lease map. The estimated nine billion SSB barrels of recoverable resources that are contained in Syncrude's leases are all considered to be surface mineable, meaning that the layers of oil sands are found beneath a relatively shallow overburden layer. Only approximately 20 per cent of the Athabasca oil sands deposits are considered to be surface mineable with the other 80 per cent having the oil bearing layers too deep to be reached by mining and instead must be exploited using in-situ methods.



Syncrude and other developers of the Athabasca oil sands have pioneered various technologies to mine the oil sands, extract the bitumen, and upgrade the bitumen into synthetic crude oil. Syncrude engineers and scientists continue to focus on technologies to improve the energy efficiency of the various processes, improve the product quality of the finished product, improve bitumen extraction recovery efficiencies and upgrading yield efficiencies, and lessen the environmental impact of the various steps in the process. Some examples of technological advancement include: low energy extraction, intended to reduce the amount of energy required to recover each barrel of bitumen and to reduce emissions; slurry hydrotransport, a process that uses pumping of an oil sands/water mixture rather than conveying solids with a view to reducing maintenance and operating costs in the material handling area; and froth

pumping, an innovative way of pumping thick tar-like bitumen slurried with water rather than with hydrocarbon-based diluents, once again intended to reduce capital, energy and operating costs.

Syncrude began operations in the late 1970s at the Mildred Lake site. The initial mining areas were developed adjacent to the main plant facilities which contained the extraction plants, the upgrading plants and the utilities plants used to support the entire operation. As the operation continued over the years, and as plant expansions were introduced, the mining operations moved further away from the base operations site. These early mining areas, located near the main processing plants, are known as the Base Mine and the North Mine. In 2000, Syncrude opened a third mining area – approximately 35 km from the base operating area at Mildred Lake – known as Aurora North. While extraction operations associated with the Base and North mines are located at the Mildred Lake site, the Aurora North mine has its own primary extraction facilities near that mine. In 2003, mining operations were again expanded with the addition of a second mining and extraction train at Aurora North called "Aurora 2".

Like mining, the upgrading facilities also have been expanded over the years. The initial upgrader comprised two fluid cokers which are designed to break down the bitumen into lighter components. These cokers were de-bottlenecked several times over the years and a third primary upgrading unit, known as the LC Finer, was added. The LC Finer uses hydrogen and catalyst to crack the bitumen into lighter fractions. In early 2001, after several years of planning, the Syncrude Participants approved Stage 3, which is the largest expansion in Syncrude's 28 year production history and includes both Aurora 2 and an upgrader expansion ("UE-1"). As part of this project, upgrading operations were again expanded with the addition of a larger, more modern third fluid coker, otherwise similar to the original two fluid cokers. As part of UE-1, the product quality of crude oil produced by Syncrude is to be enhanced to a higher quality, lighter, sweeter crude oil known as Syncrude™ Sweet Premium or SSP.

In 2006, as Stage 3 and the South West Quadrant Replacement projects were completed, capital expenditures totaled \$300 million compared to \$800 million in 2005. With the completion of Stage 3 in 2006, SERP expenditures started to ramp up and comprise 44 per cent of the 2007 expected capital expenditures. Stage 3 expenditures, amounted to about 40 per cent and 70 per cent of the 2006 and 2005 totals, respectively. As at December 31, 2006, the Syncrude Joint Venture had expended approximately \$8.5 billion of the total \$8.55 billion estimated Stage 3 project cost, which includes \$0.7 billion for Aurora 2. Ancillary costs for final clean up of facilities and completion of various units remains to be incurred, which we anticipate will total approximately \$90 million gross to Syncrude, or \$33 million net to Canadian Oil Sands. Net to Canadian Oil Sands, the total cost for Stage 3 is equivalent to approximately \$3.1 billion. Production from Coker 8-3 initially commenced in the second quarter of 2006. We anticipate that a period of lining out and optimizing the different operating units will be required to ramp up to full productive capacity of 128 million barrels annually, or 47 million barrels net to the Trust.

Syncrude's post-Stage 3 facilities have the design capability to produce approximately 375,000 barrels per day when operating at full capacity under optimal conditions and with no downtime for maintenance or turnarounds. This daily production capacity is referred to as "barrels per stream day". However, under normal operating conditions, scheduled downtime is required for maintenance and turnaround activities and unscheduled downtime will occur as a result of mechanical problems, unanticipated repairs and other slowdowns. When allowances for such downtime are included, the daily productive capacity of Syncrude's post-Stage 3 facilities is approximately 350,000 barrels per day on average and is referred to as "barrels per calendar day". Unless stated otherwise, all references to Syncrude's productive capacity in the following discussions refer to barrels per calendar day.

SERP is estimated to cost \$772 million, or approximately \$284 million net to the Trust based on its 36.74 per cent working interest. Canadian Oil Sands' share of the SERP expenditures to December 31, 2006 is approximately \$49 million. The SERP is expected to significantly reduce total sulphur dioxide emissions as well as other emissions, such as particulate matter and metals. It will involve retrofitting flue gas scrubbing facilities into the operation of Syncrude's two existing CO boilers. Procurement and construction expenditures have commenced following completion of the Stage 3 expansion and extend into the next four years to tie-in with equipment turnaround schedules. The new coker that is part of UE-1 already includes a sulphur dioxide reduction unit. These measures, along with the SERP, are expected to reduce the total sulphur dioxide emissions by up to 60 per cent from today's approved levels of 245 tonnes per day. Sulphur dioxide emissions are also expected to fall below the new maximum emission levels that will take effect following the completion of SERP.

Syncrude incurs both sustaining and expansion capital expenditures. Sustaining capital expenditures, which are costs required to maintain the current productive capacity of Syncrude's mines and upgraders, fluctuates considerably year-to-year due to timing of equipment replacement and other factors. Excluding major sustaining capital expenditure projects, which occur from time to time, such as the SERP and Southwest Quadrant replacement ("SWQR") projects, we anticipate longer-term average sustaining capital expenditures of approximately \$5 per barrel, or \$240 million annually based on Syncrude's Stage 3 design capacity of 128 million barrels, or 47 million barrels net to the Trust. Including SERP, sustaining capital expenditures are expected to average \$6 per barrel over the next four years. The Trust's sustaining capital expenditures on a per barrel basis were approximately \$5 and \$9 in 2006 and 2005, respectively, and included expenditures for the SERP and SWQR projects.

We have estimated our share of Syncrude's 2007 capital expenditures to total approximately \$255 million, of which approximately \$85 million will be directed to the SERP. Non-production costs, which consist primarily of development expenditures related to capital programs, are expected to total approximately \$74 million for 2007.

Two additional expansion phases to follow Stage 3 also are in the preliminary scoping phase and therefore have not been approved by Syncrude Participants nor has the cost of any implementation of such expansions been determined. The "Stage 3 debottleneck" expansion is expected to be principally a debottlenecking of the facilities and is expected to increase productive capacity to about 145 million barrels per year (gross to Syncrude). The Stage 4 expansion is conceptually another coker and additional mining trains, similar to Stage 3, and should increase productive capacity to approximately 185 million barrels per year (gross to Syncrude). The Stage 3 debottleneck expansion has received regulatory approval but the Stage 4 expansion has not received approval. As part of the Syncrude Participant's approval of the management services agreement, the Syncrude Participants reconfirmed their commitment to undertake preliminary design work on both the Stage 3 debottleneck and Stage 4.

NARRATIVE DESCRIPTION OF THE BUSINESS

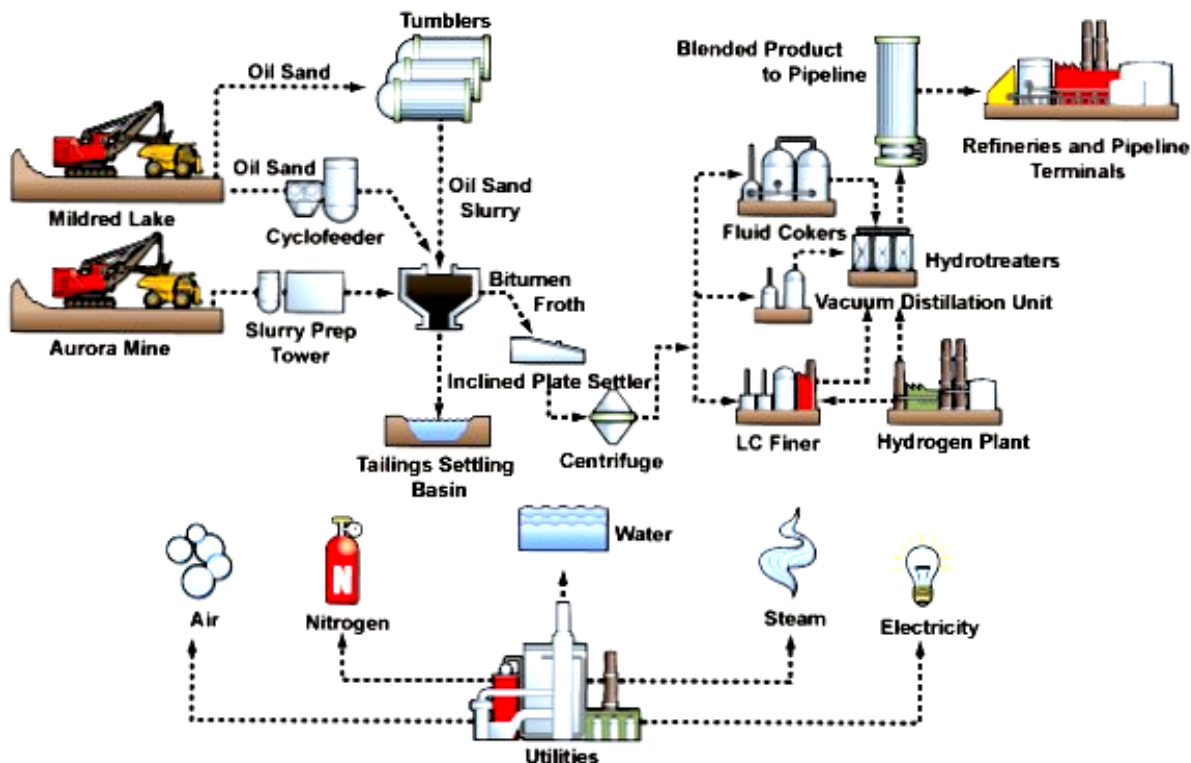
Syncrude is a vast and complex operation. The mines and extraction facilities are among the largest in the world, and the upgrading plants, which could be considered similar in nature to oil refineries, are also among the largest and most complex in the world. As such, a very strong focus on the basics of safety, environmental, operational and business excellence is imperative. We refer to these focus areas collectively as "operational excellence". In order to achieve the goal of operational excellence, Syncrude has identified the following objectives: improve the operational reliability and utilization of all of its operations, reduce unit operating costs, increase bitumen and upgrading productive capacity, improve environmental and energy efficiencies, and capture expansion-related economies of scale. On safety performance, Syncrude's track record of excellence is long-standing and compares

favourably with some of the world's best mining and energy companies. In 2006, Syncrude achieved a lost-time injury ("LTI") rate of 0.15 per 200,000 workforce hours, including permanent and contract workers, compared to Syncrude's best 0.05 per 200,000 workforce hours set in 2005.

As with nearly all commodity-based mining and manufacturing operations, the key to operational excellence lies in operational reliability and cost management. Syncrude's goals include reliability and cost performance improvements through the use of structured operating, maintenance, reliability and procurement standards. Over the last few years, Syncrude has struggled with reliability and performance issues at a time when a very complex and large scale construction project was ongoing with the Stage 3 expansion. With Stage 3 essentially complete, the Syncrude Participants have directed SCL to focus on ongoing reliability and performance issues. Safe, reliable operational performance is key to achieving lower operating costs. In that regard, in November 2006, Syncrude Participants supported SCL entering into the management services agreement with Imperial Oil to further strengthen the resolve of the Syncrude Participants to achieve this improved reliability.

Maintenance work has a key impact on Syncrude's operations and, consequently, on the revenues that Canadian Oil Sands derives. Maintenance work that occurs during the colder winter season may experience more time delays and operational issues due to the impact of having to work in extremely cold weather conditions.

The Syncrude Operations



Mining

Syncrude currently mines oil sands from three mines: the Base Mine and North Mine, located near the Mildred Lake site, and the Aurora North Mine, located 35 kilometres northeast of the base operations site. The mining and extraction methodologies utilized at Syncrude have evolved over time as technological innovation has been continuously introduced. The initial mining operations were based on

the use of very large draglines, bucket-wheel excavators and long conveyor systems. These original systems have, for the most part, been retired in favour of new technologies. The current mining operations utilize very large shovel excavators and mining haul trucks. This technology, now the standard in the oil sands industry, is known as "truck and shovel" mining. The larger shovels can excavate 100 tonnes of oil sands in a single pass and the larger haul trucks can carry 400 tonnes of material from the mine face to the dumping location. A fleet of 15-20 shovels and 80-90 haul trucks are used in the overburden and oil sands ore mining operations at Syncrude.

The Base Mine began operations in 1978, the North Mine in 1997 and Aurora North Mine in 2000. In 2006, the amount of oil sands recovered from the Aurora North Mine grew to represent approximately 58 per cent (51 per cent in 2005) of the total oil sands recovered from all three mines combined. The Aurora North Mine is comprised of Leases 10, 12 and 34. The Aurora North Mine operations use a new generation of larger 400-tonne trucks and larger shovels. It is anticipated that the Aurora North Mine portion of bitumen production will continue to increase over the next several years. As part of the transition away from the Base Mine, two mining systems, each comprised of a dragline, bucketwheel reclaimer and conveyor system, were retired in 1999 and 2002 and a third was retired in 2006. Remaining oil sands will now be recovered by truck and shovel. In each of the years 2006 and 2005, the Base Mine contributed 11 per cent and 19 per cent, respectively, of the total bitumen produced from the Syncrude mines with the North Mine producing 31 per cent in 2006 and 32 per cent in 2005 and Aurora North producing 49 per cent in 2005 and 58 per cent in 2006.

It is important to note that mining operations not only deal with oil sands excavation and delivery to extraction operations but also with overburden removal and disposition. Overburden is the sand and clay material found above the oil sands bearing layer in the Athabasca oil sands formations. It must be removed in order to expose the oil sands bearing layers for mining. In 2006, the total volume of overburden mined was approximately 214 million tonnes compared to 167 million tonnes in 2005.

Since its completion in 2005, the SWQR project has added a supplemental mining system at the North Mine, feeding the existing Mildred Lake extraction plant; integrated a third material handling train into the Aurora North mine in addition to the existing two full trains of mining and extraction systems; increased the effective utilization of the two existing Aurora North bitumen production systems by providing spare mining supply and tailings disposal systems; and provided additional thermal energy sources at Aurora North by adding a second 80MW gas turbine generator and heat recovery hot water generator.

Extraction

Historically, all extraction activity occurred at the Mildred Lake plant as the ore was mined exclusively at the Base Mine. As part of the transition from the Base Mine to the North Mine and subsequently to the Aurora North Mine, the method of extraction and the location of extraction facilities has changed.

The ore from the Base Mine is delivered to the Mildred Lake extraction facilities by conveyor and is then mixed with steam, hot water and caustic soda to produce a slurry at a temperature of approximately 80°C. This mixing process occurs in large horizontal rotating tumblers that condition the mixture for separation. This slurry is discharged from the tumblers onto vibrating screens to remove large rocks and lumps of clay prior to entering the primary separation vessel, where the floated bitumen is recovered. Much of this system continues to operate today.

At the North Mine, once the ore has left the double roll crusher, it is conveyed to a cyclofeeder where it is mixed with warm water and caustic soda to produce a slurry at a temperature of approximately

50°C. The use of warm water in this process as opposed to hot water at Mildred Lake has led to decreases in energy consumption in this part of the operations. The resulting slurry is screened, and the oversized material is rejected for further crushing and reprocessing. The slurry is further conditioned as it is transported to the Mildred Lake extraction plant via a hydrotransport pipeline where it enters the primary separation vessels.

The extraction process at the Aurora North Mine is similar to the North Mine, with a few exceptions. After the ore is crushed in the double roll crusher, it is conveyed to a mixbox where it is mixed with cooler water to produce a slurry with a temperature of approximately 35°C. Rather than shipping the oil sands slurry to the Mildred Lake extraction plant, the slurry is transported via a hydrotransport pipeline to one of two primary separation vessels located at the Aurora North Mine (approximately three to five kilometres from the mining area). Here, the sand settles to the bottom of the vessel and is transferred to the Aurora North Mine's tailings pond where the primary froth rises and is recovered. The primary froth is then piped to Mildred Lake for further processing.

At the Mildred Lake extraction plant, the slurry from the North Mine flows into primary separation vessels and further separation takes place. The resulting froth is then mixed with the froth from the Aurora North Mine and diluted with naphtha prior to further processing. A final stage of separation removes substantially all of the remaining water and clay fines, leaving a relatively clean bitumen as the feedstock for the upgrader.

The material remaining after the bitumen is extracted from the oil sands consists of water, sand, fine clay particles and some residual hydrocarbons. This material is sent to a tailings settling basin where the solids settle to the bottom and the clarified water is recycled for re-use in the extraction process. The rate at which the fine tailings settle out of the water is extremely slow and is the subject of considerable research and development activity to identify the most cost effective and environmentally acceptable disposal method. A new composite tails technology using the mature fine tailings from the settling basin to create solid, permanent landscapes in mined-out areas became operational at the Mildred Lake site during 2000. The key tailings research and development initiatives proposed for the next few years include: optimization of the composite tailings process, reclamation of tailings deposits, managing recycle water chemistry and development of thickened tailings for oil sand application.

One of the key performance metrics associated with the extraction operation is known as "recovery". Recovery measures the volume of bitumen recovered from the oil sand as a per cent of the oil that was contained in the oil sand processed in the extraction plants. In 2006, this recovery factor was approximately 90 per cent. The ratio was approximately 89 per cent in 2005. Improvements in extraction recovery ratios year-over-year are the result of continuous improvement initiatives undertaken by Syncrude.

Upgrading

Upgrading is the final stage in which the bitumen is converted into synthetic crude oil. The first step in upgrading is the removal of the diluent naphtha which was added in the extraction plant. This naphtha is recycled to the froth treatment plant for re-use. Next, the bitumen is fed through a vacuum distillation unit in which lighter fractions of hydrocarbons are removed for further processing, as discussed later. The heavier bitumen components are processed in three fluid cokers and one LC Finer. While these two forms of upgrading bitumen are somewhat different, they have the same intended purpose, namely to break down the heavier hydrocarbon components into lighter components. The lighter hydrocarbons separated in the vacuum distillation unit are "by-passed" around the cokers and the LC Finer because they are already of sufficient quality to be processed directly in secondary upgrading

process units. The vacuum distillation unit had a nominal capacity rating of 180,000 barrels per day of bitumen feed until, in the fourth quarter of 2005, its capacity was expanded as part of the Stage 3 expansion to about 285,000 barrels per day.

Fluid coking involves the thermal cracking of bitumen molecules into lighter components. The by-products of this process include petroleum coke, CO gas and off gas. CO gas is used as fuel in CO boilers to generate steam and power for the facility. Off gas is used as fuel in the upgrader. The residual coke produced in the coker is slurried into segregated cells in the tailings pond. The two original fluid cokers have been expanded in capacity over the years and, in 2005, each had a nominal capacity rating of approximately 105,000 barrels per day of a 50/50 mix of bitumen and heavier vacuum topped bitumen feed. This capacity was unchanged from the prior year. The third fluid coker, added in 2006 as part of the Stage 3 expansion, has the same purpose as the original two cokers but is designed to process 100,000 barrels per day of 100 per cent vacuum topped bitumen.

The LC Finer cracks bitumen molecules into lighter components via the addition of hydrogen and in the presence of a catalyst. This unit does not convert all of the bitumen to light products. An unconverted residual stream also is produced and this stream is sent to the fluid cokers to supplement the feed to those units. In 2006, the LC Finer unit had a nominal capacity rating of approximately 50,000 barrels per day of a 60/40 mix of bitumen and vacuum topped bitumen feed. This capacity was unchanged from the prior year.

One of the key performance metrics associated with the upgrading operation is referred to as "yield". Yield measures the volume of finished products produced per volumetric measure of bitumen feedstock. In 2006, the upgrading yield was approximately 85 per cent, basically unchanged from 2005.

The lighter hydrocarbon components produced by the two fluid cokers, the LC Finer, and those removed in the vacuum distillation unit are then sent to hydroprocessing units for further clean up, particularly for the removal of sulphur. Hydrotreating involves the removal of sulphur and nitrogen compounds via the addition of hydrogen in the presence of a catalyst. The hydrotreated components are then blended together into sweet synthetic crude oil or SSB. This SSB product contains no residuum and is low in sulphur, providing an attractive feedstock to refineries. With Stage 3 complete, the productive capacity of the upgrader rose to 128 million barrels of SSB per year by the end of 2006 compared to 90 million barrels of SSB per year in 2005. Actual production of SSB in 2006 was 94.3 million barrels, a significant increase from prior years. Production of SSB in 2005 was 78 million barrels and in 2004 was 87 million barrels.

With the start up of the new Stage 3 plants in August 2006, the quality of the finished synthetic crude oil blend, currently designated SSB, was to have been improved and re-designated SSP, short for Syncrude™ Sweet Premium. SSP is designed to have a diesel cetane number of approximately 40, up from the SSB number of approximately 33, and the jet smoke point of approximately 19, up from SSB number of 16. However, one of the other new UE-1 process units, a hydrogen plant, has a design issue which is preventing Syncrude from producing SSP. Syncrude plans to correct this design issue during the next turnaround scheduled for in the fall of 2007, after which it is expected that Syncrude will be able to produce SSP.

Utilities and Offsites

The utilities plants are tasked with producing steam, electricity, air and water for the mining, extraction and upgrading plants. These commodities are often generated from fuels and heat produced as

by-products in the major operating areas or from purchased energy sources such as natural gas or electricity.

Syncrude operates utility plants located both at the base Mildred Lake site and at the Aurora site. Energy systems are highly integrated at the Mildred Lake site, taking advantage of the heat generated in the upgraders and moving that energy to the energy-consuming plants in mining and extraction. At Aurora North, natural gas is purchased to provide the required utilities. Syncrude owns and operates two large gas turbine generators at Aurora North to provide both the required steam and power for the plants.

One of the key performance metrics associated with the integrated Syncrude operation is the "energy intensity". Energy intensity is measured in many ways in the industry but in Syncrude's case it is the amount of purchased energy consumed per barrel of SSB. In 2006, the purchased energy intensity was 0.98 GJ per barrel compared to 2005 which was 0.84 GJs per barrel. The increase in consumption to 0.98 GJ's per barrel is attributable to increased bitumen volumes sourced at the Aurora mine, and increased use of purchased natural gas for items such as steam generation during start-up of the Stage 3 facilities, which are highly integrated. Purchased energy consumption per barrel is expected to decline from levels recorded in 2006 once the Stage 3 operations have stabilized. We estimate that long-term consumption going forward will be about 0.85 GJs per barrel as additional hydrogen, which is derived from natural gas, will eventually be used to increase product quality from SSB to SSP and as bitumen is increasingly sourced from the Aurora mine. The Aurora mine relies mainly on purchased natural gas for its energy needs as process heat from the upgrader is unavailable due to the mine's distance from the Mildred Lake plant. Natural gas prices decreased 25 per cent to \$6.26 per GJ in 2006 compared to \$8.40 per GJ in 2005.

Natural gas, used by Syncrude to fuel operating plants and as feedstock in the production of hydrogen, is transported to Syncrude from Alberta's gas production and transmission infrastructure through dedicated pipelines. The gas is purchased from producers under various supply contracts to manage Syncrude's requirements. This pipeline and storage infrastructure has been expanded in the Athabasca region in recent years to improve the overall deliverability and reliability of the supply system.

Off-sites are generally referred to as those facilities required to support the operation of the main processing plants. These facilities include product storage tankfarms, waste water collection and handling systems and flares. Many of these facilities were expanded as part of the Stage 3 expansion project.

Syncrude operates a utility plant at its Mildred Lake site using refinery off gas, produced from the upgrading operation, augmented with natural gas. When operationally and economically desirable, Syncrude purchases power from, or sells power to, the Alberta electric power grid. Syncrude also owns two 80-Megawatt gas turbine power plant at the Aurora North mine site that provides electrical and thermal energy for the Aurora North mine operations. These plants provide power for the Aurora North mine's requirements and are connected with the Mildred Lake facilities. The Aurora Thermal Block ("ATB") which consists of two hot water generators, has been in operation since mid-2004. The ATB facilities provide hot water generating capacity at Aurora North and allow the extraction process to operate at 35°C temperature.

Marketing

Each Syncrude Participant is responsible for marketing its own share of SSB and associated by-products, such as sulphur. After upgrading, the SSB crude oil is transported to markets in Canada and the United States through a system of inter-connected pipelines and storage locations. SSB is sometimes processed in refineries that have been specifically designed to benefit from SSB's unique properties.

More often, however, it is purchased by refiners to blend with other crude oils to form a feedstock mixture which is suited to their specific refinery configuration. There are approximately 150 refineries in Canada and the United States. Most refineries produce motor gasolines, diesel fuels, heating oils, and jet fuels. Others can also produce asphalts, lubricants and petro-chemicals. In 2002, there were three refineries in or near Edmonton, Alberta which had the capability of taking synthetic crude oil as 25 per cent to 100 per cent of their feedstock. These three refineries consume approximately 160,000 to 170,000 barrels per day of synthetic crude oil.

Significant additions of synthetic crude oil production came on-line in 2003 thereby impacting where SSB was ultimately consumed. At the beginning of 2003, Canadian Oil Sands sold about 33 per cent of its SSB to the refineries in Edmonton but, by the fall of 2003, a larger proportion of volumes were being sold to refineries in Eastern Canada and the United States. By the end of 2004, approximately 600,000 barrels per day of synthetic crude oil production (of which about 470,000 barrels per day was sweet synthetic crude oil) was available from Syncrude and other oil sands projects from the Fort McMurray, Edmonton and Hardisty areas in Alberta and the area around Regina, Saskatchewan. In both 2006 and 2005 74 per cent of our volumes were consumed in Eastern Canada and the United States compared to 70 per cent in 2004. While it is difficult to determine where our product is ultimately consumed, we anticipate that as our production volumes increase or the amount of synthetic crude oil in the Fort McMurray and surrounding area increases, that we will see a greater percentage of our production being consumed outside of Western Canada given the limited refining capacity in that area.

Another market has emerged recently for SSB crude oil. The growing production of bitumen in Alberta has necessitated the need for additional diluents to thin the tar-like bitumen so that it can be transported in pipelines. Traditionally, natural gas condensates, a by-product of the natural gas processing industry, have been the most common hydrocarbon diluent used to thin heavy bitumen for pumping. However, the growth in natural gas condensate production has not kept pace with the rising production of bitumen and new forms of diluent have been required. SSB and other synthetic crude oils have emerged as one of those new sources of diluent. This additional supply of synthetic crude oil has also resulted in increasing proportions of synthetic crude oil being shipped and consumed beyond Edmonton. A portion of the synthetic crude oil also is being sold in the northern Alberta area as a supply for the growing diluent market. The trend of increased use of synthetic crude oil as a diluent, however, is expected to be moderated as pipeline reversals and construction either currently underway or planned are expected to allow the import of condensate diluents from the United States.

The vast array of pipeline and storage systems for the transportation of crude oils across Canada and the United States has been adequate to move Alberta based products to their intended markets. It is anticipated that these networks will both be expanded and extended at pace with the take-away capacity requirements of the growing Alberta based crude oil production in the future. The Spearhead pipeline and the ExxonMobil pipeline reversal projects in the first half of 2006 extended the market reach for Canadian oil production to new customers who previously were unable to access Canadian crude oil. However, in the near term, and prior to pipeline expansions that are scheduled to be completed, the balance between crude supply and capacity out of Western Canada is very tight. Small increases to supply or decreases to pipeline capacity could lead to temporary situations of insufficient capacity that may impact SSB sales prices and production or both.

Canadian Oil Sands takes title to SSB at Syncrude's plant gate and then the SSB is transported by a pipeline dedicated for use by the Syncrude Participants from Fort McMurray to Edmonton at which point, our SSB volumes are sold or arrangements are made for further transportation. From mid-2001 to mid-2006, EnCana marketed our share of SSB production pursuant to a marketing agreement. Under the terms of the agreement, EnCana was entitled to a marketing fee for each barrel of crude or other liquid

crude products sold subject to a minimum fee of \$33,333 per month and a reasonable fee in respect of other oil sands products sold. EnCana also was entitled to be reimbursed for its reasonable out-of-pocket costs and expenses. The marketing agreement ended August 31, 2006 after which we began marketing our own production. In 2005 and the first half of 2006, we hired additional staff to accommodate this marketing function. We believe that internalizing marketing provides greater insight into our customer needs and assists in the long-term development of product quality and distribution strategies. Profile building in the industry was a key undertaking for the new marketing team in 2006. Members of the marketing group assumed positions on the crude oil, pipeline expansion and markets and transportation committees of the Canadian Association of Petroleum Producers, focusing on ensuring that policy decisions reflect the unique needs of light oil producers. Our marketing group is developing transportation alternatives which should reduce the risk of pipeline constraints in the coming years.

Customer education is an important objective for the marketing group as we expect to transition all of our production to a higher quality light crude. This enhanced SSP product promises greater market potential with markedly higher distillate cetane and smoke point characteristics, and lower distillate sulphur and nitrogen content compared to SSB. These qualities should assist North American refiners to meet more stringent environmental requirements and assist in feedstock selection. Our customers should then be able to rely on the consistency of this quality. Syncrude's strict quality control standards ensure that its crude falls within a narrow, predictable set of parameters. We believe that this dependability has value for refiners, as it allows them to run their operations more smoothly and efficiently.

Synthetic crude oil sales contracts are commonly negotiated directly with refiners throughout North America. Typical contract terms are based on 30, 60 or 90 day arrangements which continue unless terminated but are occasionally made for one year terms. Synthetic crude oils are priced each month on the basis of Canadian and U.S. market prices, which reflect the market balance between supply and demand for crude oil, transportation costs and refined product values.

As additional volumes of synthetic crude oil came into the market in late 2003 and 2004, our sales were made to a broader group of refineries than was historically the case. In 2004, more of our production was consumed downstream from Edmonton than in the past. The trend continued in 2005 and 2006. In response to growing volumes of synthetic crude oil and Syncrude's own expanding volumes following completion of the Stage 3 expansion, we expanded our markets with the goal of achieving the price we expect for our quality product. When the final changes to a hydrogen plant are completed in the fall of 2007, the new aromatics saturation unit will be used to upgrade our entire production into the higher quality product called SSP. As noted above, this higher quality blend is expected to be more attractive to refineries, which should enhance the price per barrel that we would be able to realize relative to SSB in the same market environment.

Syncrude also produces sulphur as part of its upgrading process. Currently, the majority of sulphur produced by Syncrude is stockpiled at Syncrude's Mildred Lake plant site as present market conditions continue to limit the sale of this by-product at positive margins. Over the past few years, Syncrude has been exploring the ability to store sulphur blocks underground. Initial information indicates that this may be a viable and environmentally friendly solution. Syncrude continues to research alternatives for addressing this issue, which affects other sulphur producers in the petroleum industry. In 2005, Canadian Oil Sands entered an agreement with a major sulphur marketer to sell our share of Syncrude's sulphur production at a plant gate market price. The agreement covers an initial five year term, is renewable at Canadian Oil Sands' option, and provides that volumes will not be sold unless the price exceeds an established plant gate minimum. Delays in construction of the facilities due to issues relating to the terminal resulted in the contract being amended. Sales under this contract now are expected to begin in 2008 following the buyers' construction of

infrastructure to handle Canadian Oil Sands' sulphur volumes. Coke produced by Syncrude has never been commercially marketed and is stored on Syncrude's site.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including the distribution and marketing of petroleum products. Syncrude competes with other producers of synthetic and conventional crude oil. Most of the conventional producers have considerably lower operating costs but higher finding costs. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers. In particular, the increased activity in construction of new oil sands projects and in the production and mining of oil sands generally has created shortages in the supply of skilled labour and certain components such as large truck tires used in mining operations. With the completion of Stage 3, we do not expect to face these issues to the same degree as oil sands projects that are entering the construction phase. However, our operations in 2004, 2005 and 2006 were impacted by the labour shortage both on the cost and scheduling aspects relating to Stage 3 and on turnaround activity. Additionally, the rate of labour turnover at Syncrude increased again in 2006 compared to 2005. SCL's permanent employee turnover increased from an average of about five per cent pre 2005 to about 11 per cent in 2006, driven largely by the retirement demographics of an aging workforce at SCL's and the migration of other employees to competing projects.

Seasonal Factors

As the Syncrude Project is located in Northern Alberta, maintenance work during winter months is often more difficult as the extreme cold temperatures make steel brittle and limit the time that individuals can work in areas exposed to the elements. Accordingly, this may impact operating costs. Quarterly variances in revenues, net income, and cash from operating activities are caused mainly by fluctuations in crude oil prices, production and sales volumes, production costs, and natural gas prices. Net income is also impacted by non-cash foreign exchange gains and losses caused by fluctuations in foreign exchange rates on our U.S. dollar denominated debt and by future income tax changes. A large proportion of operating costs are fixed, and as such, per barrel operating costs are highly variable with production. While the supply/demand balance for synthetic crude oil affects selling prices, the impact of this equation is difficult to predict and quantify and has not displayed significant seasonality. Maintenance and turnaround activities are typically scheduled to occur in the spring months of the first or second quarter. However, the exact timing of unit shutdowns cannot always be accurately scheduled, and unplanned outages do occur. Therefore, production levels also do not display reliable seasonality patterns or trends. Maintenance and turnaround costs are expensed in the period incurred and can lead to significant increases in operating costs and reductions in production in those periods, as demonstrated by the high per barrel operating costs, particularly in the first quarters of 2006 and 2005. Natural gas prices are typically higher in winter months as heating demand rises, but this seasonality is significantly influenced by weather conditions.

Cost escalation, particularly as a result of inflationary pressures in the Fort McMurray area, has been a significant trend over the last few years. The Trust's depletion and depreciation rate, asset retirement obligation, operating and capital costs have all been impacted by higher cost of materials and services and the associated costs of labour shortages. We anticipate that these inflationary pressures will continue in light of the significant level of oil sands activity that is expected, particularly over the next three years as the other major oil sands projects are completed.

Environmental Protection

The oil and gas industry in Alberta is subject to extensive controls and regulations. The regulatory scheme, as it relates to oil sands, is somewhat different from that relating to conventional oil and gas production. Outlined below are some of the more significant aspects of the legislation and regulations governing the mining, extraction, upgrading and marketing of oil sands.

Environmental Regulation and Compliance

Oil sands operations, including Syncrude, are subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation requires various approvals and provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that facilities and operating sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties. In Alberta, environmental compliance is primarily governed by the AEPEA. The AEPEA imposes certain environmental responsibilities on oil and natural gas operators in Alberta and, in certain instances, also imposes significant penalties for violations. SCL has received and presently maintains the requisite environmental approvals necessary to operate the Syncrude Plant.

The December 1999 AEUB approval of Syncrude's upgrading expansion application allows production of 173 million barrels of SSB (or SSP) per year using technology identified in the application. This permit expires on December 31, 2035.

Syncrude also maintains approvals from AENV regulating the discharge of substances into the air and water. These approvals were issued with 10 year terms, which is the maximum term permitted by this legislation. The renewal or modification of approvals generally involves the AENV soliciting the views of stakeholders (the local community, Aboriginal population and other interested persons). Renewal or modification of approvals is often conditional, permitting AENV to review the effect of discharges or the implementation and effectiveness of new technologies. AENV approval for the Aurora North operations was received in 1998. SCL received an environmental approval for its Mildred Lake oil sands processing facilities, Base Mine and North Mine operations until June 23, 2007. A new AEPEA approval is expected to be issued prior to mid-June 2007.

Syncrude Participants, including Canadian Oil Sands, are liable for their share of ongoing environmental obligations for the ultimate reclamation of the Syncrude Joint Venture. The asset retirement obligation, or ARO, represents the present value estimate of Canadian Oil Sands' share of these costs for the mine and extraction facilities.

Canadian Oil Sands records the discounted estimated fair value of the future reclamation liability on our Consolidated Balance Sheet as an increase to capital assets and as an asset retirement obligation. The depreciation expense on the asset and the accretion expense on the obligation are recorded in depreciation, depletion and accretion expense. At December 31, 2006, the asset retirement obligation recorded on the Consolidated Balance Sheet was about \$173 million. Canadian Oil Sands' share of Syncrude cash reclamation expenditures was about \$2 million in each of 2006 and 2005, which reduced the liability shown on our balance sheet. A full discussion of our accounting for the reclamation liability can be found in the notes to our consolidated financial statements in our 2006 annual report.

Annually, the Syncrude Joint Venture is required to post with the AENV irrevocable letters of credit equal in amount to \$0.03 per barrel of SSB produced from the Base Mine plus estimated

reclamation costs relating to the Aurora Mine since inception of the Syncrude Project to secure the ultimate reclamation obligations of the Syncrude Project. In 2006, Canadian Oil Sands posted letters of credit with the Province of Alberta in the amount of \$49 million compared to \$42 million in 2005, to secure its pro rata share of the ultimate reclamation obligations of the Syncrude Participants.

In 2005, actual site reclamation expenditures for SCL totaled \$6.1 million and approximately 305 hectares of land were reclaimed. In 2006, site reclamation expenditures for SCL totaled \$6.3 million and approximately 312 hectares of land were reclaimed. Syncrude's long-term plan is to return the land to a stable, biologically self-sustaining condition with a vision of creating an area of forest, parklands and lakes. As at December 31, 2006, since 1978 Syncrude had reclaimed more than 4,600 hectares of the land affected by its operation and planted approximately 4.5 million seedlings in the Athabasca area. A significant portion of the land that had been tracked and mined by Syncrude and which has been reclaimed, is used as a grazing ground for more than 300 wood bison.

In addition to posting a letter of credit for its share of reclamation with the AENV, Canadian Oil Sands currently pays \$0.1322 for each barrel of SSB produced and attributable to our 36.74 per cent working interest to a mining reclamation trust to fund our share of reclamation obligations for the Syncrude Project. Since 2002, we have the right to adjust the amount deposited in the mining reclamation trust from time to time as estimates of final reclamation costs change. Canadian Oil Sands and each of the other Syncrude Participants are liable for their share of ongoing environmental obligations for the ultimate reclamation of the Syncrude Joint Venture on abandonment. We have accumulated (including interest earned on contributions), \$30 million towards future reclamation in the reclamation trust. In 2005, this amount was \$25 million.

The construction and operation of a large oil sands project such as Syncrude presents many environmental challenges. Responsible environmental management is a priority of the Syncrude Participants. The technical and managerial challenges to date have been addressed by SCL through many years of investment in research and the development of advanced management systems. SCL continues to seek ways to improve and reduce the cost of reclamation. SCL has never been assessed a significant fine or received any government control order regarding an environmental concern at SCL believes that it is in compliance with all material environmental requirements.

The Syncrude Participants support the voluntary reduction of greenhouse gas emissions, such as carbon dioxide, from Syncrude's operations. SCL is focused on reducing both energy consumption and greenhouse gas emissions per barrel of SSB produced rather than purchasing offsets or credits. SCL participates in the Cumulative Environmental Management Association and other organizations concerned with environmental, Aboriginal and community development matters.

Canada and more than 160 other nations are signatories to the 1992 United Nations Framework Convention on Climate Change, which is intended to limit emissions of carbon dioxide and other "greenhouse gases" that may be contributing to an increase in mean global temperature. In December 1997, 39 industrialized nations that signed the Convention, including Canada, establishing the Kyoto Protocol which contained a binding set of emission targets for developed nations that is intended to result in the reduction of greenhouse gases. The average reduction in greenhouse gas emissions required from all 39 signatories is 5.2 per cent from 1990 emission levels, to be achieved between 2008 and 2012, although specific emission targets vary from country to country. Canada, for example, would be required to reduce emissions by six per cent from 1990 levels.

On July 23, 2001, at the Sixth Conference of Parties on Climate Change in Bonn, Germany, a broad political agreement was reached on the operational rulebook for the 1997 Kyoto Protocol.

Following this political agreement, the Federal Government of Canada undertook some consultations with provincial and territorial governments. In late 2002, the Federal Government ratified the Kyoto Protocol. In response to comments from provincial governments and various stakeholders, the former Federal Government had provided some parameters for implementing the Kyoto Protocol. The targets for emission intensity reductions were capped at 15 per cent of emissions based on current business plans (which in our case includes the Stage 3 expansion) and the cost of the carbon credits had been limited to \$15 per tonne. With the Russian Government's ratification of the Kyoto Protocol in 2004, such Protocol is now in effect. However, numerous uncertainties regarding details of the Kyoto Protocol's implementation remain outstanding, thereby making it difficult to ascertain the cost estimate, including third party costs related to the Kyoto Protocol from Syncrude's suppliers of goods and services. Additionally, in 2005, various foreign governments questioned the ability of countries to achieve the targets set under the Kyoto Protocol. We continue to work through industry associations such as the Canadian Association of Petroleum Producers and directly with the Alberta provincial and Federal Governments to develop a cost effective plan to reduce greenhouse gas emissions.

On March 7, 2007, the Alberta Government announced as part of its Throne Speech, that it would be introducing legislation to regulate industry's greenhouse gas emissions. The regulations were tabled with a proposed effective date of July 1, 2007. Our understanding of these proposed regulations are that they are intensity based and target large emitters, of which Syncrude is one, to reduce their greenhouse gas emission intensity by 12 per cent beginning July 1, 2007. Those entities which do not meet their greenhouse gas emission reduction targets will be required to pay \$15/tonne for each tonne over their limit or to purchase offset credits from entities that have surplus emission reductions. For Syncrude, initial estimates are that the 12 per cent intensity reduction may cost Syncrude between \$0.15 and \$0.35 per barrel in operating costs. However, these estimates are very preliminary in nature and it is not fully understood how the overall impact of the regulations will have on Syncrude's suppliers and contractors. If such suppliers and contractors also face operating increases and pass such costs onto their customers, it is likely that there will be a further negative impact on costs to Syncrude.

The Federal Government also has recently indicated that it will be considering various limitations and sanctions with regard to the emission of greenhouse gas emissions, either as part of its legislative efforts regarding the Kyoto Protocol, or otherwise. Additionally, public announcements regarding the plan to reduce greenhouse gas emissions have raised the question as to what limitations and restrictions may be imposed by the Federal Government either under the *Clean Air Act* or other legislation. Sanctions relating to emissions and water quality have not been specified. The Federal Government has not published specific guidelines or further guidance on these limitations and sanctions. As such, we cannot assess the impact of potential new greenhouse gas emission reduction targets on our operations. While we believe that production will continue to be profitable under the current known factors, future changes in legislation may materially impact operating costs.

Regulation of Operations

In Alberta, the regulation of oil sands operations is undertaken by the AEUB, which derives its jurisdiction from the *Oil Sands Conservation Act*. In addition to requiring certain approvals prior to the operation of an oil sands project, the *Oil Sands Conservation Act* allows the AEUB to inspect and investigate oil sands operations and, where a practice employed or a facility used in respect of the oil sands operations does not meet operating criteria recovery targets, to make remedial orders. Certain changes to an oil sands operation also require the approval of the AEUB.

Land Tenure

Oil from oil sands is produced under oil sands leases granted by the Province of Alberta. Such leases have initial terms which vary in length but generally are for 15 years. Although the terms of future leases may vary, the current Syncrude leases have, for the most part, 15-year terms. If production attributable to a lease exceeds the minimum production thresholds set forth in the lease, it automatically renews at the end of each term. In addition, leases renew automatically if a development plan for a project involving the lease has been approved by the Minister of Energy and is being pursued by the lessor. In 1997, the Province of Alberta approved the continuation of the four Aurora leases (being leases 10, 12, 31 and 34) based on the Syncrude Project development plan, including the Aurora project, and so long as such plan and approval is in effect and being followed, the Aurora leases will continue to renew at the end of each term. In 1999, SCL received confirmation that Leases 29 and 30 also are included for tenure purposes within the Syncrude Project development plan. In 2002, Leases 17 and 22 were continued under section 13 of the Oil Sands Tenure Regulations AR 50/2000 for an indefinite term with a production status.

Royalties and Taxes

The Province of Alberta imposes royalties of varying rates on the production of crude oil from lands where it owns the mineral rights. The products recovered by Syncrude are subject to a royalty which is payable to the Alberta Government.

In January 2002, following the conclusion of a transition period, the Syncrude Participants commenced paying royalties under the *Oil Sands Royalty Regulations 1997*. This legislation stipulates that the Province of Alberta will receive the greater of one per cent of the gross revenues after transportation costs and 25 per cent of the net revenues. The net revenues for any year are generally equal to the excess of gross revenues over allowed transportation, operating and non-production costs, capital expenditures and deemed interest expense and any unutilized carry forward deductions from previous years. In May 2006, Syncrude began paying Crown royalties at the higher 25 per cent of net revenues royalty rate, resulting in significantly higher Crown royalties in 2006 compared to prior years. In 2005, due to the large capital expenditures for Stage 3, the minimum payment of one per cent of gross revenues was paid to the Alberta Government. The generic Oil Sand royalty regime supports the development of Alberta's oil sands and we acknowledge the role this regime has played in enabling us to proceed with the expansion of Syncrude's facilities.

Until 2010, the Syncrude Joint Venture has the option to switch from calculating the Crown royalty on upgraded SSB revenues, as it currently does, to a royalty based on bitumen production. The Province of Alberta has indicated that this option cannot be exercised until a Bitumen Valuation Methodology is established for the industry, which would define the process for determining a market price for Syncrude bitumen. In addition, an arrangement needs to be reached on recapture of upgrader growth capital previously claimed and a methodology for allocating common operating and capital costs. Until these and the associated economic issues are resolved, the Syncrude Participants cannot exercise the option and or properly assess its long-term impact on the Syncrude Project's royalty expense.

Taxation of Syncrude-related income follows normal resource industry practices but with a few important differences. As Syncrude is a mining operation, there are certain provisions that are unique, such as the accelerated rate of deduction (100 per cent) for class 41(a) assets which applies to new mines or a major expansion of an existing mine where there is a 25 per cent or greater increase in mine capacity. Effective March 6, 1996, mining and oil sands operations, which have made capital expenditures in excess

of five per cent of gross revenue in a fiscal year, also will be eligible for the accelerated rate of deduction (100 per cent) for such expenditures over the five per cent threshold included in class 41 (a.1).

Employees

Canadian Oil Sands Limited employs eighteen full-time employees, along with one consultant and one contractor. The Trust has no employees.

At the end of 2006, SCL employed approximately 4,500 people, all of whom were non-unionized. While it is believed that SCL will remain non-unionized, no assurance can be given that the workforce will not become unionized.

SCL also uses the services of various outside contractors to provide contract maintenance support for certain areas of the Syncrude Plant. Additional contractors also are required during shutdowns, maintenance work and major capital construction. Most of the workers employed by these contractors are unionized. Labour stability of the unionized contractor work force is maintained through a number of industry and site-wide agreements, which set labour rates and working conditions for unionized trade workers engaged in construction and maintenance activities at various projects in Alberta, including the Syncrude Plant. As part of the Stage 3 expansion, the use of contractors for construction continued in 2005, with an average of approximately 6,500 contractors on site in 2005.

RISK FACTORS

A substantial and extended decline in oil prices would have an adverse effect on Canadian Oil Sands

The financial condition, operating results and future growth of Canadian Oil Sands are substantially dependent on prevailing prices of oil. Prices for oil are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil, market uncertainty and a variety of additional factors beyond the control of Canadian Oil Sands. Prices may be influenced by global and regional supply and demand factors. These factors include: weather conditions in Canada and the United States; the condition of the Canadian, U.S. and global economies; the actions of the Organization of Petroleum Exporting Countries; governmental regulation; political stability in the Middle East and elsewhere; war, or the threat of war, in oil producing regions; the foreign supply of oil; the price of foreign imports; and the availability of alternate fuel sources. All of these factors are beyond our control and can result in a high degree of price volatility not only in crude oil and natural gas prices, but also fluctuating price differentials between heavy and light grades of crude oil, which can impact prices for SSB. Oil prices have fluctuated widely in recent years and we expect continued volatility and uncertainty in crude oil prices. A prolonged period of low crude oil prices could affect the value of our crude oil properties and the level of spending on growth projects and could result in curtailment of production. Accordingly, low crude oil prices in particular could have an adverse impact on our financial condition and liquidity and results of operations. In view of the higher fixed operating costs of SCL, the operating margin is very sensitive to oil prices. Any substantial and extended decline in the price of oil would have an adverse effect on the revenues, profitability and cash from operating activities of Canadian Oil Sands and may likely affect the ability of Canadian Oil Sands to pay distributions, and to repay its debt obligations.

While the Syncrude Project has not been shut down by the Syncrude Participants since production commenced in 1978, a prolonged period of abnormally low oil prices could result in the Syncrude Participants deciding to suspend production. Any such suspension of production could expose Canadian Oil Sands to significant additional expense and would negatively impact our ability to pay distributions and to repay our debt obligations.

Distributions ultimately made by Canadian Oil Sands to its Unitholders are expected to be adversely impacted by the proposed changes to the taxation of income trusts by the Federal Government

On October 31, 2006, the Minister of Finance announced the Federal Government's intention to impose a new tax on certain distributions from existing income and royalty trusts effective in 2011. On December 21, 2006 draft legislation was released for comment. Assuming the proposed changes are enacted, it is expected that the new tax will apply to Canadian Oil Sands' distributions and will ultimately have a material adverse impact on the cash available for distributions to Unitholders after the transition period in 2011. Under the proposed rules, distributions of non-portfolio earnings, as defined in the draft legislation, of the Trust would not be deductible to the Trust and would be taxable at the rate of 31.5 per cent, thus reducing the distributions paid. Currently, almost all of Canadian Oil Sands' Unitholder distributions are comprised of non-portfolio earnings. Distributions of non-portfolio earnings would be considered dividends under the new rule and eligible for the dividend tax credit, similar to the tax treatment on corporate dividends. As such, the after-tax impact would be relatively neutral to Canadian investors who hold our Units in taxable accounts. Investors who hold our Units in tax deferred accounts and non-resident Unitholders would see their after-tax realizations decline significantly. The impact of the Federal Government's announcement resulted in a substantial decline in the market value of trust units generally. In the absence of final legislation implementing the 2006 proposed changes, the implications are difficult to fully evaluate and no assurance can be provided as to the extent and timing of their application to Canadian Oil Sands and our Unitholders.

Canadian Oil Sands may be impacted by the complexity of integrating a major project into existing operations

There are certain risks associated with the execution of Syncrude's major projects, including without limitation, Stage 3 as well as Stage 3 debottleneck and Stage 4. These risks include: our ability to obtain the necessary environmental and other regulatory approvals; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel, especially skilled construction and engineering labour; the impact of general economic, business and market conditions; the impact of weather conditions; our ability to finance growth if commodity prices were to stay at low levels for an extended period; the impact of new entrants to the oil sands business which could take the form of competition for skilled people, increased demands on the Fort McMurray, Alberta infrastructure (for example, housing, roads and schools) and price competition for products sold into the marketplace; and the effect of changing government regulation and public expectations in relation to the impact of oil sands development on the environment. The commissioning and integration of new facilities and the execution of major projects within an operating plant present issues that require risk management. There are also risks associated with project cost estimates and scheduling provided by us. Some cost estimates are provided at the conceptual stage of projects and prior to completion of the final design scope and detailed engineering needed to reduce the margin of error. Accordingly, actual costs can vary from estimates and these differences can be material.

The petroleum industry and energy sector are highly competitive

The Canadian and international petroleum industry is highly competitive in all aspects, including the distribution and marketing of petroleum products. The Syncrude Project competes with other producers of crude oil, some of whom have considerably lower operating costs. Also, an increasing supply of synthetic crude oil came on stream in recent years and is expected to increase further in 2007 and beyond. If and when these other projects are completed, there will be a significant increase to the supply of synthetic crude oil in the market. There is no guarantee there will be sufficient demand to

absorb the increased supply without eroding the selling price, which could result in a deterioration of the price differential that Canadian Oil Sands may realize compared to benchmark prices such as WTI. Also, prices may decline to such an extent that our share of Syncrude's production is no longer economically viable. In response to growing volumes of synthetic crude oil and Syncrude's own expanding volumes following the Stage 3 completion, we likely will have to expand our markets to achieve the premium price we expect for our quality product. With the increased supply of synthetic crude oil, we may obtain lower net realized revenues and may need to sell our product to refineries further from the source of production. This will increase transportation costs to the consumers of the product and accordingly, the net realized selling price for our product may be negatively impacted. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

In addition, the competition for skilled labour in the Fort McMurray area has put pressure on recruiting, training and retaining the necessary manpower to operate Syncrude's facilities effectively and efficiently. To help provide an adequate supply of trained labour in its operations in the future, SCL supports local Aboriginal communities, colleges, universities, trade schools and various levels of government to help people develop the skills and knowledge they need to enter the workforce. SCL is one of the largest employers of Aboriginal people in Canada. In addition, SCL recruits extensively across Canada and, to a lesser extent, around the world to bring new workers to the region. The execution by SCL of the management services agreement and secondment agreements with Imperial Oil should also enable SCL to access people and expertise from Imperial Oil and its affiliates, including ExxonMobil. However, there is no assurance that the net impact of any of these actions will offset the potential loss of personnel due to an aging workforce population and the competition for skilled workers increases.

The increase in world mining and manufacturing activity of the past two years has caused longer procurement lead times for many materials used in the Syncrude operation. This has required Syncrude to place even more emphasis on maintenance planning and scheduling activities, with special attention to ensure adequate spare parts inventories are on hand at all times. Still, certain suppliers have been challenged to keep ahead of the surge in demand for maintenance and operating materials. Large haul truck tires are a good example. If Syncrude cannot obtain the required tires and other materials in its operations, production will be impacted and correspondingly, the sales volumes and cash from operating activities for Canadian Oil Sands would be negatively impacted.

Pipeline transportation and delivery infrastructure issues may cause an adverse impact on Canadian Oil Sands' results

All of our Syncrude production is transported to Edmonton, Alberta through the Alberta Oil Sands Pipeline Limited ("AOSPL") system. Disruptions in service on this system could adversely affect our crude oil sales and cash from operating activities. The AOSPL system feeds into various other crude oil pipelines that are used to deliver our SSB product to refinery customers throughout Canada and the United States. Interruptions in the availability of these pipeline systems may limit the ability to deliver production volumes and could adversely impact sales volumes or the prices received for our product. These interruptions may be caused by the inability of the pipeline to operate, or they can be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. While we believe long-term take-away capacity will exceed production growth for synthetic supply out of the Athabasca region, there can be no certainty that investments will be made to provide this capacity. There is also no certainty that short-term operational constraints on the pipeline system, arising from pipeline interruption and/or increased supply of crude oil will not occur as current capacity is believed to be adequate but tight. In addition, planned or unplanned shutdowns of our refinery customers may limit our ability to deliver our SSB crude oil with negative implications on sales and cash from operating activities.

We limit exposure to these risks by allocating deliveries to multiple customers via multiple pipelines. We also maintain knowledge of the infrastructure operational issues and influence expansion proposals through industry organizations in order to assess and respond to delivery risks.

Marketing and transportation of synthetic crude oil

A significant volume of production from the Syncrude Project is sold to customers beyond Edmonton, Alberta in Eastern Canada and the United States. As such, pipeline access and capacity, transportation tariffs and price differentials with competing products are all factors which can affect sales volumes for SSB as well as the realized selling price or netbacks received by Canadian Oil Sands for our share of production. As crude oil is consumed at delivery points further from Edmonton to accommodate the larger amount of synthetic and heavy crude oil being produced, the realized selling price net of transportation costs is typically negatively impacted. While Syncrude's move to produce SSP should help offset this, there can be no assurance that this will be the case or that the selling price realized by Canadian Oil Sands will not be negatively impacted in a significant manner.

Over the next five years, planned oil sands and heavy oil projects, including the Stage 3 expansion, could result in approximately 500,000 barrels per day of additional synthetic crude oil entering the market, some of which may be used for diluent. There can be no assurance that existing transportation systems will be sufficient to handle this additional production or that new transportation systems will be built in time or at all.

Canadian Oil Sands is subject to environmental legislation in all jurisdictions in which it operates and any changes in such legislation could negatively affect its results of operations

Each of the Syncrude Participants is liable for its share of ongoing environmental obligations and for the ultimate reclamation of the Syncrude Project site upon abandonment. Ongoing environmental obligations have been, and are expected to continue to be, funded out of the revenues from our sales of SSB.

The Syncrude Project is a significant producer of sulphur dioxide and carbon dioxide emissions. While Syncrude is focused on reducing these emissions, no assurance can be given that existing or future environmental regulations will not adversely impact the ability of the Syncrude Project to operate at present levels or increased production, or that such regulations will not result in higher unit costs of production.

SCL announced in 2003 that it intends to both design and install a sulphur dioxide scrubbing system, referred to as the SERP, which is designed to reduce the amount of sulphur dioxide produced on both a per barrel basis and absolute basis. These reductions would be in addition to any reductions in sulphur dioxide emissions which are expected as a result of the introduction of sulphur scrubbing technology as part of the Stage 3 expansion. At the present time, there is no requirement under the AEPEA or the terms of SCL's current environmental approvals to install any additional or replacement sulphur dioxide scrubbing. However, there can be no assurance that requirements for installation of a system different from the one currently planted by Syncrude will not come into existence in the future or that any system which may be selected in anticipation of, or in response to, any such requirements will effectively lower sulphur dioxide emissions to desired or required levels. The current estimate of the total cost of the SERP is approximately \$772 million, with Canadian Oil Sands' share being approximately \$284 million. Until completion of the SERP, there can be no assurance that the total costs will not exceed current estimates.

In early 2007, the Federal Government of Canada has indicated that it will be considering various limitations and sanctions with regard to the emission of greenhouse gases, either as part of its legislative efforts regarding Kyoto Protocol, or otherwise. At the current time, Canadian Oil Sands cannot estimate the

impact, if any, that such measures if implemented may have since there is no draft legislation or details on any such initiative by the Federal Government. There are also various consultation processes underway by the Province of Alberta with regard to water usage in the oil and gas industry and the oil sands sector in particular. Again, as no conclusions or recommendations have been issued by such regulatory review body, we cannot assess the impact of any such proposals on our operations. Syncrude has historically worked with the Federal and Provincial Governments to monitor its emissions of greenhouse gases and is constantly working toward reducing the per barrel emissions through greater energy efficiency. Syncrude also has operated below the license limits with respect to its use of water from the Athabasca River. However, as the Syncrude operations involve use of water and the emission of greenhouse gases, proposed legislation which significantly restricts or penalizes current production levels would have a material negative impact on our operations.

Syncrude also produces a significant volume of fine tailings, which are presently held in a settling basin. Upon cessation of production, the settling basin will be required to be reclaimed.

The benefits and expected results from the management services agreement may not materialize

The management services agreement may be cancelled by either SCL or Imperial Oil on 24 months notice. In addition, Imperial Oil has the right to terminate the agreement if Imperial Oil is not reasonably satisfied that the recommendations from OAT are approved by the Syncrude Participants. Accordingly, the management services agreement may never be implemented.

As with any service arrangement, especially one involving complex operations such as exists at Syncrude, the expected benefits and improvements in reliability, safety and energy efficiency may not be realized. This could have a negative impact not only on the operating costs as service fees continue to be payable but also on overall performance of the Syncrude operations and results.

Canadian Oil Sands has financial exposure to foreign currency exchange rates

Crude oil prices are generally based on a U.S. dollar market price, while operating and capital costs are primarily in Canadian dollars. In addition, Canadian Oil Sands makes interest payments in U.S. dollars on its U.S. dollar denominated debt and funds its share of Syncrude's U.S. dollar vendor payments. Fluctuations in exchange rates between the U.S. and Canadian dollar give rise to foreign currency exchange exposure. Consequently, exchange rate movements can have a significant impact on results. To manage its exposure to currency fluctuations, Canadian Oil Sands has, in the past, entered into currency exchange contracts to fix exchange rates on future U.S. dollar revenue receipts, Canadian dollar denominated crude oil forward contracts and issued debt securities in U.S. dollars. The use of financial instruments involves a degree of credit risk. As well, some of Canadian Oil Sands' revenues are received in U.S. dollars.

To the extent that Canadian Oil Sands issues debt securities denominated in foreign currencies, such an investment may entail significant risks that are not associated with a similar investment in a security denominated in Canadian dollars. Such risks include, without limitation, the possibility of significant changes in rates of exchange between the Canadian dollar and the various foreign currencies and the possibility of the imposition of currency controls by either the Canadian or foreign governments. These risks will vary depending upon the currency or currencies involved. At this time, Canadian Oil Sands only has Canadian and U.S. dollar denominated debt.

Canadian Oil Sands will not be economically viable if reserves from the Syncrude Project cannot be economically produced and marketed

Market fluctuations of crude oil prices may render uneconomic the mining, extraction and upgrading of oil sands reserves containing relatively lower grades of bitumen. Moreover, short-term factors relating to the oil sands reserves, such as the need for orderly development of ore bodies or the processing of new or different grades of ore, may impair the profitability of a mine and upgrading facility in any particular accounting period.

Canadian Oil Sands will not be economically viable if reserves from the Syncrude Project cannot be economically produced and marketed.

There are a number of risks particular to the Syncrude operations that could have a material adverse impact on Canadian Oil Sands

Currently, our interest in the Syncrude Project is our only material asset. The Syncrude Project is a single inter-related and inter-dependent facility. The shutdown of one part of the Syncrude Project could significantly impact the production of synthetic crude oil. Since essentially the sole source of income to Canadian Oil Sands is the sale of synthetic crude oil, a shutdown may reduce, or even eliminate our cash from operating activities. Also, complications could arise when new systems are integrated with existing systems and facilities. The risk of such complications is somewhat mitigated by Syncrude's procedures of performing a sequenced start-up of new units. However, there can be no assurance that the Syncrude Project will produce synthetic crude oil in the quantities or at the cost anticipated, or that it will not cease producing entirely in certain circumstances. Operating costs to produce synthetic crude oil are substantially higher than operating costs to produce conventional crude oil. An increase in operating costs could have a materially adverse effect on Canadian Oil Sands, our net income and cash from operating activities.

The Syncrude Project is located in a remote area, and is serviced by one all-weather road. In the event that the road is closed due to climatic conditions or other factors, SCL may encounter difficulties in obtaining materials required for it to continue production.

As the Syncrude Project is our only material asset, if a terrorist attack were to either hit Syncrude's operations or the pipelines which transport our product, this could result in a substantial or total reduction in sales of our product for a prolonged time frame which would have a material impact on our ability to generate cash from operating activities and therefore negatively impact our liability to meet our operating and debt requirement in the interim until operations could be resumed.

The production of synthetic crude oil requires high levels of investment and has particular economic risks, such as settling basin dyke failures, fires, explosions, gaseous leaks, spills and migration of harmful substances, any of which can cause personal injury, damage to property, equipment and the environment, and result in the interruption of operations. Some of these risks cannot be insured.

Syncrude produces and stores significant amounts of sulphur in sulphur blocks at its plant site as there is presently a limited market for the sulphur. There can be no assurance that future environmental regulations pertaining to the use, storage, handling and/or sale of sulphur will not adversely impact the unit costs of production of synthetic crude oil.

Canadian Oil Sands may not have capital sufficient to fund all required capital expenditures; Capital projects may experience significant cost overruns

Canadian Oil Sands and the other Syncrude Participants plan to continue to make substantial capital expenditures for the mining of oil sands and production of synthetic crude oil. There is no assurance that capital cost overruns will not occur or that investments will deliver the production increases expected by design or that start up will occur as expected. Canadian Oil Sands has credit facilities available to assist it in funding capital expenditures in excess of cash from operating activities. However, it is expected that access to public debt and equity markets may be required from time to time. There can be no assurance that such public debt and equity markets would be available to Canadian Oil Sands.

Canadian Oil Sands could experience an inability to meet debt service amounts

The ability of Canadian Oil Sands to meet our debt service obligations will depend on the future operating performance and financial results of Syncrude, which will be primarily subject to factors beyond our control, including, among others, requirements to fund our pro rata share of operating costs and capital expenditures which may exceed revenue received from the sale of our pro rata share of SSB. If we are unable to obtain sufficient cash to service our debt, we may be required to refinance all or a portion of our debt, obtain additional financing or sell certain of our assets. There can be no assurance that any such refinancing would be possible or that any additional financing could be obtained on acceptable terms, nor can there be any assurance as to the timing of any such asset sales or the proceeds which could be realized therefrom.

Continued high natural gas prices or increases in natural gas prices or shortages in the supply of natural gas could have an adverse effect on Canadian Oil Sands

The financial condition, operating results and future growth of Canadian Oil Sands is substantially affected by the price of natural gas. Natural gas is used in material quantities as a feed stock at the Syncrude Project for the production of hydrogen and as a fuel for the generation of heat, steam and power. The price of natural gas is subject to large variations based on supply and demand for natural gas in North America. SCL and Canadian Oil Sands have no control over such prices. A prolonged period of high natural gas prices or a material increase in natural gas prices could have an adverse effect on the profitability and cash from operating activities of Canadian Oil Sands. Additionally, in Alberta, there could be a restriction on the amount of natural gas available in the future, which would impact production and the operating costs for Canadian Oil Sands.

Purchased natural gas is a significant component of the bitumen production and upgrading processes. Increases in natural gas prices therefore introduce the risk of significantly higher operating costs. Similar to crude oil prices, natural gas prices have also experienced significant movements, decreasing from a high of approximately \$12 per GJ during 2005 to a low of \$4 per GJ during 2006. To the extent crude oil prices and natural gas prices move together on a stable energy equivalent basis, natural gas price risk is mitigated as the Trust is significantly more levered to oil price increases. The main risk involves a de-linking of crude oil and natural gas price movements, such that gas prices are significantly higher than oil prices on an energy equivalent basis. De-linking of crude oil and natural gas prices does occur, but historically these situations tend to be relatively short-term. The Trust has previously used natural gas hedge positions to mitigate this risk and will continue to assess the strategy as a means to manage short-term operating costs. No natural gas hedges were utilized in 2006 or 2005 and as at March 15, 2007, we have no natural gas hedges in place. On an energy equivalent basis, we are only about one-eighth as sensitive to natural gas prices as we are to crude oil prices.

Canadian Arctic's natural gas licenses are estimated to have approximately 927 billion cubic feet equivalent of natural gas resource. However, the natural gas resource is not currently in production and there are no development plans at this time and there can be no guarantee that any such plans will ever exist. Additionally, the remote location of such natural gas resource in the Arctic Islands pose difficulties regarding the transportation of such natural gas to market.

The implementation of the Kyoto Protocol or similar legislation could increase Syncrude's operating costs

The Kyoto Protocol came into effect on February 16, 2005. As yet, however, no specific details regarding its implementation in Canada have been made by the Federal Government. The Canadian Federal Government previously provided some parameters for implementing the Kyoto Protocol. Total annual emissions for large industrial emitters has been capped by the former Federal Government at 55 megatonnes, emissions have been targeted to be reduced by 15 per cent from 2003 business-as-usual levels, and the cost of a carbon credits has been limited to \$15 per tonne. Numerous uncertainties regarding details of the Kyoto Protocol's implementation remain that make it difficult to ascertain the cost estimate, including when third party costs related to the Kyoto Protocol factor their way into Syncrude's supply chain of goods and services. There is no assurance that the cost impact to Canadian Oil Sands of the Kyoto Protocol or subsequent legislation related to the Kyoto Protocol will not be significant, which could result in a material adverse effect on our financial condition or our results of operations.

The Syncrude Project's operations are subject to extensive government regulation; The costs of compliance with additional government regulation and the cancellation of government licenses could have an adverse effect on Canadian Oil Sands

The Syncrude Project's mining, extraction, upgrading and utilities activities are subject to extensive Canadian federal, provincial and local laws and regulations governing exploration, development, transportation, production, exports, labour standards, occupational health, waste disposal, protection and redemption of the environment, safety, hazardous materials, toxic substances and other matters. We believe that SCL is in substantial compliance with all applicable laws and regulations. Amendments to current laws and regulations governing operations and activities of mining and refining companies and the more stringent implementation thereof are actively considered from time to time and the implementation thereof could have a material adverse impact on the Syncrude Project. There can be no assurance that the various government licenses granted to the Syncrude Project will not be cancelled or will be renewed upon expiry or that income tax laws and government incentive programs relating to the Syncrude Project, and the mining and oil and gas industries generally, will not be changed in a manner which may adversely affect Canadian Oil Sands. The Syncrude Project facility approval granted by the AEUB expires on December 31, 2035 unless extended.

Changes in the fiscal regime between the Province of Alberta and the Syncrude Project could affect Canadian Oil Sands' profitability

Our results of operations are directly affected by the fiscal regime applicable to the Syncrude Project. In addition, the generic Crown royalty system entitles the Province of Alberta to a royalty payment equivalent to the greater of one per cent of gross revenue after transportation costs and 25 per cent of gross revenue after deducting applicable transportation, operating, non-production and capital expenditures. There can be no assurance that the Canadian Federal Government and the Province of Alberta will continue the regime currently in place in the future.

The Alberta Government has announced that it plans to review Alberta's Oil Sands Royalty regime to determine if the current regime applies the most appropriate royalty rate to oil sands production. Changes

to the Crown royalty regime by the Alberta Government could have a material and adverse impact on the Trust's net income and cash from operating activities and, ultimately, on our Unitholder distributions. The Syncrude operation shifted to the higher royalty rate of 25 per cent of net revenues from the minimum one per cent of gross revenues in the second quarter of 2006. While the Alberta Government recently announced its plans to review Alberta's Oil Sands Royalty regime, the potential impact on Canadian Oil Sands cannot be determined until the government provides information on its review findings.

Nature of Trust Units

Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in a corporation. Units represent a fractional interest in a trust. As holders of Units, Unitholders will not have all the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The market price of the Units will be sensitive to a variety of market conditions including, but not limited to, crude oil prices, interest rates and the ability of the Trust to develop and produce its reserves. Changes in market conditions, especially fluctuations in the level of crude oil prices, may adversely affect the trading price of the Units.

Certain aspects relating to oil reserves data and future net revenue estimates are uncertain

The reserves figures contained or incorporated by reference into this AIF are estimates and no assurance can be given that the indicated level of recovery of SSB will be realized. Reserves estimated for properties that have not yet commenced production may require revision based on actual production experience. Such figures have been determined based upon the term of the operating permit, plant processing capacity and estimates of yield and recovery factors as well as estimates of bitumen in place. All such estimates are to some degree uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil reserves, prepared by different engineers or by the same engineers at different times, may vary. Canadian Oil Sands' actual production, revenues and development and operating expenditures with respect to its reserves may vary from such estimates. As well, the estimates of future net revenues are dependent on estimates of future capital and operating costs. Variances to actual costs may be significant. As such, these estimates are subject to variations due to changes in the economic environment at the time and variances in future budgets and operating plans.

The reserves included in the reserves data are calculated in accordance with Canadian practices and may not be directly comparable to practices in other jurisdictions. In addition, the procedures used to estimate reserves from the Syncrude Project are not directly comparable to the procedures used to estimate conventional reserves.

Certain decisions regarding the operation of the Syncrude Project require agreement among the other Syncrude Participants

The Syncrude Project is a joint venture currently owned by seven Syncrude Participants, including the Corporation. Each Syncrude Participant's voting interest is equal to its pro rata interest in the Syncrude Project. Certain decisions regarding the operations of the Syncrude Project require majority agreement among the Syncrude Participants and some fundamental decisions require unanimity. Canadian Oil Sands, through the Corporation, has a representative who chairs Syncrude's Management Committee, which is a committee of the Syncrude Participants that determines the oversight of the Syncrude Joint Venture. Future plans of the Syncrude Project, including proceeding with Stage 3 Debottlenecking and Stage 4, will depend on such agreement and may depend on the financial strength and views of the other Syncrude Participants at the time such decisions are made.

Canadian Oil Sands cannot provide unequivocal assurance that it is not a passive foreign investment corporation for U.S. tax purposes

While Canadian Oil Sands has obtained independent advice that the better view is that it is not a passive foreign investment corporation for U.S. tax purposes, we cannot provide unequivocal assurance that U.S. tax regulators will not take a different view. The Corporation, as the Trust's operating subsidiary, has employees that are actively engaged in managing the Trust's investment in Syncrude and also market Canadian Oil Sands' share of SSB production. However, if U.S. authorities view this activity as "passive", then Unitholders residing in the United States may be subject to additional taxes and filings as a result of such determination.

Unitholders may have liability beyond their investment in limited circumstances

Canadian Oil Sands' Amended and Restated Trust Indenture (the "Trust Indenture") provides that no Unitholder will be subject to any liability in connection with the Trust or its obligations and affairs or for any act or omission of the Trustee, provided that in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of, the Trust's assets. In addition, the Trust Indenture states that no Unitholder is liable to indemnify the Trustee or any other person for any liabilities incurred by the Trustee, including with respect to taxes payable by the Trust or the Trustee, and all such liabilities will be enforced only against, and will be satisfied only out of, the Trust's assets. The Trust Indenture also provides that all contracts entered into by or on behalf of the Trust should generally contain a provision or be subject to an acknowledgement to the effect that the obligations of the Trust thereunder will not be binding upon Unitholders personally and that such provisions and acknowledgement shall be held in trust and enforced by the Trustee for the benefit of the Unitholders.

Effective July 1, 2004, the Alberta Government implemented section 2(1) of the *Income Trust Liability Act*, which specifically provides that beneficiaries, as beneficiaries, are not liable for any act, default, obligation or liability of the trustee of any Alberta income trust. The Trust is an Alberta income trust. However, a Unitholder who has been actively involved in the direction or management of the Trust beyond voting Units at Unitholder meetings may incur liability beyond their investment.

In conducting its affairs, Canadian Oil Sands has assumed certain existing contractual obligations and may have to do so in the future. Although we will use reasonable efforts to have any contractual obligations modified so as not to have such obligations binding upon any of the Unitholders personally, we may not obtain such modification in all cases. To the extent that any claims under such contracts are not satisfied by Canadian Oil Sands, there is a risk that a Unitholder may be held personally liable for obligations of Canadian Oil Sands where the liability is not expressly disavowed as described above.

RESERVES DATA AND OTHER INFORMATION

In 2003, Canadian Securities Administrators implemented new standards of disclosure for reporting issuers engaged in upstream oil and gas activities. National Instrument ("NI") 51-101 establishes a regime of continuous disclosure for oil and gas companies and includes specific reporting requirements. Canadian Oil Sands applied for and received an order from the various securities commissions in Canada allowing Canadian Oil Sands to report, on a consolidated basis, the reserves of the Trust's subsidiaries with such reporting being made only at the Trust level and to footnote the per cent of interest that the Corporation holds of such aggregate amount. The Trust's year-end reserves report summarized in this AIF is compliant with NI 51-101 and such exemptive relief order.

In conjunction with NI 51-101, the Standing Committee on Reserves Evaluation of the Calgary Chapter of the Society of Petroleum Evaluation Engineers ("SPEE") and the Standing Committee on Reserves Definitions of the Canadian Institute of Mining, Metallurgy and Petroleum ("CIM") (Petroleum Society) developed the Canadian Oil and Gas Evaluation Handbook ("COGEH") to serve as the guidelines for conducting reserves evaluations and reporting the results thereof. Canadian securities regulators require reporting issuers to comply with the COGEH, as amended from time to time.

To assist you in understanding the terminology required by NI 51-101, we are providing the following definitions:

Proved Reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. NI 51-101 further identifies the certainty level for proved reserves as "at least a 90 per cent probability that the quantities actually recovered will equal or exceed the estimated proved reserves".

Proved plus Probable Reserves are those additional reserves that are less certain to be recovered than proved reserves. NI 51-101 defines the certainty level as "at least a 50 per cent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves." Therefore, under NI 51-101, the proved plus probable reserves represent a "best estimate" or "expected reserves".

Based on an independent engineering evaluation conducted by GLJ Petroleum Consultants ("GLJ") effective December 31, 2006 and prepared in accordance with NI 51-101, Canadian Oil Sands had proved plus probable reserves of 1.8 billion barrels. All reserve information in this section is based on Canadian Oil Sands' working interest of 35.49 per cent as at December 31, 2006 and does not include the acquisition of an additional 1.25 per cent interest on January 2, 2007. Proved developed producing reserves represent 56 per cent of proved plus probable reserves. Proved non-producing reserves have not been assigned. Canadian Oil Sands produces only one product type, namely synthetic crude oil.

Our crude oil reserves quantities and future net revenues were determined by GLJ under a constant price case as of December 31, 2006 and utilizing GLJ's price forecast as of December 31, 2006. The reserves estimates were constrained to areas where Syncrude currently has approvals to mine. The future net revenues shown below are prior to provision for currency hedging, interest, debt service charges, general and administrative costs, insurance, mine reclamation costs and income taxes. It should not be assumed that the discounted future net revenues estimated represents the fair market value of the reserves. The effective date of the reserves estimate and revenue projection in this AIF is December 31, 2006.

Estimates of reserves and projections of production were generally prepared using data to January 20, 2007. The GLJ report is dated February 12, 2007. Canadian Oil Sands, on behalf of the Trust and its subsidiaries, have provided GLJ with a representation letter confirming that complete and correct information has been provided to GLJ.

The reserves quantities and future net revenues set out in this AIF are dependent upon a number of assumptions and estimates. They are also subject to risks and uncertainties regarding crude oil prices, including the realized selling price that Canadian Oil Sands receives relative to Edmonton par, any impact of the Kyoto Protocol or other potential environmental legislation or sanctions that may be imposed and various other factors outlined in this AIF as well as the impact that the timing and costs of developing Aurora South may have. We would refer you to the discussion under the heading Risk Factors for the full

discussion. In addition, the evaluation does not consider the potential impact of Syncrude's research efforts and new technology developments.

Summary of Reserves as at December 31, 2006

Constant Prices and Costs⁽²⁾⁽³⁾

Reserves Category ⁽¹⁾	Synthetic Crude Oil Reserves		Before Income Tax				
	Working Interest	Net After Royalty	Discounted Present Value (\$ millions) ⁽³⁾				
	million bbl	million bbl	0%	5%	10%	15%	20%
Proved Developed Producing	982	828	\$ 30,717	\$ 17,719	\$ 11,714	\$ 8,529	\$ 6,641
Proved Developed Nonproducing	-	-	-	-	-	-	-
Total Proved	982	828	30,717	17,719	11,714	8,529	6,641
Probable	780	658	24,357	6,885	2,285	870	374
Total Proved Plus Probable	1,761	1,486	\$ 55,074	\$ 24,604	\$ 13,999	\$ 9,399	\$ 7,015

Notes:

- (1) Canadian Oil Sands Limited constitutes 100 per cent of the total reserves shown, of which 11 per cent were held indirectly through Canadian Oil Sands Limited's interest in the LP.
- (2) Figures may not add correctly due to rounding.
- (3) Based on a light sweet crude oil price at Edmonton, Alberta of \$67.58 per barrel and synthetic crude oil price at the Syncrude plant gate of \$66.58.

Total Future Net Revenue (Undiscounted Constant Prices and Costs)⁽¹⁾

Reserves Category	Revenue	Royalties	Operating Costs ⁽²⁾	Capital Development Costs ⁽²⁾	Future Net Revenue ⁽²⁾⁽³⁾
	(\$ millions)	(\$ millions)	(\$ millions)	(\$ millions)	Before Income Taxes (\$ millions)
Proved Developed Producing	\$ 65,358	\$ 10,184	\$ 20,540	\$ 3,918	\$ 30,717
Proved Developed Nonproducing	-	-	-	-	-
Total Proved	65,358	10,184	20,540	3,918	30,717
Total Probable	51,913	8,117	14,874	4,566	24,357
Total Proved Plus Probable	\$ 117,272	\$ 18,301	\$ 35,413	\$ 8,484	\$ 55,074

Notes:

- (1) Figures may not add correctly due to rounding.
- (2) Mining reclamation costs were not included in these calculations. Future mining reclamation costs for proved reserves are estimated at \$595 million and for proved plus probable reserves, at \$779 million.
- (3) As the Trust and its subsidiaries do not expect to pay any income taxes under tax legislation in force as of December 31, 2006, the calculation of the future net revenue pre and post tax are the same amount. See "Tax Horizon".

Forecast Prices and Costs⁽²⁾

Reserves Category ⁽¹⁾	Synthetic Crude Oil Reserves		Before Income Tax				
	Working Interest	Net After Royalty	Discounted Present Value (\$ millions) ⁽³⁾				
	(million bbls)	(million bbls)	0%	5%	10%	15%	20%
Proved Developed Producing	982	854	\$ 29,395	\$ 16,315	\$ 10,536	\$ 7,586	\$ 5,887
Proved Developed Nonproducing	-	-	-	-	-	-	-
Total Proved	982	854	29,395	16,315	10,536	7,586	5,887
Probable	780	681	29,965	7,929	2,385	777	255
Total Proved Plus Probable	1,761	1,535	\$ 59,361	\$ 24,243	\$ 12,922	\$ 8,363	\$ 6,142

Notes:

- (1) Canadian Oil Sands Limited constitutes 100 per cent of the total reserves shown, of which 11 per cent were held indirectly through Canadian Oil Sands Limited's interest in the LP.
- (2) Figures may not add correctly due to rounding.
- (3) Based on a light sweet crude oil price at Edmonton, Alberta (see Forecast Prices used in Estimates).

Total Future Net Revenue (Undiscounted Forecast Prices and Costs)⁽¹⁾

Reserves Category	Revenue (\$ millions)	Royalties (\$ millions)	Operating Costs ⁽²⁾ (\$ millions)	Capital Development Costs ⁽²⁾ (\$ millions)	Future Net Revenue ⁽²⁾⁽³⁾ Before Income Taxes (\$ millions)
Proved Developed Producing	\$ 75,080	\$ 9,741	\$ 30,401	\$ 5,543	\$ 29,395
Proved Developed Nonproducing	-	-	-	-	-
Total Proved	75,080	9,741	30,401	5,543	29,395
Total Probable	77,005	9,978	29,537	7,524	29,965
Total Proved Plus Probable	\$ 152,085	\$ 19,719	\$ 59,937	\$ 13,067	\$ 59,361

Notes:

- (1) Figures may not add correctly due to rounding.
- (2) Mining reclamation costs were not included in these calculations. Future mining reclamation costs for proved reserves are estimated at \$595 million, and for proved plus probable reserves, at \$779 million.
- (3) As the Trust and its subsidiaries do not expect to pay any income taxes under tax legislation in force as of December 31, 2006, the calculation of the future net revenue pre and post tax are the same amount. See "Tax Horizon".

The reserves have been estimated in accordance with procedures contained in the COGEH.

The proved developed producing reserves and production forecast reflect completion of the UE-1 project. Although the center and west pits of Aurora North are not yet on production, reserves from these pits are classified as proved developed producing since their recovery does not require a material amount of additional capital. The scenario includes capital relating to the Syncrude Emissions Reduction Project or SERP and certain recovery optimization projects. The production forecast reflects an estimate of bitumen production capacity which does not fully utilize the expanded upgrading capacity available after UE-1.

The probable reserves primarily reflect development of Aurora South, as well as improvements to both extraction recovery and upgrading yield. GLJ's evaluation assumes that Aurora North capacity will not be increased further by installation of a third primary separation vessel. It is assumed that Aurora South will be developed to replace depletion of the North Mine and source the production growth under a Stage 3 debottlenecking program, which takes advantage of unused capacity in the new coker without any change in product quality.

Forecast Prices Used in Estimates

The forecast reference prices used in preparing Canadian Oil Sands' reserves data are provided in the table below. The Syncrude plant gate price is expected to correspond to "Light Sweet Crude Oil at Edmonton" (e.g. \$70.25 in 2007).

Year	Inflation (%)	Exchange Rate (\$US/\$Cdn)	WTI Crude Oil at Cushing Oklahoma (\$US/bbl)	Light, Sweet Crude Oil at Edmonton (40 API, 0.3% S) (\$Cdn/bbl)	AECO-C Spot Gas (\$/MMBTU)
2007	2	0.87	62.00	70.25	7.20
2008	2	0.87	60.00	68.00	7.45
2009	2	0.87	58.00	65.75	7.75
2010	2	0.87	57.00	64.50	7.80
2011	2	0.87	57.00	64.50	7.85
2012	2	0.87	57.50	65.00	8.15
2013	2	0.87	58.50	66.25	8.30
2014	2	0.87	59.75	67.75	8.50
2015	2	0.87	61.00	69.00	8.70
2016	2	0.87	62.25	70.50	8.90
2017	2	0.87	63.50	71.75	9.10
2018+	2	0.87	+2.0%/yr	+2.0%/yr	+2.0%/yr

The above price forecast is GLJ's, the independent evaluator's, price forecast as of December 31, 2006. In consideration of oil sands mining cost pressures, rather than the projected inflation of 2.0 per cent above, GLJ used a 5.0 per cent inflation factor for our evaluation during the period 2007 through 2009, 4.0 per cent in 2010, and 3.0 per cent in 2011.

In 2006, Canadian Oil Sands received a weighted average price of \$71.96 per barrel (after crude oil purchases, transportation and marketing fees but before hedging) for its synthetic crude oil.

Reconciliation of Net Reserves by Principal Product Type Based on Forecast Prices and Costs

The following table sets forth a reconciliation of the changes in our reserves as at December 31, 2006 against such reserves as at December 31, 2005 based on the forecast prices and costs assumptions:

	<u>Synthetic Crude Oil</u>		
	<u>Net Proved</u> <u>(million bbls)</u>	<u>Net Probable</u> <u>(million bbls)</u>	<u>Net Proved</u> <u>Plus</u> <u>Probable</u> <u>(million bbls)</u>
At December 31, 2005	890	689	1,579
Technical Revisions	2	(1)	1
Economic Factors	(6)	(7)	(13)
Production	(32)	0	(32)
At December 31, 2006	<u>854</u>	<u>681</u>	<u>1,535</u>

Reconciliations of reserves in Canada on a company net reserves basis are more complex than on a company gross reserves basis due to price and rate-sensitive royalties, which can cause the net company reserves to change without a change in the gross company reserves. In considering the above reconciliation table, it should be noted that the economic factors are primarily related to the average royalty rate.

Reconciliation of Changes in Net Present Values of Future Net Revenue Based on Constant Prices and Costs

The following table sets forth changes between future net revenue estimates, discounted at 10 per cent, attributable to net proved reserves as at December 31, 2006 against such reserves as at December 31, 2005:

Estimated Net Present Value of Future Net Revenue at December 31, 2005	<u>(\$ millions)</u> \$12,211
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(1,293)
Net Changes in Prices, Production Costs and Royalties Related to Future Production	(391)
Development Costs During the Period	371
Changes in Estimated Future Development Costs	(410)
Accretion of Discount	1,221
Changes Resulting from Technical Reserve Revisions	5
Estimated Net Present Value of Future Net Revenue at December 31, 2006	<u>\$11,714</u>

Future Development Costs

The following table sets forth the future development costs associated with the development of our reserves as set forth in the GLJ report. Development costs will be funded from cash from operating activities.

	Total Proved Estimated Using Constant Prices and Costs (\$ millions)	Total Proved Estimated Using Forecast Prices and Costs (\$ millions)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (\$ millions)
2007	\$ 257	\$ 270	\$ 270
2008	319	352	372
2009	284	329	390
2010	213	256	684
2011	158	196	728
Remainder	2,687	4,140	10,623
Total for all years undiscounted	<u>\$ 3,918</u>	<u>\$ 5,543</u>	<u>\$ 13,067</u>
Total for all years discounted at 10%/year	<u>\$ 1,766</u>	<u>\$ 2,230</u>	<u>\$ 4,179</u>

Other Oil and Gas Information

See page 11 of this AIF for an outline of the leases held by the Syncrude Joint Venture, which total about 252,000 acres. These leases include a significant amount of contingent resources not classified as proved plus probable reserves which may not currently be economic because of uncertainty in their recovery relating to extraction and upgrading assumptions, geological confidence, the status of both regulatory and Syncrude Participants approvals, and the timeframe to develop. Syncrude's current remaining recoverable resource estimate of approximately nine billion barrels of synthetic crude oil (approximately three billion barrels net to Canadian Oil Sands) includes volumes classified as proved plus probable reserves, as well as contingent resources based on the current regulatory operating criteria. Current oil prices may enable mining of higher cost ore than considered in Syncrude's current resource estimate. Resources are, by definition, inherently uncertain and there is no assurance that these resources will be economic and ultimately developed and produced. Guidelines for estimation of resources have not yet been provided by the COGEH.

Hedging

Canadian Oil Sands did not have any crude oil production hedged as of December 31, 2006.

Costs Incurred

The following table sets forth costs incurred by Canadian Oil Sands for the year ended December 31, 2006:

Property Acquisition Costs (\$millions)		Explorations Costs (\$ millions)	Development Costs (\$ millions)
<u>Proved Properties</u>	<u>Unproved Properties</u>		
Nil	Nil	Nil	371

Abandonment and Reclamation Costs

Canadian Oil Sands has abandonment and reclamation obligations relating to the Mines, Upgrader and related facilities. Canadian Oil Sands estimates the abandonment liability, net of salvage,

for the mines with consideration given to the expected costs to abandon and reclaim the lands and extraction facilities on an undiscounted current cost basis to amount to \$595 million for proved reserves and \$779 million for proved plus probable reserves. No amounts are included with respect to the Upgrader and related facilities as these assets have indeterminate useful lives and the reclamation obligation cannot be reasonably determined. These estimates are based on prevailing industry conditions, regulatory requirements and past experience.

Our share of the present value of abandonment and reclamation costs that require recognition in our financial statements at December 31, 2006 is approximately \$173 million. These liabilities relate to our 35.49 per cent working interest at December 31, 2006 in the Syncrude future dismantlement costs and site restoration costs for the Base, North and Aurora North mines, but exclude Aurora South as no disturbance has yet occurred on that lease. Syncrude's Upgrader has an indeterminate useful life. Therefore, the fair values of the related asset retirement obligation cannot be reasonably determined. Also, the timing and amount of the reclamation expenditures, if any, related to Syncrude's sulphur blocks are not determinable at the present time. The asset retirement obligations pertaining to the Upgrader and the sulphur blocks will be recognized in the year in which the settlement amounts and dates can be reasonably estimated. GLJ has not included any abandonment and reclamation costs in the GLJ reserve report.

Tax Horizon

Under the income tax legislation that is in force as of December 31, 2006, Canadian Oil Sands, as a royalty trust, is not anticipated to incur or pay any income tax. Thus the calculation of future net revenues does not include any deduction for income tax.

On October 31, 2006 the Minister of Finance announced the Federal Government's intention to impose a new tax on certain distributions from existing income and royalty trusts effective in 2011. On December 21, 2006 draft legislation was released for comment. The proposed changes, if enacted, are anticipated to subject the Trust to income taxes at a rate of 31.5 per cent in 2011, thereby resulting in a substantial reduction in future net revenue. Assuming the Trust incurs taxes at this rate, net of expected tax carry forward balances, the total proved plus probable future net revenue at constant prices and costs would be reduced by approximately 28 per cent on an undiscounted basis and 20 per cent at a 10 per cent discount rate.

Production Estimates

A forecast of Canadian Oil Sands' production for 2007 using forecast prices is presented below:

	<u>Synthetic Crude Oil (million barrels)</u>	
<u>Reserves Category</u>	<u>Working Interest</u>	<u>After Royalty</u>
Proved developed producing	37.7	32.6
Total proved	37.7	32.6
Total proved plus probable	40.9	35.2

Production History

The following table sets forth certain information in respect of production, product prices received, royalties and netbacks received by the Corporation for each quarter of its most recently completed financial year.

	<u>Quarter 1</u>	<u>Quarter 2</u>	<u>Quarter 3</u>	<u>Quarter 4</u>	<u>Year</u>
Average Daily Sales (bbls/d) ⁽¹⁾	74,929	86,394	95,438	110,185	91,844
Realized Selling Price before Currency Hedging ⁽²⁾	\$ 69.17	\$ 78.33	\$ 78.19	\$ 63.47	\$ 71.96
Currency Hedging Gains ⁽²⁾	1.07	1.02	0.29	0.24	0.60
Net Realized Selling Price ⁽²⁾	70.24	79.35	78.43	63.71	72.56
Operating Expenses ⁽²⁾	(40.26)	(28.48)	(19.68)	(23.60)	(27.07)
Royalties ⁽²⁾	(0.67)	(3.82)	(13.01)	(8.23)	(6.93)
Netback ⁽²⁾	<u>\$ 29.31</u>	<u>\$ 47.05</u>	<u>\$ 45.74</u>	<u>\$ 31.88</u>	<u>\$ 38.56</u>

Notes:

- (1) The average daily volumes reported for 2006 represent Canadian Oil Sands' average daily sales, which differ from its average daily production volumes primarily due to in-transit pipeline volumes.
- (2) Canadian dollars per barrel.

Reserve Life Index

Canadian Oil Sands' estimated reserve life index using reserves prepared by GLJ based on Canadian Oil Sands' January 29, 2007 guidance of approximately 110 million barrels per year of Syncrude production is as follows:

	<u>Reserves</u> <u>(Millions of barrels)</u>	<u>Reserve Life</u> <u>Index (Years)</u>
Total Proved Reserves	982	25
Proved plus Probable Reserves	1,761	45

DISTRIBUTABLE INCOME

In accordance with the Trust Indenture, Unitholders of record on or about the last business day of each of January, April, July and October are entitled to receive cash distributions from the Trust on the last working day of the following month. Prior to 2006, the Trust accrued the distribution made to Unitholders as a payable at each quarter end, even though the distribution was not declared and actually paid until the subsequent quarter. This resulted in Unitholders receiving a distribution in February of a given year but having the taxable portion of such distribution payment being treated as income for Canadian tax purposes for the prior tax year. Having considered market practise and having received advice from legal counsel, Canadian Oil Sands amended the Trust Indenture to allow, commencing with quarterly distribution payments in 2006, the Trust to distribute all income, less applicable expenses, received or expected to be received in a given quarter as a distribution to Unitholders and thereby to record such distribution in the quarter paid. As a result, the financial statements for the year ended December 31, 2005 do not reflect a distribution payable at December 31, 2005. However, all four distributions declared in 2006 were reflected in the financial statements for the year ended December 31, 2006. This change in how Unitholder distributions are recorded has no impact on the ultimate distributions declared and paid to the Unitholders or to the timing of such payments, nor does it impact

Canadian Oil Sands' net income or funds from operations. Rather, it provided symmetry of Unitholders being taxed and receiving payment of a distribution in the same quarter. The Trust found that this eliminated some of the confusion that certain Unitholders previously had with regard to the timing and taxability of the distribution payment made in the first quarter of each year. A full copy of the current Trust Indenture can be found at www.cos-trust.com under corporate, or at www.sedar.com.

Pursuant to Section 5.1 of the Trust Indenture, the Trust is required to distribute all the income received or receivable by the Trust in a quarter less expenses and any other amounts required by law or the Trust Indenture itself. The Trust primarily receives income by way of a royalty and interest on intercompany loans from the Corporation (its principal operating subsidiary). The royalty is designed to capture the cash generated by the Corporation, after the deduction of all costs and expenses, including: operating and administrative costs, income taxes, capital expenditures, debt interest and principal repayments, working capital, and reserves for future obligations deemed appropriate. The amount of royalty income that the Trust receives in any period has a considerable amount of flexibility through the use of discretionary reserves and debt borrowings or repayments (either intercompany or third party). Quarterly distributions are determined by the Board of Directors of the Corporation after considering current and expected economic and operating conditions, ensuring financing capacity of Syncrude's expansion projects and/or Canadian Oil Sands acquisitions, and with the objective of maintaining an investment grade credit rating.

In 2006, Unitholder distributions were comprised of the trust royalty payments, revenues from the six per cent gross overriding royalty on a five per cent working interest in Syncrude and interest income earned received by the Trust less the direct expenses of the Trust. Cash distributions paid to Unitholders are determined by the Corporation's Board of Directors, in their sole discretion, and will only be declared and paid if deemed prudent to do so.

At the discretion of the Corporation's Board of Directors, the Trust may also make cash distributions of the Trust's capital provided that such distributions are made out of funds that are in excess of amounts reasonably required to satisfy obligations of Canadian Oil Sands.

During normal operations when no major turnarounds are occurring, the production of SSB is generally consistent from month to month, but capital and other expenditures will generally occur in a less consistent manner. As a result, the Corporation has the right to hold back certain funds in the calculation of the trust royalty to allow it to meet cash requirements attributable to the Syncrude working interest and to meet its ongoing obligations as a Participant.

The actual amount of the trust royalty received by the Trust from the Corporation depends on the quantity of oil sold, prices received, hedging contract receipts and payments, capital, operating and administrative expenses, Crown royalties, debt service charges, and changes to the utilization of expansion financing determined to be prudent by the Corporation. Further information is contained in our 2006 MD&A under "Liquidity and Capital Resources", which section is incorporated herein by reference and is available at www.sedar.com.

Distribution History

Payment Date	Amount per Unit ⁽¹⁾
February 28, 2007	\$0.30
November 30, 2006	\$0.30
August 31, 2006	\$0.30
May 31, 2006	\$0.30
February 28, 2006	\$0.20
November 30, 2005	\$0.20
August 31, 2005	\$0.10
May 31, 2005	\$0.10
February 28, 2005	\$0.10
November 30, 2004	\$0.10
August 31, 2004	\$0.10
May 31, 2004	\$0.10
February 27, 2004	\$0.10

Note:

(1) Amounts adjusted to reflect the 5:1 Unit split that occurred on May 3, 2006.

DESCRIPTION OF CAPITAL STRUCTURE

General Description

The Trust is authorized to issue an unlimited number of ordinary trust units (“Units”). Each Unit represents a beneficial interest in the Trust and entitles the holder to one vote per Unit and participation in any distributions made by or liquidation of the Trust. At the annual general and special meeting of Unitholders held in April 2003, Unitholders approved the issuance by the Trust of convertible securities. As of March 15, 2007, there were no securities of the Trust created and issued other than Units. All Unitholders share equally in all distributions of the Trust. No conversion, retraction or pre-emptive rights are attached to the Units. Units are redeemable at the option of the Unitholder at a price that is the lesser of 90 per cent of the average closing price of the Units on the principal trading market for the previous 10 days and the closing market price on the date of tender for redemption. There is a limit of \$250,000 per quarter for such redemptions. At the annual meeting of Unitholders held in April 2006, Unitholders approved a 5:1 split in the number of Units outstanding and also increased the authorized number of Units from 500,000,000 to an unlimited number of Units.

Foreign Ownership

The Trust Indenture, under which the Trust was created, provides that no more than 49 per cent of the Units of the Trust can be held by non-Canadian residents. Depending upon the nature of the Trust's operations at the time, the potential impact of exceeding this threshold may be the loss of mutual fund trust status to the Trust, which may significantly adversely impact the valuation of the Units. As such, the

Trust continues to monitor, to the extent possible given the practical limitations regarding beneficial ownership information, the level of non-Canadian resident Unitholders. To the best of our knowledge, the Trust has always had less than 50 per cent non-Canadian resident Unitholders.

The Trust uses declarations from Unitholders and, occasionally, geographical searches to estimate the level of Canadian and non-Canadian resident Unitholders of the Trust at certain periods throughout the year. While the Trust believes that these results are reasonable estimations at the time that they are provided, the inability of all public issuers to obtain the residency information of its beneficial holders means that issuers are reliant upon the information provided to the transfer agent. As a result, the residency information is subject to the accuracy provided by third party data and by information system limitations. Accordingly, the reported level of Canadian ownership is subject to these limitations and the level of Canadian ownership may change at any time without notice and without our knowledge.

Based on account data at February 8, 2007, Canadian Oil Sands estimates that approximately 33 per cent of our Units are held by non-Canadian residents with the remaining 67 per cent being held by Canadian residents. We will continue to monitor the non-resident ownership levels.

If, based on the declarations or on the geographical list, the level of Units held by non-Canadian residents is 46 per cent or more, then Canadian Oil Sands plans to issue a press release advising of the increased level and stating that it is anticipated that the Trust may reach 49 per cent or more non-Canadian resident Unitholders and that, in such case, each person purchasing the Units, whether through a broker or directly in registered form, will need to complete a declaration as to their residency.

If the level of non-Canadian resident ownership appears to be approximately 49 per cent or more, Canadian Oil Sands will make a public announcement that no further sales to non-Canadian residents will be allowed. No transfers will be allowed without the completion of a declaration indicating their status as a Canadian or non-Canadian resident. As part of such announcement, the Trustee shall state that it shall not accept a subscription for Units from or issue or register a transfer of Units to a person unless the person provides a declaration that the person is not a non-Canadian resident. In addition, if non-Canadian ownership is greater than 50 per cent, then the Trustee will send a notice to non-resident holders of Units, chosen in inverse order to the order of acquisition or registration or in such other manner as the Trustee may consider equitable and practicable, requiring them to sell their Units or a specified portion thereof within the specified period of not less than 60 days. If the Unitholders receiving such notice have not sold the specified number of Units or provided the Trustee with satisfactory evidence that they are not non-Canadian residents within such period, the Trustee may, on behalf of such Unitholders sell such Units and, in the interim, shall suspend the voting and distribution rights attached to such Units. Any sale shall be made on the Toronto Stock Exchange and, upon such sale, the affected holders shall cease to be holders of Units and their rights shall be limited to receiving the net proceeds of sale upon surrender of the certificates representing the Units.

As part of Canadian Oil Sands' assessment of the proposed changes to the taxation of income trust announced by the Federal Government on October 31, 2006, the Board of Directors may consider these restrictions in light of the proposed changes if and when the Board faces a situation where it may need to implement these restrictions. If the result of the proposed tax legislation is to force income trusts to be treated the same as a corporation, Canadian Oil Sands does not understand why the Federal Government would impose restrictions on the foreign ownership of income trusts when no such restrictions exist on corporations. Accordingly, further clarity on this issue is required from the Federal Government before Canadian Oil Sands can determine the best course of action for its Unitholders should this ownership limitation arise when the proposed tax change is in effect.

Rights Plan

A Unitholders rights plan for the Trust was approved by Unitholders in 2001 and Unitholders further approved an amended and restated plan in 2004 (the "Rights Plan"). Unitholders are being asked to approve and reconfirm, the Rights Plan together, with minor amendments, at the annual meeting to be held on April 25, 2007.

The primary objective of the Rights Plan is to provide the Board with sufficient time to explore and develop alternatives for maximizing Unitholder value if a takeover bid is made for Units and to provide every Unitholder with an equal opportunity to participate in such a bid. The Rights Plan encourages a potential acquiror to proceed either by way of a Permitted Bid (as defined in the Rights Plan), which requires the takeover bid to satisfy certain minimum standards designed to promote fairness, or with the concurrence of the Board. Unitholders are advised that the Rights Plan may preclude their consideration or acceptance of offers which do not meet the requirements of a Permitted Bid.

The effective date of the Rights Plan is April 26, 2004 and such Rights Plan has a ten year term. On May 11, 2001, one right (a "Right") was issued and attached to each Unit then outstanding and will continue to attach to each Unit subsequently issued.

The Rights will separate from the Units and will be exercisable eight trading days (the "Separation Time") after a person has acquired, or commences a takeover bid to acquire, 20 per cent or more of the Units, other than by an acquisition pursuant to a takeover bid permitted by the Rights Plan (a "Permitted Bid"). The acquisition by any person (an "Acquiring Person") of 20 per cent or more of the Units, other than by way of a Permitted Bid, is referred to as a "Flip-in Event". Any Rights held by an Acquiring Person will become void upon the occurrence of a Flip-in Event. Eight trading days after the occurrence of the Flip-in Event, each Right, (other than those held by the Acquiring Person), will permit the purchase of Units at a 50 per cent discount to their market price. The issue of the Rights is not initially dilutive. Upon a Flip-in Event occurring and the Rights separating from the Units, reported earnings per Unit on a fully diluted or non-diluted basis may be affected. Holders of Rights not exercising their Rights upon the occurrence of a Flip-in Event may suffer substantial dilution.

A bidder may enter into lock-up agreements with Unitholders whereby such Unitholders agree to tender their Units to the takeover bid (the "Subject Bid") without a Flip-in Event (as referred to above) occurring. Any such agreement must permit the Unitholder to withdraw the Units to tender to another takeover bid or to support another transaction that exceeds the value of the Subject Bid by as much or more than a specified amount, which specified amount may not be greater than seven per cent.

Prior to the Separation Time, the Rights are evidenced by a legend imprinted on certificates for the Units issued from and after the effective date of the Rights Plan and are not to be transferable separately from the Units. From and after the Separation Time, the Rights will be evidenced by Rights certificates which will be transferable and traded separately from the Units.

The requirements for a Permitted Bid include the following:

- (a) the takeover bid must be made by way of a takeover bid circular;
- (b) the takeover bid must be made to all Unitholders;
- (c) the takeover bid must be outstanding for a minimum period of 60 days and Units tendered pursuant to the takeover bid may not be taken up prior to the expiry of the 60 day period and

only if at such time more than 50 per cent of the Units held by Unitholders, other than the bidder, its affiliates and persons acting jointly or in concert and certain other persons (the "Independent Unitholders"), have been tendered to the takeover bid and not withdrawn; and

- (d) if more than 50 per cent of the Units held by Independent Unitholders are tendered to the takeover bid within the 60-day period, the bidder must make a public announcement of that fact and the takeover bid must remain open for deposits of Units for an additional 10 business days from the date of such public announcement.

The Rights Plan allows for a competing Permitted Bid (a "Competing Permitted Bid") to be made while a Permitted Bid is in existence. A Competing Permitted Bid must satisfy all the requirements of a Permitted Bid except that it may expire on the same date as the Permitted Bid, subject to the requirement that it be outstanding for a minimum period of 35 days.

The Board, acting in good faith, may, prior to the occurrence of a Flip-in Event, waive the application of the Rights Plan to a particular Flip-in Event (an "Exempt Acquisition") where the takeover bid is made by a takeover bid circular to all holders of Units. Where the Board exercises the waiver power for one takeover bid, the waiver will also apply to any other takeover bid for the Trust made by a takeover bid circular to all holders of Units prior to the expiry of any other bid for which the Rights Plan has been waived.

The Board, with the prior approval of a majority vote of the votes cast by Unitholders (or the holders of Rights if the Separation Time has occurred) voting in person and by proxy, at a meeting duly called for that purpose, may redeem the Rights at \$0.001 per Unit. Rights may also be redeemed by the Board without such approval following completion of a Permitted Bid, Competing Permitted Bid or Exempt Acquisition.

The Board may amend the Rights Plan with the approval of a majority vote of the votes cast by Unitholders (or the holders of Rights if the Separation Time has occurred) voting in person and by proxy at a meeting duly called for that purpose. The Board of Directors without such approval may correct clerical or typographical errors and, subject to approval as noted above at the next meeting of the Unitholders (or holders of Rights, as the case may be), may make amendments to the Rights Plan to maintain its validity due to changes in applicable legislation.

The Rights Plan will not detract from or lessen the duty of the Board to act honestly and in good faith with a view to the best interests of the Trust. The Board, when a Permitted Bid is made, will continue to have the duty and power to take such actions and make such recommendations to Unitholders as are considered appropriate.

Investment advisors, trust companies (acting in their capacities as trustees and administrators), statutory bodies whose business includes the management of funds and administrators of registered pension plans acquiring greater than 20 per cent of the Units are exempted from triggering a Flip-in Event, provided that they are not making, or are not part of a group making, a takeover bid.

Ratings

As at March 15, 2007, the Units of the Trust have a stability rating of SR-4 issued by Standard and Poor. The debt securities of the Corporation, the main operating subsidiary of the Trust, were rated BBB with a stable outlook by Standard and Poor's and Baa2 with a stable outlook by Moody's Investor Service.

A Standard & Poor's Canadian Income Fund Stability Rating is an opinion of a fund's overall sustainability and variability of cash flow, and a measurement of relative risk of cash-flow generation across all income fund sectors. Ratings range from "SR-1" for the highest level of distributable cash stability, to "SR-7" for the lowest with "SR-4" having a moderate level of distributable cash flow generation relative to other income funds in the Canadian marketplace.

Moody's credit ratings are on a long-term debt rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, obligations rated Baa are subject to moderate credit risk. They are considered medium-grade and as such may possess certain speculative characteristics. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through Caa in its corporate bond rating system. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates mid-range ranking and the modifier 3 indicates a ranking in the lower end of its generic rating category.

S&P's credit rating are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, an obligation rated 'BBB' exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories.

The credit ratings mentioned herein are not a recommendation to purchase, hold or sell the Units and do not comment as to market price or suitability for a particular investor. Neither the Corporation nor the Trust can assure investors that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant and, if any such rating is so revised or withdrawn, neither the Corporation nor the Trust is under any obligation to update this AIF.

MARKET FOR SECURITIES

Price Range and Trading Volumes of Trust Units

The Units are listed for trading on the Toronto Stock Exchange ("TSX") and trade under the symbol COS.UN. The table below sets out the price ranges and volumes traded on the TSX during 2006.

Month	High (\$/Unit)	Low (\$/Unit)	Close (\$/Unit)	Volume Traded (thousands)
January	30.20	26.40	30.20	28.31
February	32.84	28.09	31.03	31.88
March	33.69	30.66	33.52	29.64
April	35.50	33.08	35.00	21.39
May	37.60	31.18	35.50	36.81
June	36.00	28.61	36.00	29.91
July	37.22	31.51	37.22	20.11
August	38.20	33.75	33.80	51.65
September	34.44	29.20	29.82	33.99
October	31.78	27.18	30.42	37.49
November	31.30	27.17	29.99	58.50
December	33.32	29.95	32.61	26.89

Note 12 *Unitholder Equity* of the audited annual financial statements of the Trust is incorporated herein by reference.

DIRECTORS AND OFFICERS

The Trust has no directors, officers or employees. The following information pertains to the board of directors and officers of the Corporation as at March 15, 2007.

Directors

The following are the names, the province and country of residence of each director of the Corporation, their positions with the Corporation and principal occupations within the past five years and the year in which each first became a director of the Corporation.

Name and Province and Country of Residence	Position Held and Principal Occupation	Year First Became a Director
Marcel R. Coutu Alberta, Canada	President and Chief Executive Officer of Canadian Oil Sands Limited	2001
E. Susan Evans, Q.C. ⁽¹⁾⁽²⁾ Alberta, Canada	Corporate Director	1997
The Right Honourable Donald F. Mazankowski ⁽²⁾ Alberta, Canada	Corporate Director and Business Consultant	2002
Wayne M. Newhouse ⁽¹⁾⁽³⁾ Alberta, Canada	Corporate Director	1996
Walter B. O'Donoghue, Q.C. ⁽²⁾ Alberta, Canada	Counsel, Bennett Jones LLP (law firm)	1995
Brant G. Sangster ⁽²⁾⁽³⁾ Alberta, Canada	Corporate Director	2006
C.E. (Chuck) Shultz ⁽¹⁾⁽³⁾ Alberta, Canada	Chairman, Canadian Oil Sands Limited; Chairman and Chief Executive Officer, Dauntless Energy Inc. (private oil and gas corporation)	1996
Wesley R. Twiss ⁽¹⁾⁽³⁾ Alberta, Canada	Corporate Director	2001
John B. Zaozirny, Q.C. ⁽²⁾ Alberta, Canada	Counsel, McCarthy Tétrault LLP (law firm)	1996

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Corporate Governance and Compensation Committee.
- (3) Member of the Reserves, Marketing Operations and Environmental, Health & Safety Committee.

Each of the directors listed above has been engaged in the occupation set forth in the above table or similar occupations with the same employer for the last five years except: Mr. Twiss (who was Executive Vice President and Chief Financial Officer of PanCanadian Energy Corporation from January 2000 to April 2002); and Mr. Newhouse (who was President of Morgas Ltd. from 2001 to 2005).

The term of office of all directors will expire on the date of the next annual meeting of Unitholders.

Mr. O'Donoghue is counsel to Bennett Jones LLP and Mr. Zaozirny is counsel to McCarthy Tétrault LLP, both of which firms provide legal services to Canadian Oil Sands from time to time.

Computershare Trust Company of Canada, the successor in interest to Montreal Trust Company of Canada, is the Trustee of the Trust. The Corporation does not have an executive committee. The Corporate Governance and Compensation Committee was formed in early 2002. From the fall of 2003 to December 31, 2006, the Audit Committee also has acted as the reserves committee of the Board. Effective January 1, 2007, the Board created a new Reserves, Marketing Operations and Environmental, Health & Safety Committee to deal with reserves matters, marketing matters and environmental, health and safety issues.

The Audit Committee is comprised of the members listed below. The Board has determined that each member of the Audit Committee is an "independent" director and is "financially literate" under applicable securities policies. In considering criteria for the determination of financial literacy, the Board of Directors considered at the member's ability to read and understand a balance sheet, an income statement and a cash flow statement of a public company as well as the member's past experience in reviewing or overseeing the preparation of financial statements. Beside each member's name is such person's education and experience relevant to such member's performance as an audit committee member.

Name	Relevant Education and Experience
Wesley R. Twiss (Chair)	Mr. Twiss has over 30 years experience in the oil and gas industry, including more than 10 years of which were in the position as chief financial officer of large public oil and gas companies which held or managed an interest in the Syncrude Joint Venture. Mr. Twiss chairs the Audit Committee of three other public issuers, including Addax Petroleum Corporation, EPCOR and Keyera Facilities Income Fund. Given this background, Mr. Twiss has experience on both trust and financial issues. Mr. Twiss has an MBA from the University of Western Ontario and is a member of the Institute of Corporate Directors. He has completed the ICD Corporate Governance College Director Education Program and has received the ICD.D. designation.
E. Susan Evans, Q.C.	Ms. Evans has acted as a director on numerous boards of public and private entities which operated in the areas of oil and gas, utility, banking, government and charities. Ms. Evans was a former Chair of the Audit Committee for the Province of Alberta, is a member of the Audit, Risk and Finance Committee of Enbridge Inc. and was a member of the Audit Committee of Anderson Exploration Ltd. and the Chair of the Audit Committee of Canadian Oil Sands prior to and immediately following the merger with Canadian Oil Sands Trust and Athabasca Oil Sands Trust in 2001. She was also a Commissioner of the Alberta Financial Review Commission. Ms. Evans has completed an MBA level accounting course at Edinburgh Business School, Heriot-Watt University, and has completed the Ivey League Executive Program at the Richard Ivey School of Business.
C.E. (Chuck) Shultz	Mr. Shultz has acted on the boards and audit committees of several public and private entities including Newfield Exploration Company and Enbridge Inc. He was the former Vice Chairman of the University of Calgary and Chair of the Audit Committee of the University of Calgary. Mr. Shultz was the former Chief Executive Officer of Gulf Canada Resources Limited. He has over 30 years of experience in the oil and gas sector and has completed the Advanced Management Program at Harvard Business School and has completed the ICD Corporate Governance College Director Education Program and has received the ICD.D designation.

Name	Relevant Education and Experience
Wayne M. Newhouse	Mr. Newhouse has acted in various director and executive capacities for a number of private and public entities, primarily in the oil and gas sector. He is currently the Chair of the Audit Committee of ET Energy Ltd., a private company. In particular, he was the former Chair of the Audit Committee of Progas Ltd. and former director and Chair of the Reserves Audit Committee of Petrofund Energy Trust. Mr. Newhouse has also completed an Alexander Hamilton Institute two year business program and Investment Dealer Association courses as well as the Financial Literacy for Directors course.

The terms of reference for the Audit Committee are available on the Trust's website at www.cos-trust.com under corporate information and are attached hereto as Schedule "A". As part of such terms of reference, the Audit Committee has adopted procedures relating to the engagement of non-audit services.

The Audit Committee has restricted the auditors from providing any services that could reasonably be seen as functioning in the role of management, auditing their own work or acting in an advocate role for Canadian Oil Sands. In particular, the external auditor is not to provide bookkeeping functions, actuarial or appraisal services (other than related to tax services), internal audit, human resources, or legal services (other than for French translation services). The Audit Committee has defined what constitutes audit services, audit related services, tax services and other services. Except in relation to audit services, amounts over \$25,000 require the pre-approval of the Audit Committee. However, all of the services provided and the amounts paid, regardless of their magnitude, must be disclosed to the Audit Committee at the Audit Committee meeting immediately following such engagement. If any of the services (other than audit services) are over \$25,000, such services must be pre-approved by the Audit Committee or the Chair of the Audit Committee.

Officers

There are no direct officers of the Trust. Instead, management of the Trust is exercised by the Corporation and its directors and officers. The following table identifies each of the officers of the Corporation, as at March 15, 2007, their jurisdiction of residence, their current office, and their principal occupations for the five-year period proceeding December 31, 2006.

Name and Jurisdiction of Residence	Current Office	Five Year History of Principal Occupations
C.E. (CHUCK) SHULTZ Alberta, Canada	Chairman of the Board of Directors	Chairman and Chief Executive Officer of Dauntless Energy Inc. (private oil and gas corporation)
MARCEL R. COUTU Alberta, Canada	President and Chief Executive Officer	
ALLEN R. HAGERMAN, FCA Alberta, Canada	Chief Financial Officer	Vice President and Chief Financial Officer of Fording Canadian Coal Trust from March 2003 to May 2003; Vice President and Chief Financial Officer of Fording Inc. from June 2001 to March 2003
TREVOR R. ROBERTS, Alberta, Canada	Chief Operations Officer	Vice President, Operations of Suncor, Inc. from 1997 to May 2005

Name and Jurisdiction of Residence	Current Office	Five Year History of Principal Occupations
TRUDY M. CURRAN Alberta, Canada	General Counsel and Corporate Secretary	Corporate Secretary of the Corporation from November 2001 to May 2002; Senior Counsel and Assistant Corporate Secretary, EnCana Corporation from April 2002 to September 2002; prior thereto, Staff Legal Counsel, PanCanadian Energy Corporation from November 2001 to March 2002
RYAN M. KUBIK Alberta, Canada	Treasurer	Advisor, Corporate Finance, EnCana Corporation from April 2002 to August 2002 and prior thereto, Associate Director, Treasury, PanCanadian Energy Corporation
LAUREEN C. DUBOIS Alberta, Canada	Controller	Manager, Accounting of the Corporation from November 2002 to January 2004; Senior Accountant, EnCana Corporation November 2001 to October 2002
SIREN FISEKCI Calgary, Alberta	Director, Investor Relations	Manager, Investor Relations from November 2002 to April 2006 and prior thereto, Investor Relations Analyst, EnCana Corporation.

As of March 9, 2007, the Directors and Officers of Canadian Oil Sands, as a group, beneficially own, directly or indirectly, or exercise control or direction over 566,032 Units of the Trust (557,920 Units for the Directors and Executive Officers), representing less than one per cent of the issued and outstanding Units of the Trust.

FEES PAID TO AUDITORS

PricewaterhouseCoopers LLP was first appointed on April 19, 1996 as the auditor of a predecessor of the Trust, also named Canadian Oil Sands Trust, and was appointed as the auditor of the Trust and the Corporation's predecessors in July and August 2001. The aggregate fees paid to PricewaterhouseCoopers LLP (exclusive of GST) in 2006 and 2005 were as follows:

Fees Descriptions	2006	2005
Audit	\$336,500	\$203,000
Audit Related	\$8,000	\$14,000
Tax	\$213,000	\$167,000

Audit fees increased substantially in 2006 primarily as a result of the increased scope of audit with the expanded review process as part of the auditors' review of the Trust's internal control over financial reporting as well as the internalization of the marketing activities. Audit related services relate primarily to review of specific accounting issues related to the financial statements such as future tax calculations. Most of the tax services relates to tax return filings and assessments.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed in this AIF, no Director or Executive Officer of the Corporation, nor any direct or indirect Unitholder who beneficially owns, or who exercises control or direction over, more than 10% of the outstanding Units, nor any know associate or affiliate of any such persons, has a material interest, direct or indirect, in any transaction since January 1, 2004 that has materially affected or will materially affect the Trust.

Computershare Trust Company of Canada acts as both Trustee and the transfer agent and registrar for the Units, and receives fees for its services in both capacities. In its capacity as Trustee of the Trust, the Trustee is paid a reasonable fee in connection with the administration and management of the Trust and is also reimbursed for all expenses properly incurred, as agreed by the Trustee and the Corporation.

The Trustee, on behalf of the Trust, holds all of the issued and outstanding shares of the Corporation.

LEGAL PROCEEDINGS

There are no legal proceedings to which we are a party or of which any of our property is the subject, nor are there any proceedings known by us to be contemplated that involves a claim for damages exceeding ten per cent of our current assets.

TRANSFER AGENT AND REGISTRARS

Computershare is our trustee and the transfer agent and registrar for the Units at its principal offices in Vancouver, Calgary, Toronto, Montreal, and Halifax. They may be contacted at 710, 530 – 8th Avenue S.W., Calgary, Alberta T2P 3S8; phone (403) 267-6800; facsimile (403) 267-6598.

INTEREST OF EXPERTS

PricewaterhouseCoopers LLP

The Trust's auditors are PricewaterhouseCoopers LLP, Chartered Accountants ("PwC"), who have prepared an independent auditors' report dated February 22, 2007 in respect of the Trust's consolidated financial statements with accompanying notes as at and for the years ended December 31, 2006 and 2005. PwC has advised that they are independent with respect to the Trust within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

GLJ Petroleum Consultants Ltd.

In July 2006, the Board appointed GLJ as the independent reserves evaluator for Canadian Oil Sands. The partners and associates of GLJ, as a group, own, directly or indirectly, less than one per cent of the outstanding Units.

ADDITIONAL INFORMATION

Additional information relating to Canadian Oil Sands is available through the internet via SEDAR at www.sedar.com.

In particular, additional information, including with respect to Directors' and Executive Officers' remuneration and indebtedness, principal holders of the Trust's securities, and securities authorized for issuance under equity, compensation plans if applicable, is contained in the Trust's Management Proxy Circular dated March 12, 2007, which relates to the Annual and Special Meeting of Unitholders to be held on April 25, 2007. Additional financial information is also provided in the Trust's consolidated comparative audited financial statements and notes thereto for the year ended December 31, 2006.

SCHEDULE "A"

TERMS OF REFERENCE OF THE AUDIT COMMITTEE

I. PURPOSE

- A. The primary function of the Audit Committee (the "Committee") is to assist the Board of Directors of Canadian Oil Sands Limited ("COSL") in fulfilling its oversight responsibilities by reviewing:
- i) the financial information that will be provided to the unitholders of Canadian Oil Sands Trust (the "Trust") and the public;
 - ii) the systems of internal controls that management and the Board have established, including monitoring the integrity of the controls regarding financial reporting and accounting compliance; and
 - iii) all audit processes.
- B. Primary responsibility for the financial reporting, information systems, risk management and internal controls of the Trust, COSL and the other subsidiaries of the Trust is vested in management and is overseen by the Board.
- C. Review and receive the reports of the internal auditor as part of the internal control oversight of the Trust, COSL and the other subsidiaries of the Trust.
- D. The Committee shall monitor the independence and performance of the external auditors and of the internal auditors of the Trust, COSL and the other subsidiaries of the Trust.

II. CONSTITUTION, COMPOSITION AND DEFINITIONS

- A. The Committee shall be composed of not fewer than three directors, none of whom shall be officers or employees of COSL. The Committee shall only be comprised of "independent" directors. An "independent" director is a director who is free from any direct or indirect relationship with COSL or the Trust and its subsidiaries that, in the Board's view, would or could reasonably interfere with the exercise of his or her independent judgment. A member must be "independent" within the meaning ascribed thereto in Multilateral Instrument 52-110, as amended. All members of the Committee shall be financially literate, as determined by the Board of Directors. Committee members will include only duly elected directors.

- B. The Committee shall ensure that management advises the external auditors of the names of the Committee members and provides notice of and invites, where appropriate, the external auditors to attend meetings of the Committee. The Committee shall ensure that the external auditors are heard at those meetings on matters relating to the auditor's duties.
- C. The Committee shall meet with the external auditors at least quarterly and otherwise as it deems appropriate to consider any matter that the Committee or the external auditors determine should be brought to the attention of the Board or unitholders.
- D. The Committee shall meet at least four times each year. The Chairman may call additional meetings as required. In addition, a meeting may be called by the non-executive Chairman of the Board, the President & Chief Executive Officer, any member of the Committee or by the external auditors.
- E. The Committee shall have the right to determine who shall and who shall not be present at any time during a Committee meeting. The President & Chief Executive Officer and the Chief Financial Officer of COSL are expected to be available to attend the Committee's meetings or portions thereof.
- F. The Board shall appoint members to the Committee. Where a vacancy occurs at any time in the membership of the Committee, the Board may fill it. A majority of the Board may remove any member of the Committee at any time. If a member of the Committee ceases to be a Board member, then such individual shall automatically cease to be a member of the Committee.
- G. The Committee shall be given access to senior management of COSL and all documents as required to fulfill its responsibilities and shall be provided with the resources necessary to carry out its responsibilities.
- H. The Committee shall have the right to:
 - i) engage independent counsel and other advisors as it determines necessary to carry out its duties;
 - ii) to establish and pay the compensation for any advisors employed by the Committee; and
 - iii) to communicate directly with the external auditors and, if applicable, internal auditors.
- I. The Committee provides open venues of communication among management, employees, external auditors and the Board.

- J. The non-executive Chairman of the Board shall be a non-voting member of the Committee unless he is a member of the Committee in which case he shall have the same voting rights as any other member of the Committee.
- K. The secretary to the Committee shall be either the Corporate Secretary or his/her delegate.
- L. Committee meetings may be held in person, by video conference, by means of telephone or by a combination of the foregoing.
- M. Notice of the time and place of each meeting may be given orally, or in writing (including by electronic means) or by facsimile to each member of the Committee at least 48 hours prior to the time fixed for such meeting. Notice shall also be given to the external auditors. Any member and the external auditors may, in any manner, waive notice of the meeting. Attendance of a member or the external auditors at a meeting shall constitute waiver of notice of the meeting except where a member or the external auditors attend the meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.
- N. A majority of members, present in person or by videoconference, by means of telephone or combination thereof, shall constitute a quorum.

III. DUTIES AND RESPONSIBILITIES

Subject to the powers and duties of the Board and without limiting the members' duties as Board members, the Committee will perform the following duties:

A. Financial Statements and Other Financial Information

The Committee will review and consider all financial information that will be made publicly available. This includes:

- i) reviewing and recommending approval of the annual financial statements and management's discussion and analysis with regard to the Trust, COSL and other subsidiaries of the Trust, as applicable, and report to the Board before the statements are approved by the Board;
- ii) reviewing and approving the quarterly unaudited financial statements and management's discussion and analysis with regard to the Trust, COSL, and other subsidiaries of the Trust, as applicable, and approving the release of such financial statements and interim management's discussion and analysis to the public together with the press releases thereon;

- iii) reviewing and authorizing for release any earnings release to the public;
- iv) reviewing and recommending to the Board for approval, the financial content of the annual report and any material reports required by government or regulatory authorities;
- v) reviewing and recommending for approval by the Board the Annual Information Form of the Trust and COSL;
- vi) reviewing and recommending to the Board for approval any prospectus or offering memorandum;
- vii) reviewing and discussing the appropriateness of accounting policies and financial reporting practices used by the Trust, COSL and/or other subsidiaries of the Trust;
- viii) reviewing and discussing any significant proposed changes in financial reporting and accounting policies and practices to be adopted by the Trust, COSL and/or other subsidiaries of the Trust;
- ix) reviewing and discussing any new or pending developments in accounting and reporting standards that may materially affect the Trust, COSL and/or other subsidiaries of the Trust;
- x) reviewing and assessing the appropriateness of management's key estimates and judgments that may be material to financial reporting;
- xi) reviewing and discussing with the internal auditors any matters which affect or may reasonably be expected to affect the accuracy or robustness of reporting as such relate to the financial statements or other financial disclosure matters;
- xii) reviewing and discussing with management the use of "pro forma" or non-GAAP financial information and earnings guidance contained in news releases, any other public disclosure or any filings with the securities regulators and considering whether the information is consistent with the information contained in the financial statements of the Trust or COSL; and
- xiii) reviewing and reassess annually that procedures are in place regarding the review of any other corporate disclosure derived or extracted from financial statements is being properly handled.

B. Financial Risk Management, Internal Control and Disclosure Control Systems

The Audit Committee will review and obtain reasonable assurance that the financial risk management, internal control and disclosure control systems are operating effectively to produce accurate, appropriate and timely management of financial risks and financial information. This includes:

- i) review, at least annually, the financial risk management policies and practices of the Trust, COSL and other subsidiaries of the Trust as such relate to financial matters and accounting, it being recognized that the Board is responsible for the review of the overall risk management affecting the Trust, COSL and other subsidiaries of the Trust;
- ii) obtain reasonable assurance from management or external sources as deemed appropriate that the disclosure control systems are reliable and the systems of disclosure and internal controls are properly designed and effectively implemented through discussions with and reports from management, the internal auditor, if such position exists, and the external auditor, as deemed appropriate by the Committee;
- iii) review management steps to implement and maintain appropriate internal control procedures including a review of policies, including without limitation, internal controls over marketing;
- iv) monitor compliance with statutory and regulatory obligations;
- v) establish procedures for the receipt, retention and treatment of complaints received by the Trust or COSL regarding accounting, internal accounting controls or auditing matters and establish procedures so that the confidential, anonymous submission by employees regarding questionable accounting matters are handled appropriately; and
- vi) review the report from the Risk Management Committee regarding any credit risk or violations of applicable marketing policies as part of the Audit Committee's oversight of financial risk management for the Trust, COSL and any other subsidiary of the Trust.

For greater certainty, the Audit Committee will review and assess the internal controls and disclosure controls as part of the certification process regarding financial statements and financial disclosure. However, the review and overall assessment of risk management and control processes related to non-financial matters shall remain with the Board.

C. External Audit

The external auditors shall report directly to the Audit Committee. The Committee will oversee, and review the planning and results of external audit activities and the ongoing relationship with the external auditors. This includes:

- i) review, assess the performance and recommend to the Board, for unitholder approval, the appointment, retention and compensation of the external auditors;
- ii) review the annual external audit plan;
- iii) meet with the external auditors to discuss quarterly and annual financial statements of the Trust, COSL, and other subsidiaries of the Trust, as applicable, and the auditors' reports thereon;
- iv) review and report to the Board with respect to the planning, conduct and reporting of the annual audit, including but not limited to:
 - a) any difficulties encountered, or restriction imposed by management, during the annual audit;
 - b) critical accounting policies and estimates and alternatives to such policies and estimates;
 - c) any significant accounting or financial reporting issue;
 - d) the auditors' evaluation of the system of disclosure and internal controls, procedures and documentation for the Trust, COSL and other subsidiaries of the Trust;
 - e) the post audit or management letter containing any findings or recommendation of the external auditors, including management's response thereto and the subsequent follow-up to any identified disclosure or internal control weaknesses; and
 - f) any other material matters the external auditors bring to the Committee's attention;
- v) review and pre-approve the non-audit services to be provided by the external auditors' firm or its affiliates (including estimated fees), and consider the impact on the independence of the external audit; where circumstances warrant, this pre-approval may be delegated to the Chair of the Audit Committee;

- vi) meet periodically, and at least quarterly, with the external auditors without management present;
- vii) meet periodically, and at least quarterly, with management, without the external auditors present;
- viii) review any decision by COSL to hire employees or former employees of the Trust's or COSL's current or former external auditors; and
- ix) discuss and review with the external auditor, all relationships such auditor has with the Trust and COSL as part of the assessment of the independence of the external auditor, as well as the external auditor's qualification and performance and the results of any internal reviews of the external audit firm as regards to any findings of inadequacies or concerns raised by external governance or regulating bodies.

D. Internal Audit

- i) review the internal audit functions including:
 - (A) the purpose, authority and organizational reporting lines;
 - (B) the annual audit plan, budget and staffing thereof; and
 - (C) the results of the quarterly reporting memos and of the semi-annual and annual internal audit reports;
- ii) review, with the Chief Financial Officer, the Controller and others, as appropriate, the internal system of audit controls and the results of internal audits.

E. Tax

- i) review and approve any material changes to the corporate structure related to tax planning as proposed by management for the Trust and its subsidiaries; and
- ii) review all material tax issues.

F. Other

- i) review material litigation as such impacts on financial reporting;
- ii) review policies and procedures for the review and approval of directors' and officers' expenses and perquisites, including the use of corporate assets, and consider the results of any review of these

areas by an internal audit function, if available, or by the external auditors or a third party consultant, as the Committee deems applicable;

- iii) review and approve a summary of the Committee's composition and responsibilities as well as summary of any audit, audit-related and other services by the external auditors for inclusion in the public disclosure documentation of the Trust and COSL, including without limitation, any such disclosure contained in a management proxy circular;
- iv) review any related party transactions between the Trust or any subsidiary of the Trust, including COSL and the directors and officers of COSL;
- v) review any legal and regulatory matters that may have a material impact on the interim or annual financial statements that are brought to the attention of any member of the Committee or the Board;
- vi) conduct or authorize investigation into any matters within the Committee's scope of responsibilities. The Committee shall be empowered to retain independent counsel, accountants or others to assist it in the conduct of any investigation; and
- vii) approve the appointment, re-assignment or removal of the Chief Financial Officer of the Corporation, subject to the recommendation of the Corporate Governance and Compensation Committee and the final approval of the Board.

IV. ACCOUNTABILITY

The Committee shall report its discussions to the Board by either distributing the minutes of its meetings or a written summary of such discussions or by oral report at the next Board meeting. Any sensitive materials shall be kept by the Corporate Secretary and/or the Chairman of the Committee.

V. REVIEW

The Committee shall review these terms of reference each annual or, where circumstances warrant, at such short interval as the Committee deems appropriate or necessary, to determine if further additions, deletions or other amendments are required.