



Canadian Oil Sands

CANADIAN OIL SANDS TRUST

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2007

March 15, 2008

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GLOSSARY

"**AENV**" means Alberta Environment;

"**AEPEA**" means *Alberta Environmental Protection and Enhancement Act* (Alberta);

"**AEUB**" means Alberta Energy Utilities Board;

"**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. This capacity is referred to as "barrels per stream day". When required scheduled downtime and other allowances under normal operations are considered, the capacity is referred to as "barrels per calendar day". Unless otherwise stated, all references to Syncrude's productive capacity refer to barrels per calendar day;

"**cocker**" means vessels in which bitumen is cracked into light fractions and coke is withdrawn to start the conversion process of bitumen to upgraded crude oil;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 in 2001;

"**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, the successor to the AEUB;

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

"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 ventures 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, 2007;

"MSA" means the management services agreement and secondment agreement dated November 1, 2006 between Syncrude Canada Ltd. and Imperial Oil Resources Ltd., and amended and restated as of May 1, 2007;

"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;

"SCO" means the synthetic crude oil produced by Syncrude, which may be SSB or SSP or some other product type from time to time;

"SER" means the Syncrude Emissions 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, LP (5 per cent), the Corporation (31.74 per cent), and effective January 2, 2007, the Corporation (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 SCL 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 that was the successor to the AEUB and currently approved in Approval Nos. 8573 and 8250, as issued by the AEUB, 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 SCL 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;

"synthetic crude oil" means the crude oil produced by the Alberta oil sands industry, including crude oil produced by Syncrude

"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;

"Units" means the trust units of the Trust;

"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	Gigajoule
MW	Megawatt
tcf	Trillion cubic feet equivalent of natural gas

Notes: Unless otherwise specified:

- (1) all information is as at December 31, 2007;
- (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 certain financial measures that do not have a meaning under Canadian generally accepted accounting principals ("GAAP"). In prior years, we referred to free cash flow as an indicator of the Trust's ability to repay debt and pay distributions to its Unitholders. It was a measure that did not have any standardized meaning under GAAP. During 2007, we discontinued our discussions of free cash flow, and now refer to the GAAP measure of cash from operating activities, which is derived from the Trust's Consolidated Statements of Cash Flows. We also refer to the Trust's cash from operating activities on a per Unit basis, which does not have any standardized meaning under Canadian GAAP. Cash from operating activities per Unit is calculated as cash from operating activities reported on the Trust's Consolidated Statement of Cash Flows divided by the weighted-average number of Units outstanding in the period, as used in the Trust's net income per Unit calculations. This measure is an indicator of the Trust's capacity to fund capital expenditures, distributions, and other investing activities without incremental financing, allocated to our outstanding Units. In addition, the Trust refers to various per barrel figures, such as net realized selling prices, operating costs and Crown royalties, which are also considered non-GAAP measures, but provide meaningful information on the operational performance of the Trust. We derive per barrel figures by dividing the relevant revenue or cost figure by our sales net of purchased crude oil volumes in a period. Cash from operating activities per Unit and per barrel figures may not be directly comparable to similar measures presented by other companies or trusts.

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" under applicable securities laws. Forward-looking statements are typically identified by words such as "anticipate", "expect", "believe", "plan", "intend" or similar words suggesting future outcomes and in this AIF include but are not limited to statements with respect to: the expected amount of natural gas resources in the Arctic Island assets and the ability for these assets to act as a hedge against increases in natural gas costs at Syncrude; the estimated value and amount of reserves and recoverable and the time frame to recover such reserves; the estimated resources both at Syncrude and in the Arctic Islands licenses; the expectation that the Syncrude Emissions Reduction ("SER") project will significantly reduce total sulphur dioxide and other emissions; the anticipated cost and completion date for the SER project; the expected increased reliability and other benefits from the Management Services Agreement between Syncrude Canada Ltd. and Imperial Oil Resources; the expected impact of the announced and potential changes to the Alberta Crown royalties regime including the impact on Crown royalties or the ongoing negotiations between the Syncrude Participants and the Alberta Government regarding the Syncrude Crown royalty agreement; any expectations regarding the enforceability of legal rights and in particular, legal rights regarding the Alberta Crown royalty agreement; the expected level for sustaining capital in 2008 and over the long term; the amount of bitumen purchases in 2008; the expected impact on the Trust from the enacted 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 timeframe that current tax pools will allow Canadian Oil Sands to shelter income post-2010; the potential amount payable in respect of any future income tax liability; the plan to move to fuller payout of cash from operating activities; the expected realized selling price, which includes the anticipated differential to WTI crude oil to be received in 2008 for Canadian Oil Sands' product; the level and timing of growth in production volumes expected from the Stage 3 debottleneck and Stage 4 expansion projects, and whether these projects will be approved by the Syncrude Participants; the expected price for crude oil and natural gas in 2008; the expected production, revenues and operating costs for 2008 and beyond; the anticipated impact that certain factors such as natural gas and oil prices, foreign exchange rates and operating costs have on the Trust's cash from operating activities and net income; the energy consumption levels for 2008 and beyond; the anticipated timing to reach full production rates at Syncrude; 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 expected impact of any announced or future environmental or climate change legislation; the expected structure to be assumed given the federal government's tax changes in 2011; the ability to mitigate pipeline constraints in the future; intentions and expectations regarding future distribution levels; the expectation that there will not be any material funding increases relative to Syncrude's future reclamation costs or pension funding for the next few years; the belief that the Trust will not be restricted by its net debt to total capitalization financial covenant; 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 assumptions and 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 impacts of regulatory changes especially those which relate to royalties, taxation and the environment; the impact of technology on operations and processes and how new complex technology may not perform as expected; labour turnover and shortages and the productivity achieved from labour in the Fort McMurray area; uncertainty of estimates with respect to bitumen and

SCO reserves and resources; 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; the results of discussions with the Alberta Government on Crown royalties; the obtaining of required owner approvals from the Syncrude Participants for expansions, operational issues and contractual issues such as any settlement with the Alberta Government regarding Crown royalties; 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. 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 beneficially owned, or controlled, or directed, directly or indirectly and the jurisdiction of incorporation, continuance or formation of the Trust's subsidiaries as at March 15, 2008.

	Percentage of Voting Securities	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, 2007.
- (2) Effective January 2, 2007, holds a direct 36.74 per cent working interest in Syncrude (see note 4).
- (3) Markets the SCO production for the Trust and its subsidiaries outside of Canada.
- (4) Prior to January 2, 2007, the Corporation also acted as general partner and held a 75 per cent of Canadian Oil Sands Limited Partnership ("LP") units in LP with Talisman Energy Inc. ("Talisman") holding 25 per cent of LP. When the Corporation purchased Talisman's interest in LP on January 2, 2007, LP was dissolved with the 5 per cent working interest that had been held by LP now held directly by the Corporation.

GENERAL DEVELOPMENT OF THE BUSINESS

Summary

We are the largest energy trust in Canada, based on market capitalization as at March 10, 2008 of approximately \$20 billion, and the only public investment vehicle that provides a non-diversified ownership in Syncrude, a large oil sands open-pit mining project. Syncrude is located near Fort McMurray, Alberta, Canada and operates oil sands mines, bitumen extraction plants, an upgrading complex that processes bitumen into a high quality sweet synthetic crude oil, and electrical power utility plants. Syncrude's principle product is a high quality, light, sweet synthetic crude oil blend, referred to as "Syncrude™ Sweet Premium" ("SSP"), which has an average gravity of about 31° API, low sulphur content of less than 0.2 per cent and a cetane level of 38. During 2007, Syncrude transitioned its production volumes from its historical Syncrude™ Sweet Blend ("SSB") quality level to the higher quality SSP blend (see the discussion on page 18 of this AIF as to the improved qualities of SSP compared to SSB). We use the terms "synthetic crude oil" or "SCO" to refer to Syncrude's production and sales volumes in lieu of the terms SSB and SSP. The Trust's business is its indirect ownership of Syncrude and the marketing and sales of SCO 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 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. 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.

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 (“LP”). This acquisition, which closed on January 2, 2007, was for approximately \$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 LP, resulting in the full 36.74 per cent working interest in Syncrude being held directly by the Corporation. This 36.74 per cent working interest in Syncrude is the major asset of the Trust as of the date of this AIF.

Canadian Oil Sands' cash from operating activities and the distributions paid to Unitholders are highly dependent on the net selling price received for our SCO, production and sales volumes, and the operating costs and other expenses of producing SCO, 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 were 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 increase our influence over that landscape. Establishing our own marketing capability has resulted in more direct control over our marketing processes, a better understanding of our customers' needs, and enhancement of our connection with changing market dynamics. These insights have assisted us in making 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 and ancillary storage facilities to move our product will continue to be a cornerstone of the marketing department's activities.

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' Syncrude production to customers with title transfer points in the United States (the “U.S.”) as opposed to the Corporation which sells to customers with title transfer points within Canada. COSMI purchases SCO from the Corporation for resale to the customers in the U.S. and enters into U.S. pipeline and other transportation and marketing arrangements. COSMI has no employees or officers of its own and instead contracts management services from the Corporation and is allocated a portion of the overhead costs of the Corporation.

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 distributions to Unitholders; 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 pro rata share of SCO 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 and reclamation trust contributions, 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.

Following Unitholder approval; the Trust effected on May 3, 2006 a five for one Unit split by issuing to its Unitholders, four more Units for each Unit held by such Unitholder on the record date.

In 2006, Canadian Oil Sands acquired Canada Southern Petroleum Ltd. (“CSP”) for cash proceeds of approximately \$223 million. The objective of the acquisition was natural gas interests in the Arctic Islands estimated to contain approximately 0.9 trillion cubic feet equivalent (“tcf”) of natural gas, net to CSP, based on available information and third party and internal estimates. Following the acquisition, all of the issued and outstanding shares of CSP were amalgamated with two wholly-owned subsidiaries of the Corporation to form Canadian Arctic Gas Ltd. (“Canadian Arctic”). By May, 2007, CSP’s conventional oil and natural gas reserves in B.C., Alberta, Saskatchewan and the Yukon were sold in various stages to third parties leaving the Arctic Islands natural gas interests as the sole remaining significant asset of Canadian Arctic.

The acquisition of CSP was a strategic acquisition that provided Canadian Oil Sands with a unique opportunity to secure a large, long-life natural gas resource as an offset to the risk of significant future natural gas price increase impacts on its Syncrude oil sands production. On a macro-basis, the estimate in 2006 by CSP of 0.9 tcf of natural gas resource in the Arctic Island assets represents the Trust’s expected natural gas requirements to produce its share of SCO at the productive capacity rate of 129 million barrels per year for approximately 25 years. This acquisition thereby provides a long-term financial hedge against any significant increases in natural gas prices. Canadian Oil Sands financed the acquisition with bank debt and cash from operating activities.

In 2006, Syncrude completed the largest expansion project in its history, known as Stage 3. The aggregate project cost for Stage 3 was estimated at \$8.55 billion, or \$3.1 billion net to the Trust based on its 36.74 per cent ownership. The expansion was designed to increase annual Syncrude productive capacity to about 129 million barrels and enhance the product quality of our SCO to 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, for which additional retrofit work was completed. The unit was restarted in late 2006, and produced at or near its design rates at various times during 2007. However, the unit underwent maintenance in the second and fourth quarters of 2007 to remove coke deposits. While Syncrude had not anticipated such extensive maintenance on Coker 8-3 that early in its run length, various performance issues are expected when bringing a new, complex expansion such as Stage 3 into operation. The unit was also brought down for a week in December 2007 following a fire in the environmental section of the coker. The estimated repair costs as a result of the fire are not considered material, and production was resumed prior to the end of 2007. Syncrude achieved production of SSP during 2007. See the discussion on page 18 of the AIF under “Syncrude”.

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 (the “MSA”) with Imperial Oil Resources (“Imperial Oil”). The agreement has an initial term of 10 years with renewal provisions. It was effective November 1, 2006 and was further amended and restated as of May 1, 2007. Each of SCL and Imperial Oil has the option to terminate the MSA on 24 months’ notice for any reason.

Following a comprehensive onsite assessment of the Syncrude operations in the first quarter of 2007, the Syncrude Joint Venture owners approved the recommendations of an Opportunity Assessment

Team as part of the MSA. Imperial Oil began implementing the recommendations in 2007 and continues to work with Syncrude to try and establish sustained annual production of 129 million barrels, or 47 million barrels net to the Trust. Implementation of the MSA is ongoing, including the secondment of Imperial and ExxonMobil personnel to Syncrude, appointment of a new President and Chief Executive Officer and the implementation of some ExxonMobil best practices and operating systems. Pursuant to the MSA, Imperial Oil, with the support of ExxonMobil, has been providing global practices in several areas including maintenance and reliability, energy management, procurement, safety, health, and environmental performance with the goal of delivering sustainable improvement in Syncrude's operating performance.

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 SCL 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, more effective prioritization and execution of sustaining capital costs expenditures, reduced maintenance and operating costs, and other efficiencies from new business control systems, we believe that the value to be captured should exceed the fees paid. Other than as disclosed herein, the MSA 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 Syncrude Joint Venture is owned as various undivided interests by the Syncrude Participants and has produced SCO for 29 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 Chair of the Syncrude Management Committee. He is also Chair of the Board of Directors of SCL and chairs the CEO Committee of the Board of SCL. Our Chief Financial Officer is the Chair of the Audit and Business Controls sub-committee of the Syncrude Management Committee. None of the representatives of the Syncrude Joint Venture Participants on the Board and committees of SCL receives 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. Since the start up of our latest expansion, Stage 3, in the fall of 2006, Syncrude production continued to increase to 111 million barrels in 2007, compared to 94 million barrels in 2006 and 78 million barrels in 2005. This significant increase from 18 million barrels in 1979, the first full year of operations, shows the incredible growth and potential of Syncrude. The focus in 2008 and beyond is to achieve more reliable and efficient operations, so as to allow Syncrude to reach annual productive capacity of 129 million barrels gross to Syncrude. We believe that the implementation of the MSA between SCL and Imperial Oil is a significant step towards achieving this goal.

Syncrude's facilities have the design capability to produce approximately 375,000 bbls/d 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 facilities is approximately 350,000 bbls/d on average (129 million barrels annually) and is referred to as “barrels per calendar day”. Unless stated otherwise, all references to Syncrude’s productive capacity refer to barrels per calendar day.

Production volumes reflect the capacity of the Syncrude facility and the reliability of its operations. Our proved plus probable reserves life index, currently estimated at more than 37 years, provides a secure, long-term source of bitumen for the production of SCO. 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 and operating costs. An oil sands operation such as Syncrude is essentially a manufacturing business, whereby reliability is a key factor as costs are largely fixed. If the facilities can process more barrels for the same costs, per barrel costs are reduced, enhancing project economics. Therefore, production volumes have a significant impact on per barrel operating costs 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; accordingly, operating costs are also sensitive to changes in natural gas prices and natural gas volumes consumed in the production process.

Historically, our realized selling price has correlated closely to the U.S. West Texas Intermediate (“WTI”) benchmark oil price, and has also been 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 SCO product relative to Canadian dollar WTI prices. This price differential can quickly 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\$42 per barrel to a high of approximately US\$98 per barrel.

On October 25, 2007, the Alberta Government announced that it plans to introduce a new Crown Royalty regime, currently scheduled to be effective January 1, 2009 for the Alberta oil and gas industry. For a detailed discussion of the proposed changes, and the potential impacts to Syncrude and the Trust, refer to “Royalties and Taxes” in this AIF.

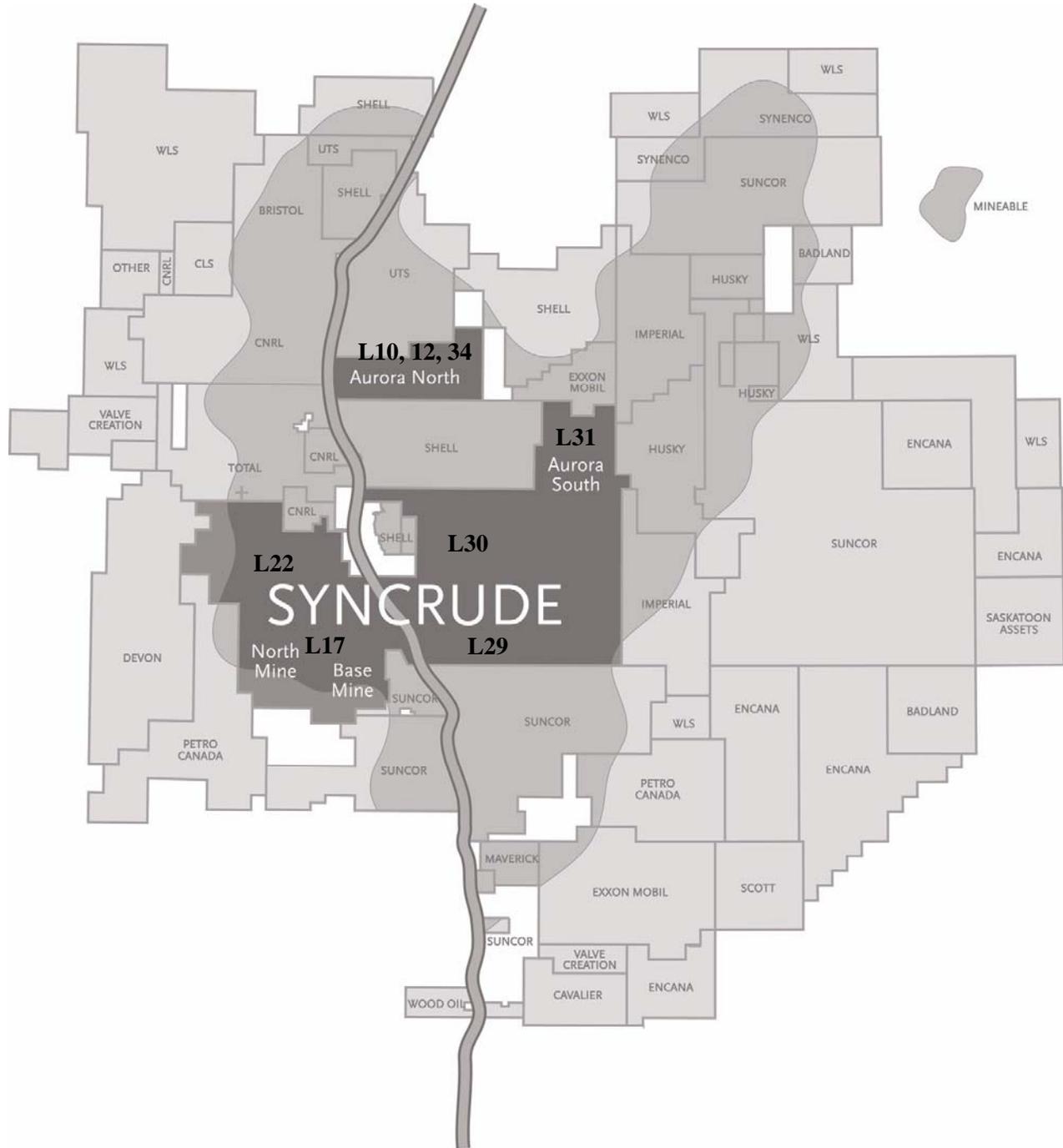
On June 8, 2007, the Corporation filed a short form base shelf prospectus qualifying an aggregate principal amount of up to \$1 billion of unsecured medium term notes. No notes have been issued to date.

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 synthetic crude oil product. Syncrude does not currently produce a slate of different heavy, light, sweet and sour crude oils. Bitumen, in its raw state, is a thick, tar-like, crude oil that requires diluent and/or 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 12.7 billion barrels of remaining estimated recoverable resources (see page 50 of this AIF for a detailed discussion of our estimate of remaining 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".

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 was the largest expansion in Syncrude's history and included 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 was enhanced to a higher quality crude oil.

The Syncrude Joint Venture expended \$8.55 billion on the Stage 3 project, which includes \$0.7 billion for Aurora 2. Net to Canadian Oil Sands, the total cost for Stage 3 is equivalent to approximately \$3.1 billion. While productive capacity increased to 350,000 bbls/d, we anticipate that a period for lining out and optimizing the different operating units will be required to ramp up to full productive capacity of 129 million barrels annually, or 47 million barrels net to the Trust.

The Syncrude Emissions Reduction Project ("SER") is being undertaken to retrofit technology into the operation of Syncrude's original two cokers and 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. While expenditures on the SER are currently estimated at approximately \$772 million (\$284 million net to the Trust based on its 36.74 percent working interest), there are indications of upward cost pressure on the project. Syncrude is currently performing a full review of the SER and we plan to provide an update to the cost estimate and timing once that review has been completed. The Trust's share of the SER project expenditures incurred to December 31, 2007 was approximately \$106 million, with the remaining costs to be incurred over the next three years to coordinate with equipment turnaround schedules. The new coker that is part of the Stage 3 expansion already includes a sulphur dioxide reduction unit. These measures are expected to reduce total sulphur dioxide emissions by up to 60 per cent from current 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 the SER.

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, can fluctuate considerably year-to-year due to timing of equipment replacement and other factors. We have estimated that Syncrude's longer-term sustaining capital expenditures will average about \$5 per barrel; however, this estimate will be impacted by inflationary cost pressures in the Fort McMurray region as well as costs for large environmental and infrastructure projects, in addition to the SER, that Syncrude expects to undertake over the next few years. These projects include the relocation of certain mining trains and tailings systems, which are required as mining operations progress across the active leases. Tailings system projects also include initiatives to improve and supplement the effectiveness of systems used to separate water from sand and clay so that the water can be recycled back to the operation and solids can be incorporated into the final reclamation landscapes. These infrastructure projects, including the SER, are expected to add about \$2 to \$5 per barrel annually to our \$5 per barrel longer-term sustaining capital expenditure estimate over the next few years. Our per barrel estimates are based on estimated annual Syncrude production, which increases from the current forecast of 108 million barrels in 2008, or 39 million barrels net to the Trust, to 129 million barrels, or 47 million barrels net to the Trust, at design capacity.

We have estimated our share of Syncrude's 2008 capital expenditures to total approximately \$279 million, of which approximately \$51 million will be directed to the SER.

Syncrude is currently in the preliminary scoping phase for two additional expansion phases to follow Stage 3. The "Stage 3 debottleneck" expansion phase is expected to be principally a debottlenecking of the facilities and is anticipated to increase productive capacity to about 139 million to 145 million barrels per year gross to Syncrude. The Stage 4 expansion phase is conceptually another coker and additional mining trains, similar to Stage 3, and may increase productive capacity to approximately 185 million barrels per year gross to Syncrude. The Stage 3 debottleneck expansion has received regulatory approval and the Stage 4 expansion has received partial approval. As part of the Syncrude Participant's approval of the MSA, the Syncrude Participants reconfirmed their commitment to undertake preliminary design work on both the Stage 3 debottleneck and Stage 4 expansions. However, the plans for these projects are preliminary and have not been approved by the Syncrude Participants, and as such, may change. Due to the early stage of development, no cost estimates have been provided for either of these projects.

NARRATIVE DESCRIPTION OF THE BUSINESS

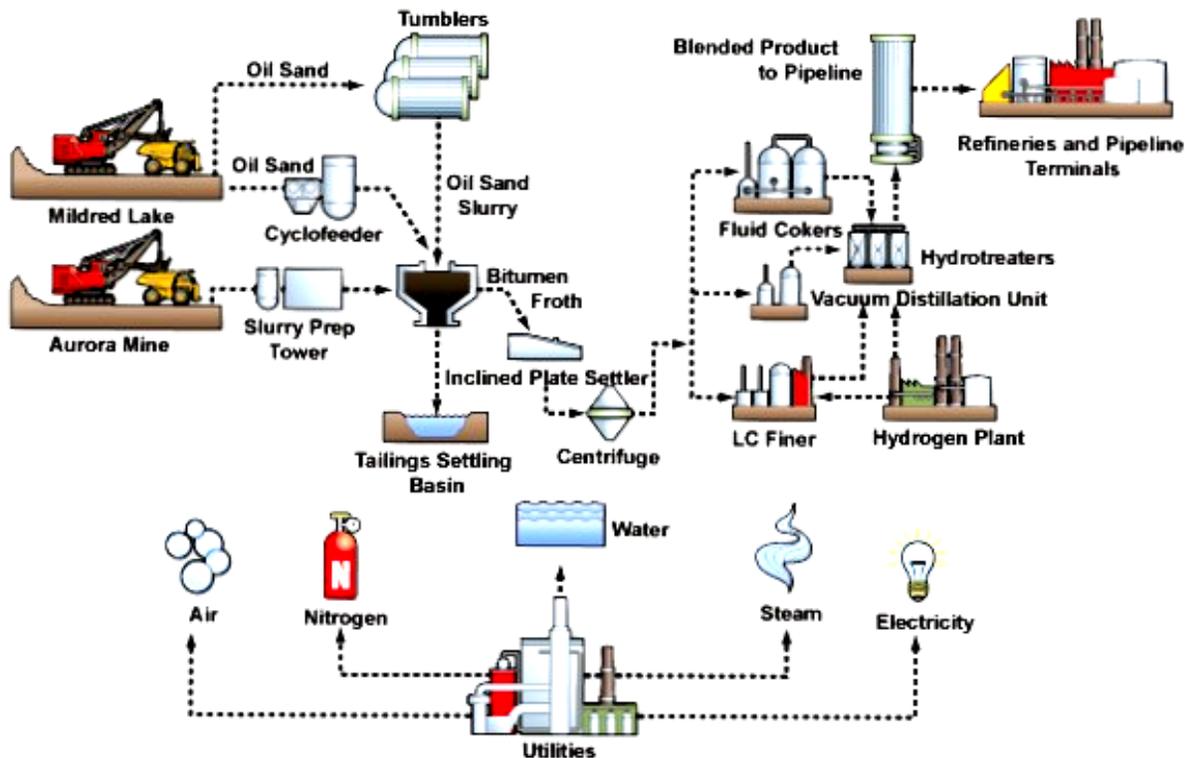
Syncrude is a vast and complex operation. The mines and extraction facilities are among the largest in the world, and the upgrading plants, which could be considered similar in nature to oil refineries, are also among the largest and most complex in the world. As such, a very strong focus on the basics 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 2007, Syncrude re-achieved its best ever safety performance record set in 2005 with a lost-time injury ("LTI") rate of 0.05 per 200,000 workforce hours, including permanent and contract workers (2006 – 0.15 per 200,000; 2005 – 0.05 per 200,000).

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 been challenged with reliability and performance issues at a time when a very complex and large scale construction project was ongoing with the Stage 3 expansion. Currently, with no significant growth projects underway, the Syncrude Participants have directed SCL to focus on ongoing reliability and performance issues. Safe, reliable operational performance is key to achieving lower per barrel operating costs. The ongoing implementation of the MSA between SCL and Imperial Oil remains a key component of the commitment made by the Syncrude Participants' to achieve this improved reliability.

Maintenance work has a key impact on Syncrude's operations and, consequently, on the cash from operating activities 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. During these times, productivity of the mining operations may be reduced, resulting in temporary decreases of internally produced bitumen. Third party purchased bitumen supply will support increased production during times when excess upgrading capacity is available. Syncrude is focused on improving reliability in the mining operations to meet the rising needs of the upgrader as production is increased to design capacity rates. We currently estimate third party purchased bitumen volumes in 2008 will be less than five percent of total supply at Syncrude and, therefore we do not anticipate such purchases to have a material impact on Syncrude's production, and correspondingly, our financial results.

The Syncrude Operations



Mining

Syncrude currently mines oil sands from two mines: The North Mine, located near the Mildred Lake site, and the Aurora North Mine, located 35 kilometres northeast of the base operations site. During 2006 and 2007, ore extraction was phased out of Syncrude's original Base Mine. 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 mining industry, is known as "truck and shovel" mining. The larger shovels can excavate 100 tonnes 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 and was closed in 2007. The North Mine began operations in 1997 and Aurora North Mine in 2000. 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. The Aurora North mine contributed 55 per cent of the total bitumen produced from Syncrude in 2007 (2006 – 58 per cent) and the North mine contributed 45 per cent (2006 – 31 per cent). The Base Mine did not contribute any bitumen in 2007 (2006 – 11 per cent).

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 2007, the total volume of overburden mined was approximately 226 million tonnes compared to 214 million tonnes in 2006.

Since its completion in 2005, the South West Quadrant Relocation 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; and provided additional thermal energy sources at Aurora North by adding a second 80MW gas turbine generator and heat recovery hot water generator. This additional mining capacity has served to offset the phased out production from the Base Mine.

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 have changed.

The ore from the Supplemental Mining System at the North Mine is delivered to the Mildred Lake extraction facilities by conveyor and is then mixed with steam, hot water and caustic soda to produce 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, the ore is crushed in a double roll crusher, and 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.

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 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 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. The primary froth rises, is recovered and is then piped to Mildred Lake for further processing.

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 began application 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 2007, this recovery factor was approximately 92 per cent (2006 – 90 per cent). 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 SCO. 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 bbls/d 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 bbls/d.

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 2007, each had a nominal capacity rating of approximately 105,000 bbls/d 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 95,000 bbls/d 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 2007, the LC Finer unit had a nominal capacity rating of approximately 50,000 bbls/d 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 2007, the upgrading yield was approximately 84 per cent, basically unchanged from 2006.

The lighter hydrocarbon components produced by the three 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 and nitrogen. 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 SCO. This SCO 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 129 million barrels of SCO per year by the end of 2006 (unchanged for 2007) compared to 90 million barrels of SCO per year in 2005. Actual production of SCO in 2007 was 111 million barrels, a significant increase from prior years. Production of SCO was 94 million barrels in 2006 and 78 million barrels in 2005.

With the start up of the new Stage 3 plants in August 2006, the quality Syncrude's finished synthetic crude oil blend was improved and re-designated SSP, short for Syncrude™ Sweet Premium. SSP is designed to have a diesel cetane number of approximately 38, up from the previous number of approximately 33, and the jet smoke point of approximately 19, up from 16. Our recent expectation was that the quality transition to SSP would occur in 2008 following repairs to the new hydrogen plant. However, the transition occurred in 2007, earlier than expected, as a result of the removal of some hydrogen constraints on various units. New hydrogen plant repairs are still expected to occur in 2008 to secure additional hydrogen feedstock for the continued production of SSP for when the operations reach design capacity rates.

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 SCO. In 2007, the purchased energy intensity was 0.84 GJ per barrel compared to 2006 which was 0.98 GJs per barrel. The increased consumption of 0.98 GJ's per barrel in 2006 was 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. The 2007 energy intensity reflects a full year of Stage 3 volumes. 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, is used to produce the higher quality SCO 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 remoteness from the Mildred Lake plant. Purchased natural gas prices decreased to \$6.14 per GJ in 2007 compared to \$6.26 per GJ in 2006.

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 tank farms, 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 plants at the Aurora North mine site that provide electrical and thermal energy for the Aurora North mine operations. These plants 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 the required 35°C temperature.

Marketing

Each Syncrude Participant is responsible for marketing its own share of SCO and associated by-products, such as sulphur. After upgrading, the SCO is transported to markets in Canada and the U.S. through a system of inter-connected pipelines and storage locations. SCO is sometimes processed in refineries that have been specifically designed to benefit from SCO'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 U.S. Most refineries produce motor gasolines, diesel fuels, heating oils, and jet fuels. Others can also produce asphalts, lubricants and petro-chemicals. There are three refineries in or near Edmonton, Alberta

which have 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.

Beginning in 2003, significant additions of synthetic crude oil production have come on-line, impacting where SCO was ultimately consumed. The production of synthetic crude oil from projects in the Fort McMurray, Edmonton and Hardisty areas of Alberta is expected to continue to increase over the next several years. As additional volumes of synthetic crude oil come into the market, our sales are made to a broader group of refineries than was historically the case. In 2004, more of our production was consumed downstream from Edmonton, Alberta to Eastern Canada and the U.S. than in the past. The trend continued in 2005, 2006 and 2007. 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 production in the Fort McMurray and surrounding area increases, that we will continue to see a greater percentage of our production being consumed outside of Western Canada given the limited refining capacity in that area.

The growing production of bitumen in Alberta has necessitated the need for additional diluents to thin the 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. Synthetic crude oil has emerged as one of those new sources of diluent. 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 U.S.

The vast array of pipeline and storage systems for the transportation of crude oils across Canada and the U.S. 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 oil 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 SCO sales prices and production, or both.

Canadian Oil Sands takes title to SCO at Syncrude's plant gate and then the SCO is transported by a pipeline dedicated for use by the Syncrude Participants from Fort McMurray to Edmonton at which point, our SCO volumes are sold or arrangements are made for further transportation. From mid-2001 to mid-2006, EnCana marketed our share of SCO production pursuant to a marketing agreement. During 2006, the marketing agreement with EnCana was not renewed and effective August 31, 2006 we began marketing our own production. Per barrel marketing costs as compared between 2007 and 2005 were reduced (excluding initial implementation costs). We believe that internalizing marketing has provided greater insight into our customer needs and assisted 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 and 2007. 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 have transitioned all of our production to SSP. This enhanced SSP product promises greater market potential with higher distillate cetane and smoke point characteristics compared to SSB. 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. We had anticipated that SSP's improved cetane level and jet fuel smoke point relative to SSB would enable some of our existing refinery customers to increase the amount of Syncrude production they process, and thereby contain transportation costs as our production would not have to move as far to clear the market. Early indications seem to support this expectation based on increases in certain refinery customers' demand for our product in the fourth quarter of 2007. Since Syncrude does not produce both products concurrently, it is not possible to determine if our new SSP volumes attract or will attract a premium price over our SSB product.

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 usually 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.

Syncrude also removes sulphur as part of its upgrading process. Currently, the majority of this sulphur is stockpiled at Syncrude's Mildred Lake plant site. 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 the Trust entered an agreement with a major sulphur marketer to sell our share of Syncrude's sulphur production. The agreement provided for the sale of sulphur once certain port infrastructure was constructed, if the price exceeded an established minimum plant gate price. The construction of port infrastructure has been delayed pending approvals and project support. Sales under this contract may begin in 2009 if the buyer proceeds with the construction of the port infrastructure later this year. In the meantime, interim sales are also accruing from time to time for smaller volumes of sulphur.

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 were, and continue to be, impacted by the labour shortage both on the cost and scheduling aspects. The rate of labour turnover at Syncrude increased again in 2007 compared to 2006 driven largely by the retirement demographics of an aging workforce at SCL and the migration of other employees to competing projects.

Seasonal Factors

As the Syncrude Project is located in Northern Alberta, 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 and capital costs as demonstrated by the operational upset that occurred in January 2008. Quarterly variances in revenues, net income, and cash from operating activities are caused mainly by fluctuations in crude oil prices, production and sales volumes, operating 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, unit operating costs are highly variable to production volumes. 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. Syncrude maintenance and turnaround activities are typically scheduled to occur in the first or second quarter. However, the exact timing of unit shutdowns cannot be accurately scheduled, and unplanned outages will occur. As a result, production levels also may 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 per barrel operating costs of \$30.13 in the second quarter of 2007 and \$40.26 in the first quarter of 2006. Natural gas prices are typically higher in winter months as heating demand rises, but this seasonality is significantly influenced by weather conditions and North American natural gas inventory levels.

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, services and labour. We anticipate that these inflationary pressures will continue in light of the significant level of expected oil sands activity over the next several years.

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 SCO 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, the maximum term permitted by this legislation. The renewal or modification of approvals generally involves 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 was issued in June 2007 and is effective until June 23, 2017. In the approval, the AEPEA has stipulated revised parameters for soil salvage, soil placement thickness and soil layering requirements as part of Syncrude's reclamation obligation. This was the primary reason for the 31 per cent increase in the Corporation's asset retirement obligation from December 31, 2006 to December 31, 2007 (see below).

Syncrude Participants, including Canadian Oil Sands, are liable for their share of ongoing environmental obligations for the ultimate reclamation of the Syncrude Joint Venture properties. 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 (ARO liability) on our Consolidated Balance Sheet as an increase to capital assets and as an ARO liability. The depreciation expense on the asset and the accretion expense on the obligation are recorded in depreciation, depletion and accretion expense. At December 31, 2007, the ARO liability recorded on the Consolidated Balance Sheet was approximately \$226 million, a 31 per cent increase from the \$173 million recorded at December 31, 2006. As noted above, the increase is primarily due to the changes required under the new AEPA approval. Canadian Oil Sands' share of Syncrude cash reclamation expenditures was about \$1 million in 2007 and \$2 million in 2006, 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 2007 annual report.

Since the inception of the Syncrude Project, the Syncrude Joint Venture is required to post annually with the AENV irrevocable letters of credit equal in amount to \$0.03 per barrel of SCO produced from the Base Mines since inception of the Syncrude Project plus estimated reclamation costs relating to the Aurora North Mine to secure the ultimate reclamation obligations of the Syncrude Project. As at December 31, 2007, Canadian Oil Sands had posted letters of credit with the Province of Alberta in the amount of \$61 million in 2007 compared to \$49 million in 2006, to secure its pro rata share of the ultimate reclamation obligations of the Syncrude Participants.

In 2007, site reclamation expenditures totaled \$1.8 million (2006 - \$6.3 million) and approximately 86 hectares of land (2006 - 312 hectares) 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, 2007, 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 since 1978. A significant portion of the land that has been reclaimed by Syncrude 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 SCO produced and attributable to our 36.74 per cent working interest to a 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. As at December 31, 2007, we have accumulated (including interest earned on contributions), \$37 million towards future reclamation in the reclamation trust. In 2006, this amount was \$30 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 believes that it is currently 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 SCO 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.

A number of environmental regulations focus on limiting the emissions of gases and other substances from the Syncrude operations. In 2007, the Alberta government's Specified Gas Emitters Regulation under the Climate Change Emissions Management Act came into effect. The regulation requires that facilities emitting more than 100,000 tonnes of GHGs per year ("Large Emitters") must reduce their greenhouse gas ("GHG") emissions intensity by 12 per cent over the average emissions intensity levels of 2003, 2004 and 2005. If the emissions intensity target is not met through improvements in operations, compliance tools include: per tonne payment into the climate change and emissions management fund; purchase of Alberta based offsets; or purchase of emission performance credits from a different Alberta facility. The charge payable to the fund is \$15 per tonne for every tonne above the 12 per cent target, beginning July 1, 2007.

These payments will be deposited into an Alberta-based technology fund for developing infrastructure to reduce emissions or support research into climate change solutions.

In the last six months of 2007, Syncrude accrued approximately \$0.19 per barrel for compliance with the Specified Gas Emitters Regulation, which is reflected in the Trust's operating costs. The cost estimate remains preliminary pending Syncrude's actual CO₂ emission intensity level and clarification from the Alberta Government regarding details of the implementation of the legislation, the calculation of the base-line emissions target and the actual 2007 emissions measurements. No cost estimates are available yet for future years.

On April 27, 2007 and March 10, 2008, the federal government released and enhanced, respectively, the Regulatory Framework for Air Emissions (the "Framework") which also sets out new GHG and air pollutant emission reduction targets. The Framework establishes an emission-intensity reduction target for existing facilities of six per cent per year to 2010, resulting in an initial enforceable reduction of 18 per cent from 2006 emission-intensity levels starting in 2010. Every year thereafter, a two per cent continuous emission-intensity improvement will be required. Oil sands mines and upgraders which begin operations between 2004 and 2012 (including major expansions, defined as increasing capacity by at least 25%) will be required to make a "clean fuel standard" emissions intensity reduction in

addition to the initial 18 per cent reduction. Further, upgraders or major expansions to upgraders which begin operations in 2012 or later will be required to have an emissions intensity profile equivalent to that of a facility employing carbon capture and sequestration technology. In addition to GHGs, the Framework also contemplates reductions in air pollutants such as nitrogen oxides (NOx), Sulphur Oxides (SOx), Volatile Organic Compounds (VOCs), and Particulate Matter (PM) post-2012. Compliance with the new requirements would allow contribution to a technology fund until 2017 at a rate of \$15 per tonne from 2010 to 2012, increasing to \$20 per tonne and escalating by the rate of GDP growth from 2013 to 2017. Maximum compliance can be met through contributions to the technology fund of up to 70 per cent in 2010 declining to 10 per cent by 2017. After 2017, contributions to the technology fund are no longer possible, and an emissions trading market is envisioned.

The federal government's Framework formed the basis for public consultations, with draft regulations anticipated to be released in 2008. Specifics regarding implementation of the Framework and harmonization between the Framework and Alberta's regime remain unresolved, making it difficult for Canadian Oil Sands to provide an accurate estimate of the cost impact for compliance with the proposed federal regulations: However, the Framework is a challenging plan that could have a significant adverse effect on operating costs and/or require significant capital investment.

American legal and regulatory regimes regarding emissions and environmental protection may also impact the Trust. Environmental legislation in importing jurisdictions in the U.S. may directly affect costs associated with sales of Syncrude production in those jurisdictions. For example, legislation regulating carbon fuel standards in California and other states could result in increased costs to the Trust, if purchases of emission permits or credits are required in order to effect sales in those jurisdictions. The legal and regulatory regimes applicable to American refineries may also have significant, indirect consequences on Canadian Oil Sands' marketing of Syncrude products to the extent that the capacity of refining companies to handle Syncrude products is negatively impacted.

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 industry, in particular. Currently, no guidelines or recommendations have been issued by such regulatory review body, and as a result, we cannot assess the impact of any such proposals on our operations. Syncrude currently operates well within its water license limits and recycles approximately 85 per cent of its water usage.

Refer to the "Risk Factors" section of this AIF for a description of the risks associated with the various Environmental Regulations to which Syncrude is subject.

Regulation of Operations

In Alberta, the regulation of oil sands operations is now undertaken by the ERCB, which replaced the AEUB effective January 1, 2008. The ERCB derives its jurisdiction, in part, from the *Oil Sands Conservation Act* (Alberta). In addition to requiring certain approvals prior to the operation of an oil sands project, the *Oil Sands Conservation Act* (Alberta) allows the ERCB 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 ERCB.

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 2007 and 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. We acknowledge the role this regime has played in enabling us to proceed with the expansion of Syncrude's facilities.

On October 25, 2007, the Alberta Government announced that it plans to introduce a new Crown Royalty regime, currently scheduled to be effective January 1, 2009, for the energy sector. The new royalty regime for oil sands projects is to be based on a sliding scale royalty rate that responds to WTI oil price levels. The pre-payout rate is proposed to start at one per cent of revenue and increase for every dollar WTI oil is priced above \$55 per barrel, to a maximum of nine per cent of revenue when WTI oil is priced at \$120 per barrel or higher. The royalty applied post-payout will start at 25 per cent of net revenue and increase for every dollar WTI oil is priced above \$55 per barrel up to a maximum of 40 per cent of net revenue when WTI oil reaches \$120 per barrel or higher. In addition to the revised royalty rates, the announced changes also note the Alberta Government's possible intention to take bitumen production in kind in lieu of Crown Royalty payments.

The Syncrude Joint Venture owners have a Crown Agreement with the Alberta Government that codifies the current royalty terms of 25 per cent of net revenues to December 31, 2015. The Agreement also provides Syncrude with a one time option prior to 2010 to convert from a royalty based on synthetic crude oil to a bitumen based royalty consistent with the rest of the Alberta oil sands industry. Under the Crown Agreement, a royalty based on crude bitumen shall provide for recapture by the Crown of the remaining value of costs previously deducted relating to upgrader growth capital in accordance with an amortization methodology agreed to by the parties.

The Syncrude owners are currently assessing the merits of exercising the option to convert to a bitumen based royalty, which is dependent upon certain items being clarified, including the upgrader growth recapture amount and amortization methodology. A methodology to value crude bitumen is also required as the Syncrude owners do not sell bitumen into the market place. The Province of Alberta, with input from industry, is considering bitumen valuation methodologies and has indicated that it intends to establish and implement a bitumen valuation methodology (“BVM”) in 2008 that is based on a reference price (or a weighted average reference price) from one or more liquid, transparent, arm’s-length Canadian heavy oil markets with adjustments to recognize differences in quality between the product represented by the selected market and the Bitumen from each particular source of Bitumen subject to the Crown Royalty, and adjustments to recognize transportation and handling costs of Bitumen and diluent. The Crown presently intends that the BVM may include a provision pursuant to which the Crown is entitled to increase the BVM price for royalty purposes if the Canadian heavy oil market prices are suppressed relative to North American heavy oil market prices as a result of a temporary disconnect between Canadian heavy oil and North American heavy oil market prices.

Canadian Oil Sands, as one of the Syncrude owners, is currently in discussions with the Alberta Government regarding both the conversion to a bitumen-based royalty and an equitable solution to offset Syncrude’s transition to the higher generic royalty rate prior to 2016. Canadian Oil Sands is of the view that any transition to the new generic royalty terms must recognize our legal rights to the embedded value in Syncrude’s contract with the Alberta Government. Any amendment to the current Crown Royalty agreement with the Alberta Government requires the agreement of all the Syncrude owners, not just a majority of those Syncrude owners. The Alberta Government has stated that in the event an agreement cannot be reached, the Alberta Government will take other measures to ensure a level playing field for all industry stakeholders. Until uncertainties regarding the conversion to a bitumen based royalty and the new regime and associated economic issues are resolved, Canadian Oil Sands cannot fully assess the long term impacts on the Syncrude Project’s royalty expense.

Taxation of Syncrude-related income follows normal resource industry practices with a few important differences. As Syncrude is a mining operation, there are certain provisions that are unique, such as the accelerated capital cost allowance (“ACCA”) up to the income from a mine for class 41(a) assets which applied to new mines or a major expansion of an existing mine where there was 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, are also eligible for ACCA for such expenditures over the five per cent threshold included in class 41 (a.1). The federal government, in its March 19, 2007 budget, enacted the phase out ACCA for oil sands projects. The current ACCA will continue to be available for assets acquired before March 19, 2007 and for assets acquired before 2012 that are a part of projects where major construction commenced prior to March 19, 2007. Other assets will still be eligible for ACCA but will be subject to phase-out rates between 2012 and 2015. The standard 25 per cent CCA rate will continue to apply after 2015.

On June 12, 2007, the new trust taxation rules previously announced by the Canadian federal government on October 31, 2006 were substantively enacted as Bill C-52. As a result, a 29 per cent tax will be applied to distributions from the Trust beginning in 2011, reducing to 28 per cent of distributions in 2012. Additional proposed changes announced by the Canadian federal government may reduce these rates further to 25 per cent. In response to the income trust tax changes, Canadian Oil Sands continues to evaluate alternatives as to the best structure for its Unitholders in the future. In Alberta where the Trust is registered, a corporation is subject to a lower overall tax rate than the rate that will apply to income trusts post-2010. The federal government has confirmed that it intends to allow conversions from a trust to a corporate structure to occur on a tax-deferred basis, although the rules of such a conversion have yet to be established. Under current expectations, we expect to convert to a corporate structure. We plan however, to retain the flow-through advantages of a trust structure until 2011, unless circumstances arise that favour a faster transition to an alternate structure.

Employees

As at December 31, 2007, the Corporation employs 16 full-time and 4 part-time employees and one consultant. The Trust has no employees.

At the end of 2007, as the operator of the Syncrude Project, SCL employed approximately 4,700 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.

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 and expected 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 U.S.; 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 SCO. 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 high 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 for non operational reasons 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 its ability to pay distributions and to repay its debt obligations.

Distributions ultimately made by Canadian Oil Sands to its Unitholders are expected to be adversely impacted by changes to the taxation of income trusts and changes to the accelerated capital cost allowance classes by the federal government

The new tax changes will ultimately have a material adverse impact on the cash available for distributions to Unitholders after the transition period in 2011 (Namely, distributions of non-portfolio earnings would not be a tax deduction to the Trust, 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 trust tax announcement resulted in a substantial decline in the market value of trust units generally. In response to these changes, and based on current expectations, Canadian Oil Sands will likely convert to a corporation. We will also consider other options that may emerge based on further information from the federal government regarding transition rules. Implications of pending changes are difficult to evaluate without further clarification from the federal government and no assurance can be provided regarding the outcome of the transition.

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

Refer to the "Royalties and Taxes" section of this AIF for a detailed discussion of the current royalty issues impacting Syncrude and Canadian Oil Sands.

Our results of operations are directly affected by the provincial government's fiscal regimes applicable to the Syncrude Project. The Syncrude Joint Venture owners are party to a Crown Agreement with the Alberta Government that codifies the current royalty terms of 25 per cent of net SCO revenues to December 31, 2015. The Crown Agreement also provides Syncrude with the option to convert to a bitumen-based royalty, consistent with the rest of the industry, prior to 2010. Canadian Oil Sands, as one of the Syncrude owners, is currently in discussions with the Alberta Government regarding both the conversion to a bitumen-based royalty and an equitable solution to offset Syncrude's transition to the higher generic royalty rate prior to 2016.

Canadian Oil Sands believes that any transition to the new generic royalty terms must recognize and preserve our legal rights to the embedded value in Syncrude's contract with the government. However, the Alberta Government has stated that in the event agreement cannot be reached, it will take other measures to ensure a level playing field for all industry stakeholders. Until current uncertainties regarding the conversion to a bitumen based royalty (including without limitation the establishment of a bitumen valuation methodology and the determination of upgrader growth capital recapture), the terms

and timing of the transition to the new regime (including without limitation the resolution of the ongoing negotiations with the Alberta Government, further clarification regarding the government's intentions to potentially receive bitumen in kind in lieu of cash payments, and further clarification of certain items announced as part of the new regime), and the associated economic issues are resolved, Canadian Oil Sands cannot fully assess the long term impacts on the Syncrude Project's royalty expense.

Even if the Syncrude owners are able to reach an agreement with the Alberta Government, there can be no assurance that there will not be further changes to the Province of Alberta's regimes beyond those already announced.

Canadian Oil Sands may be impacted by risks inherent in the execution of and/or integration of a major project into existing operations.

There are certain risks associated with the execution of Syncrude's major projects, including without limitation, 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 Wood Buffalo Region, 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 is 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 2008 and beyond. 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 crude oils 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 have had 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 Wood Buffalo Region area has put pressure on recruiting, training and retaining the necessary personnel 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 MSA 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.

The increase in world mining and manufacturing activity 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. If Syncrude cannot obtain such materials for 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 SCO 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 tight. In addition, planned or unplanned shutdowns of our refinery customers may limit our ability to deliver our SCO 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 to Eastern Canada and the U.S. As such, pipeline access and capacity, transportation tariffs and price differentials with competing products are all factors which can affect sales volumes for SCO 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, Alberta 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 a higher quality product 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 bbls/d 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 SCO. As the Syncrude operations involve use of water and the emission of sulphur dioxide and greenhouse gases such as CO₂, legislation which significantly restricts or penalizes current production levels would have a material impact in our operations. While Syncrude is focused on reducing these emissions on a per barrel basis, no assurance can be given that existing or future environmental regulations (see pages 22 to 25 of this AIF) 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 SER, which is designed to reduce the amount of sulphur dioxide produced on both a per barrel and absolute annual basis. These reductions would be in addition to reductions in sulphur dioxide emissions from the sulphur scrubbing technology that is part of the Stage 3 facilities. 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 planned 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. Syncrude's current cost estimate of \$772 million for the SER is under review. There can be no assurance that the revised cost estimate will not be exceeded.

There are 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. 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 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. Any proposed legislation which significantly restricts or penalizes current production levels would have a material negative impact on our operations.

American legal and regulatory regimes regarding emissions and environmental protection may also impact the Trust. Environmental legislation in importing jurisdictions in the United States may directly affect costs associated with sales of Syncrude production in those jurisdictions. For example, legislation regulating carbon fuel standards in California and other states could result in increased costs to the Trust, if purchases of emission permits or credits are required in order to effect sales in those jurisdictions. The legal and regulatory applicable to American refineries may also have significant, indirect consequences on the marketing of Syncrude products to the extent that the capacity of refining companies to handle Syncrude products may be negatively impacted.

Syncrude produces a significant volume of fine tailings, which are presently held in a settling basin. Syncrude's closure and reclamation plan and thus its EUB approval depends on the use of consolidated tails ("CT") technology to manage tailings fluids and solids associated with bitumen production. As this is developmental technology, there is an inherent risk that the CT technologies used by Syncrude and most other oil sands producers may not be as effective as desired or perform as required in order to meet the approved closure and reclamation plan. While Syncrude continues to develop CT technologies and investigate alternative tailings management technologies, there is a risk of increased costs to develop and implement various measures and the potential for tailings specific regulatory approval conditions to be attached to future regulatory applications and/or renewals.

American climate change legislation could negatively affect markets for crude and synthetic crude oil

Environmental legislation in importing jurisdictions in the United States regulating carbon fuel standards could result in increased costs and/or reduced revenue to the Trust. For example, both California and the United States federal government have passed legislation which, in some circumstances, considers the lifecycle greenhouse gas emissions of purchased fuel and which may negatively affect marketing of Syncrude products, or require the purchase of emissions credits in order to affect sales in such jurisdictions.

The implementation of federal climate change legislation could increase Syncrude's operating costs

The Kyoto Protocol came into effect on February 16, 2005, and the federal Regulatory Framework for Air Emissions was proposed on April 27, 2007 and an enhanced version was released on March 10, 2008. The proposed Regulatory Framework provides details of proposed regulations which will require emissions intensity reductions, including an additional "clean fuel standard" emissions intensity requirement specific to upgraders and in situ oil sands operations commencing operation between 2004 and 2012. Also specific to upgraders and in situ oil sands operations commencing operations after 2012 is the requirement to meet a carbon capture and sequestration technology emissions intensity standard.

Numerous uncertainties regarding details of the implementation of both the Kyoto Protocol and the proposed federal Regulatory Framework remain, as well as harmonization with the Alberta Specified Gas Emitters Regulation, make it difficult to ascertain the cost estimate of climate change legislation compliance, including when third party costs 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, subsequent legislation related to the Kyoto Protocol or the proposed Regulatory Framework will not be significant, which could result in a material adverse effect on our financial condition or our results of operations.

The benefits and expected results from the MSA may not materialize

The MSA may be cancelled by either SCL or Imperial Oil on 24 months notice. In addition, 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 exposure to financial market risk

Canadian Oil Sands is subject to financial market risk as a result of fluctuations in foreign currency rates, interest rates and liquidity.

Foreign Currency Risk

Canadian Oil Sands' results can be significantly affected by fluctuations in the U.S./Canadian currency exchange rates as we generate revenue from oil sales based on a U.S. dollar WTI benchmark price, while operating costs and capital costs are denominated primarily in Canadian dollars. Over the last two years, the Canadian dollar has experienced significant volatility, ranging from a low of \$0.84 US/Cdn in February 2007 to a high of \$1.09 US/Cdn in November 2007. Our revenue exposure is partially offset by U.S. dollar obligations, such as interest costs on U.S. dollar denominated debt and our share of Syncrude's U.S. dollar vendor payments. In addition, when our U.S. Senior Notes mature, we have exposure to U.S. dollar exchange rates on the principal repayment of the notes. This repayment of U.S. dollar debt acts as a partial economic hedge against the U.S. denominated revenue payments we receive from our customers.

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.

Interest Rate Risk

Canadian Oil Sands' results, and in particular our net interest expense, are impacted by U.S. and Canadian interest rate changes as our credit facilities and investments are exposed to floating interest rates. At December 31, 2007 the Trust had \$16 million drawn on its credit facilities, but no other floating rate debt was outstanding. The Trust did not have a significant exposure to interest rate risk in 2007 based on the amount of floating rate debt or investments outstanding during the year.

Liquidity Risk

Liquidity risk is the risk that Canadian Oil Sands will not be able to meet its financial obligations as they fall due. Canadian Oil Sands was in full compliance of its debt covenants as at December 31, 2007.

In the next several years, two tranches of Canadian Oil Sands' debt will mature. As well, Canadian Oil Sands has stated its intention to increase net debt to approximately \$1.6 billion. Therefore, Canadian Oil Sands will be subject to liquidity and interest rate risk in the coming years in respect of

these financing requirements. In addition, we are exposed to liquidity risk to the extent we have financing requirements related to significant capital or operating commitments.

During 2007 the U.S. experienced a number of economic crises related to subprime lending and structured finance products which also impacted financial markets within Canada. One of the results was a tightening of North American credit markets characterized by a decline in liquidity and higher borrowing costs. Canadian Oil Sands has not been materially affected by this situation and we believe that the capital markets are still available to finance our obligations. There can be no assurance that this will continue to be the case.

Capital projects may experience cost overruns

Inherent in the mining of oil sands and production of synthetic crude oil is a need to make substantial capital expenditures. Inflationary pressures in the mining industry in general, and the Fort McMurray area specifically, are resulting in higher costs. This cost pressure impacts capital expenditures associated with expansion projects and sustaining capital expenditures. Further, there is a risk that maintenance at Syncrude will be required more often than currently planned or that significant capital projects could arise that were not previously anticipated. Canadian Oil Sands often provides estimates of costs for major projects. These projects typically evolve over time and we often provide estimates at various points from the conceptual stage, through to final scope design and detailed engineering. Updates are also often provided during project construction. At each stage, cost estimates involve uncertainties. Accordingly, actual costs can vary from estimates and these differences can be significant.

There is also a risk associated with providing cost estimates for major projects. Canadian Oil Sands often provides estimates for Syncrude's major projects, which encompass the conceptual stage through to final scope design, including detailed engineering cost estimates. However, these projects typically evolve over time and updates for significant timing and cost estimate changes are often required during project construction. At each stage of these major projects, cost estimates involve uncertainties. Accordingly, actual costs can vary from these estimates and these differences can be significant.

Canadian Oil Sands may not have the 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 SCO. There is no assurance that capital cost overruns will not occur, 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. As noted in "Liquidity Risk", there can be no assurance that such public debt and equity markets would be available to Canadian Oil Sands.

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 SCO. Since essentially the sole source of income to Canadian Oil Sands is the sale of SCO, 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 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 SCO 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 and labour required for it to continue production.

As the Syncrude Project is our only material producing asset, if a terrorist or other third party 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 ability 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 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. Moreover, there are regulatory and economic risks associated with the emerging technologies required to economically and feasibly produce SCO at the Syncrude Project. For example, there are limited assurances that current reclamation technologies associated with the fine tailings will achieve current objectives, which may result in new investments in research as well as more stringent involvement by regulators. As such, there may be greater technological risks. 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 SCO.

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 SCO. 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.

An increase 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 primarily for the production of hydrogen and to a lesser extent 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, monthly average natural gas prices have also experienced significant movements over the last three years, from a high of approximately AECO \$12 per GJ during November 2005 to a low of approximately AECO \$4.22 per GJ during October 2006. To the extent crude oil prices and natural gas prices move together, the risk of natural gas price increases 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 increase relative to crude oil prices. The Trust has previously used hedge positions to mitigate natural gas price risk and will continue to assess the strategy as a means to manage short-term operating costs. No natural gas hedges were utilized in 2007, 2006 or 2005, and as at March 15, 2008, we have no natural gas hedges in place.

While the natural gas resource is not currently in production and there are no development plans at this time, the 2006 acquisition of CSP's natural gas interests, which are estimated to have approximately 0.9 tcf of natural gas resource, provides Canadian Oil Sands with a partial long-term hedge against significant future natural gas price increases.

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.

Environmental legislation in importing jurisdictions in the United States regulating carbon fuel standards could result in increased costs and/or reduced revenue to the Trust. For example, both California and the United States federal government have passed legislation which, in some circumstances, considers the lifecycle greenhouse gas emissions of purchased fuel and which may negatively affect marketing of Syncrude products, or require the purchase of emissions credits in order to affect sales in such jurisdictions.

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, contingent resources, prospective resources and estimated remaining to be recovered resources figures contained or incorporated by reference into this AIF are estimates and no assurance can be given that the indicated level of recovery of SCO will be realized. Reserves, contingent resources, prospective resources and estimated remaining to be recovered resources estimated for properties that have not yet commenced production may require revision based on actual production experience, further core hole drilling and several other factors. 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, contingent resources, prospective resources and estimated remaining to be recovered resources figures are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable reserves or resources, 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, contingent resources, prospective resources and estimated remaining to be recovered resources figures may vary from such estimates. As well, the estimates of future net revenues are dependent on estimates of future oil prices, 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 contingent resources, prospective resources and estimated remaining to be recovered resources figures included in the reserves and resources 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 SCO production. However, if U.S. authorities view this activity as "passive", then Unitholders residing in the U.S. 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

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 51-101 ("NI 51-101") establishes a regime of continuous disclosure for oil and gas companies and includes specific reporting requirements. NI 51-101 was further amended on December 31, 2007. 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.

In conjunction with NI 51-101, the Standing Committee on Reserves Evaluation of the Calgary Chapter of the Society of Petroleum Evaluation Engineers and the Standing Committee on Reserves Definitions of the Canadian Institute of Mining, Metallurgy and Petroleum 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 Ltd. ("GLJ") effective December 31, 2007 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 36.74 per cent in the Syncrude Joint Venture as at December 31, 2007. Proved developed producing reserves represent 55 cents of proved plus probable reserves. Proved non-producing reserves have not been assigned. Canadian Oil Sands currently produces only one product type, namely SCO.

Our crude oil reserves quantities and future net revenues were determined by GLJ utilizing GLJ's price forecast as of December 31, 2007. In addition, future net revenues using constant prices and costs as prepared by GLJ are also disclosed. The reserves estimates were constrained to areas where Syncrude currently has approvals to mine. The future net revenues shown below are based on the current Alberta oil sands royalty regulations and are prior to provision for currency hedging, interest, debt service charges, general and administrative costs, insurance and mine reclamation costs. It should not be assumed that the discounted future net revenues estimated represent the fair market value of the reserves. The effective date of the reserves estimate and revenue projection in this AIF is December 31, 2007.

Estimates of reserves and projections of production were generally prepared using data to February 8, 2008. The GLJ report is dated February 25, 2008. Canadian Oil Sands, on behalf of the Trust and its subsidiaries, 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, the impact of proposed Crown royalty changes, any impact of announced or 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 of these risks and uncertainties. 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, 2007

Forecast Prices and Costs ⁽¹⁾⁽²⁾⁽³⁾

Reserves Category	Synthetic Crude Oil Reserves		Before Income Taxes				
	Gross million bbls	Net million bbls	Future Net Revenue Discounted (\$ millions) ⁽⁴⁾				
			0%	5%	10%	15%	20%
Proved Developed Producing	986	857	35,685	19,837	12,973	9,516	7,539
Proved Developed Nonproducing	-	-	-	-	-	-	-
Total Proved	986	857	35,685	19,837	12,973	9,516	7,539
Probable	812	703	37,697	11,126	4,000	1,716	850
Total Proved Plus Probable	1,798	1,560	73,382	30,963	16,973	11,232	8,389

Reserves Category	Synthetic Crude Oil Reserves		After Income Taxes				
	Gross million bbls	Net million bbls	Future Net Revenue Discounted (\$ millions)				
			0%	5%	10%	15%	20%
Proved Developed Producing	986	857	28,317	16,171	10,873	8,179	6,622
Proved Developed Nonproducing	-	-	-	-	-	-	-
Total Proved	986	857	28,317	16,171	10,873	8,179	6,622
Probable	812	703	28,158	8,227	2,916	1,225	589
Total Proved Plus Probable	1,798	1,560	56,475	24,398	13,789	9,404	7,211

Notes:

- (1) Canadian Oil Sands Limited constitutes 100 per cent of the total reserves shown.
- (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).
- (4) The before income tax future net revenue discounted at 10 per cent on a \$/bbl (net) basis for each category is as follows:

	<u>\$/bbl</u>
Proved developed producing	\$15.13
Proved developed non producing	\$ -
Total proved	\$15.13
Probable	\$ 5.70
Total proved plus probable	\$10.88

Total Future Net Revenue (Undiscounted Forecast Prices and Costs)⁽¹⁾⁽²⁾

(\$ Millions)

Reserves Category	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment Costs	Future Net Revenues Before Income		Future Net Revenues After Income	
						Taxes	Tax	Taxes	Taxes
Proved Developed Producing	90,525	11,895	31,250	11,695	-	35,685	7,369	28,317	-
Proved Developed Nonproducing	-	-	-	-	-	-	-	-	-
Total Proved	90,525	11,895	31,250	11,695	-	35,685	7,369	28,317	-
Total Probable	92,672	12,566	33,091	9,318	-	37,697	9,538	28,158	-
Total Proved Plus Probable	183,197	24,461	64,341	21,013	-	73,382	16,907	56,475	-

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 \$743 million and for proved plus probable reserves at \$988 million.

Constant Prices and Costs⁽¹⁾⁽²⁾⁽³⁾

Reserves Category	Reserves		Before Income Taxes				
	Gross million bbls	Net million bbls	Future Net Revenue Discounted (\$ millions) ⁽⁴⁾				
			0%	5%	10%	15%	20%
Proved Developed Producing	986	822	45,456	26,173	17,392	12,775	10,049
Proved Developed Nonproducing	-	-	-	-	-	-	-
Total Proved	986	822	45,456	26,173	17,392	12,775	10,049
Probable	812	671	38,978	12,287	4,761	2,209	1,185
Total Proved Plus Probable	1,798	1,493	84,434	38,460	22,153	14,984	11,234

Reserves Category	Synthetic Crude Oil Reserves		After Income Taxes				
	Gross million bbls	Net million bbls	Future Net Revenue Discounted (\$ millions)				
			0%	5%	10%	15%	20%
Proved Developed Producing	986	822	35,953	21,196	14,430	10,841	8,702
Proved Developed Nonproducing	-	-	-	-	-	-	-
Total Proved	986	822	35,953	21,196	14,430	10,841	8,702
Probable	812	671	29,203	9,156	3,523	1,621	860
Total Proved Plus Probable	1,798	1,493	65,156	30,352	17,953	12,462	9,562

Notes:

- (1) Canadian Oil Sands Limited constitutes 100 per cent of the total reserves shown.
- (2) Figures may not add correctly due to rounding.
- (3) Based on a light sweet crude oil price at Edmonton, Alberta as at December 31, 2007 of \$93.39 per barrel and a synthetic crude oil price at the Syncrude plant gate of \$92.39 per barrel.

- (4) The before income tax future net revenue discounted at 10 per cent on a \$/bbl (net) basis for each category is as follows:

	<u>\$/bbl</u>
Proved developed producing	\$21.17
Proved developed non producing	\$ -
Total proved	\$21.17
Probable	\$ 7.09
Total proved plus probable	\$14.84

Total Future Net Revenue (Undiscounted Constant Prices and Costs)⁽¹⁾⁽²⁾⁽³⁾
(\$ Millions)

Reserves Category	Revenue	Royalties	Operating Costs	Capital Development Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Tax	Future Net Revenue After
								Income Taxes
Proved Developed Producing	91,072	15,152	22,008	8,457	-	45,456	9,503	35,953
Proved Developed Nonproducing	-	-	-	-	-	-	-	-
Total Proved	91,072	15,152	22,008	8,457	-	45,456	9,503	35,953
Total Probable	75,016	12,993	17,850	5,194	-	38,978	9,775	29,203
Total Proved Plus Probable	166,088	28,145	39,858	13,651	-	84,434	19,278	65,156

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 \$743 million, and for proved plus probable reserves at \$988 million.
- (3) Based on a light sweet crude oil price at Edmonton, Alberta as at December 31, 2007 of \$93.39 per barrel and a synthetic crude oil price at the Syncrude plant gate of \$92.39.

The constant prices are based on a light sweet crude oil price at Edmonton, Alberta as at December 31, 2007 of \$93.39 per barrel, a synthetic crude oil price at the Syncrude plant gate of \$92.39 per barrel and an AECO-C spot gas price of \$6.63 per MMBTU.

Proved and probable reserves have been estimated in accordance with procedures and standards contained in the COGEH.

There are no proved undeveloped reserves. 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 proved undeveloped reserves case includes capital relating to the Syncrude Emissions Reduction Project or SER and certain recovery optimization projects. The production forecast reflects the current upgrading capacity at Syncrude.

The probable undeveloped gross synthetic crude oil reserves correspond to 677 million barrels. These volumes relate solely to the Aurora South mine, which was initially attributed reserves prior to the most recent three financial years. The mine has all major regulatory approvals in place and a relatively high drill density. The timing of development will be driven by upgrader demand and the productive capacity associated with currently developed mine areas. The Aurora South mine is classified as probable rather than proved in view of the significance of the associated development capital and the uncertainty that major capital spending will commence within the next three years.

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 as at December 31, 2007 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. \$91.10 per barrel in 2008).

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)
2008	2.0	1.00	92.00	91.10	6.75
2009	2.0	1.00	88.00	87.10	7.55
2010	2.0	1.00	84.00	83.10	7.60
2011	2.0	1.00	82.00	81.10	7.60
2012	2.0	1.00	82.00	81.10	7.60
2013	2.0	1.00	82.00	81.10	7.60
2014	2.0	1.00	82.00	81.10	7.80
2015	2.0	1.00	82.00	81.10	7.97
2016	2.0	1.00	82.02	81.12	8.14
2017	2.0	1.00	83.66	82.76	8.31
2018	2.0	1.00	+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, 2007. 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 2008 through 2010, 4.0 per cent in 2011, and 3.0 per cent in 2012.

In 2007, Canadian Oil Sands received a weighted average price of \$79.02 per barrel (after crude oil purchases and transportation expense but before hedging) for its SCO.

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

The following table sets forth a reconciliation of the changes in our working interest reserve volumes before deducting Alberta Crown royalties as at December 31, 2007 against such reserves as at December 31, 2006 based on the forecast prices and costs assumptions:

	Synthetic Crude Oil		
	Proved (million bbl)	Probable (million bbl)	Proved Plus Probable (million bbl)
At December 31, 2006	982	779	1,761
Technical Revisions	13	5	18
Acquisition (1)	32	28	60
Production	(41)	0	(41)
At December 31, 2007	986	812	1,798

Note:

- (1) On January 2, 2007 an additional 1.25 per cent working interest was acquired resulting in a total working interest of 36.74 per cent.

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 are expected to be funded from cash from operating activities, thus the cost of funding is not expected to affect the reserve balances or estimated future net revenues.

	Total Proved Estimated Using Forecast Prices and Costs (\$ millions)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (\$ millions)
2008	328	357
2009	527	608
2010	659	946
2011	807	1,051
2012	866	1,105
Remainder	8,508	16,946
Total for all years undiscounted	\$ 11,695	\$ 21,013
Total for all years discounted at 10%/year	\$ 5,143	\$ 6,688

Other Oil and Gas Information

Costs Incurred

The following table sets forth costs incurred by Canadian Oil Sands for the year ended December 31, 2007:

Property Acquisition Costs (\$millions)		Exploration Costs (\$ millions)	Development Costs (\$ millions)
Proved Properties	Unproved Properties		
\$475	Nil	Nil	\$183

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 \$743 million (\$143 million at a 10 per cent discount rate) for proved reserves and \$988 million (\$167 million at a 10 per cent discount rate) for proved plus probable reserves. 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, 2007 was approximately \$226 million. These liabilities relate to our 36.74 per cent working interest at December 31, 2007 in the Syncrude future dismantlement 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 and related facilities have indeterminate useful lives. 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. In estimating the future net revenue, GLJ has not included any abandonment and reclamation costs in the GLJ reserve report.

Tax Horizon

During 2007, Bill C-52 (Canada) was enacted which introduces an income tax on trust distributions for certain Canadian public income and royalty trusts starting in 2011. As a result the future net revenue calculations now include a provision for income taxes anticipated to be incurred post 2010.

The 36.74 per cent working interest in the Syncrude leases is held by the Corporation. Historically, taxable income in the Corporation has been sheltered by a trust royalty payable to the Trust. Therefore, prior to 2011, both the Trust and the Corporation are assumed to be non-taxable as the royalty trust structure effectively transfers the income tax obligation to individual trust Unitholders.

For purposes of the future net revenue calculations, this royalty trust structure is assumed to be discontinued effective January 1, 2011. Therefore the future net revenue calculations assume that the Corporation will be taxable at Alberta Corporate Tax rates and will have approximately \$2 billion of tax pools as of January 1, 2011.

Crown Royalty Changes

As discussed in the “Royalties and Taxes” section of this AIF, the Alberta Government has announced that it plans to introduce new crown royalty terms, effective January 1, 2009. Please refer to the “Royalties and Taxes” section for a detailed discussion of the announced changes to the current Crown royalty regime. Assuming the new regime is implemented as proposed, becomes effective for the Syncrude Project post 2015 and the royalty continues to be based on synthetic crude oil, the total proved plus probable after income taxes future net revenue at forecast prices and costs would be reduced by approximately 13 per cent on an undiscounted basis and seven per cent at a 10 per cent discount rate.

Bitumen Royalty Changes

As discussed in the “Royalties and Taxes” section of this AIF, an Alberta Crown Agreement provides the Syncrude Joint Venture owners with a one time option prior to 2010 to convert from a royalty based on synthetic crude oil to bitumen based royalty consistent with the rest of the Alberta oil sands industry. Please refer to the “Royalties and Taxes” section for a detailed discussion of the bitumen royalty option.

The economic consideration of conversion to a bitumen based royalty and the resulting royalty payments is highly sensitive, among other factors, to the BVM methodology and the relationship between synthetic crude oil prices and bitumen prices. Over the past four years estimated monthly prices for Syncrude bitumen based on Lloyd Blend at Hardisty and using reasonable estimated adjustments for quality, location and diluent, are estimated to have ranged from 15 per cent to 64 per cent of light sweet crude oil postings at Edmonton, with the average being slightly less than 50 per cent.

Assuming that the bitumen royalty option is exercised effective January 1, 2009, that Syncrude bitumen is valued at 50 per cent of the light sweet crude oil price at Edmonton, and utilizing an upgrader growth recapture amount of approximately \$6 billion then the total proved plus probable after income tax future net revenues at forecast prices and costs would increase by approximately 16 per cent on an undiscounted basis and 13 per cent on a 10 per cent discounted basis.

The preceding estimates for Alberta Crown Royalties and the bitumen royalty option have a significant level of uncertainty. In addition to the assumptions regarding the bitumen valuation methodology, the impact of announced changes to the Alberta Crown Royalty regime, the timing and amount of upgrader growth capital recapture, forecast prices and total costs, these reserve estimates make several additional assumptions, including, but not limited to the extraction recovery and bitumen yield achieved and the proportion of total capital and operating costs related to bitumen production. Further, any amendment to the Crown Royalty agreement with the Alberta Government as well as the decision to exercise the bitumen royalty option requires the agreement of all the Syncrude owners, not just a majority of those Syncrude owners. As a result, actual results may be different than the estimates provided, and these differences may be material.

Production Estimates

A forecast of Canadian Oil Sands' production from the Syncrude Joint Venture for 2008 based on the guidance and information known at January 30, 2008 using forecast prices is presented below:

Synthetic Crude Oil (million barrels)

<u>Reserves Category</u>	<u>Working Interest</u>	<u>After Royalty</u>
Proved developed producing	42.1	35.5
Total proved	42.1	35.5
Total proved plus probable	43.2	36.4

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 of SCO (bbls/d) ⁽¹⁾	108,981	98,720	124,904	116,368	112,298
Realized Selling Price before Currency Hedging ⁽²⁾	68.47	76.41	81.23	88.50	79.02
Currency Hedging Gains ⁽²⁾	0.22	0.40	0.25	0.23	0.27
Net Realized Selling Price ⁽²⁾	68.69	76.81	81.48	88.73	79.29
Operating Expenses ⁽²⁾	(23.56)	(30.13)	(20.84)	(27.38)	(25.23)
Royalties ⁽²⁾	(9.58)	(9.94)	(14.32)	(12.81)	(11.83)
Netback ⁽²⁾	35.55	36.74	46.32	48.54	42.23

Notes:

- (1) The average daily volumes reported for 2007 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 30, 2008 guidance of approximately 115 million barrels per year of Syncrude production is as follows:

	<u>Reserves (Millions of barrels)</u>	<u>Reserve Life Index (Years)</u>
Total Proved Reserves	986	23
Proved plus Probable Reserves	1,798	43

Resources

In addition to the reserve definitions provided on page 40 of this AIF, we are providing the following definitions to assist you in understanding the terminology used in the following discussion of “Resources”:

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

Best Estimate is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. The best estimate of Contingent and Prospective Resources is prepared independent of the risks associated with achieving commercial production.

Remaining Recoverable Resources are the sum of reserves, contingent resources and prospective resources.

See page 12 of this AIF for an outline of the leases held by the Syncrude Joint Venture, which total about 252,000 acres. Based upon independent evaluations conducted by GLJ effective December 31, 2007, our best estimate of the reserves and resources remaining to be recovered from these leases are as follows:

(billions of barrels of SCO)	Syncrude Project	COS⁽¹⁾
Proved plus probable reserves	4.9	1.8
Contingent resources – best estimate	5.6	2.1
Prospective resources – best estimate	<u>2.2</u>	<u>0.8</u>
Remaining recoverable resources	<u>12.7</u>	<u>4.7</u>

(1) Based on the Corporation’s 36.74 per cent working interest in the leases.

The contingent resources are primarily associated with separate pits not currently planned to be developed in a timeframe that enable them to be classified as reserves, and for which an application for regulatory approval has not yet been prepared. A component of the contingent resources are associated with expansion (pushback) opportunities to pits assigned reserves at December 31, 2007, but that have not yet been incorporated into Syncrude’s mine plans as of the effective date of the evaluation, and for which owner commitment is currently considered insufficient to enable all of the expansion to be recognized as reserves. The pit design assumptions utilized in preparing the estimates are within the ranges currently being considered by industry in applications for regulatory approval of commercial surface mining developments. To the extent the Syncrude Joint Venture owners have not committed to mine any of the contingent resources, any decision to mine may reflect a different planning basis than utilized in preparing the estimates. While we consider the contingent resources to be potentially recoverable under reasonable economic and operating conditions, there is no certainty that they will be commercially viable.

Prospective resources have significant additional risks relative to contingent resources. They are associated with specific areas within the Syncrude leases where existing well control is not sufficient, and it is believed that additional drilling could either result in the movement of these areas to contingent resources or their elimination from the assumed planning basis. Drilling within the areas of this continuous-type deposit that have been classified by GLJ as prospective is relatively exploratory at this point in time. GLJ's best estimate of prospective resources corresponds to 50 percent of their high estimate and hence makes some adjustment for risk. Nevertheless, there is no certainty that any portion of the prospective resources will be discovered. Furthermore, if discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

DISTRIBUTABLE INCOME

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 2007, Unitholder distributions were comprised of the trust royalty payments and interest income 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 SCO 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 2007 MD&A under the headings "Liquidity and Capital Resources" and under "Unitholder

Distributions”, which sections are incorporated herein by reference and is available on SEDAR at www.sedar.com.

Distribution History

Payment Date	Amount per Unit ⁽¹⁾
February 29, 2008	\$0.75 ⁽²⁾
November 30, 2007	\$0.55 ⁽²⁾
August 31, 2007	\$0.40 ⁽²⁾
May 31, 2007	\$0.40 ⁽²⁾
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

Notes:

- (1) Amounts adjusted to reflect the 5:1 Unit split that occurred on May 3, 2006.
- (2) Increased cash flow from operating activities and a reduction in capital spending as a result of the completion of the Stage 3 expansion, and the continuing high crude oil price environment, resulted in Canadian Oil Sands increasing its quarterly distributions from \$0.30 per unit per quarter in February 2007 to \$0.75 per Unit per quarter in February 2008.

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, 2008, 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. As at December 31, 2007, an aggregate of 479,389,728 Units were issued and outstanding.

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 28, 2007, Canadian Oil Sands estimates that approximately 32 per cent of our Units are held by non-Canadian residents with the remaining 68 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 ("TSX") 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.

The Board of Directors may consider these restrictions regarding non-Canadian resident ownership in light of the income trust taxation changes that take effect in 2011 if and when the Board faces a situation where it may need to implement these restrictions. If the result of the 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 prior to trust taxation taking 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. On April 25, 2007, at the annual meeting of Unitholders, Unitholders also approved and reconfirmed an amended and restated rights plan together with minor amendments (the "Rights Plan").

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 10 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 14, 2008, the Units of the Trust have a stability rating of SR-4 issued by Standard & Poor's ("S&P"). The debt securities of the Corporation, the main operating subsidiary of the Trust, were rated BBB with a stable outlook by S&P and Baa2 with a stable outlook by Moody's Investor Service ("Moody's").

A S&P 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 ratings 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 TSX and trade under the symbol “COS.UN”. The table below sets out the closing price ranges and volumes traded on the TSX during 2007.

Month	High (\$/Unit)	Low (\$/Unit)	Close (\$/Unit)	Volume Traded (millions)
January	32.39	26.70	30.07	34.13
February	29.35	26.87	27.30	32.55
March	28.84	25.43	28.26	34.89
April	30.79	27.84	30.16	27.43
May	33.43	30.09	32.41	26.05
June	32.94	29.42	32.94	29.88
July	35.10	31.40	32.58	43.10
August	33.05	29.11	30.49	28.21
September	34.04	30.78	33.00	27.49
October	35.60	31.00	34.70	38.80
November	37.75	34.07	36.24	29.08
December	38.71	35.50	38.71	23.36

Note 15 *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, 2008.

Directors

As at December 31, 2007, the directors of the Corporation were as set forth below. The Corporation's articles provide that the Corporation must have a minimum of five and a maximum of ten directors. The Corporation's directors are elected annually by the Trust's Unitholders directing the Trustee to appoint the approved directors. In addition, in between meetings of Unitholders, the Trustee may appoint one additional director to the Board.

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
Ian A. Bourne ⁽¹⁾⁽²⁾⁽⁴⁾ Alberta, Canada	Corporate Director, Chairman, Ballard Power Systems Inc.	2007
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
Donald J. Lowry ⁽¹⁾⁽²⁾⁽⁵⁾ Alberta, Canada	Corporate Director; President and Chief Executive Officer of EPCOR Inc.	2007
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
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. ⁽³⁾ 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.
- (4) Mr. Bourne became a director on November 15, 2007.

- (5) Mr. Lowry became a director on April 25, 2007.
- (6) All of the directors of the Corporation have been appointed to hold office until the next annual meeting of Unitholders or until their successors are duly elected or appointed, unless their office was earlier vacated.

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. Bourne (who was the Executive Vice President and Chief Financial Officer from January 1998 to December 2005 and President of TransAlta Power LP from March 1998 to December 2006); 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. Zaozirny is counsel to McCarthy Tétrault LLP, which provides legal services to Canadian Oil Sands from time to time.

Computershare 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. Effective January 1, 2007, the Board created a Reserves, Marketing Operations and Environmental, Health & Safety Committee to deal with reserves matters, marketing matters and environmental, health and safety issues, taking over responsibility for reserves from the Audit Committee.

Audit Committee

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 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 Power LP 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 ("ICD"). He has completed the ICD Corporate Governance College Director Education Program and has received the ICD.D. designation.

Name	Relevant Education and Experience
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 of COST and AOST 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.
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.
Donald J. Lowry	Mr. Lowry has over 25 years of industry experience in the utilities and communications sectors. He has acted in various director capacities. Currently, he is the Chairman for EPCOR Power L.P. and of the Canadian Electrical Association and a director of the Alberta Climate Change Central, Alberta Economic Development Authority and the Banff Centre. Mr. Lowry is currently the Chief Executive Officer of EPCOR Inc. Mr. Lowry holds an MBA and has completed the Advanced Management Program at Harvard Business School.
Ian A. Bourne	Mr. Bourne has acted in various director capacities for a number of public entities. He is currently the Chair of Ballard Power Systems Inc., a board member of the Canada Pension Plan Investment Board and a director of WAJAX Income Fund and WAJAX Limited. Mr. Bourne has over 30 years experience including eight years as the Executive Vice President and Chief Financial Officer of TransAlta Corporation, President of TransAlta Power L.P. as well as serving as the Chief Financial Officer of Canada Post and GE Canada. He has completed the ICD Corporate Governance College Director Education Program and has received the ICD.D. designation.

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, 2008, their jurisdiction of residence, their current office, and their principal occupations for the five-year period proceeding December 31, 2007.

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	
RYAN M. KUBIK Alberta, Canada	Chief Financial Officer	Chief Financial Officer of the Corporation since April, 2007; prior thereto, Treasurer of the Corporation from September, 2002 to April, 2007 with a dual role as Controller from July, 2005 to July, 2006
ALLEN R. HAGERMAN, FCA Alberta, Canada	Executive Vice President	Executive Vice President since April, 2007; prior thereto, Chief Financial Officer of the Corporation from June, 2003 to April, 2007; prior thereto, Vice President and Chief Financial Officer of Fording Canadian Coal Trust from March, 2003 to May, 2003; and Vice President and Chief Financial Officer of Fording Inc. from June, 2001 to March, 2003
TREVOR R. ROBERTS, Alberta, Canada	Chief Operations Officer	Chief Operations Officer of the Corporation since September, 2005; prior thereto, Vice President, Operations of Suncor Inc. from 1997 to May, 2005
TRUDY M. CURRAN Alberta, Canada	General Counsel and Corporate Secretary	General Counsel and Corporate Secretary of the Corporation
ROBERT P. DAWSON Alberta, Canada	Treasurer	Treasurer of the Corporation since May, 2007; prior thereto, Director, Financial Governance and External Reporting, Suncor Energy Inc. from March, 2004 to April, 2007; prior thereto, Finance Director, Corporate, Global Crossing Ltd.
LAUREEN C. DUBOIS Alberta, Canada	Controller	Controller of the Corporation since January, 2004; prior thereto, Manager, Accounting of the Corporation from November, 2002 to January, 2004
SIREN FISEKCI Calgary, Alberta	Director, Investor Relations	Directors, Investor Relations of the Corporation since April, 2006; prior thereto, Manager, Investor Relations of the Corporation from November, 2002 to April, 2006

Name and Jurisdiction of Residence	Current Office	Five Year History of Principal Occupations
SCOTT W. ARNOLD Calgary, Alberta	Assistant Treasurer	Assistant Treasurer of the Corporation since January, 2007; prior thereto, Senior Financial Analyst of the Corporation from July 2005 to January 2007 prior thereto Senior Manager, Financial Advisory, Deloitte & Touche LLP from 2002 to July 2005

As of March 1, 2008, to the knowledge of the Corporation, the directors and officers of the Corporation, as a group, beneficially own, directly or indirectly, or exercise control or direction over 610,364 Units of the Trust, representing less than two 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 2007 and 2006 were as follows:

Fees Descriptions	2007	2006	2005
Audit	\$324,000	\$336,500	\$203,000
Audit Related	\$15,000	\$8,000	\$14,000
Tax	\$192,000	\$213,000	\$167,000

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 officer of the Corporation, nor any person or company who beneficially owns, or controls or directs, directly or indirectly, more than 10 per cent of the outstanding Units, nor any associate or affiliate of any such persons, has a material interest, direct or indirect, in any transaction since January 1, 2005 that has materially affected or is reasonably expected to 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 common shares of the Corporation.

LEGAL PROCEEDINGS

There are no legal proceedings to which we are a party to or of which any of our property is or was the subject of, 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 28, 2008 in respect of the Trust's consolidated financial statements with accompanying notes as at and for the years ended December 31, 2007 and 2006. 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.

MATERIAL CONTRACTS

The following is a list of the material contracts required to be disclosed under NI 51-102 *Continuous Disclosure Obligations* that either the Trust or the Corporation had entered into and which were still in effect as of March 15, 2008 and for which copies may be found at www.sedar.com:

a) *Fifth Amended and Restated Trust Indenture dated as of April 26, 2006*

This trust indenture created the Trust and sets out the governance of the Trust and is available on the Trust's website at www.cos-trust.com.

b) *Management Agreement between the Corporation and the Trust*

The Trust has no directors, officers or employees. Instead, pursuant to the provisions of the Trust Indenture and the Management Agreement, the Corporation provides management services to the Trust. Under the Management Agreement, in each quarter the Corporation is to be paid an amount equal to the sum of the following: (a) a fixed fee of \$125,000 per quarter and (b) all other out-of-pocket and third party fees, costs and expenses reasonably incurred by the Corporation in carrying out its obligations or duties under the Management Agreement.

c) ***The Amended and Restated Rights Plan Agreement dated as of April 25, 2007, between the Trust and Computershare Trust Company of Canada***

The amended and restated rights plan was approved by Unitholders in April 25, 2007. A copy of the document is available on SEDAR. See a description of the Rights Plan on pages 54 to 56 of this AIF.

d) ***Ownership and Management Agreement dated March 5, 1975, as amended, among Syncrude participants and SCL***

This agreement outlines and governs the basis upon which the various owners of the Syncrude Project created the Syncrude Joint Venture and how the Syncrude Participants authorize and govern the operation of such project by SCL. There is no term to the agreement. The agreement sets out the requirements for unanimous agreement of the Syncrude Participants to undertake major expansions to the Syncrude Project or to change the operator of the Project. Under the terms of the Ownership and Management Agreement, each Syncrude Participant is required to fund its proportionate share of the operating and approved capital expenditures of the Syncrude Project and in turn receives its share of the SCO and other products produced by SCL as operator of the Syncrude Project. Failure to fund by a Syncrude Participant results in the loss by that Syncrude Participant of its share of the SCO and products produced from the Syncrude Project until the other Participants have been able to offset the expenditure liability for which the defaulting Participant owes.

e) ***Crown Royalty Agreement among the Syncrude Participants and Her Majesty the Queen in Right of Canada dated February 4, 1975, as amended***

The agreement sets out the basis upon which the Syncrude Participants will pay Crown royalties to the Alberta Government in respect of production from various leases in the Syncrude Project. Through various amendments, the Alberta Government agreed to a maximum royalty payable by the Syncrude Participants in respect of production from various leases in the Syncrude Project as to one per cent of the gross revenues prior to payout of capital expansions and then 25 per cent of revenues less operating costs post payout. This maximum payment agreement is in effect until December 31, 2015. The agreement also allows the Syncrude Participants to elect to switch the method on which the royalty is calculated from being based on the revenue from sales of synthetic crude oil to being based on the value of bitumen sales, subject to recapture of expansion capital relating to the upgrader.

f) ***Bank Credit Facilities***

Each of the credit facilities of the Corporation is unsecured. These credit agreements contain typical covenants relating to the restriction on Canadian Oil Sands' ability to sell all or substantially all of its assets or to change the nature of its business. In addition, Canadian Oil Sands has agreed to maintain its total debt-to-total book capitalization at an amount less than 60 percent, or 65 percent in certain circumstances involving acquisitions. In particular, there are currently three bank facilities as follows:

(i) **Extendible Revolving Term Facility dated April 27, 2005, as amended and extended, with the Royal Bank of Canada**

The \$40 million extendible revolving term facility is a 364-day facility with a one year term out, expiring April 24, 2009. This facility may be extended on an annual basis with the agreement of the bank. Amounts borrowed through this facility bear interest at a floating rate based on bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees.

(ii) Operating Credit Facility among a syndicate of banks and the Corporation dated April 27, 2005, as amended and extended

The \$800 million operating credit facility is a five-year facility, expiring April 27, 2012. Amounts borrowed through this facility bear interest at a floating rate based on either prime interest rates or bankers' acceptances plus a credit spread, while any unused amounts are subject to standby fees.

g) Long term debt instruments

The Corporation is the entity which issues all of the material debt instruments relating to Canadian Oil Sands. All of the medium term notes and senior notes issued by the Corporation are unsecured, rank pari passu with other senior unsecured debt of the Corporation, and contain certain covenants that place limitations on the sale of assets and the granting of liens or other security interests.

The medium term notes are guaranteed by the Trust and were issued pursuant to the same trust indenture. The Senior Notes issued by the Corporation were placed in the United States under a private placement exemption and are not guaranteed by the Trust. Each of the Senior Notes is issued under separate trust indentures.

(i) Trust Indenture made as of April 2, 2003

The Corporation issued and has outstanding two tranches of medium term notes under this trust indenture, namely the 5.75 per cent medium term notes and the 5.55 per cent medium term notes. The Corporation issued on April 8, 2003 \$150 million of 5.75 per cent unsecured medium term notes, maturing April 9, 2008. Interest is payable on the notes semi-annually on April 9 and October 9. On June 29, 2004 the Corporation issued \$200 million of 5.55 per cent unsecured medium term notes, maturing June 29, 2009. Interest on these notes is payable semi-annually on June 29 and December 29.

(ii) Trust Indenture dated as of April 1, 1997, as amended, between the Bank of New York, as trustee, and the Corporation as successor to AOSII

On April 4, 1997, the Corporation issued US\$75 million of 8.2 per cent Senior Notes, maturing April 1, 2027, and retired US\$1.05 million during 2000. Interest is payable on the notes semi-annually on April 1 and October 1.

(iii) Trust Indenture dated as of August 24, 2001, as amended, between The Bank of New York as trustee and the Corporation

On August 24, 2001 COSL issued US\$250 million of 7.9% Senior Notes, maturing September 1, 2021. Interest is payable on the notes semi-annually on March 1 and September 1. COSL has agreed to maintain its senior debt to book capitalization at an amount less than 55 percent. Unlike the trust indentures relating to the other issuances of senior notes, this trust indenture contains a provision whereby if the ratings for the unsecured debt of the Corporation fall below investment grade, there is a step up in the amount of interest payable on the notes.

(iv) Trust Indenture dated as of August 6, 2003, between the Bank of New York as trustee and the Corporation as the issuer

On August 6, 2003, the Corporation issued US\$300 million of 5.8 per cent Senior Notes, maturing August 15, 2013. Interest is payable on the notes semi-annually on February 15 and August 15.

(v) Trust Indenture dated as of August 9, 2004, as amended, between the Bank of New York as trustee and the Corporation as the issuer

On August 9, 2004, the Corporation issued US\$250 million of 4.8 per cent Senior Notes, maturing August 10, 2009. Interest is payable on the notes semi-annually on February 10 and August 10.

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 officers' remuneration and indebtedness, principal holders of the Trust's securities, and securities authorized for issuance under equity, compensation plans is contained in the Trust's Management Proxy Circular dated March 10, 2008, which relates to the Annual and Special Meeting of Unitholders to be held on April 28, 2008. Additional financial information is also provided in the Trust's consolidated comparative audited financial statements and notes thereto and management's discussion and analysis for the year ended December 31, 2007.

SCHEDULE "A"

AUDIT COMMITTEE INFORMATION

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. The Committee reviews and receives 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 from time to time. All members of the Committee shall be financially literate, as determined by the Board of Directors. Committee members will include only duly elected directors.

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- 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

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- 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.
- O. The Chair of the Audit Committee shall be appointed by the Board. The Chair shall preside as chair at each Committee meeting, lead Committee discussion on meeting agenda items and report to the Board, on behalf of the Committee, with respect to the proceedings of each Committee meeting. In the event that either the Chair or the Secretary is absent from any meeting, the members present shall designate any Director present to act as Chair and shall designate any Director, officer or employee of the Company to act as Secretary.

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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 or guidance document to the public;
- iv) reviewing and recommending to the Board for approval, the financial content of the annual report and of 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 the financial content in 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;

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- 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 reassessing annually that adequate procedures are in place to review any other corporate disclosure derived or extracted from financial statements.

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

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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;
- 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; and
- vii) review management's monitoring of compliance with COSL's Code of Business Conduct.

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;

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- 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) if appropriate, the auditors' evaluation of the system of 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;

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- 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; and
- 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 and consider the findings and the appropriateness of follow-up plans of the internal auditor.

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

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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;
- 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;
- viii) approve the appointment, re-assignment or removal of the internal auditor, if any exists, of the Corporation, subject to the recommendation of the Corporate Governance and Compensation Committee and the final approval of the Board; and
- ix) the Committee shall have the authority to direct and to supervise the investigation into any matter brought to its attention within the scope of its duties. It shall establish procedures for the receipt, retention and treatment of:
 - (A) Complaints COSL may receive regarding accounting, internal accounting controls, or auditing matters; and

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- (B) Confidential, anonymous submissions from COSL employees expressing concern regarding questionable accounting or auditing matters.

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.

The Committee shall conduct a review of the Committee's effectiveness at least annually and follow up on any suggested improvements that are identified out of such review or otherwise brought to the attention 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.