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REGISTRANT'S NAME Deer Creek Energy Limited

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Suite ~~2600~~ 2600
205 - 5th Avenue S.W.
Calgary, Alberta T2P 2V7

**FORMER NAME

**NEW ADDRESS

PROCESSED
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THOMSON FINANCIAL

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* *Complete for initial submissions only* ** *Please note name and address changes*

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No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise. This prospectus constitutes a public offering of these securities only in those jurisdictions where they may lawfully be offered for sale and therein only by persons authorized to sell such securities. These securities have not been and will not be registered under the United States Securities Act of 1933, as amended (the "1933 Act"), or any state securities law. Accordingly, except to the extent permitted by the Underwriting Agreement (as defined below), these securities may not be offered or sold in the United States (as such term is defined in Regulation S under the 1933 Act). This prospectus does not constitute an offer to sell or a solicitation of an offer to buy any of the securities offered hereby within the United States. See "Plan of Distribution".

Initial Public Offering July 21, 2004

DEER CREEK
Energy Limited

12-31-03
AR/S

$160,550,000
16,900,000 Common Shares

This prospectus qualifies for distribution the issuance of 16,900,000 common shares (the "Offered Shares") in the capital of Deer Creek Energy Limited ("Deer Creek" or the "Corporation") at a price of $9.50 per Offered Share (the "Offering"). The terms of the Offering were determined by negotiation between the Corporation and Peters & Co. Limited, RBC Dominion Securities Inc., Merrill Lynch Canada Inc., CIBC World Markets Inc., Scotia Capital Inc., Canaccord Capital Corporation, First Associates Investments Inc., FirstEnergy Capital Corp., Raymond James Ltd. and Salman Partners Inc. (collectively, the "Underwriters"). **There is presently no market through which the Offered Shares may be sold and purchasers may not be able to resell securities purchased under this prospectus.** The Toronto Stock Exchange (the "TSX") has conditionally approved the listing of the common shares (the "Common Shares") in the capital of the Corporation, which includes the Offered Shares and the Over-Allotment Shares (as hereinafter defined). Listing is subject to the Corporation fulfilling all of the requirements of the TSX on or before October 17, 2004, including the distribution of Common Shares to a minimum number of public shareholders. In connection with the Offering, the Underwriters are permitted to engage in transactions that stabilize or maintain the market price of the Common Shares at levels other than those that might prevail in the open market. Such transactions, if commenced, may be discontinued at any time. See "Plan of Distribution".

Price: $9.50 per Common Share

	Price to the Public	Underwriters' Fee	Net Proceeds to the Corporation(1)
Per Offered Share	$9.50	$0.475	$9.025
Total Offering	$160,550,000	$8,027,500	$152,522,500

Notes:

(1) Before deducting the expenses of the Offering estimated to be $1,400,000, which will be paid by the Corporation.

(2) The Corporation has granted to the Underwriters an over-allotment option (the "Over-Allotment Option"), exercisable in whole or in part, for a period of 30 days from closing the Offering, to purchase up to an additional 1,690,000 Common Shares (the "Over-Allotment Shares") (representing 10% of the Offered Shares to be issued pursuant to the Offering), at the same price as set forth above (the "Over-Allotment Offering"), to cover over-allotments, if any, and for market stabilization purposes. If the Over-Allotment Option is exercised in full, the total Price to the Public, Underwriters' Fee and Net Proceeds to the Corporation will be $176,605,000, $8,830,250 and $167,774,750, respectively. This prospectus also qualifies the distribution of the Over-Allotment Shares issuable upon exercise of the Over-Allotment Option. See "Plan of Distribution".

In the opinion of Bennett Jones LLP, counsel to the Corporation and Stikeman Elliott LLP, counsel to the Underwriters, the Common Shares, which includes the Offered Shares and the Over-Allotment Shares, if, as and when listed on a prescribed stock exchange (including the TSX), will be qualified investments for a trust governed by a registered retirement savings plan, a registered retirement income fund, a registered education savings plan or a deferred profit sharing plan and will not be precluded as investments under certain other statutes. See "Eligibility for Investment".

The Underwriters, as principals, conditionally offer the Offered Shares, subject to prior sale, if, as and when issued, sold and delivered by the Corporation and delivered to and accepted by the Underwriters in accordance with the conditions contained in the Underwriting Agreement referred to under "Plan of Distribution" and subject to the approval of certain legal matters on behalf of the Corporation by Bennett Jones LLP and on behalf of the Underwriters by Stikeman Elliott LLP. **Each of RBC Dominion Securities Inc. and CIBC World Markets Inc. is a subsidiary of a Canadian financial institution which is a lender to the Corporation. As a result, the Corporation may be considered to be a "connected issuer" of each of RBC Dominion Securities Inc. and CIBC World Markets Inc. under applicable Canadian securities legislation.** See "Relationship Between the Corporation and Certain Underwriters".

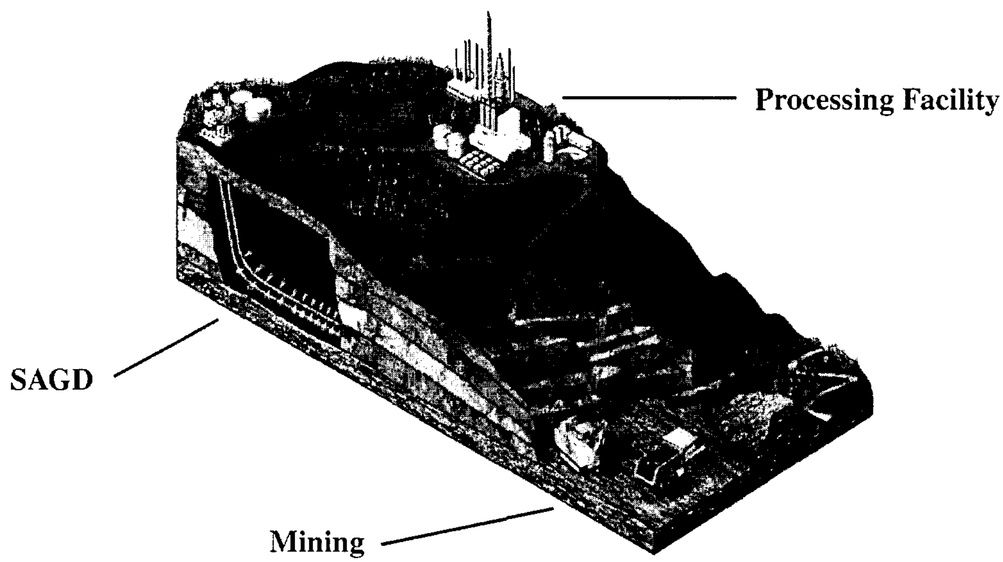
Investment in the Common Shares is considered to be speculative due to the Corporation's present stage of development and certain other factors. See "Risk Factors".

Subscriptions for Offered Shares will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the certificates representing the Offered Shares will be available for delivery at the closing, which is expected to occur on or about July 29, 2004, or such later date as the Corporation and the Underwriters may agree but in any event not later than 42 days after the date of the receipt for this prospectus.

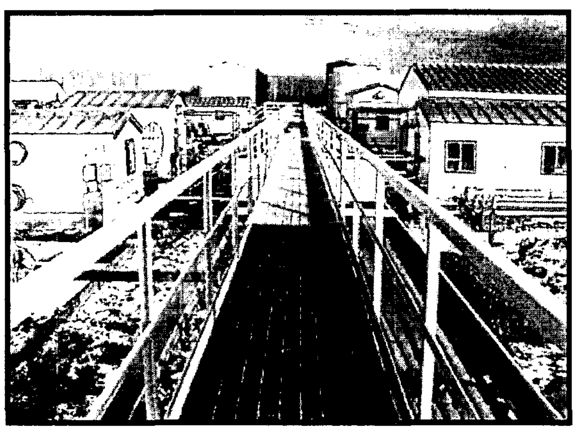
DEER CREEK
Energy Limited

Building a Pure Oil Sands Company

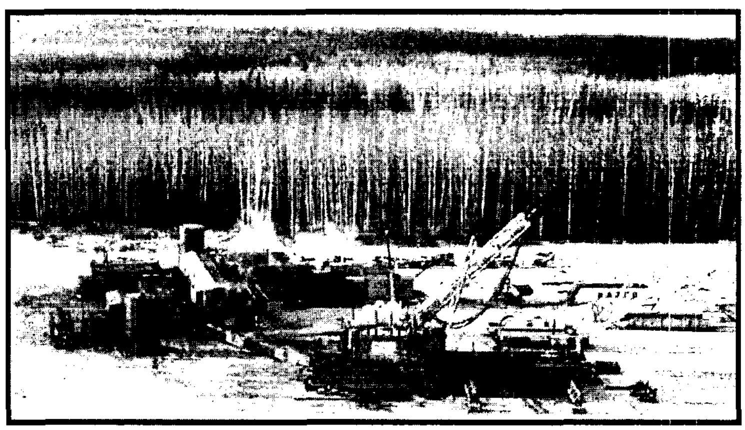
Joslyn Project



(Figure is representative only)



SAGD Phase I Plant



Drilling SAGD Phase I Dual Well Pair

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FORWARD-LOOKING INFORMATION

This prospectus contains forward-looking statements relating to the Corporation's plans and expectations concerning the cost, development and operation of the Joslyn Project and other aspects of the Corporation's anticipated future operations, strategies, financial and operating results and business opportunities. Forward-looking information typically contains statements using words such as "anticipate", "believe", "project", "expect", "plan", "intend" or similar words suggesting future outcomes, statements that actions, events or conditions "may", "would", "could" or "will" be taken or occur in the future, or statements regarding the outlook for petroleum prices, estimated amounts and timing of capital expenditures, anticipated results of development and construction projects, estimates of future production, reserves and resources or other expectations, beliefs, plans, objectives, assumptions or statements about future events or performance. Statements concerning resources and reserves are also forward-looking statements, as they reflect estimates as to the volume and nature of petroleum deposits that will be found to be present when a project is developed, and, in the case of reserves, the expectation that the deposits can be economically exploited in the future.

Readers are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information involves numerous assumptions, risks and uncertainties and other factors that contribute to the possibility that the predicted outcome will not occur. Among the factors that could cause actual events, results or outcomes to differ materially from those reflected in the forward-looking information in this prospectus include those identified under the heading "Risk Factors" and elsewhere in this prospectus. Readers should be aware that the list of risks set forth under "Risk Factors" is not exhaustive.

The Corporation undertakes no obligation to update or revise any forward-looking information.

ELIGIBILITY FOR INVESTMENT

In the opinion of Bennett Jones LLP, counsel to the Corporation and Stikeman Elliott LLP, counsel to the Underwriters (collectively, "Counsel"), the Common Shares, which includes the Offered Shares and the Over-Allotment Shares, if, as and when listed on a prescribed stock exchange (including the TSX), will be qualified investments for a trust governed by a registered retirement savings plan, a registered retirement income fund, a registered education savings plan or a deferred profit sharing plan under the *Income Tax Act* (Canada) (the "Tax Act") and the regulations made under the Tax Act and, based upon information provided by the Corporation, at the date of their issue, the Common Shares will not constitute "foreign property" for the purposes of the Tax Act for persons subject to tax under Part XI of the Tax Act.

In the opinion of Counsel, based on the legislation in effect on the date hereof, the provisions of:

Insurance Companies Act (Canada)
Trust and Loan Companies Act (Canada)
Pension Benefits Standards Act, 1985 (Canada)
Cooperative Credit Associations Act (Canada)
Financial Institutions Act (British Columbia)
Loan and Trust Corporations Act (Alberta)
Insurance Act (Alberta)
Employment Pension Plans Act (Alberta)
Alberta Heritage Savings Trust Fund Act (Alberta)
Pension Benefits Standards Act (British Columbia)
The Trustee Act (Manitoba)
Pension Benefits Act (Nova Scotia)
Trustee Act (Nova Scotia)
The Pension Benefits Act, 1992 (Saskatchewan)
The Insurance Act (Manitoba)
The Pension Benefits Act (Manitoba)
Pension Benefits Act (Ontario)
Loan and Trust Corporations Act (Ontario)
An Act respecting insurance (Québec) (for an insurer incorporated under the laws of the Province of Québec, other than guarantee fund corporations)
An Act respecting trust companies and savings companies (Québec) (for a trust corporation investing its own funds and funds received as deposits and a savings corporation investing its own funds)
Supplemental Pension Plans Act (Québec)

would not preclude, subject to compliance with prudent investment standards or criteria, or, if applicable, investment policies, procedures or goals which have been filed, where required, with the appropriate regulatory authorities and the general investment provisions of such statutes and the regulations thereunder, an investment in the Common Shares by companies, corporations, pension plans or persons registered thereunder or governed thereby.

TAX CONSEQUENCES

Prospective investors should be aware that the purchase of Offered Shares and Over-Allotment Shares has tax consequences, which are not described in this prospectus. Accordingly, prospective investors are advised to consult their own tax advisors with respect to the tax aspects of investing in the Offered Shares and Over-Allotment Shares.

PROSPECTUS SUMMARY

The following is a summary of the principal features of this distribution and should be read together with the more detailed information and financial data and statements contained elsewhere in this prospectus. Reference is made to the "Glossary of Terms" for the meanings of certain capitalized defined terms used in this prospectus.

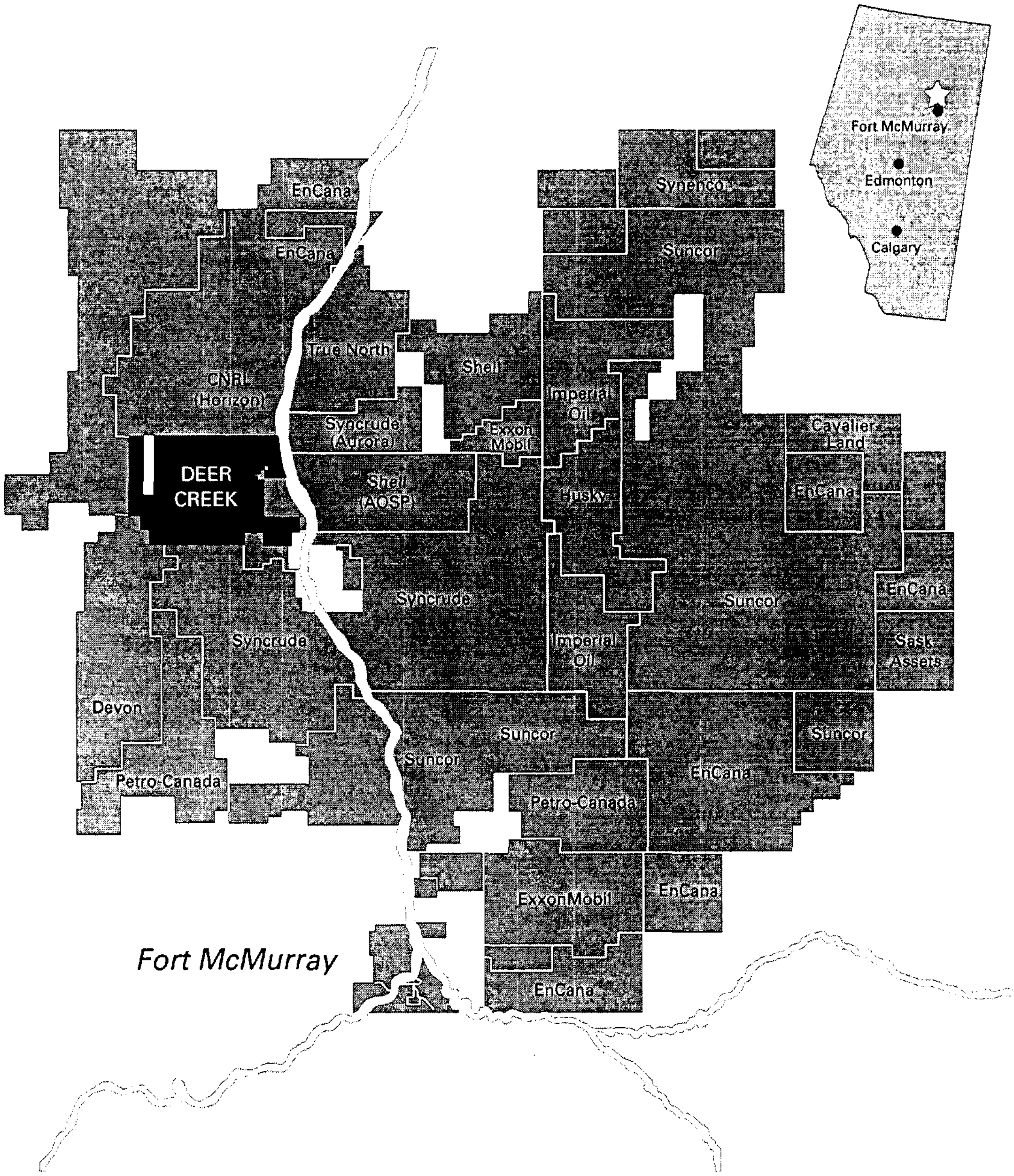
The Offering

Offering:	16,900,000 Offered Shares.
Price:	$9.50 per Offered Share.
Gross Proceeds:	$160,550,000.
Use of Proceeds:	The net proceeds of the Offering to the Corporation, after deducting the fees payable to the Underwriters and the expenses of the Offering, are estimated to be $151,122,500. The net proceeds will be used by the Corporation to fund the Corporation's share of the projected capital costs of SAGD Phase II, the regulatory, engineering design and environmental work related to additional expansions of the Joslyn Project and other related expenses.
Over-Allotment Option:	The Corporation has granted to the Underwriters the Over-Allotment Option to purchase up to 1,690,000 Over-Allotment Shares at a price of $9.50 per Over-Allotment Share to cover over-allotments, if any, and for market stabilization purposes.
Eligibility for Investment:	In the opinion of Counsel, the Common Shares, if, as and when listed on a prescribed stock exchange (including the TSX), will be qualified investments for a trust governed by a registered retirement savings plan, a registered retirement income fund, a registered education savings plan or a deferred profit sharing plan under the Tax Act and the regulations made under the Tax Act and, based upon information provided by the Corporation, at the date of their issue, the Common Shares will not constitute "foreign property" for the purposes of the Tax Act for persons subject to tax under Part XI of the Tax Act. In addition, the Common Shares will not be precluded as investments under certain statutes. See "Eligibility for Investment".

Deer Creek Energy Limited

Deer Creek is a Calgary-based oil sands development and exploitation company. Established in October 1996, the Corporation is engaged in the business of developing, operating, producing and selling recoverable bitumen found in the Athabasca oil sands deposits through SAGD and mining extraction methods. Deer Creek's principal assets include Lease 24 and Permit 70, collectively known as the Joslyn Lease. The Joslyn Lease is located in the regional municipality of Wood Buffalo, approximately 60 kilometres north of Fort McMurray in northern Alberta. Deer Creek has been evaluating and developing the Joslyn Project over the course of the last six years and has formulated a strategy to advance the program for the recovery of bitumen as a multi-phased SAGD and mining development. The Corporation holds an 84% working interest in, and is the operator of, the Joslyn Project, which contains over 50,000 acres of land and oil sands rights in the McMurray formation. Enerplus holds the remaining 16% working interest in the Joslyn Project, which was purchased from the Corporation in 2002.

Athabasca Oil Sands Area

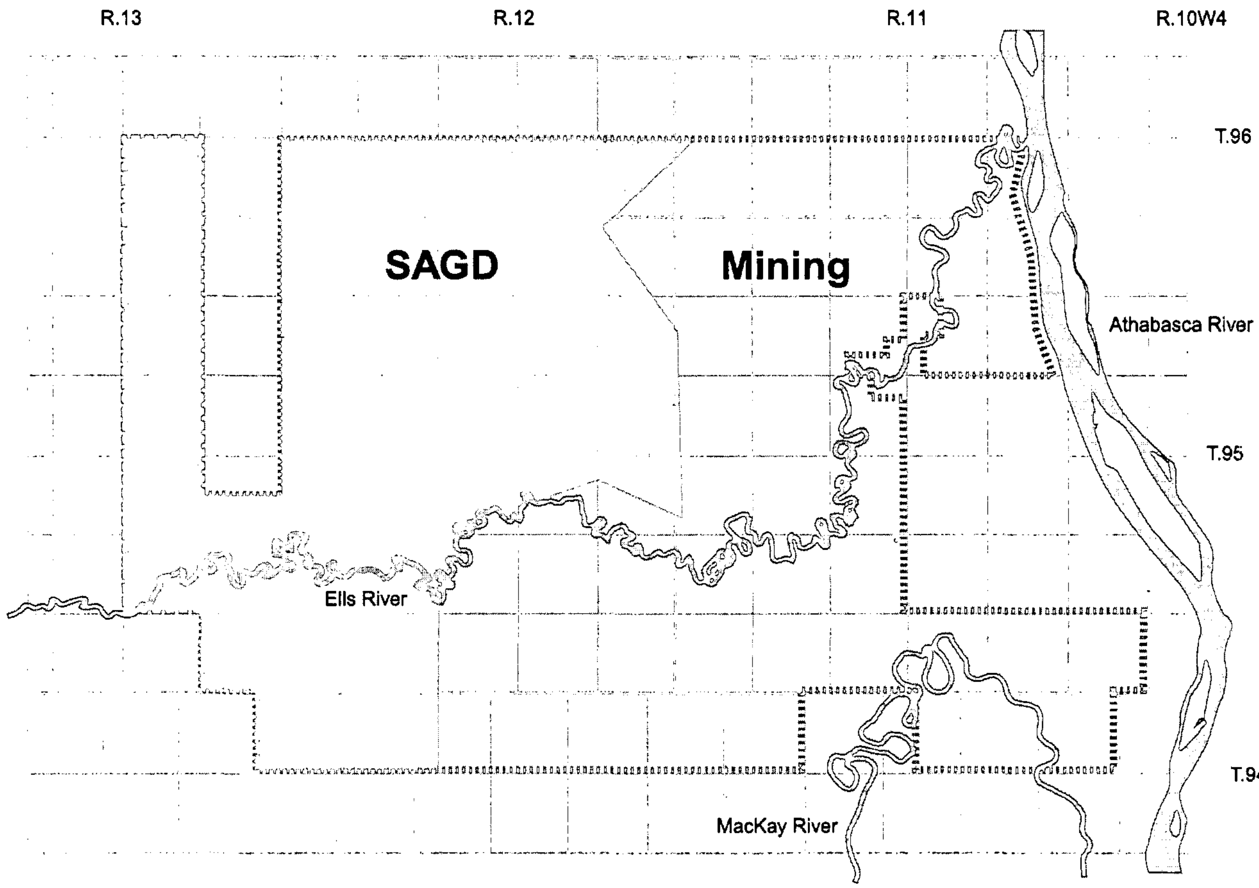


Source: Alberta Department of Energy and Industry Sources

The Joslyn Project

Deer Creek plans to develop the Joslyn Project by way of three phases of SAGD recovery and four phases of oil sands mining recovery, which is designed to produce more than 200,000 barrels of bitumen per day for more than 30 years. The Corporation's strategy is to use SAGD production recovery methods on the western portion of the Joslyn Lease where bitumen reserves and resources are not suited for mining operations. Conventional surface mining and extraction methods are planned to be used in the eastern and southern portions of the Joslyn Lease where the bitumen resource is at shallower depths suitable to mining.

Joslyn Project — SAGD and Mining



The above map of the Joslyn Lease illustrates the areas that correspond to the primary method of production and extraction that the Corporation is intending to implement.

Deer Creek expects to produce approximately 25% of the potential recoverable reserves and resources on the Joslyn Lease through SAGD production recovery methods and approximately 75% by surface mining and extraction methods.

Deer Creek plans to develop the SAGD portion of the Joslyn Lease in three phases and the mining portion of the Joslyn Lease in four phases over the next several years.

- **SAGD Phase I** is designed to produce up to 600 barrels of bitumen per day as a demonstration phase. SAGD Phase I is a small scale development focused on optimizing design, operating and production parameters to be utilized for development of later phases. This phase consists of a single well pair with steam generation, water treatment and handling facilities, and bitumen treating facilities. The SAGD

Phase I well pair and facility were completed in the first quarter of 2004 and steam injection began in April 2004. SAGD Phase I was completed on budget and on schedule.

- **SAGD Phase II** is expected to expand the production level of the Joslyn Project by 10,000 barrels of bitumen per day. The SAGD Phase II regulatory application was submitted in July 2003 and approval to produce up to 12,000 barrels of bitumen per day was received in May 2004. To achieve an incremental 10,000 barrels of bitumen production per day, SAGD Phase II is expected to initially require 17 well pairs. Additional wells will be drilled in the future, as required, to maintain a stable production profile as the production from each well pair declines. Once initial well performance is confirmed, additional wells may be drilled to increase production to the full 12,000 barrels of bitumen per day of design capacity for the SAGD Phase II facility.

- **SAGD Phase III** is expected to expand the production level of the Joslyn Project by an additional 30,000 barrels of bitumen per day. The regulatory process to obtain approval for this expansion has commenced with the preparation of a public disclosure document. The application for regulatory approval is expected to be submitted by Deer Creek in early 2005. See "The Joslyn Project — Thermal Operations". Deer Creek intends to optimize its strategy and may choose to develop SAGD Phase III as a series of smaller expansions to exploit the reserves in the most favourable manner.

- **Mine Phase I and Mine Phase II** involve the development of an initial mine pit proposed to be located on the northeast side of the Joslyn Lease over a six year development period. Each phase is expected to expand production by 50,000 barrels of bitumen per day, with Mine Phase I start up and full production expected to commence in 2011. The regulatory process to obtain approval for this expansion has commenced with the preparation of a public disclosure document. The application for regulatory approval is expected to be submitted by Deer Creek in late 2005 or early 2006.

- **Mine Phase III and Mine Phase IV** entail two additional phases, each with expected production capability of 50,000 barrels of bitumen per day. See "The Joslyn Project — Mining and Extraction Operations".

The following table sets out the current development plan for the Joslyn Project:

Joslyn Project Phases

Project Phase	Expected Incremental Bitumen Production	Estimated Start up(1)	Estimated Date of Full Production(1)
	(bbl/d)		
SAGD Phase I	600	Q2 2004	2005
SAGD Phase II	10,000	2006	2007
SAGD Phase III	30,000	2009	2010
Mine Phase I	50,000	2011	2011
Mine Phase II	50,000	2014	2014
Mine Phase III	50,000	2017	2017
Mine Phase IV	50,000	2020	2020

Note:

(1) Start up for the SAGD phases of the Joslyn Project refers to initial steaming of the wells, with full production expected 12 to 18 months after start up. Start up for the mining phases of the Joslyn Project refers to initial extraction, with full production expected six months after start up.

Reserves and Resources Evaluation

In June 2003, Deer Creek engaged Norwest to develop a resource and geologic model of the total in-place bitumen underlying the Joslyn Lease. In its report dated December 2003 (updated April 2004), Norwest estimated, based on constraints which are consistent with standard oil sands mining practices, that the Joslyn Lease contains 8.0 billion barrels of in-place bitumen resources. Norwest also estimated that a total of 3.0 billion barrels of in-place bitumen resources were suitable for evaluation as surface mineable reserves in the mining area designated by Deer Creek. Additionally, Norwest estimated that a total of 1.1 billion to 2.1 billion barrels of in-place bitumen were suitable for evaluation for recovery using SAGD from the SAGD portion of the Joslyn Lease. See "The Joslyn Project — Reserves and Resources — Norwest Report".

GLJ Associates evaluated the bitumen reserves and resources of the Joslyn Lease at year-end 2003. The following is a summary of the GLJ Report:

Summary of Reserves and Resources of the Joslyn Lease
(Forecast Prices and Costs)

	Gross Lease[1]			Working Interest[2]		
SAGD Reserves	**Reserves**		**NPV @ 10% before tax**	**Reserves**		**NPV @ 10% before tax**
	(mmbbl)		(MM$)	(mmbbl)		(MM$)
Probable		298	232		250	195
Possible		181	214		152	180
Probable plus Possible		479	446		402	375
Mining Contingent Resources	**Resources**		**NPV @ 10% before tax**	**Resources**		**NPV @ 10% before tax**
	(mmbbl)		(MM$)	(mmbbl)		(MM$)
Low estimate[3]	720		—	605		—
Best estimate	1,470	1,470	722	1,235	1,235	607
High estimate[3]	2,220		—	1,865		—
Total Probable plus Possible Reserves and Contingent Resources		**1,949**			**1,637**	

Notes:

(1) "Gross Lease" means 100% interest in the Josyln Lease before deduction of royalties and without including any royalty interests.

(2) "Working Interest" means the Corporation's 84% working interest share before deduction of royalties and without including any royalty interests.

(3) The economic forecasts for the low estimate and high estimate were not prepared.

See "The Joslyn Project — Reserves and Resources — GLJ Report".

Deer Creek Attributes

Deer Creek believes that the fundamentals for oil sands development are positive due to global economic growth and increasing demand for oil in North America and Asia. Canada's oil sands offer a secure supply to satisfy this growing demand using proven technologies. The potential growth in upgrading capacity combined with the decline of conventional heavy oil production is expected to limit the volume of heavy crude oil available for export, supporting the market for Deer Creek's bitumen production. See "Industry Overview".

In this favourable market environment, the Joslyn Project offers a significant oil sands resource with a rare combination of both SAGD and mining potential. This unique geologic setting is located near existing major oil sands projects which provides considerable access to transportation and supporting infrastructure.

The following are among Deer Creek's additional strengths:

1. *Management Depth and Experience* — Deer Creek has assembled a management team with extensive experience in the oil and gas and oil sands mining industries. A significant amount of this experience was obtained in operating large scale mining and oil and gas projects. The officers of Deer Creek are as follows:

S. Barry Jackson	—	Chairman of the Board
Glen C. Schmidt	—	President and Chief Executive Officer
John S. Kowal	—	Vice President, Finance and Chief Financial Officer
Mark A. Montemurro	—	Vice President, Thermal
Gary R. Purcell	—	Vice President, Business Development
Donald A. Riva	—	Vice President, Mining

See "The Business — Human Resources" and "Directors, Officers and Management".

2. *Staged Development* — Deer Creek's development plans for the Joslyn Project include phasing the full project development over three SAGD phases and four mine phases. Deer Creek believes the staged development of the Joslyn Project creates significant advantages over the 'mega-project' approach of other recently announced and completed oil sands projects. These advantages include:

   - greater control and management of capital costs with modular construction and manageable on-site work forces;
   - greater percentage of engineering completion prior to construction and growing experience from each stage;
   - the ability to incorporate improved and proven technology at each advancing stage; and
   - maximization of shareholder exposure to oil sands resources by minimizing dilution at each stage of development.

3. *Project Development Success* — Deer Creek has successfully engineered, implemented, financed and constructed both the Pilot Project and SAGD Phase I on budget and on schedule. In doing so, Deer Creek has:

   - demonstrated an open communication and consultation strategy;
   - validated SAGD application to the Joslyn Lease;
   - developed positive relationships with stakeholders; and
   - developed insight into carrying on business in Alberta's oil sands by working with governments, contractors, local stakeholder groups and the financial community, which will assist Deer Creek in dealing with the challenges associated with the larger scale of subsequent phases.

4. *Alternative Development and Exploitation Opportunities* — As the future phases of the Joslyn Project evolve, Deer Creek will be in a position to investigate alternatives to further optimize the Joslyn Project. Examples of such alternatives include:

   - combining SAGD and mining operations to improve capital, operating and environmental efficiencies;
   - use of alternative fuel sources to reduce Deer Creek's reliance on natural gas;
   - optimization of marketing and bitumen upgrading options as production from the Joslyn Project increases and as markets, transportation and refining options evolve; and
   - implementation of a tested and proven modular design for the exploitation of other oil sands opportunities.

See "The Business — Deer Creek's Attributes".

Risk Factors

Prospective purchasers of Common Shares should carefully consider the information set forth under "Risk Factors" and other information set forth herein before deciding to invest in the Common Shares.

An investment in Common Shares is speculative due to the Corporation's present stage of development and certain other factors. Risks inherent in an investment in Common Shares include construction and operation risks associated with the Joslyn Project and the overall feasibility and viability of the Joslyn Project. Subscribers for Common Shares must rely on the ability, expertise, judgment, discretion and good faith of the management of the Corporation and the Board of Directors.

Based on current scheduling, the Joslyn Project is not expected to commence commercial SAGD operations until 2006. Accordingly, various changes to the Joslyn Project may be made prior to its completion. The information contained herein, including, without limitation, estimates of resources, reserves, and costs and economic evaluations, is conditional upon no material changes being made to the Joslyn Project or its scope. In addition, an investment in Common Shares will be subject to certain other risks including, without limitation:

- fluctuation of oil and natural gas prices and heavy oil differentials;
- project delays;
- interruption of operations or increased operating costs;
- the operation and performance of the Joslyn Project's wells and bitumen recovery facilities;
- operational hazards associated with the Joslyn Project's operations;
- the possibility of cost overruns;
- the availability of additional capital needed to develop the Joslyn Project;
- the Corporation's dependence upon others including Enerplus, third party licensors of technology and third party designers, contractors and suppliers;
- quantities and qualities of reserves and resources which may be subject to variance;
- availability of diluent which is required to transport bitumen to market;
- uncertain demand for the bitumen produced by the Joslyn Project (which the Corporation expects will not be available until at least 2006, based on current scheduling);
- uncertainty as to the timing of construction of oil production and diluent pipelines which are to be built by third parties;
- uncertainty as to the costs of transportation of production;
- competition, including from other entities or oil sands projects;
- the availability of debt financing and the ability of the Corporation to service that debt;
- the possibility of adverse foreign exchange fluctuations;
- adverse changes to government regulation, including regulation concerning fiscal and environmental matters;
- the risk of aboriginal claims;
- hedging risks; and
- the need to hire and retain an experienced pool of employees.

See "Risk Factors".

GLOSSARY OF TERMS

In this prospectus, the following terms shall have the meanings set forth below, unless otherwise indicated:

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any amendments thereto and all regulations promulgated thereunder;

"**AECO**" means the regional pricing hub for natural gas located at storage facilities of Alberta Energy Company, near Medicine Hat, Alberta;

"**Alberta Environment**" means Alberta Environment, a department of the Government of Alberta;

"**BDR Engineering**" means Bower Damberger Rolseth Engineering Ltd., an independent engineering, procurement and construction management firm;

"**bitumen**" means a heavy viscous crude oil;

"**Board of Directors**" means the board of directors of the Corporation, from time to time;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society);

"**Common Shares**" means the common shares in the capital of the Corporation, after giving effect to the Consolidation;

"**Consolidation**" means the five for one consolidation of the Common Shares effective June 1, 2004;

"**Corporation**" or "**Deer Creek**" means Dear Creek Energy Limited, a corporation incorporated pursuant to the ABCA;

"**Enerplus**" means Enerplus Resources Fund, which wholly-owns EnerMark Inc.;

"**EUB**" means the Alberta Energy and Utilities Board;

"**Existing Credit Facility**" means the $6 million, 364-day revolving, committed credit facility extended to the Corporation by a Canadian chartered bank;

"**First Preferred Shares**" means the first preferred shares in the capital of the Corporation;

"**GAAP**" means Canadian generally accepted accounting principles;

"**GLJ Associates**" means Gilbert Laustsen Jung Associates Ltd., an independent petroleum consulting firm;

"**GLJ Report**" means the report prepared by GLJ Associates dated March 16, 2004 and effective January 1, 2004 setting out GLJ Associates' evaluation of the bitumen reserves and resources of the Joslyn Lease;

"**heavy oil differential**" means the difference in market price between heavy and light crude oils grades;

"***in-situ***" means, when referring to oil sands, a process for recovering bitumen from oil sands by means other than surface mining;

"**Joint Venture Agreement**" means the joint venture agreement dated for reference July 1, 2002 made between the Corporation and a wholly-owned subsidiary of Enerplus;

"**Joslyn Lease**" means the sections of land contained within Lease 24 and Permit 70;

"**Joslyn Project**" or "**Project**" means the Thermal Operations and the Mining and Extraction Operations on the Joslyn Lease;

"**Lease 24**" means Alberta Oil Sands Lease No. 7280060T24;

"**Lime Rock**" means The Beacon Group Energy Investment Fund II, L.P., Riverside Investments LLC on behalf of The Beacon Group Energy Investment Fund II, L.P. and Friends of Lime Rock LP;

"**Mining and Extraction Operations**" means the facilities to be constructed for the purpose of, and the activities associated with, extracting and producing bitumen from the Joslyn Lease using surface mining recovery;

"**Mine Phase I**" means the first phase of the mining development of the Joslyn Project, including the facilities and infrastructure to be constructed for the purpose of extracting and producing bitumen from the Joslyn Lease;

"**Mine Phase II**" means the second phase of the mining development of the Joslyn Project, including the facilities and infrastructure to be constructed for the purpose of extracting and producing bitumen from the Joslyn Lease;

"**Mine Phase III**" means the third phase of the mining development of the Joslyn Project, including the facilities and infrastructure to be constructed for the purpose of extracting and producing bitumen from the Joslyn Lease;

"**Mine Phase IV**" means the fourth phase of the mining development of the Joslyn Project, including the facilities and infrastructure to be constructed for the purpose of extracting and producing bitumen from the Joslyn Lease;

"**NEB**" means the National Energy Board;

"**NI 51-101**" means National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*;

"**New Credit Facility**" means the committed credit facility of $65 million to be provided by certain Canadian chartered banks to the Corporation;

"**1933 Act**" means the *United States Securities Act of 1933*, as amended;

"**Norwest**" means Norwest Corporation, an independent mining and environmental consulting company;

"**Norwest Report**" means the Lease 24/Permit 70 Geological Modeling and Evaluation of Bitumen Potential report prepared by Norwest dated December 2, 2003 (updated April 2004);

"**Offered Shares**" means the Common Shares to be issued by the Corporation pursuant to this prospectus;

"**Offering**" means the offering by the Corporation of the Offered Shares;

"**Over-Allotment Offering**" means the option granted by the Corporation to the Underwriters to purchase the Over-Allotment Shares at a price of $9.50 per Over-Allotment Share;

"**Over-Allotment Option**" means the option, granted by the Corporation to the Underwriters, exercisable in whole or in part, for a period of 30 days from closing of the Offering, to purchase the Over-Allotment Shares (representing 10% of the Offered Shares to be issued pursuant to the Offering);

"**Over-Allotment Shares**" means up to 1,690,000 Common Shares to be distributed by the Corporation to the Underwriters pursuant to the Over-Allotment Offering;

"**Permit 70**" means Alberta Oil Sands Permit No. 7099110070;

"**Pilot Project**" or "**Pilot**" means the initial field tests on Lease 24 to test the application of proprietary multi drain and SAGD technology;

"**Pre-Consolidation Shares**" means common shares in the capital of the Corporation, before giving effect to the Consolidation;

"**PSU Plan**" means the performance share unit plan of the Corporation;

"**SAGD**" means Steam Assisted Gravity Drainage, an *in-situ* production process used to recover bitumen from oil sands;

"**SAGD Phase I**" means the first phase of the SAGD development of the Joslyn Project, including the facilities, infrastructure, wells and well pads to be constructed for the purpose of producing bitumen from the Joslyn Lease;

"**SAGD Phase II**" means the second phase of the SAGD development of the Joslyn Project, including the facilities and infrastructure, wells and well pads to be constructed for the purpose of producing bitumen from the Joslyn Lease;

"**SAGD Phase III**" means the third phase of the SAGD development of the Joslyn Project, including the facilities and infrastructure, wells and well pads to be constructed for the purpose of producing bitumen from the Joslyn Lease;

"**Stock Option Plan**" means the stock option plan of the Corporation;

"**synbit**" means a blend of bitumen and synthetic crude oil;

"**synthetic crude oil**" means a mixture of hydrocarbons similar to crude oil derived by upgrading bitumen from oil sands;

"**Talisman**" means Talisman Energy Inc.;

"**Talisman Agreement**" means the asset purchase and sale agreement dated as of March 1, 1998 made between the Corporation and Talisman;

"**Talisman Debenture**" means the debenture dated December 1, 1999 granted by the Corporation in favour of Talisman in the principal amount of $21 million and any amendments thereto;

"**Thermal Operations**" means the facilities to be constructed for the purpose of, and the activities associated with, producing bitumen from the Joslyn Lease using the SAGD process together with the Pilot Project;

"**TSX**" means the Toronto Stock Exchange;

"**Underwriters**" means Peters & Co. Limited, RBC Dominion Securities Inc., Merrill Lynch Canada Inc., CIBC World Markets Inc., Scotia Capital Inc., Canaccord Capital Corporation, First Associates Investments Inc., FirstEnergy Capital Corp., Raymond James Ltd. and Salman Partners Inc.;

"**United States**" or "**U.S.**" means the United States of America;

"**Washington Group**" means Washington Group International, Inc., an independent engineering, construction and management solutions company;

"**Washington Group Study**" means the Joslyn Oil Sands Project Preliminary Feasibility Study prepared by Washington Group dated March 2004; and

"**WTI**" means West Texas Intermediate grade crude oil at a reference sales point in Cushing, Oklahoma, a common benchmark for crude oil.

ABBREVIATIONS

"**°API**" means degrees API, a measure of hydrocarbon density;

"**bbl**" means barrels, which are equal to 0.15899 cubic metres;

"**bbl/d**" means barrels per day;

"**Bbbl**" means billions of barrels;

"**GJ**" means gigajoule, the metric unit of heating value equivalent to 943,213 British thermal units;

"**kVa**" means kilovolt-ampere demand, the maximum number of kilovolt-ampere hours per defined time interval;

"**M$**" means thousands of dollars and "**MM$**" means millions of dollars;

"**mbbl**" means thousands of barrels;

"**mmbbl**" means millions of barrels;

"**mmbbl/d**" means millions of barrels per day;

"**mcf**" means thousands of cubic feet;

"**mmbtu**" means millions of British thermal units; and

"**m^3**" means metres cubed.

DEER CREEK ENERGY LIMITED

The Corporation was incorporated pursuant to the ABCA on October 1, 1996. On January 17, 1997, the Corporation filed Articles of Amendment to remove both the share transfer restrictions attached to the Pre-Consolidation Shares and the private company restrictions contained in its Articles of Incorporation. On September 2, 1999, the Corporation filed Articles of Amendment to redesignate 70,000,000 First Preferred Shares as First Preferred Shares, Series A and to provide for the rights, privileges, restrictions and conditions attaching to such shares. On March 20, 2000, the Corporation filed Restated Articles of Incorporation to amend the rights, privileges, restrictions and conditions attaching to the First Preferred Shares, Series A. On October 9, 2002, the Corporation filed Articles of Amendment to cancel the First Preferred Shares, Series A. On June 1, 2004, the Corporation filed Articles of Amendment to, among other things, consolidate the then outstanding Pre-Consolidation Shares on a five for one basis.

The Corporation's head office is located at Bow Valley Square II, Suite 2600, 205 - 5th Avenue S.W., Calgary, Alberta, T2P 2V7, and its registered office is located at Suite 4500, 855 - 2nd Street S.W., Calgary, Alberta T2P 4K7.

THE BUSINESS

Business and Strategy

Deer Creek is a Calgary-based oil sands development and exploitation company. Established in October 1996, the Corporation is engaged in the business of developing, operating, producing and selling recoverable bitumen found in the Athabasca oil sands deposits through SAGD and mining extraction methods. Deer Creek's principal assets include Lease 24 and Permit 70, collectively known as the Joslyn Lease. The Joslyn Lease is located in the regional municipality of Wood Buffalo, approximately 60 kilometres north of Fort McMurray in northern Alberta. Deer Creek has been evaluating and developing the Joslyn Project over the course of the last six years and has formulated a strategy to advance the program for the recovery of bitumen as a multi-phased SAGD and mining development. The Corporation holds an 84% working interest in, and is the operator of, the Joslyn Project, which contains over 50,000 acres of land and oil sands rights in the McMurray formation. Enerplus holds the remaining 16% working interest in the Joslyn Project, which was purchased from the Corporation in 2002.

The Corporation's strategy is to develop the Joslyn Project in manageable phases. The business plan envisions three phases of SAGD production development and four phases of mining and extraction development. Deer Creek is of the view that its stepped development approach will allow it to manage the operational and financial requirements of the Joslyn Project as it grows in scale and complexity. The Corporation intends to have an adaptive development strategy that allows for the continuous evaluation and adjustment of design and execution options as it incorporates its own and industry experiences, improvements in technology, and stakeholder input. Deer Creek expects this strategy to allow future developments to be more technically advanced and cost effective than developing the Joslyn Project as one large project. The Joslyn Project's estimated life is more than 30 years and Deer Creek intends to revise and optimize its strategy and plan of development for the Joslyn Project, with the aim to exploit the reserves and resources in the most optimal manner. See "The Joslyn Project".

Deer Creek's Attributes

Significant Reserves and Resources

In the Norwest Report, Norwest estimated that the Joslyn Lease contains 8.0 billion barrels of in-place bitumen. In the GLJ Report, GLJ Associates estimated Deer Creek's working interest of (i) probable plus possible reserves, before royalties, assigned to the SAGD portion of the Joslyn Lease to be 402 million barrels of bitumen and (ii) contingent resources best estimate, before royalties, assigned to the mining portion of the Joslyn Lease to be 1.2 billion barrels of bitumen. See "The Joslyn Project — Reserves and Resources".

SAGD and Mining Potential

The Joslyn Project is planned to be developed using a combination of both SAGD and mining methods. This is expected to allow Deer Creek to first establish SAGD production, which benefits from lower economies of scale. Through SAGD operations, Deer Creek will establish on-site infrastructure and utilities and cash flow as a platform from which to develop the mining phases of the Project. Deer Creek's current development plans anticipate an oil sands production base of approximately 40,000 barrels of bitumen per day from the Joslyn Lease, before the Corporation launches the development of its mining phases.

Management Depth and Experience

Deer Creek has assembled a management team with extensive experience in the oil and gas and oil sands mining industries. A significant amount of this experience was obtained in operating large scale mining and oil and gas projects. See "The Business — Human Resources" and "Directors, Officers and Management".

Staged Development

Deer Creek's development plans for the Joslyn Project include phasing the full project development over three SAGD phases and four mine phases. Deer Creek believes the staged development of the Joslyn Project creates significant advantages over the 'mega-project' approach of other recently announced and completed oil sands projects. These advantages include:

- greater control and management of capital costs with modular construction and manageable on-site work forces;
- greater percentage of engineering completion prior to construction and growing experience from each stage;
- the ability to incorporate improved and proven technology at each advancing stage; and
- maximization of shareholder exposure to oil sands resources by minimizing dilution at each stage of development.

Project Development Success

Deer Creek has successfully engineered, implemented, financed and constructed both the Pilot Project and SAGD Phase I on budget and on schedule. In doing so, Deer Creek has:

- demonstrated an open communication and consultation strategy;
- validated SAGD application to the Joslyn Lease;
- developed positive relationships with stakeholders; and
- developed insight into carrying on business in Alberta's oil sands by working with governments, contractors, local stakeholder groups and the financial community, which will assist Deer Creek in dealing with the challenges associated with the larger scale of subsequent phases.

See "Joslyn Project Development — Stakeholder Consultation".

Alternative Development and Exploitation Opportunities

Both SAGD and mining operations will be used in the Joslyn Project. While these activities can be developed independently, the geography and geology of the Joslyn Lease are such that operations may be combined and developed simultaneously. Initial studies suggest that such a combination has the potential to decrease both capital requirements and operating costs from independent staged development. The advantages include potential reductions in per unit costs of production, energy requirements, water utilization and emissions. Deer Creek plans to continue to refine these initial studies to confirm the potential of such combined operations.

Natural gas is the current fuel of choice for steam generation given its availability and infrastructure accessibility. Options to replace natural gas as a fuel source are under review by industry and include alternatives such as coal, bitumen, or using the heaviest, least valuable, component of a produced bitumen barrel. Deer Creek has focused on studies utilizing bitumen or the heavy components of the produced bitumen barrel as alternatives to natural gas. The test burning of bitumen as a fuel source was included in the SAGD Phase II EUB approval received in May 2004. Testing will be conducted during the SAGD Phase II operations to better define the economics of this steam generation option.

Focusing on staged operations and a defined strategy of optimizing the modularization of the Joslyn Project affords Deer Creek the ability to target a SAGD production template of 10,000 to 15,000 barrels of bitumen per day. Definition of this template size will not only allow for the management of capital costs, but will also provide the potential to create a competitive advantage in exploiting smaller SAGD opportunities in the Athabasca region. The focus on smaller scale and modular installations brings a more conventional oil exploitation strategy to capturing and developing new oil sands opportunities. This strategy is distinct from the large project, single step, strategy of other recently announced and completed oil sands projects.

By staging the development of the Joslyn Project, Deer Creek will retain the option to best optimize bitumen upgrading and marketing. When a production level of approximately 100,000 barrels of bitumen per day has been reached, Deer Creek could have the financial capacity and economies of scale to elect to develop its own upgrading solution. Prior to that, Deer Creek will monitor future developments in synthetic crude, upgrading and bitumen production, as well as changes in the transportation and the refining sectors. Monitoring these future developments and related results will better define the optimal economics for Deer Creek's upgrading decision.

Human Resources

The Corporation's human resources objective is to build and retain an entrepreneurial, highly skilled and dedicated team. A priority of the Corporation is to develop an atmosphere for an effective workplace that attracts and retains key personnel and empowers effective decision making.

Deer Creek has taken steps to anticipate and plan for growth that mirrors its stepped multi-phase development and exploitation plan. It has been the practice of the Corporation to staff key positions early and to add depth as operational plans progress. The Corporation has assembled a core management team with a diverse and complementary set of skills and experience with the capacity and capability to develop the Joslyn Project.

Management and Technical Team

The management team reflects a depth of experience, leadership and technical expertise to allow Deer Creek to realize its development plans. See "Directors, Officers and Management".

In addition to its leadership group, Deer Creek has assembled a team of talented technical and management individuals comprised of:

	Full Time	Contracted Professionals
Technical Managers(1)	6	—
Geologists	1	3
Engineering Personnel(1)	9	6
Financial/Planning	5	—
Regulatory and Stakeholder	1	2

Note:

(1) Includes members of Deer Creek's executive and management engineering staff who may fall into this category.

SAGD Field Operations Team

In addition to the management and technical teams, the 11 field operations personnel located at the SAGD Phase I plant site collectively have approximately 198 combined years of operating experience, including 37 years of commissioning experience and 107 years of lead operator experience. This background qualifies this group of individuals to commission and run facilities in the phased approach Deer Creek has planned.

Historical Development

Early Venture Capital Investment

Lime Rock provided Deer Creek with the original venture capital required to undertake the Joslyn Project. In 1998 and 1999, Deer Creek issued debentures in four separate financings. The first debenture, in the amount of $1.5 million, was issued in 1998 and provided the Corporation with the funds required to satisfy the initial obligations under a farmout with Talisman, thereby earning the option to acquire Lease 24 pursuant to the Talisman Agreement. In 1999, the Corporation completed three additional debenture financings with proceeds of $93,533, US$4.5 million, and US$5.7 million. The proceeds from these transactions were used to complete the purchase of assets under the Talisman Agreement and to fund the Pilot Project. All of the outstanding debentures were consolidated in December 1999. In August 2002, Deer Creek completed an agreement with Lime Rock to set-off the consolidated debenture together with all accrued interest, by the subscription for 14,361,800 Common Shares.

Pilot Project

The development of the Joslyn Project commenced in 1998 with initial field tests on Lease 24 using proprietary multi drain SAGD oil recovery technology. The Pilot Project was located on the north part of Lease 24. In November 1998, Deer Creek carried out the initial stage of the Pilot Project with the drilling of one horizontal well and one vertical well followed by 45 days of steam injection operations. Engineering and other technical work then continued in preparation for the second stage of the Pilot Project. The second stage of the Pilot Project field operations commenced in the winter of 2000 and continued until March 2001 with the drilling of four additional vertical wells and a second horizontal well. Steam injection commenced in February 2000, followed by a second round of drilling in September and October 2000, which included a SAGD well pair.

The Pilot Project consisted of a total of 13 pilot wells, two disposal wells, and one water supply well. The Pilot tested a variety of well architectures, including a dual well pair. In November 2000, the bitumen production rate exceeded the target rate established in the Talisman Agreement. The Pilot operation was subsequently discontinued in March 2001 and the test facilities dismantled. The dual well pair had a cumulative steam oil ratio of approximately 2.8 m^3/m^3 during the four month duration of the test and an average steam oil ratio in the final month of the test of approximately 2.4 m^3/m^3. The results of the test confirmed well performance and were sufficiently positive that Deer Creek proceeded with plans to develop the Joslyn Project.

Three Year History

The following is a summary of the general development of the business of the Corporation since January 2001:

2001

During 2001, Deer Creek completed a 28 well core hole drilling program to further delineate the Joslyn Project and to provide additional resource definition and successfully completed the Pilot Project.

During 2001, the Corporation issued 259,274 flow-through special warrants at a price of $1.35 per special warrant (approximately 51,855 flow-through special warrants at a price of $6.75 per special warrant after giving effect to the Consolidation) and 1,267,608 flow-through special warrants at a price of $1.25 per special warrant (approximately 253,523 flow-through special warrants at a price of $6.25 per special warrant after giving effect to the Consolidation) for total gross proceeds of $1.9 million. Each special warrant entitled the holder to receive, upon exercise, one Pre-Consolidation Share at no additional cost. All of the outstanding special warrants were exercised prior to the effective date of the Consolidation and the Corporation issued 1,526,882 Pre-Consolidation Shares (approximately 305,378 Common Shares).

2002

During 2002, Deer Creek completed a 31 well core hole drilling program to further delineate the Joslyn Project resource base. This drilling program completed Deer Creek's evaluation requirements to extend the tenure of Lease 24. Approval of the lease extension was granted in June 2002 with the designated status of a continued lease. Regulatory approval for SAGD Phase I was received in May 2002. A regulatory application was made in August 2002 to relocate the SAGD Phase I demonstration development to the west side of Lease 24, away from the potential mining area.

On August 8, 2002, the Corporation sold 16% of its then 100% interest in the Joslyn Project to Enerplus for gross proceeds of $16.0 million plus the assumption by Enerplus of 16% of the contingent obligations to Talisman. See "Enerplus Joint Venture". As continuing security for the due performance and discharge of its covenants, obligations and liabilities under the Talisman Agreement, the Corporation also granted the Talisman Debenture in the principal amount of $21.0 million to Talisman, which is contingently payable by reference to Deer Creek achieving certain production thresholds from the Joslyn Lease. See "Talisman Debenture". Enerplus has assumed its 16% share of the Talisman Debenture and the obligations of the Corporation thereunder.

On August 8, 2002, the Corporation completed an agreement with Lime Rock to satisfy the previously issued consolidated debenture and all accrued interest, by the subscription for 71,809,000 Pre-Consolidation Shares (approximately 14,361,800 Common Shares).

On August 8, 2002, the Corporation completed a private placement of 26,321,407 Pre-Consolidation Shares at a price of $0.93 per Pre-Consolidation Share (approximately 5,264,282 Common Shares at a price of $4.65 per Common Share) for gross proceeds of $24.5 million. The net proceeds from this financing were used for the continued development of the Joslyn Project.

On August 30, 2002, the shareholders of the Corporation approved a special resolution to reduce the stated capital of the Pre-Consolidation Shares, pursuant to the ABCA, in the aggregate amount of $7,208,000 and to contribute this amount to the Corporation's contributed surplus. Putting this resolution before shareholders for their consideration was in accordance with the contractual obligations of the Corporation to Lime Rock under agreements relating to their investment in Deer Creek. See "Historical Development — Early Venture Capital Investment".

On November 28, 2002, the Corporation completed a private placement of 4,545,455 flow-through Pre-Consolidation Shares at a subscription price of $1.10 per flow-through Pre-Consolidation Share (approximately 909,091 Common Shares at a price of $5.50 per flow-through Common Share) for gross proceeds of $5.0 million. The net proceeds from this financing were used to pay costs related to the 2003 winter drilling program.

During the year, Deer Creek expanded its management team with the addition of two senior officers, Mark Montemurro, Vice President, Thermal and Don Riva, Vice President, Mining.

2003

During the first quarter of 2003, the Corporation completed a 107 well drilling program of core holes and utility wells. By year end, the well database for the Joslyn Project had increased to more than 370 wells, providing additional information to evaluate the total resource.

In July 2003, the Corporation applied for regulatory approval for SAGD Phase II, a 10,000 barrels of bitumen per day SAGD expansion. While the regulatory review process continued, the Corporation worked with stakeholders over the course of the year to address their concerns and interests regarding the development plans for SAGD Phase II.

In the second half of 2003, the Corporation focused on the engineering design, major equipment construction, and site and access road construction for SAGD Phase I. Deer Creek's objectives included managing the modularization of the SAGD Phase I facilities, start-up protocols and detailed well design optimization.

During the second half of 2003, Deer Creek began gathering initial base-line environmental data and developing the preliminary engineering design for the SAGD Phase II facility. Detailed engineering commenced on SAGD Phase II in the third quarter of 2003.

In November 2003, the Corporation successfully drilled its initial demonstration well pair for SAGD Phase I.

On November 4, 2003, the Corporation completed a private placement of 5,000,000 flow-through Pre-Consolidation Shares at a price of $2.00 per Pre-Consolidation Share (approximately 1,000,000 flow-through Common Shares at a price of $10.00 per Common Share), for gross proceeds of $10.0 million. The net proceeds from this financing were used to fund the Corporation's winter core hole delineation program in early 2004.

Deer Creek continued to advance the mining aspects of the Project by retaining Norwest to construct a geological model using industry-accepted surface mining criteria. See "The Joslyn Project — Reserves and Resources — Norwest Report". The Corporation commissioned a preliminary feasibility study conducted by Washington Group that was finalized in early 2004. See "The Joslyn Project — Reserves and Resources — Washington Group Study". In addition, Deer Creek commissioned GLJ Associates to evaluate the reserves and resources of the Corporation. See "The Joslyn Project — Reserves and Resources — GLJ Report".

During the year, Deer Creek expanded its management team with the addition of two senior officers, John Kowal, Vice President, Finance and Chief Financial Officer and Gary Purcell, Vice President, Business Development.

Year to Date

During the first quarter of 2004, the Corporation completed an additional 195 well core hole drilling program that expanded its geological well database to more than 560 wells on the Joslyn Lease. Successful completion of the SAGD Phase I facility construction occurred in the first quarter of 2004.

On January 28, 2004, the Corporation completed a private placement of 10,100,000 Pre-Consolidation Shares at a price of $1.75 per Pre-Consolidation Share (approximately 2,020,000 Common Shares at a price of $8.75 per Common Share) for gross proceeds of $17.7 million. The net proceeds from this financing were used for the continued development of the Joslyn Project and, specifically, the completion of SAGD Phase I construction and start up.

On March 25, 2004, the Corporation secured the Existing Credit Facility.

During the first quarter of 2004, Washington Group completed a preliminary feasibility study of the Mining and Extraction Operations. See "The Joslyn Project — Reserves and Resources — Washington Group Study". Follow-up analysis of this study over the balance of 2004 will focus on optimizing the mine development plan.

On April 10, 2004, steam injection began as SAGD Phase I operations commenced. Production response from the production well is expected in the third quarter of 2004.

Year to date 2004, engineering design has continued for SAGD Phase II and the initial mine development. The SAGD Phase II design base memorandum was completed in April 2004.

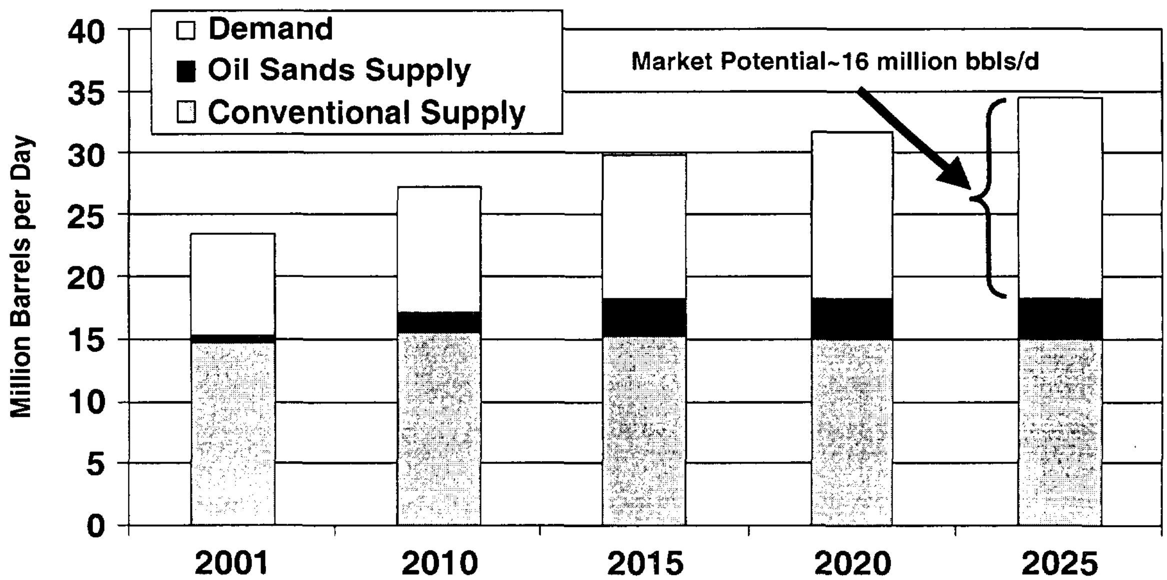
In May 2004, the Corporation received EUB regulatory approval for the SAGD Phase II expansion.

On May 20, 2004, the shareholders of the Corporation approved, among other things, a special resolution to reduce the stated capital of the Pre-Consolidation Shares, pursuant to the ABCA, in the aggregate amount of $18,227,960 and to contribute such amount to the Corporation's contributed surplus. Putting this resolution before shareholders for their consideration was in accordance with the contractual obligations of the Corporation to Lime Rock under agreements relating to their investment in Deer Creek. Additionally, a special resolution approving the Consolidation was presented and approved by shareholders. Articles of Amendment to give effect to the Consolidation were filed on June 1, 2004.

General Overview

The Energy Information Agency of the United States Department of Energy forecasts petroleum demand in North America to grow to 34 million barrels per day by 2025. United States' consumption represents the largest share of this growing demand and the United States is currently only capable of producing approximately 45% of its requirement from domestic sources. This forecasted increase in demand means the United States is expected to grow increasingly dependent on foreign oil supplies from 9 million barrels per day in 2001 to approximately 16 million barrels per day by 2025.

North American Petroleum Supply and Demand



Note:

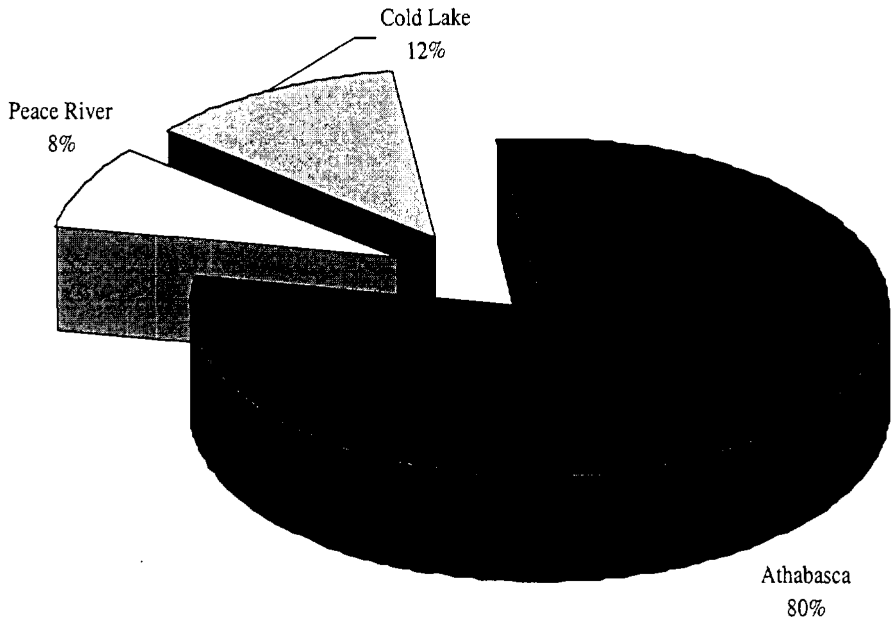
This chart has been prepared from information obtained from the Energy Information Agency of the United States Department of Energy.

Canada is playing a key role as a secure supplier of crude oil to meet this growing demand. The United States imports more crude oil from Canada than any other country. Canada is expected to continue to be amongst the largest exporters to the United States over the next 15 years.

Resource Size and Potential

Alberta's oil sands are abundant and interest in the region's potential has accelerated as reductions in development and production costs have made oil sands economically viable. In the Alberta's Reserves 2003 and Supply/Demand Outlook 2004-2013, the EUB estimated that Alberta's oil sands contain approximately 1.6 trillion barrels of bitumen in-place. Alberta's massive crude bitumen resources are contained in sand and carbonate formations in three regions: the Athabasca, Cold Lake and Peace River oil sands areas.

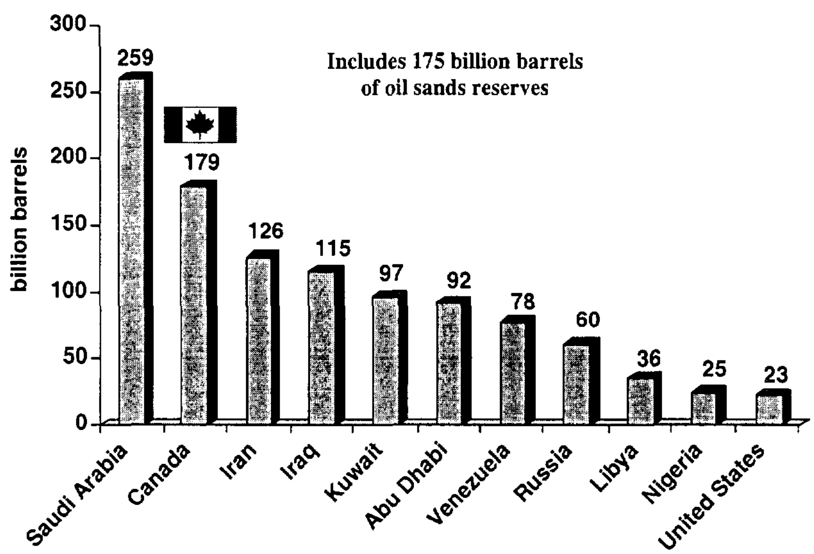
Initial in-place volume of crude bitumen



Note:
This chart has been prepared from information obtained from the Alberta's Reserves 2003 and Supply/Demand Outlook 2004-2013.

The Alberta's Reserves 2003 and Supply/Demand Outlook 2004-2013 further estimates that approximately 315 billion barrels are considered potentially recoverable under anticipated technologies, of which 175 billion barrels are categorized as proven reserves that can be recovered using current technology. This petroleum resource is second in size only to Saudi Arabia, representing approximately 15% of world reserves. In comparison, estimates of the potential for recoverable crude are 23 billion barrels from the Gulf of Mexico and 8 billion barrels from the Alaska National Wildlife Reserve, as determined by the United States Department of the Interior and United States Geological Survey, respectively.

Global Crude Oil Reserves by Country

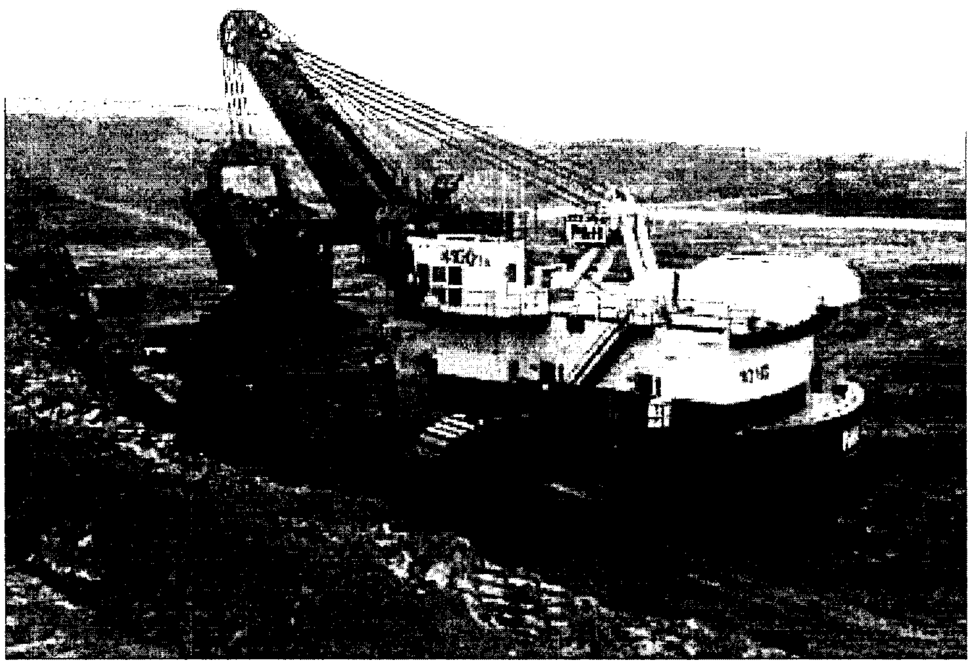


Source: Oil & Gas Journal

Recovery Methods

Oil sands consist of a mixture of sand, bitumen, clays, minerals and water. The depth and location of the crude oil in Alberta's oil sands influences the production methods used for the recovery of bitumen. Overcoming the high viscosity and lack of mobility of the crude oil is achieved either physically or thermally. Physical surface mining and extraction is used in the production of Athabasca oil sands where the total overburden generally does not exceed 75 metres. Thermal production recovery techniques that involve heating the bitumen are used in Athabasca, as well as Cold Lake and Peace River. Overall, 20% of Alberta's oil sands is estimated to be suitable for mining and 80% for *in-situ* recovery techniques.

Oil sands mining operations typically utilize open pit truck and shovel techniques. Soil and rock overburden and the oil sands are excavated using large shovels and hauled away by large trucks. Waste material is either disposed of in previously mined areas or stored for future disposal or reclamation while the oil sands are transported to ore processing facilities where it is crushed, sized and conveyed to the slurry preparation facility. The oil sands are then mixed with warm water to create a slurry mixture that is then transported to the extraction facility.



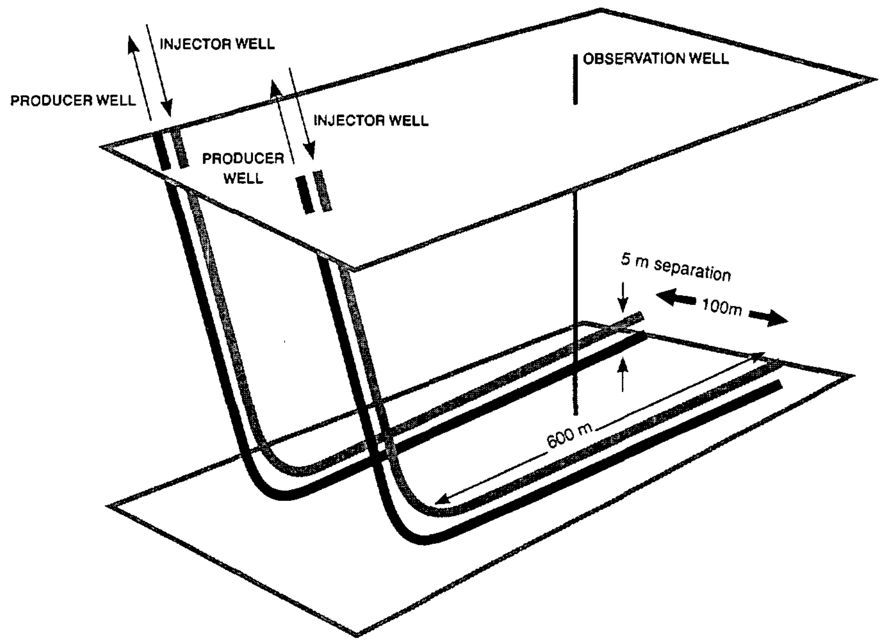
Source: Harnischfeger Corporation of Canada Ltd.

The energy input costs for mining operations are approximately one third of the natural gas required for thermal *in-situ* operations. The dominant cost in mining operations is materials handling as approximately two tons of oil sands are required to produce one barrel of oil. The implementation of large truck and shovel operations has significantly reduced operating costs from the original bucketwheel technology utilized in the first oil sand mine in the late 1960's. An NEB publication titled "Canada's Oil Sands: A Supply and Market Outlook to 2015" projects operating costs for combined mine and upgrading projects to decline to $10 per barrel by 2005 from $20 per barrel in 1998.

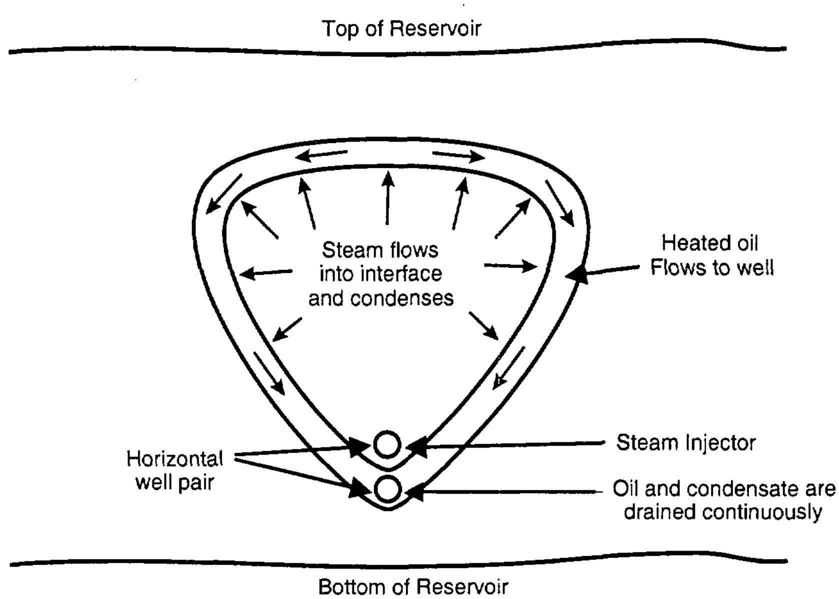
Suncor Energy Inc., the pioneer of oil sands mining has been operating since the late 1960's and Syncrude Canada Ltd. has been operating since the late 1970's. The Athabasca Oil Sands Project, operated by Albian Sands Energy Inc. came on stream in 2004. Other mining projects under construction and approved projects in the planning stages include Fort Hills (TrueNorth Energy LP) and Horizon (Canadian Natural Resources Limited).

The two most common methods of *in-situ* production recovery are cyclic steam stimulation and SAGD. Cyclic steam stimulation involves the cyclic process of steam injection followed by production from a single well bore. SAGD is an *in-situ* production process that produces bitumen from oil sands reservoirs without removing the associated sand. SAGD involves the use of a stacked pair of horizontal wells spaced approximately five vertical meters apart. Steam is injected into the upper well where it heats the oil sands reservoir. The heated bitumen becomes mobile and flows with condensed steam to the lower horizontal well and is then pumped to the surface. *In-situ* recovery processes cause considerably less surface disturbance than mining operations that involve excavation of the sand and bitumen, extraction of the bitumen from the sand and the return of the sand to tailings ponds. The SAGD process was first used in 1978 and is now being employed as the production recovery process in virtually all new Athabasca oil sand *in-situ* projects under development.

SAGD Well Pair



SAGD Production Process



Commercial SAGD projects currently producing or under development include Foster Creek and Christina Lake (EnCana Corporation), McKay River (Petro-Canada), Firebag (Suncor Energy Inc.), Hangingstone (Japan Canada Oil Sands Ltd.), Surmont (ConocoPhillips Canada Ltd.), Long Lake (OPTI Canada Inc. and Nexen Inc.) and Tucker Lake (Husky Energy Inc.).

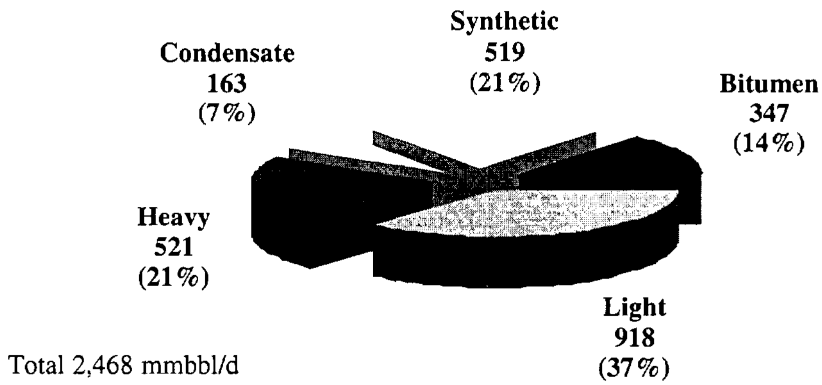
Typically, *in-situ* operations consume 0.9 mcf to 1.2 mcf of natural gas to heat water to produce steam for each barrel of bitumen produced. The cost of natural gas can represent as much as 70% of the operating costs for these projects. To mitigate and reduce the exposure to natural gas supply and price, industry is focused on adapting *in-situ* operations to reduce natural gas use. Testing is underway to examine solvent processes that eliminate natural gas entirely. Testing is also underway to develop fuel from the lower valued components of the produced bitumen barrel through gasification or the creation of liquid fuels.

Technology is advancing to improve the effectiveness of both mining and *in-situ* recoveries. Mine improvements are focused on the reduction of the distance and number of times material is moved while improvements in *in-situ* operations are focused on the reduction of energy requirements. Testing of these developing technologies is currently underway by a number of operators throughout Alberta's oil sands.

Production

In 2003, according to the EUB, surface mining and extraction accounted for 64% and *in-situ* production for 36% of Alberta's total crude bitumen production. Oil sands, comprised of synthetic crude oil and bitumen, now account for approximately 35% of Canada's total crude oil production. Production from Alberta's three oil sands regions is expected to increase from approximately 1.0 million barrels per day in 2003 to 1.8 million barrels per day by 2010 and to grow to 3.0 million barrels per day by 2020 according to the Alberta Department of Energy.

Breakdown of Canadian Crude Oil Production in 2003
(mmbbl/d)

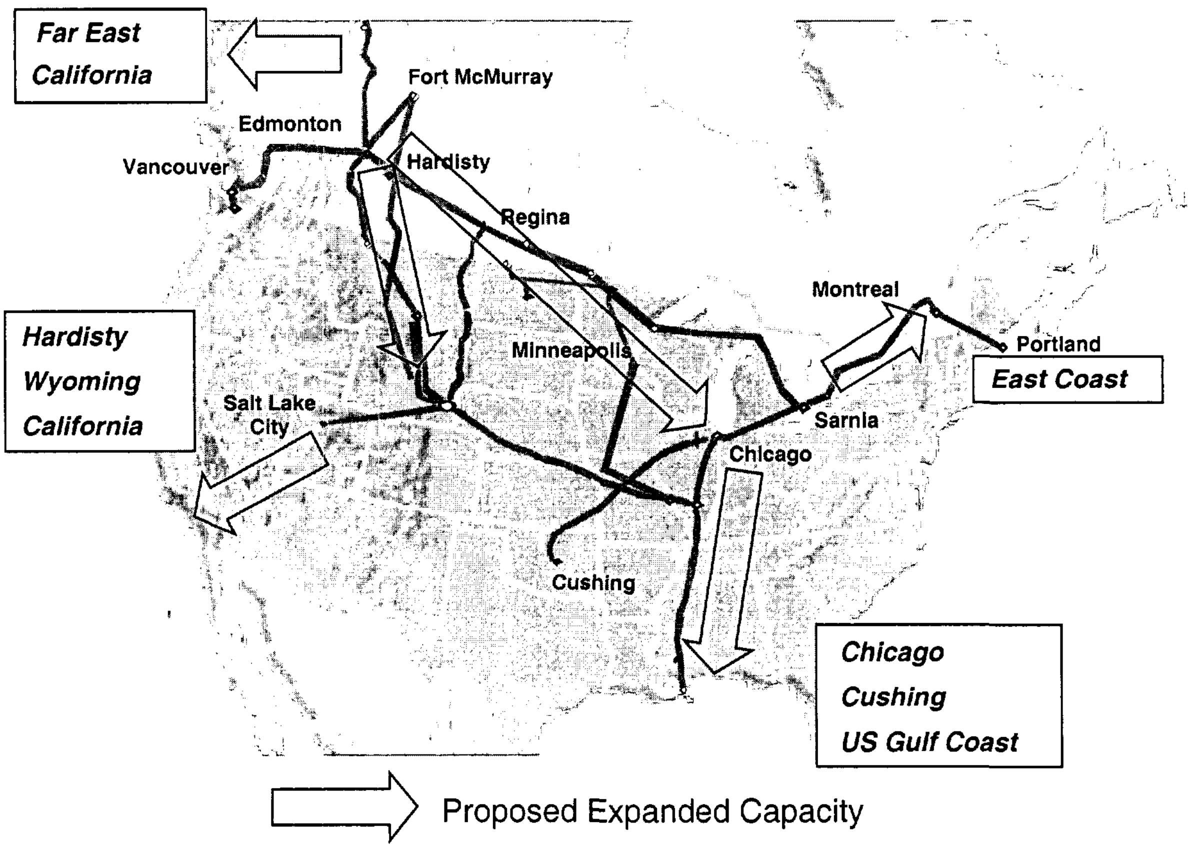


Source: NEB

Markets and Transportation

Canadian and U.S. pipelines extend across North America. The Alberta Department of Energy forecasts that current pipeline capacity in Alberta is sufficient to meet its forecast of production until 2012. The United States is expected to import almost one million barrels per day of production from Canadian oil sands alone by 2025. The increase in United States demand for energy and the expansion of Alberta's oil sands has created a need for new pipelines to transport crude oil to United States markets. Potential pipeline expansion projects from western Canada over the next two decades into the United States markets are forecasted by the Alberta Department of Energy to meet this production growth to 2020 and increase the share of oil sands production reaching United States imports.

Canadian and U.S. Crude Oil Pipelines



Source: Canadian Association of Petroleum Producers/Alberta Department of Energy/Industry Sources

Production from oil sands is sold in two forms, as synthetic or upgraded oil, or as a blend of bitumen and a lighter oil referred to as diluent. Upgraded synthetic oil targets the light crude needs of refiners. Bitumen blends compete with the heavy crude demand. Bitumen production in excess of demand impacts the heavy oil price differential.

The recent forecast by the Alberta Department of Energy estimated heavy oil production in excess of Alberta based upgrading in the amount of 304,000 barrels per day in 2005. This is approximately 10% less than the 2003 estimate due to a decline in conventional heavy oil production and an increase in Alberta based upgrading by 300,000 barrels per day. This excess supply of heavy oil production is further forecast by the Alberta Department of Energy to decrease to 100,000 barrels per day by 2010 with upgrading capacity based in Alberta forecast at 1.7 million barrels per day and heavy oil production at 1.8 million barrels per day.

Alberta Upgrading (bbl/d)

	Capacity		
Company	**2003**	**2005**	**2010**
Shell Canada Limited	155,000	225,000	425,000
Suncor Energy Inc.	225,000	260,000	500,000
Syncrude Canada Ltd.	245,000	345,000	500,000
Husky Energy Inc.	75,000	150,000	150,000
Other(1)	0	30,000	90,000
Total Capacity	**700,000**	**1,010,000**	**1,665,000**
Heavy Forecast(2)	1,041,000	1,314,000	1,765,000
Difference	(341,000)	(304,000)	(100,000)

Notes:

(1) Represents OPTI Canada Inc. at 90,000 barrels per day.

(2) Includes production from mining and *in-situ* operations, as well as conventional heavy crude.

Source: Alberta Department of Energy

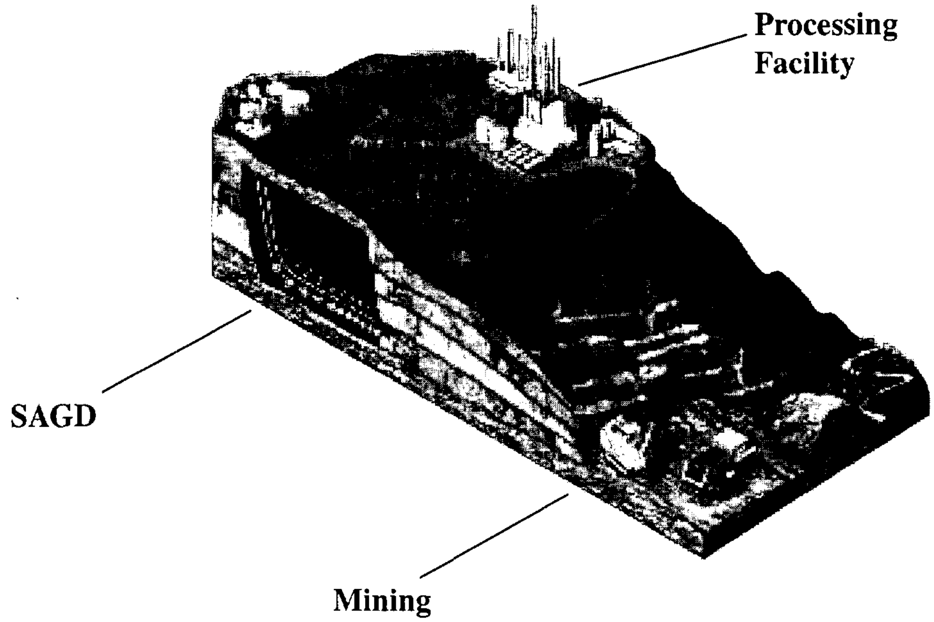
Access to refining capacity is being addressed not only by the Alberta Department of Energy forecast of increased Alberta based upgrading, but includes a change in blending and diluent. The combination of bitumen with synthetic crude creates a blend called synbit. According to the Canadian Association of Petroleum Producers, this blend has properties that are potentially similar to a medium sour crude. This change in blend from the historical use of condensate creates a ready-made medium sour crude better suited for some refinery crude slates. The blending in many cases is best carried out in the field and creates a product more available to a greater number of United States refiners than synthetic crude or historical condensate-based blend.

THE JOSLYN PROJECT

Background

The Corporation entered into an agreement to acquire Lease 24 from Talisman on March 1, 1998 pursuant to the terms of the Talisman Agreement for an initial payment of $5.3 million plus a commitment to pay an additional amount of up to $21.0 million plus accrued interest. See "Talisman Debenture". On November 3, 1999, Deer Creek purchased Permit 70 at an Alberta crown land sale for $0.2 million. On August 8, 2002, the Corporation sold 16% of its then 100% interest in the Joslyn Lease to Enerplus for proceeds of $16.0 million plus the assumption by Enerplus of 16% of the contingent obligations to Talisman. See "Enerplus Joint Venture".

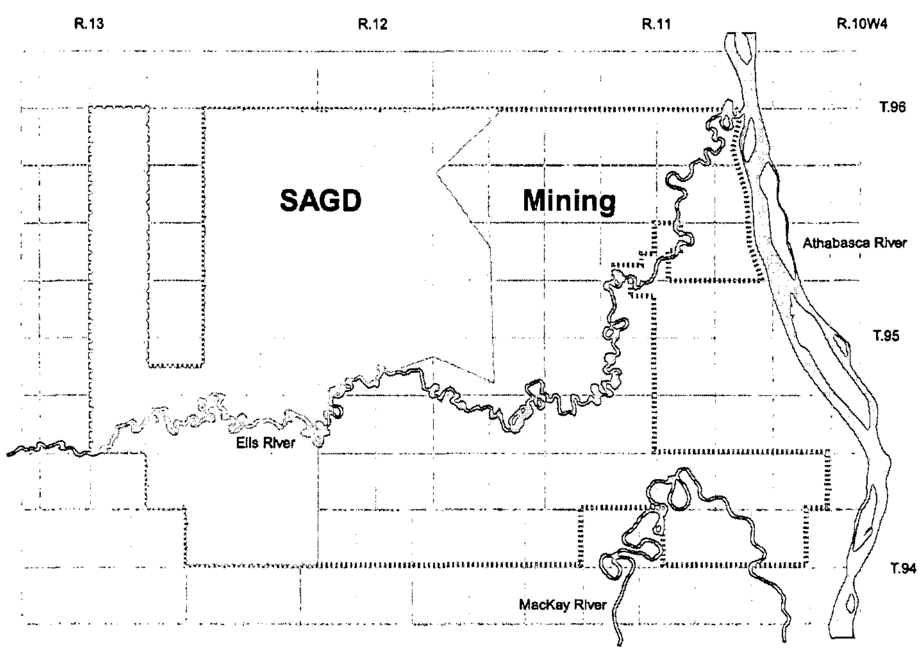
Joslyn Project



(Figure is representative only)

Deer Creek plans to develop the Joslyn Project by way of three phases of SAGD recovery and four phases of oil sands mining recovery, which is designed to produce more than 200,000 barrels of bitumen per day for more than 30 years. The Corporation's strategy is to use SAGD production recovery methods on the western portion of the Joslyn Lease where bitumen reserves and resources are not suited for mining operations. Conventional surface mining and extraction methods are planned to be used in the eastern and southern portions of the Joslyn Lease where the bitumen resource is at shallower depths suitable to mining.

Joslyn Project — SAGD Mining

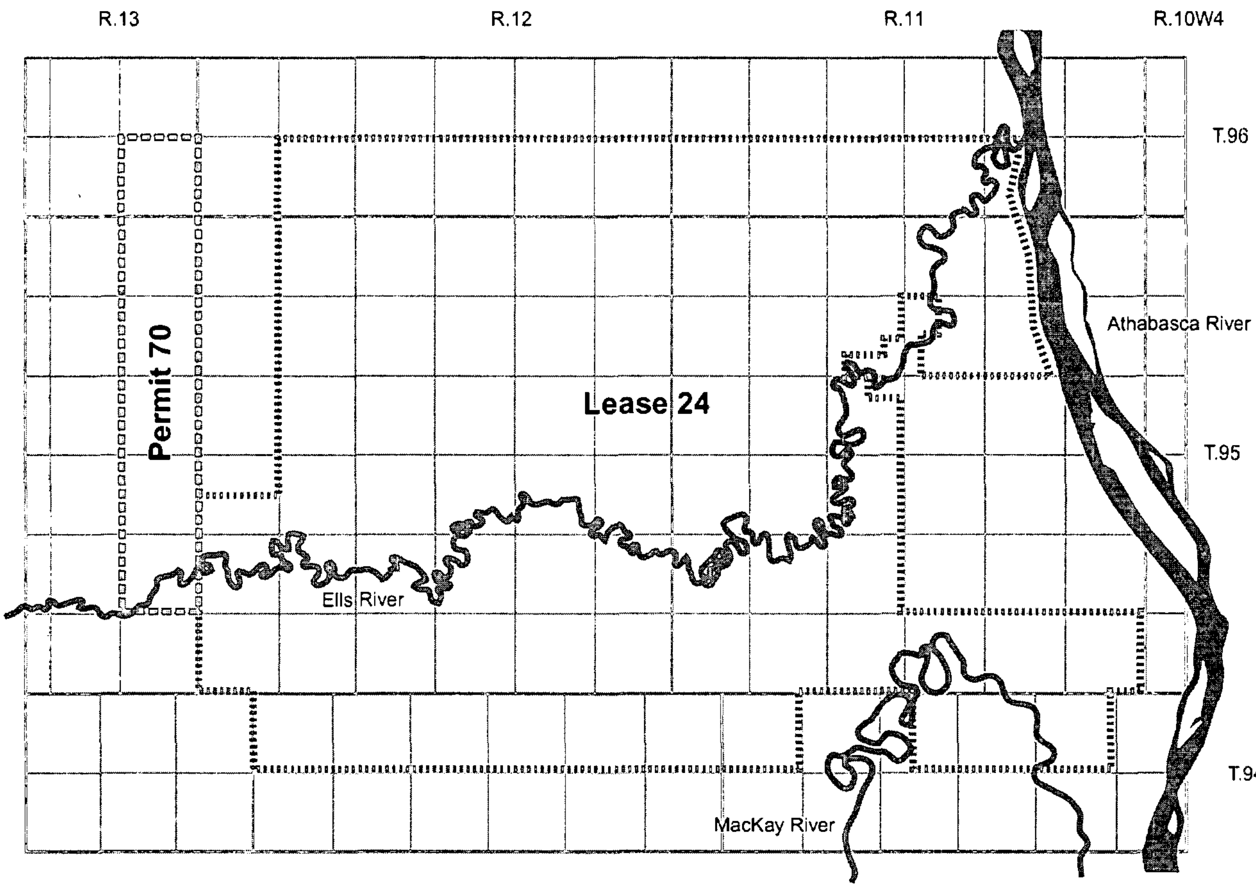


The above map of the Joslyn Lease illustrates the areas that correspond to the primary method of production and extraction that the Corporation is intending to implement.

Joslyn Project Lands

Deer Creek holds an 84% interest in the rights to recover bitumen resources from the Wabiskaw and McMurray formations of the Joslyn Lease. Lease 24 comprises 19,500 hectares. Deer Creek has completed work that exceeds the minimum levels of evaluation required in respect of Lease 24, and it has been classified as a "Continued Lease" under Section 13 of the *Oil Sands Tenure Regulations* and is subject to the payment of annual rentals and escalating rentals as prescribed therein. Permit 70 comprises 1,536 hectares. Permit 70 reaches the end of its term on November 3, 2004 and the Corporation expects it to be converted to an Alberta Oil Sands Lease with a term of 15 years.

Joslyn Project Lands



Delineation of Lands

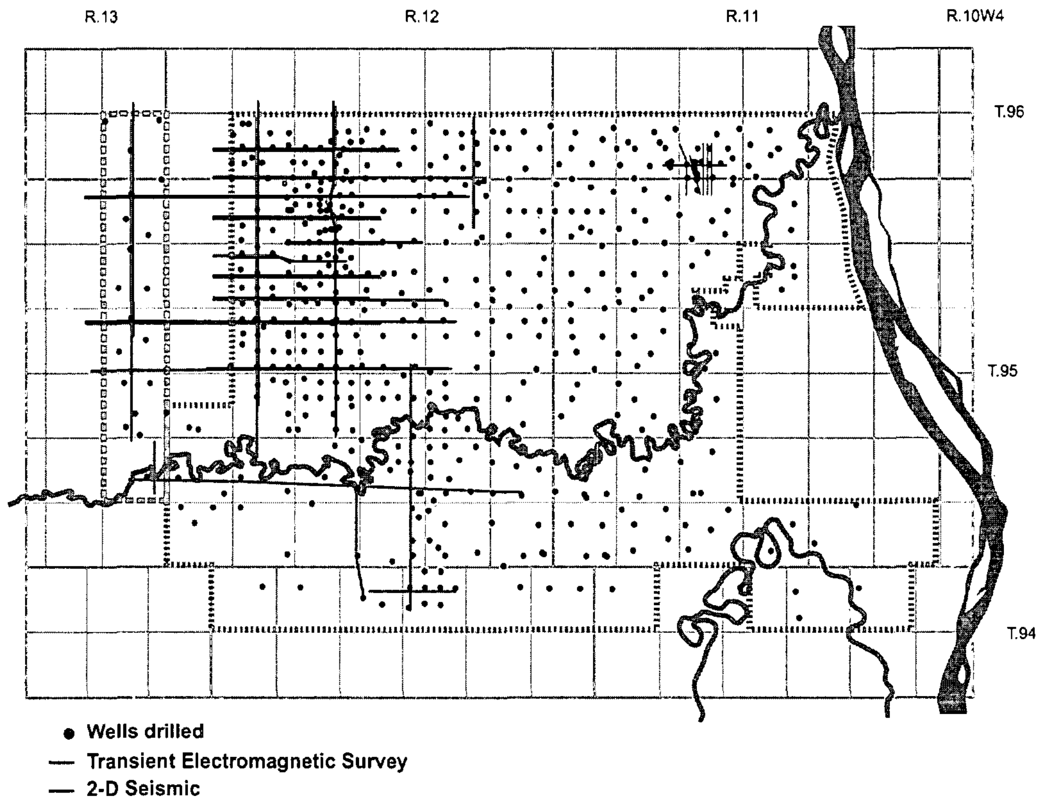
Data obtained from geophysical surveys and the core hole drilling programs are essential to gaining an understanding of the bitumen resource deposit. Prior to a regulatory application, lease delineation through core hole drilling in the oil sands is typically one well per 40 acres on SAGD channels and 700 metre inter-well spacing within the mining area. This data, together with geological and reservoir studies, provides information that identifies and describes the oil sands deposits and optimum well development architecture.

During 2003, Deer Creek drilled a total of 107 core hole wells on the Joslyn Lease, comprised of 73 core holes in the identified thermal area, 20 core holes in the proposed mine development area and 14 utility-related well bores.

The Corporation completed a very active drilling program in early 2004, with more than 195 core hole wells spread over the thermal area (91 core holes) and mine area (101 core holes), as well as three utility wells. The completion of this program has increased the well database to more than 560 core hole wells.

In addition, Deer Creek acquired over 28 kilometres of surface geophysical surveys and 493 kilometres of airborne geophysical surveys in 2003 on the Joslyn Lease. The Corporation has completed an additional 100 kilometres of geophysical survey work in 2004 to further improve the reservoir delineation. The Corporation's total data inventory after the completion of the 2004 program will consist of over 680 kilometres of geophysical surveys. This program, when combined with the drilling program information, will continue to provide the data necessary for reservoir description to advance SAGD Phase III to the regulatory process and to finalize the well drilling design plan for SAGD Phase II.

Delineation of Joslyn Project



Thermal Operations

Overview

In 1998, Deer Creek began the Pilot Project on Lease 24 to test the recovery of bitumen using proprietary multi drain SAGD production technology. The Pilot Project evolved to include the evaluation of a short SAGD well pair. See "The Business — Historical Development — Pilot Project". See "Industry Overview". The results of the Pilot Project confirmed the applicability of SAGD production technology to the bitumen resources under the Joslyn Lease.

SAGD Project Timeline

Note:

There is not necessarily a consistent level of activity throughout the range of task completion.

SAGD Phase I Engineering Demonstration Project

SAGD Phase I is designed to produce 600 barrels of bitumen per day from the McMurray formation as an initial demonstration project to confirm construction, engineering and operations practices. Engineering design of surface facilities and construction for SAGD Phase I commenced in the summer of 2003 and installation of facility modules began in February 2004.

The SAGD Phase I facility includes a steam generator, water treatment and handling facilities, oil treating facilities, and one horizontal well pair. During the fourth quarter of 2003, Deer Creek drilled the SAGD Phase I well pair, with a horizontal length of approximately 600 metres. The initial well pair will help to define the most efficient distribution of steam in the injector for maximum operating and production performance of later phases.

In April 2004, construction of the facilities was completed and steam injection commenced. The well pair is projected to be switched from warm-up mode to production mode in the third quarter of 2004. Deer Creek expects the well pair to reach full production of approximately 600 barrels of bitumen per day by the third quarter of 2005.

SAGD Phase II Expansion Project

In July 2003, Deer Creek applied for regulatory approval for the SAGD Phase II commercial expansion. Approval for SAGD Phase II was received from the EUB in May 2004, authorizing Deer Creek to produce up to 12,000 barrels of bitumen per day. Alberta Environment approval was received in July 2004.

Detailed engineering commenced on SAGD Phase II in the third quarter of 2003. It is expected that more than 60% of the detailed facility and gathering system engineering will be completed by the third quarter of 2004. Approximately 90% of engineering is anticipated to be completed prior to its construction. This has positioned the Corporation to be able to implement its plan upon receipt of complete regulatory approval and successful completion of the Offering.

To achieve an expansion of 10,000 barrels per day of bitumen production, SAGD Phase II is expected to initially require 17 well pairs. There will be upwards of four well pads in addition to the SAGD Phase I well pair site. The SAGD Phase I well pair will be tied-in to the SAGD Phase II facility and the facility equipment associated with SAGD Phase I will be shut-down, decommissioned and dismantled. Additional wells will be drilled in the future, as required, to maintain a stable production profile as the production from each well pair declines. Once well performance is confirmed, additional wells may be drilled to utilize the 12,000 barrels per day of design capacity of the SAGD Phase II facility, which matches the production approval obtained for this phase.

Down hole pumping will be employed as the method to lift the produced well fluids to the surface. Produced well fluids from the reservoir, consisting of bitumen, water and gas, will be gathered from the wells at each well pad. The produced fluids will be separated into liquid and vapour phases by separators. The liquid, a mixture of bitumen and water, will be pumped and the vapour will be flowed, via above ground insulated pipelines from the well pads to the central facility.

In addition to the horizontal wells, the SAGD Phase II expansion of the Joslyn Project will include surface facilities to process the bitumen, water and steam. SAGD Phase II will consist of well pads, gathering pipelines, steam distribution pipelines, water supply and disposal wells and pipelines, bitumen, water and gas treating facilities, steam generation facilities, product tankage, and other associated buildings and facilities. The water that is produced with the bitumen will be treated and recycled to generate steam for re-injection into the reservoir.

SAGD Production and Treating Process

Production Separation and Treating

The production separation and treating area receives and processes the production streams from the well pads to sales pipeline specifications.

The bitumen and water emulsion will be combined with diluent, cooled and treated to produce approximately a 12° API product. By processing the resulting product through a pressurized treating vessel, the final bitumen product will have less than 0.5% basic sediments and water, and will meet sales pipeline specifications.

The oil processing equipment will be designed to use a range of diluents such as synthetic crude oil, condensate or naphtha. Since synthetic crude oil is heavier than condensate or naphtha, a higher proportion of synthetic crude oil to bitumen will be required to treat the bitumen. The use of synthetic crude oil to treat the bitumen will not limit the amount of bitumen that may be processed. It is anticipated that synthetic crude oil will be used as diluent for SAGD Phase II. See "Joslyn Project Development — Marketing".

Produced water will be separated from the bitumen in the treating system and will be sent to the de-oiling system to be recycled.

The produced vapour received from the well pads will be a combination of steam and sour produced gas. The vapour will be cooled in order to condense the steam and allow separation of the liquids. The sour produced gas will be combined with the natural gas used to fuel the steam generators. Water recovered from the produced gas separation equipment will be combined with the produced water from the treating vessels and recycled through the process.

Water De-Oiling

Produced water recovered in the production separation and treating area will contain a small amount of bitumen. In order to make the produced water suitable for re-use as steam generator feed water, the bitumen content will be reduced. The de-oiled water will then be piped to the water treatment area to be treated for use as steam generator feed water. The skimmed oil recovered in the de-oiling system will be recycled for processing in the production separation and treating system.

Water Treatment

The produced water treatment area will be comprised of two main process units: the produced water treatment system and the steam generator blow down water treatment. The produced water treatment system will process the de-oiled produced water along with make-up water streams. Water downstream from the steam generator will be processed to concentrate the solids into a waste stream and recover a portion of the water to be recycled into the produced water treatment stream. The waste water stream will be disposed of into deep disposal wells.

Steam Generation

The steam generation system will receive feed water from the water treatment system. Steam generator booster pumps will send the water through a series of exchangers that preheat the feed water and cool process streams from other units. After preheating, the feed water will be pumped to the steam generators by high pressure pumps.

There will be four steam generators, two larger and two smaller ones. The smaller generators will be used for periods of low steam requirements such as during well start up. The primary fuel source for the steam generators will be natural gas. The two larger generators will be designed to allow the burning of liquid fuels such as emulsified bitumen, if that option is proven viable in the future.

Future SAGD Phase III Expansion

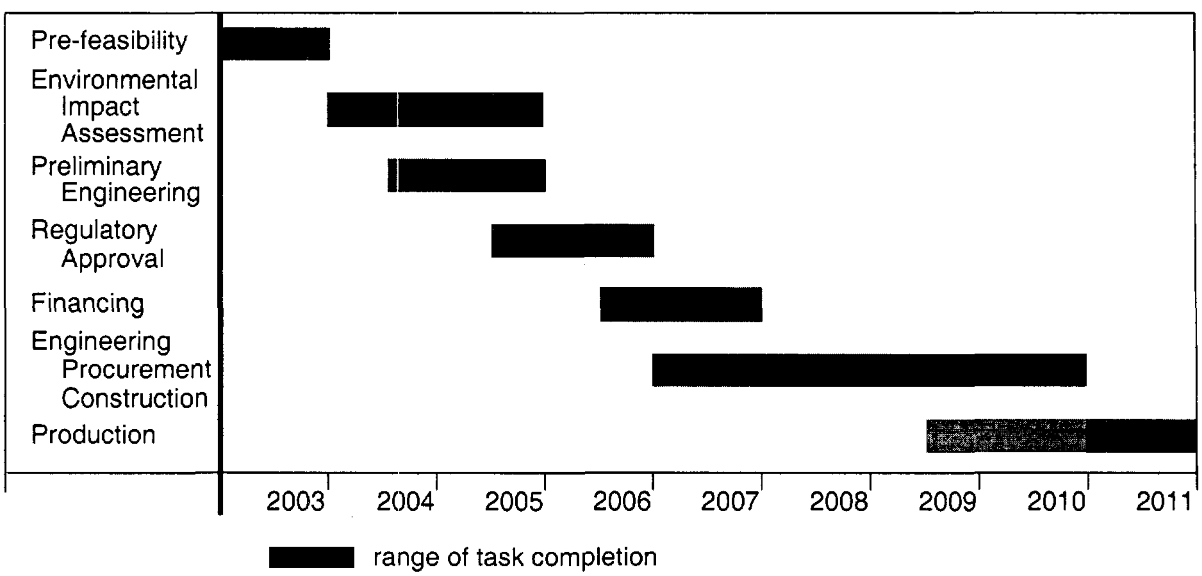
Over the past year, Deer Creek began gathering initial base-line environmental data and working on preliminary facility engineering design for SAGD Phase III, a commercial operation that is designed to add 30,000 barrels of bitumen per day. This work has shaped the direction, timing and approach for pursuing regulatory approval for the next phase of development. The initiation of the regulatory process for SAGD Phase III has started with the preparation of public disclosure documents in the second quarter of 2004. Additional environmental assessment, stakeholder consultation and technical evaluations will be completed throughout the year to position the SAGD Phase III application for submission in early 2005. Deer Creek intends to revise and optimize its strategies and development plans and may choose to develop SAGD Phase III as a series of smaller expansion projects to exploit the reserves and resources in the most favourable manner to the Corporation.

Mining and Extraction Operations

Overview

The mining and extraction operations proposed for the Joslyn Project represent approximately 75% of the total potential recoverable resources on the Joslyn Lease. The mining potential is significant and a stepped, well-managed development program is planned to optimize value and control costs. The unique opportunity to establish production and cash flow from the SAGD phases enhances Deer Creek's ability to stage the mining and extraction development, control costs, benefit from technology improvements and enhance shareholder value.

Mining Project Timeline



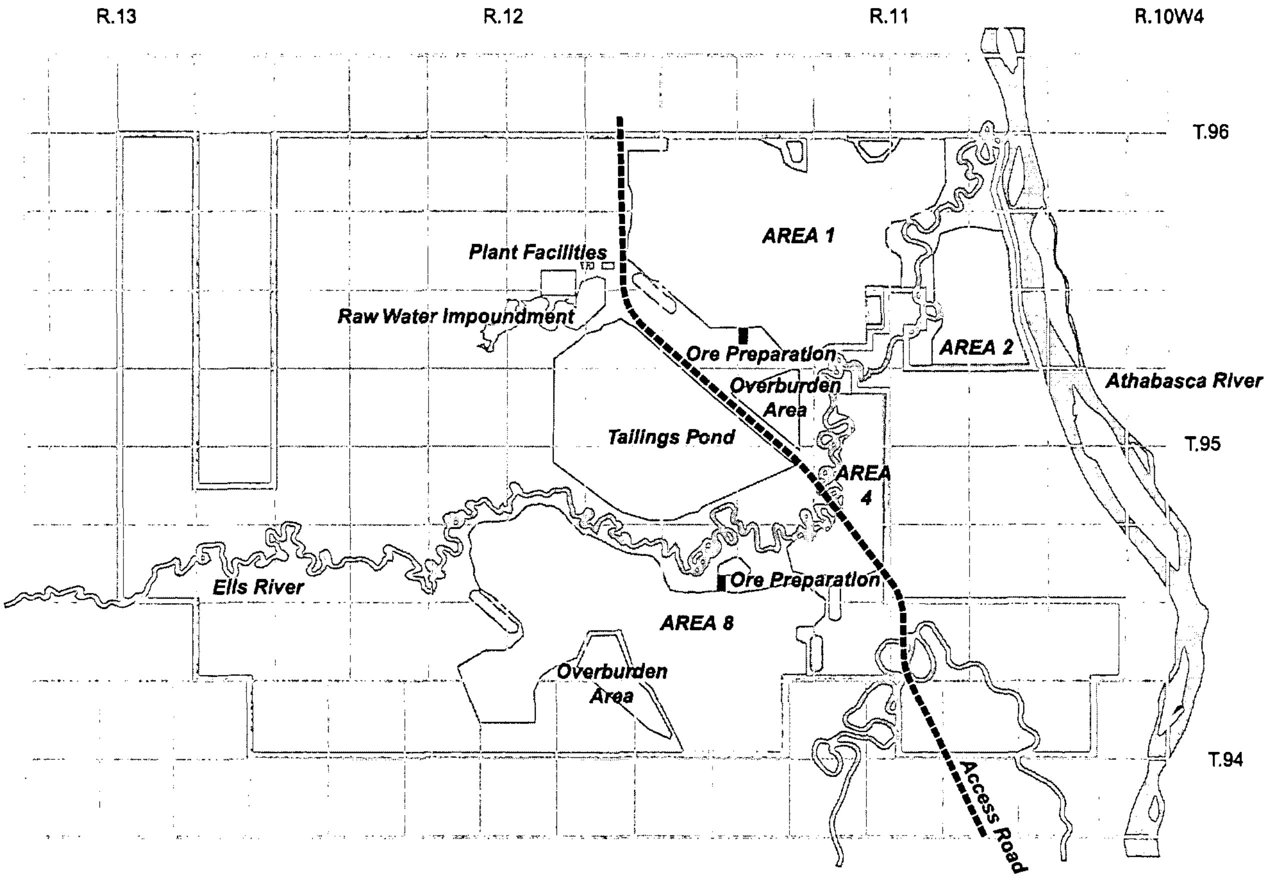
Note:

There is not necessarily a consistent level of activity throughout the range of task completion.

Mine Design

To further understand the economics of the mine development, Deer Creek commissioned Washington Group to conduct a preliminary feasibility study in 2003. The Washington Group Study addresses the mining and processing of oil sands to produce pipeline grade diluted bitumen for transportation to sales markets and defines recoverable bitumen from two main pit areas and two smaller pits.

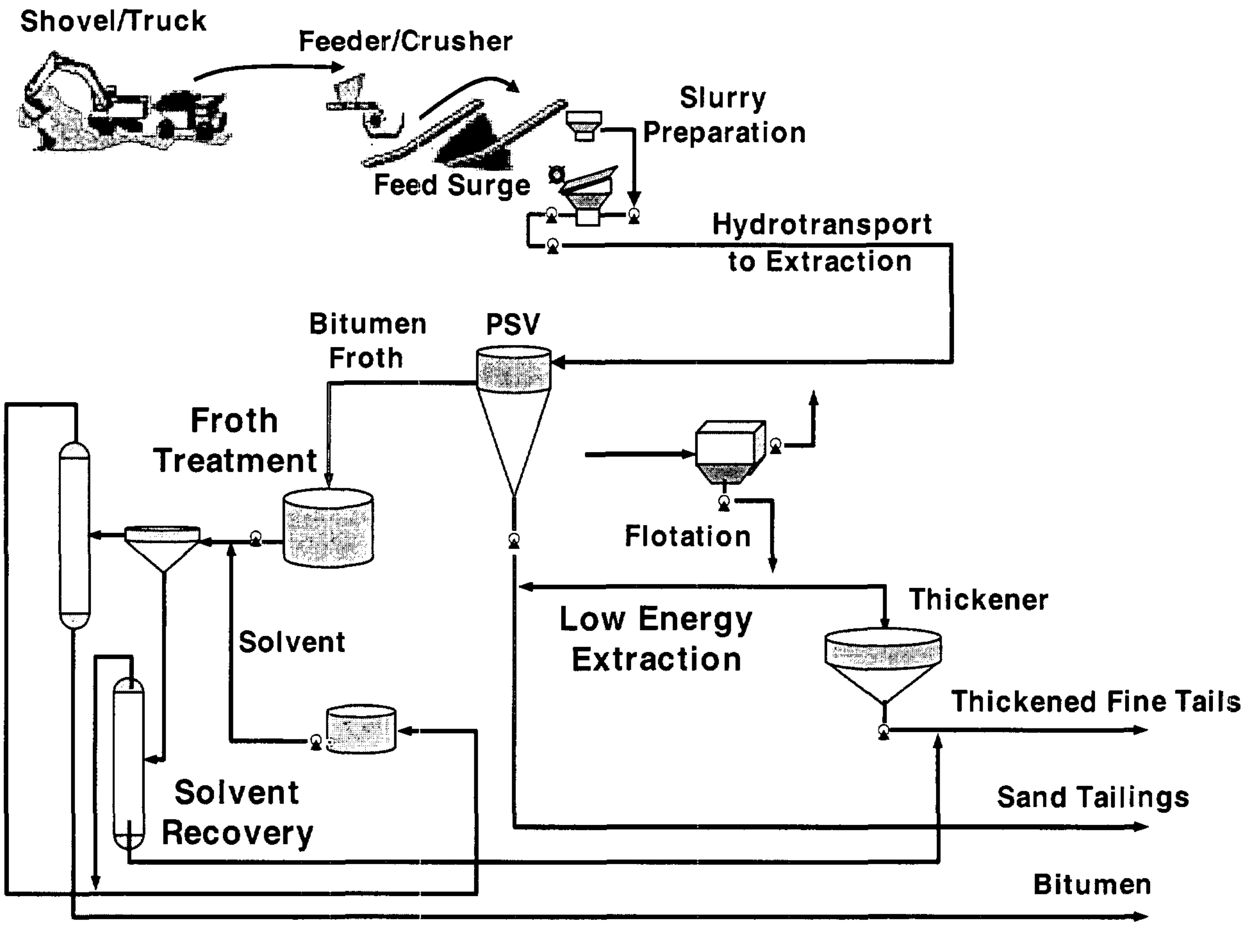
Joslyn Project Proposed Mine Design



Source: Washington Group Study

An important aspect of the Washington Group Study is the selection of technology and the possibility of future technological advancements for both mining and mineral processing. Deer Creek reviewed both conventional proven technologies as well as certain step-out technologies that would require testing as the mine development advances. The Washington Group Study will assist in defining the most economic option for extracting the mining resource and serve, in part, as the basis for moving ahead with regulatory applications. This will be followed by detailed engineering for design and construction of the mine development, processing facilities and infrastructure necessary for the processed oil to reach market.

Studies to date have assumed the use of conventional truck and shovel mining techniques and warm water extraction, which are currently being utilized by other oil sands operators. Environmental issues, including water usage and land disturbance, are being considered as well.



The Washington Group Study assumes an initial project implementation plan of four 50,000 barrels of bitumen per day phases, for total potential production of 200,000 barrels of bitumen per day. Follow-up analysis and additional studies in 2004 will examine specific technical issues, the results of which will be used to optimize the development plan, as well as to identify opportunities for improving operating efficiency and reducing capital and operating costs. See "The Joslyn Project — Reserves and Resources — Washington Group Study".

Mine Phase I and Mine Phase II

The initial mine is scheduled for start-up by 2011, with forecast production rates of 50,000 barrels of bitumen per day by 2012. Mine construction is expected to commence in 2008. The initial mine pit is proposed to be located on the northeast side of Lease 24, identified as Area 1 (see map entitled "Joslyn Project Proposed Mine Design" under "Mining and Extraction Operations — Mine Design"). The mining activity is expected to proceed in Area 1 in two phases over a six year development period. Mine Phase I and Mine Phase II are each expected to add production of 50,000 barrels of bitumen per day. Deer Creek has initiated the regulatory process with the preparation of public disclosure documents, which are expected to be submitted in mid 2004. Deer Creek plans to be in a position to submit its regulatory applications for approval of the initial development of Area 1 in late 2005 or early 2006.

Mine Phase III and Mine Phase IV

The initial Washington Group Study mine plan envisages further expansion of two more phases of the Joslyn Project by using all the resources in Area 1 and continuing production in Area 8 (see map entitled "Joslyn Project Proposed Mine Design" under "Mining and Extraction Operations — Mine Design"). Following full production from Mine Phase III and IV, total mining and extraction production is expected to increase to 150,000 barrels and then 200,000 barrels per day, respectively. Mine Phase III and Mine Phase IV are conceptual only and are dependent on, among other things, economics, future delineation drilling and mine planning. Given the stage of mine development, various changes to the mine plan may be made by the Corporation and the construction and operations schedules may change as further information is obtained and future engineering evaluations are completed. See "Mining and Extraction Operations — Mine Design".

Mining and Extraction Process

Ore Mining and Preparation

Deer Creek proposes to utilize conventional open pit truck and shovel mining techniques similar to those used at other oil sands mining operations in the region.

Overburden and oil sands are excavated with large shovels and hauled by large trucks. The oil sand is hauled to ore processing facilities where it is crushed, sized and conveyed to the slurry preparation facility. The oil sand is then mixed with warm water and the resulting slurry is transported to bitumen processing/extraction facilities.

Extraction and Froth Treatment

Deer Creek currently plans to utilize a low temperature (40°C), non-caustic extraction process to reduce energy consumption and facilitate rapid settling of tailings (See diagram entitled "Mining and Extraction" under "Mining and Extraction Operations — Mine Design") and that froth flotation should be utilized to maximize recovery through treatment of a middlings stream and primary separation tailings. Froth treatment will reduce mineral and water content in the bitumen to a specification suitable for transportation by pipeline. A blended product will be delivered to refineries in Canada and the United States through the existing pipeline system and infrastructure.

Tailings

The mining operation will employ a thickened tailings process as currently employed in the industry. The solids removed in the extraction process will be sent back to the mine area. An out-of-pit tailings pond will be required initially until enough of the mine has been excavated to accommodate in-pit storage of the tailings stream. The thickened tailings process enables the fine clays to settle and consolidate faster than in conventional tailings. This should result in less extensive tailings structures and earlier reclamation.

Technology Development

Deer Creek is reviewing technological developments in the areas of mobile mining/slurry systems, extraction and froth treatment, tailings management and water use efficiency. Deer Creek will incorporate demonstrated new technologies as engineering design progresses.

Project Enhancement Opportunities

Current studies provide the basis for moving forward with the mine development and identifying opportunities for improving the project economics. These potential opportunities include:

- optimization of the preliminary mine plan to reduce strip ratio and operating costs;
- application of developing mine technology, which positions crushing and slurry preparation equipment closer to the mine face and reduces the number of trucks required;
- integration of mining and SAGD facilities and infrastructure, which offers the potential to reduce capital and operating costs through energy efficiency, reduction in water treatment requirements and combined bitumen cleaning; and
- due to the relatively small size of each planned phase, to the extent practical, utilization of modular construction which offers the potential to reduce capital costs and realize savings.

Oil Sands Mining Comparison

The following table, prepared by Norwest, compares some of the key resource attributes of other oil sands projects, both operating and in development. The Deer Creek data below has been added for comparative purposes.

Project	Recoverable Bitumen (mmbbls)	Ore Grade (weight %)	Strip Ratio (m^3/m^3)	*TV:BIP* (m^3/m^3)
Operating				
Albian Sands Energy Inc. — Muskeg River (East Pit)(1)	1,120	11.4	0.65	7.0
Suncor Energy Inc. — Millennium (Pit 2)(2)	2,593	11.5	1.31	9.7
Syncrude Canada Ltd. — Aurora North(3)	1,973	11.2	0.57	6.8
In Development				
Canadian Natural Resources Limited — Horizon(4)	3,449	10.6	1.29	10.3
TrueNorth Energy LP — Fort Hills Oil Sands Project(5)	2,832	11.6	1.45	10.0
Shell Canada Limited — Jackpine(6)	1,407	10.4	0.55	7.2
Syncrude Canada Ltd. — Aurora South(3)	1,742	11.3	0.89	8.0
Deer Creek — Joslyn Project(7)	**2,064**	**10.5**	**1.21**	**10.0**

Notes:

(1) Based on the Muskeg River Mine Application filed in December 1997. Includes some asphaltene removal in bitumen clean-up process.

(2) Based on the Project Millennium Application filed in April 1998. Figures do not include Steepbank Pit 1. Assumes EUB recovery formula.

(3) Based on the Aurora Mine Application filed in June 1996. Assumes EUB recovery formula.

(4) Based on the Horizon Oil Sands Project Application filed in June 2002 and Supplemental Information filed in March 2003. Assumes average Horizon plant recovery.

(5) Based on the Fort Hills Oil Sands Project Application filed in June 2001 and Supplemental Information filed in February 2002, and information provided in the UTS Energy Inc. Preliminary Prospectus dated April 26, 2004. Includes some asphaltene removal in bitumen clean-up process.

(6) Based on the Jackpine Mine Phase 1 Application filed in May 2002 and Supplemental Information filed in December 2002. Includes some asphaltene removal in bitumen clean-up process.

(7) Recoverable Bitumen and Ore Grade represent the full recoverable mining resource. Strip Ratio and TV:BIP represent the first ten years of mining. Strip Ratio and TV:BIP estimates for a 30 year mine plan are 1.37 and 10.4, respectively.

Definitions:

"Recoverable Bitumen" — The recoverable bitumen for each of the projects has been determined on the basis of either the EUB recovery formula or specific recovery information provided in the source documents. The Albian Muskeg River Project, Jackpine Project and Fort Hills Oil Sands Project produce higher quality bitumen than the other projects, which feed upgraders in close proximity to the mining and extraction facilities.

"Ore Grade" — Ore grade, measured in weight percent bitumen, is a measure of the richness of the ore. In most cases, the ore grade provided is based on the ore quality that is fed to the recovery process. The values provided above are "diluted grade", which reflects some mixing of non-ore grade material with the ore, reducing the quality slightly from the in-place value.

"Strip Ratio" — Strip ratio is a measure of how much waste material has to be mined for every volume of ore mined. This is expressed as cubic metres of waste per cubic metre of ore.

"TV:BIP" — TV:BIP, is a measure of the total volume mined relative to the bitumen in-place and expressed as cubic metres of material mined per cubic meter of bitumen, and is an indicator of relative economics of a project.

Deer Creek believes that its resource and mining parameters are competitive with current industry and other developing projects, and it is expected that future iterations of Deer Creek's preliminary mine plan will improve the mining economics. Variations in the parameters listed could impact the operating costs of the mining phases. As an example, a 10% variation in TV:BIP would affect Deer Creek's bitumen production costs by $0.50 to $0.80 per barrel of bitumen produced.

Reserves and Resources

The oil sands reserves and resources underlying the Joslyn Lease are contained within the McMurray formation. The McMurray formation is comprised of a sequence of uncemented quartz sands and associated shales that reside above the unconformity with the underlying Upper Devonian carbonates (limestone) of the Waterways formation. The underlying Waterways formation does not contain bitumen and is considered a barrier to water flow.

The division between proposed surface mining operations and SAGD operations is a boundary that has been chosen based on the understanding of the resource base at this time, and represents the identification of areas that are most likely to correspond to the respective method of production. There are some areas that may be amenable to both recovery methods.

The target zone for the SAGD development is the Middle Member of the McMurray formation. The depth of the SAGD zone in the development area ranges from 65 metres to 110 metres.

The Corporation estimates that the average reservoir parameters for SAGD Phase II area are:

Porosity	—	33%
Permeability		
Horizontal	—	8,000 to 8,500 milliDarcies
Vertical	—	3,500 to 4,500 milliDarcies
SAGD Pay Thickness	—	21 metres

Based on the delineation drilling results to date, the proposed development area does not have any top water or natural gas.

The mining and extraction development will occur on the east side of the lease where the overburden is thinner and therefore the deposit is more amenable to mining. Mining of the Upper, Middle and Lower McMurray zones is to occur in the area of the two primary mine pits, Area 1 and Area 8, and potentially the secondary mine pits. See "The Joslyn Project — Mining and Extraction Operations".

Deer Creek commissioned three reports to independently complete the description of the Joslyn Project. Norwest was retained to complete a full project geological model and resource assessment. Washington Group was retained to complete a preliminary feasibility study on the mining project. GLJ Associates was commissioned to complete a reserves and resources evaluation in compliance with the requirements of NI 51-101.

Norwest Report

Norwest is an employee owned energy, mining and environmental consulting company. Over the past 25 years, Norwest has grown to offer a wide range of services in the energy, minerals and natural resource industries. Norwest provides geological, engineering and consulting services that relate to the evaluation and development of coal, coalbed methane, oil sands, oil shale, industrial minerals and base and precious metals projects. With over 100 employees, Norwest serves clients around the world from its offices in Canada, the United States, England, Australia and China.

In June 2003, Deer Creek engaged Norwest to develop a resource and geologic model of the in-place bitumen resource underlying the Joslyn Lease. The model was developed to support engineering evaluations of the potential to recover bitumen through either surface mining and extraction or SAGD production methods.

In-place bitumen resources suitable for mining and extraction within the Joslyn Lease were estimated by Norwest using the following constraints, which are consistent with standard oil sands mining practices:

- in-place material has a grade equal to or exceeding seven percent bitumen by weight; and
- the minimum thickness of an ore or waste unit is three metres.

This first level estimate identified 8.0 billion barrels of in-place bitumen resources. A second level estimate was prepared using the additional constraint of:

- the total volume to bitumen-in-place (TV:BIP) ratio is less than or equal to 12:1.

In the Norwest Report, Norwest estimated that a total of 4.0 billion barrels of in-place bitumen satisfied the criteria within the Joslyn Lease. Additional constraints for continuity reasonable for surface mining and setbacks from waterways resulted in 3.0 billion barrels of in-place bitumen in the surface mining area designated by Deer Creek. The conclusions set out in the Norwest Report were based on a consideration of various aspects of the Joslyn Project including the geology of the Joslyn Lease, integrity of the exploration database and models used to represent the geology of the Joslyn Lease and ore characteristics.

Based on a model constructed using SAGD criteria provided by Deer Creek, Norwest estimated that a total of 1.1 billion to 2.1 billion barrels of in-place bitumen were suitable for evaluation for recovery using SAGD. The range of values provided is dependent on the percentage of non-pay material selected as a constraint in the model, with the low end of the range representing a maximum 15% non-pay material in the SAGD zone. Of the 1.1 billion barrels of in-place bitumen, 860 million barrels of bitumen are within the primary SAGD area identified by Deer Creek.

The Corporation plans to commission Norwest to update the Norwest Report in late 2004 when the core analysis results of the 2004 drilling program are available.

Washington Group Study

Washington Group provides integrated engineering, construction, and management solutions for businesses and governments worldwide. Washington Group provides professional, scientific, management and development services in mining and processing engineering, power generation, environmental remediation and facilities operations, among other services.

In October 2003, Washington Group began a preliminary feasibility study of the proposed mining development to investigate the potential of the mining operations and issued the Washington Group Study in March 2004. The information contained in the Norwest Report defined resources suitable for evaluation as mineable reserves. Using the Norwest model of in-place bitumen, Washington Group developed an open pit design and production plan, which totaled an estimated 1.8 billion to 2.1 billion barrels of bitumen and set a peak production rate of 200,000 barrels of bitumen per day from the mining and extraction development.

The Washington Group Study addressed a staged approach to reach the estimated peak production rate from mining and extraction. Technologies were reviewed and selected for both mining and extraction. Capital and operating costs were estimated and a financial evaluation was presented.

GLJ Report

GLJ Associates is a private independent petroleum consulting firm based in Calgary, Alberta. Established in 1972, GLJ Associates has provided independent reserve, resource and economic evaluation services to the Canadian and international oil and gas community for over 30 years.

GLJ Associates evaluated the bitumen reserves and resources of the Joslyn Lease at year-end 2003. The following definitions are used in information derived from the GLJ Report:

"**Contingent Resources**" are defined in the COGE Handbook as those quantities of oil and gas estimates on a given date to be potentially recoverable from known accumulations but are not currently economic. Contingent resources include, for example, accumulations for which there is currently no viable market. Further clarification of resource definitions and guidelines are forthcoming in the COGE Handbook. Criteria other than economics may cause a quantity to be classified as a resource rather than a reserve. In the case of Deer Creek, these include the absence of mining approvals as well as detailed design estimates to confirm economic producibility as well as an absence of near term development plans. Technically, GLJ Associates believes this volume will likely be economic to develop some time in the future. Over time with additional drilling and financial commitment GLJ Associates would expect these contingent resources to be converted to reserves. The resource estimate has been classified as "Best Estimate" as there is an expectation that this quantity will be actually recovered from the accumulation. The "Best Estimate" in the GLJ Report relates to production of 150,000 barrels of bitmen per day from the mining portion of the Joslyn Lease. Low and high estimates have also been prepared by GLJ Associates.

"**Gross Lease**" means 100% interest in the Josyln Lease before deduction of royalties and without including any royalty interests.

"**Net After Royalty**" means the Corporation's total working interest share after the deduction of royalties.

"**Possible Reserves**" are those additional Reserves that are less certain to be recovered than Probable Reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated Proved plus Probable plus Possible Reserves.

"**Probable Reserves**" are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less then the sum of the estimated Proved plus Probable Reserves. At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves is the targeted level of certainty.

"**Proved Reserves**" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty.

"**Reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical, engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with estimates.

"**Undeveloped Reserves**" are those Reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (proved, probable, possible) to which they are assigned.

"**Working Interest**" means the Corporation's total working interest share before deduction of royalties and without including any royalty interests.

The following is a summary of the GLJ Report based on GLJ Associates' forecast prices and costs:

Summary of Reserves and Resources of the Joslyn Lease
(Forecast Prices and Costs)

	Gross Lease			Working Interest		
SAGD Reserves	**Reserves**		**NPV @ 10% before tax**	**Reserves**		**NPV @ 10% before tax**
	(mmbbl)		(MM$)	(mmbbl)		(MM$)
Probable		298	232		250	195
Possible		181	214		152	180
Probable plus Possible		479	446		402	375
Mining Contingent Resources	**Resources**		**NPV @ 10% before tax**	**Resources**		**NPV @ 10% before tax**
	(mmbbl)		(MM$)	(mmbbl)		(MM$)
Low estimate(1)	720		—	605		—
Best estimate	1,470	1,470	722	1,235	1,235	607
High estimate(1)	2,220		—	1,865		—
Total Probable plus Possible Reserves and Contingent Resources		**1,949**			**1,637**	

Note:

(1) The economic forecasts for the low estimate and high estimate were not prepared.

An updated reserves evaluation incorporating the results of the 2004 core hole drilling program will be completed as at year end.

The following tables set forth certain information relating to the net working interest bitumen reserves and resources of the Corporation and the net present value of future net revenue associated with such reserves as at January 1, 2004. The Corporation does not have any Proved Reserves; however data on Probable Reserves and Possible Reserves is provided. The information set forth below is derived from the GLJ Report, which has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The tables summarize the data contained in the GLJ Report and, as a result, may differ slightly from those in the GLJ Report due to rounding.

It should not be assumed that the estimates of future net revenue presented in the tables below represent the fair market value of the Corporation's reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of Deer Creek's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The Report on Reserves Data by GLJ Associates in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Appendices B and C hereto, respectively.

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE

CONSTANT PRICES AND COSTS

RESERVES CATEGORY	HEAVY OIL RESERVES Working Interest (mbbl)	Net After Royalty (mbbl)
Probable	250,195	228,100
Possible	152,247	136,360
Total Probable plus Possible	402,442	364,460

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	AFTER FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Probable	1,394,956	531,215	180,237	26,951	(42,747)	916,838	311,864	69,088	(34,200)	(78,702)
Possible	861,474	359,694	166,165	81,601	40,763	560,863	221,848	94,321	40,232	15,094
Total Probable plus Possible	2,256,430	890,909	346,402	108,552	(1,984)	1,477,701	533,712	163,409	6,032	(63,608)

ESTIMATED FUTURE NET REVENUE TOTAL PROBABLE PLUS POSSIBLE RESERVES (UNDISCOUNTED)

CONSTANT PRICES AND COSTS

YEAR	DAILY HEAVY OIL PRODUCTION (bbl/d)	WELLHEAD PRICE(1) ($)	TOTAL REVENUE (MM$)	CROWN ROYALTY NET OF ARTC(2) (MM$)	TOTAL OPERATING EXPENSES (MM$)	TOTAL CAPITAL EXPENDITURES (MM$)	NET REVENUE BEFORE TAX (MM$)	INCOME TAX (MM$)
2004	—	—	—	—	—	10.6	(10.6)	—
2005	672	18.81	4.6	—	4.9	8.4	(8.7)	—
2006	1,428	18.81	9.8	0.1	9.3	137.8	(137.4)	—
2007	6,212	18.81	42.6	0.3	24.8	123.9	(106.3)	—
2008	15,662	18.81	107.5	0.8	57.0	172.2	(122.5)	0.1
2009	29,501	18.81	202.5	1.5	85.6	184.8	(69.4)	0.1
2010	42,395	18.81	291.1	2.4	105.1	126.0	57.5	14.9
2011	49,938	18.81	342.9	2.9	111.7	67.2	161.0	34.8
2012	51,450	18.81	353.2	3.0	108.9	—	241.3	47.9
2013	49,832	18.81	342.1	2.9	111.0	67.6	160.6	46.7
2014	49,984	18.81	343.2	21.7	128.0	82.3	111.1	35.2
2015	45,830	18.81	314.7	25.1	128.9	88.2	72.4	23.8
REMAINDER	39,983		5,215.7	640.3	2,090.6	577.3(3)	1,907.5	575.1
TOTAL	**35,567**		**7,569.9**	**701.1**	**2,965.9**	**1,646.4**	**2,256.4**	**778.7**

Notes:

(1) The wellhead price used in this table is as at December 31, 2003.

(2) ARTC means Alberta Royalty Tax Credit.

(3) Includes abandonment costs of $21.5MM.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Probable	4,706,170	403,813	1,855,379	1,042,363	9,660	1,394,956	478,117	916,838
Possible	2,863,769	297,322	1,110,570	582,558	11,844	861,474	300,612	560,863
Total Probable plus Possible	7,569,939	701,135	2,965,949	1,624,921	21,504	2,256,430	778,729	1,477,701

FUTURE NET REVENUE BY PRODUCTION GROUP

CONSTANT PRICES AND COSTS

HEAVY OIL	FUTURE NET REVENUE BEFORE INCOME TAXES (Discounted at 10%/year)
	(M$)
Probable Reserves	180,237
Probable plus Possible Reserves	346,402

SUMMARY OF HEAVY OIL RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE

FORECAST PRICES AND COSTS

RESERVES CATEGORY	HEAVY OIL RESERVES	
	Working Interest	Net After Royalty
	(mbbl)	(mbbl)
Probable	250,195	228,258
Possible	152,247	136,038
Total Probable plus Possible	402,442	364,296

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT (%/year)					AFTER FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT (%/year)				
	0	5	10	15	20	0	5	10	15	20
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Probable	1,742,695	626,186	194,669	16,050	(60,419)	1,143,699	368,176	71,790	(47,749)	(96,022)
Possible	1,128,982	430,685	180,444	79,150	33,817	734,591	266,155	101,974	37,370	9,575
Total Probable plus Possible	2,871,677	1,056,871	375,113	95,200	(26,602)	1,878,290	634,331	173,764	(10,379)	(86,447)

ESTIMATED FUTURE NET REVENUE
TOTAL PROBABLE PLUS POSSIBLE RESERVES
(UNDISCOUNTED)

FORECAST PRICES AND COSTS

YEAR	DAILY HEAVY OIL PRODUCTION	WELLHEAD PRICE(1)	TOTAL REVENUE	CROWN ROYALTY NET OF ARTC(2)	TOTAL OPERATING EXPENSES	TOTAL CAPITAL EXPENDITURES	NET REVENUE BEFORE TAX	INCOME TAX
	(bbl/d)	($)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
2004	—	—	—	—	—	10.6	(10.6)	—
2005	672	20.50	5.0	0.1	4.8	8.5	(8.4)	—
2006	1,428	19.25	10.0	0.1	9.1	141.9	(141.1)	—
2007	6,212	16.50	37.4	0.3	22.8	129.6	(115.3)	—
2008	15,662	16.50	94.3	0.7	52.3	182.8	(141.5)	0.1
2009	29,501	16.50	177.7	1.4	78.1	199.1	(100.9)	0.1
2010	42,395	17.00	263.1	2.1	96.4	137.8	26.8	2.2
2011	49,938	17.50	319.0	2.7	104.3	74.6	137.4	23.8
2012	51,450	18.00	338.0	2.9	103.7	—	231.4	40.2
2013	49,832	18.50	336.5	2.9	107.5	77.3	148.8	41.9
2014	49,984	19.00	346.6	3.0	125.1	95.5	123.0	39.7
2015	45,830	19.50	326.2	2.8	127.7	103.9	91.8	31.3
REMAINDER	39,983		6,628.4	878.3	2,363.2	756.7(3)	2,630.2	814.1
TOTAL	**35,567**		**8,882.2**	**897.0**	**3,195.2**	**1,918.4**	**2,871.7**	**993.4**

Notes:

(1) Based on Hardisty Heavy 12° API.

(2) ARTC means Alberta Royalty Tax Credit.

(3) Includes abandonment costs of $30.8MM.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)

FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Probable	5,416,347	508,887	1,967,813	1,183,621	13,330	1,742,695	598,996	1,143,699
Possible	3,465,887	388,121	1,227,379	703,966	17,440	1,128,982	394,391	734,591
Total Probable plus Possible	8,882,234	897,008	3,195,192	1,887,587	30,770	2,871,677	993,387	1,878,290

FUTURE NET REVENUE
BY PRODUCTION GROUP

FORECAST PRICES AND COSTS

HEAVY OIL	FUTURE NET REVENUE BEFORE INCOME TAXES (Discounted at 10%/year)
	(M$)
Probable	194,669
Probable plus Possible	375,113

The pricing assumptions used in the GLJ Report with respect to net cumulative cash flow as well as the inflation rate used for operating costs are set forth below.

SUMMARY OF PRICING ASSUMPTIONS

CONSTANT PRICES AND COSTS

YEAR	OIL: WTI Cushing Oklahoma	Edmonton Par Price 40° API	Hardisty Heavy 12° API	Cromer Medium 29.3° API	NATURAL GAS AECO Gas Price	EXCHANGE RATE
	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/mmbtu)	($US/$Cdn)
2003 (Year End)	32.52	40.81	23.31	34.81	6.09	0.77

SUMMARY OF PRICING AND INFLATION

FORECAST PRICES AND COSTS(1)

YEAR	OIL: WTI Cushing Oklahoma	Edmonton Par Price 40° API	Hardisty Heavy 12° API	Cromer Medium 29.3° API	NATURAL GAS AECO Gas Price	INFLATION RATE	EXCHANGE RATE
	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/mmbtu)	(%/Year)	($US/$Cdn)
Forecast							
2004	34.25	44.75	29.00	41.00	6.65	1.50	0.75
2005	29.00	37.75	25.00	33.75	5.55	1.50	0.75
2006	27.00	35.25	23.75	31.25	5.20	1.50	0.75
2007	25.00	32.50	21.00	28.50	5.00	1.50	0.75
2008	25.00	32.50	21.00	28.50	5.00	1.50	0.75
2009	25.00	32.50	21.00	28.50	5.00	1.50	0.75
2010	25.50	33.00	21.50	29.00	5.10	1.50	0.75
2011	25.75	33.50	22.00	29.50	5.20	1.50	0.75
2012	26.25	34.00	22.50	30.00	5.25	1.50	0.75
2013	26.50	34.50	23.00	30.50	5.35	1.50	0.75
2014	27.00	35.00	23.50	31.00	5.45	1.50	0.75
Thereafter	Escalated at 1.5% per year					1.50	0.75

Note:

(1) The price forecast used in this table is GLJ Associates' commodity price forecast as at April 1, 2004. This price forecast is within reasonable limits to price forecasts used by independent petroleum consulting firms as at January 1, 2004.

RECONCILIATION OF NET RESERVES

FORECAST PRICES AND COSTS

FACTORS	HEAVY OIL: NET AFTER ROYALTY PROBABLE
	(mbbl)
December 31, 2002	—
Extensions	228,258
December 31, 2003	228,258

Additional Information Relating to Reserves Data

Undeveloped Reserves

The Corporation does not have any proved undeveloped reserves. Probable undeveloped reserves have been estimated in accordance with the procedures and standards contained in the COGE Handbook. In general, a significant majority of the Corporation's probable undeveloped reserves are scheduled to be developed within five years of December 31, 2003. Capital expenditures to develop all of the Corporation's undeveloped reserves under forecast prices and costs are estimated at $11 million in 2004, $9 million in 2005 and $142 million in 2006.

Significant Factors or Uncertainties

The forecast and reserves estimates contained in this prospectus are predicated on the Corporation securing financing for the Joslyn Project.

Future Development Costs

The following table sets forth GLJ Associates' forecast of future SAGD development costs. The costs are presented by reserve category and quoted without discount and with a discount rate of 10%.

	FORECAST PRICES AND COSTS	
YEAR	PROBABLE	PROBABLE PLUS POSSIBLE
	(MM$)	(MM$)
2004	11	11
2005	9	9
2006	144	142
2007	53	130
2008	165	183
2009	199	199
2010	28	138
2011	—	75
2012	33	—
2013	50	77
2014	85	96
2015	—	104
Subtotal	776	1,162
Remainder	407	726
TOTAL UNDISCOUNTED	1,184	1,888
TOTAL DISCOUNTED AT 10%	562	800

The Corporation anticipates that its future development costs relating to its SAGD phases will be financed through a combination of internally generated cash flow, equity financings and debt. Disclosed reserves and future net revenue is not expected to be materially affected by the costs of funding the future development expenditures. Based on the commodity price and cost assumptions adopted for the forecast prices and costs, all the expenditures included in the future development costs are economic as they enhance net present values. See "Financing Plan — Sources and Uses of Funds".

Other Oil and Gas Information

Properties with No Attributed Reserves

The following table sets forth the gross and net hectares of unproved properties held by the Corporation.

	UNPROVED PROPERTIES	
LOCATION	Gross Lease	Working Interest
	(Hectares)	
Alberta	21,036	17,670
TOTAL	21,036	17,670

Abandonment and Reclamation Costs

Abandonment and reclamation costs have been included in the economic forecast contained in the GLJ Report as deductions in arriving at future net revenues. Future abandonment and reclamation costs have been estimated based on $100,000 per well to be incurred the year after the well ceases to be productive as set forth in the GLJ Report. Abandonment and reclamation costs totaling approximately $21.5 million, net of salvage value ($2.5 million with a discount rate of 10%), are included in the estimate of future net revenue. Estimates of abandonment and reclamation costs for the next three years is nil. Expected future abandonment costs related to facilities, pipelines and site reclamation have been excluded from the economic forecasts contained in the GLJ Report.

Tax Horizon

Based on the after tax economic forecast contained in the GLJ Report, which excludes certain items impacting income taxes payable (e.g. mining development, exploration and seismic, and land or property acquisition costs), it is estimated that income taxes will not be payable until the beginning of 2011. If the planned mining and extraction capital expenditures are made, Deer Creek estimates that income taxes will not be payable until 2018.

Costs Incurred

The following table sets out the exploration and development costs incurred by the Corporation for the year ended December 31, 2003.

NATURE OF COST	AMOUNT (M$)
Exploration Costs	6,179
Development Costs	13,564
TOTAL	19,743

Drilling and Development Activities

For the year ended December 31, 2003, the Corporation drilled 93 (78.1 net) core holes and 14 (11.8 net) utility wells. The Corporation drilled its initial SAGD well pair (0.84 net) for SAGD Phase I during 2003. As at December 31, 2003, the wells drilled by the Corporation had not been completed and were not producing.

Alternative Price Forecast Evaluation

The forecast prices used by GLJ Associates in the GLJ Report as at April 1, 2004 differ from those currently in the public domain with respect to a number of the Corporation's industry peers. As a result, at the request of the Corporation, GLJ Associates conducted a price sensitivity analysis of the reserves of the Corporation and the net present value of future net revenue associated with such reserves as at January 1, 2004 using an alternative price forecast supplied by the Corporation. The alternative price forecast correlates with the price forecast used in appraisals of some of the Corporation's industry peers in the public domain and, by comparison to the information set forth in the GLJ Report, provides some measure of guidance in respect of the sensitivity of the evaluation to price forecast changes, particularly having regard to the period over which reserves are, pursuant to the evaluation, estimated to be recovered. GLJ Associates otherwise used the same assumptions and definitions as in the GLJ Report. The tables below summarize the alternative price forecast and the results of such analysis.

It should not be assumed that the estimates of future net revenue presented in the tables below represent the fair market value of the Corporation's reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of Deer Creek's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the

estimates provided herein. The information set forth below is supplemental to the disclosure required by NI 51-101 and is not a substitute therefor.

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE

ALTERNATIVE PRICE FORECAST

RESERVES CATEGORY	HEAVY OIL RESERVES Working Interest (mbbl)	HEAVY OIL RESERVES Net After Royalty (mbbl)
Probable	250,195	219,880
Possible	152,247	131,620
Total Probable plus Possible	402,442	351,500

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT (%/year)						AFTER FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT (%/year)					
	0	5	8½	10	15	20	0	5	8½	10	15	20
	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
Probable	2,851.7	1,141.9	610.6	465.1	172.9	38.2	1,868.9	709.0	350.9	253.4	59.7	(26.9)
Possible	1,846.4	731.5	411.2	326.2	159.1	82.3	1,203.6	462.4	252.1	196.8	89.4	41.1
Total Probable plus Possible	4,698.1	1,873.4	1,021.8	791.3	332.0	120.5	3,072.5	1,171.4	603.0	450.2	149.1	14.2

ESTIMATED FUTURE NET REVENUE TOTAL PROBABLE PLUS POSSIBLE RESERVES (UNDISCOUNTED)

ALTERNATIVE PRICE FORECAST

YEAR	DAILY HEAVY OIL PRODUCTION (bbl/d)	WELLHEAD PRICE ($)	TOTAL REVENUE (MM$)	CROWN ROYALTY NET OF ARTC[1] (MM$)	TOTAL OPERATING EXPENSES (MM$)	TOTAL CAPITAL EXPENDITURES (MM$)	NET REVENUE BEFORE TAX (MM$)	INCOME TAX (MM$)
2004	0	0.00	0	0	0	11	(11)	0
2005	672	27.28	7	0	5	9	(7)	0
2006	1,428	17.88	9	0	9	142	(141)	0
2007	6,212	18.57	42	0	22	130	(110)	0
2008	15,662	19.28	110	1	50	183	(124)	0
2009	29,501	20.00	215	1	76	199	(62)	0
2010	42,395	20.73	321	2	94	138	86	28
2011	49,938	21.49	392	3	102	75	211	54
2012	51,450	22.25	418	3	103	0	311	71
2013	49,832	23.04	419	48	107	77	186	57
2014	49,984	23.83	435	53	126	96	159	54
2015	45,830	24.64	412	45	129	104	134	47
REMAINDER	39,983		8,639	1,362	2,456	757[2]	4,064	1,314
TOTAL	**35,567**		**11,419**	**1,524**	**3,279**	**1,919**	**4,698**	**1,626**

Notes:

(1) ARTC means Alberta Royalty Tax Credit.

(2) Includes abandonment costs of $31.0MM.

The following table shows a comparison between the GLJ Associates forecast prices and the alternative price forecast provided to GLJ Associates by the Corporation.

OIL AND NATURAL GAS PRICE FORECAST COMPARISON

YEAR	GLJ ASSOCIATES FORECAST			ALTERNATIVE FORECAST		
	WTI	WELLHEAD PRICE	NATURAL GAS AECO Gas Price	WTI	WELLHEAD PRICE	NATURAL GAS AECO Gas Price
	($US)	($)	($/mmbtu)	($US)	($)	($/mmbtu)
2005	29.00	20.50	5.55	34.00	27.28	6.05
2006	27.00	19.25	5.20	26.01	17.88	4.48
2007	25.00	16.50	5.00	26.53	18.57	4.59
2008	25.00	16.50	5.00	27.06	19.28	4.71
2009	25.00	16.50	5.00	27.60	20.00	4.82
2010	25.50	17.00	5.10	28.15	20.73	4.94
2011	25.75	17.50	5.20	28.72	21.49	5.06
2012	26.25	18.00	5.25	29.29	22.25	5.18
2013	26.50	18.50	5.35	29.88	23.04	5.30
2014	27.00	19.00	5.45	30.47	23.83	5.43
2015	27.40	19.50	5.53	31.08	24.64	5.56
Remainder	+1.5%/yr	23.47	+1.5%/yr	+2%/yr	30.61	+2%/yr

Contingent Resources

The GLJ Report also contains estimates of contingent resources for the mining portion of the Joslyn Lease. The forecast and constant prices and costs assumptions used in the resources estimate were the same as those used in the reserves evaluation above. Contingent Resources is defined under the heading "The Joslyn Project — Reserves and Resources — GLJ Report".

It should not be assumed that the estimates of future net revenue presented in the tables below represent the fair market value of the Corporation's resources. There is no assurance that the constant prices and costs assumptions and forecast prices and cost assumptions will be attained and variances could be material. The recovery and resource estimates of Deer Creek's resources provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. Actual resources may be greater than or less than the estimates provided herein.

SUMMARY OF CONTINGENT RESOURCES AND NET PRESENT VALUES OF FUTURE NET REVENUE

CONSTANT PRICES AND COSTS

	CONTINGENT RESOURCES	
	Working Interest	Net After Royalty
	(mbbl)	(mbbl)
Low Estimate[(1)]	605,000	—
Best Estimate	1,234,800	1,108,151
High Estimate[(1)]	1,865,000	—

Note:

(1) The economic forecasts for the low estimate and high estimate were not prepared.

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT (%/year)					AFTER FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT (%/year)				
	0	5	10	15	20	0	5	10	15	20
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Best Estimate	7,368,178	2,142,530	617,911	121,193	(49,073)	4,816,345	1,330,083	321,422	(163)	(103,385)

TOTAL FUTURE NET REVENUE OF CONTINGENT RESOURCES (UNDISCOUNTED)

CONSTANT PRICES AND COSTS

	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
Best Estimate	23,227	2,382	10,561	2,897	—	7,386	2,570	4,816

SUMMARY OF CONTINGENT RESOURCES AND NET PRESENT VALUES OF FUTURE NET REVENUE

FORECAST PRICES AND COSTS(1)

	CONTINGENT RESOURCES	
	Working Interest	Net After Royalty
	(mbbl)	(mbbl)
Low Estimate(2)	605,000	—
Best Estimate	1,234,800	1,119,936
High Estimate(2)	1,865,000	—

Notes:

(1) The price forecast used in this table is GLJ Associates' commodity price forecast as at April 1, 2004.

(2) The economic forecasts for the low estimate and high estimate were not prepared.

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT (%/year)					AFTER FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT (%/year)				
	0	5	10	15	20	0	5	10	15	20
	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)	(M$)
Best Estimate	10,164,436	2,612,470	607,279	23,167	(147,104)	6,623,946	1,598,145	272,556	(101,233)	(198,017)

TOTAL FUTURE NET REVENUE OF CONTINGENT RESOURCES (UNDISCOUNTED)

FORECAST PRICES AND COSTS[1]

	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
Best Estimate . . .	31,959	3,237	14,771	3,787	—	10,164	3,540	6,624

Note:

(1) The price forecast used in this table is GLJ Associates' commodity price forecast as at April 1, 2004.

JOSLYN PROJECT DEVELOPMENT

Infrastructure

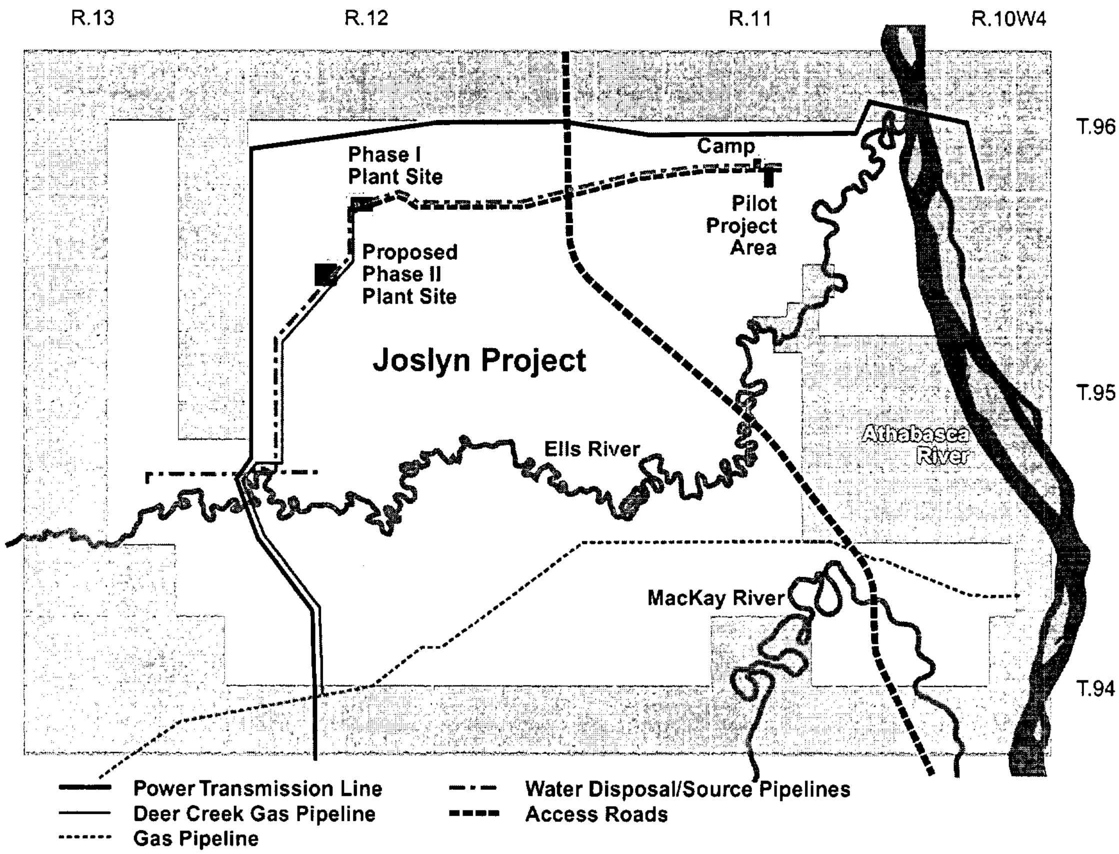
The main infrastructure requirements of the Joslyn Project consist primarily of buildings, electrical power, product, diluent and natural gas pipelines, and roadways. Due to the ongoing development in the Athabasca area, considerable infrastructure exists and more is planned. Several utilities already exist on Deer Creek's property including a natural gas pipeline and a power transmission line. In 2004, Deer Creek constructed 17 kilometres of three inch pipeline to access and connect the ATCO Ltd. owned and operated natural gas pipeline to the SAGD Phase I plant site for the purpose of transporting fuel gas for Deer Creek's SAGD operations. The line was sized with sufficient capacity to meet the anticipated fuel gas requirements for SAGD Phase II. Additionally, over 45 kilometres of water source and disposal pipelines have been installed. This pipeline infrastructure will also be used to support SAGD Phase II operations.

A 240-kVa electrical grid transmission line passes within two kilometres of the SAGD Phase I plant site. ATCO Ltd. is proposing to construct a 144-kVa shielded transmission line from the electrical grid to a substation to be located approximately three kilometres northeast of the plant site. ATCO Ltd. has communicated that it expects to build this substation and transmission line in 2005.

In 2003, with Deer Creek's approval and right-of-use, a senior oil and gas company constructed an all-weather access road through the centre of the Joslyn Lease to its mining property north of the Joslyn Lease. This road provides excellent access to several areas on the property and connects to Highway 63, which leads to Fort McMurray. Deer Creek constructed approximately 10 kilometres of road in 2003, connecting this road with the SAGD Phase I plant site and to the original Pilot Project site. The Pilot Project site is currently being reclaimed, and a third party has constructed a 160-man camp adjacent to the Pilot Project site. Though the camp is open to all industries, it will be the prime accommodation site for Deer Creek contractors. Approximately four kilometres of road connecting the SAGD Phase I plant site to the proposed SAGD Phase II plant site and well pads will be built as part of the SAGD Phase II development plan.

The Joslyn Lease is strategically positioned for tie-in to major pipelines in the Fort McMurray area which transport oil production to market. A pipeline to transport diluent and produced bitumen from the Joslyn Project will require construction and is expected to be in place by mid-year 2006. Deer Creek continues to define the optimum pipeline size and routing and negotiate terms with potential third party providers.

Joslyn Project Infrastructure



Marketing

Bitumen is typically sold as a bitumen blend, in which the bitumen is mixed with a diluent to reduce its viscosity to meet pipeline specifications, or, it is upgraded to synthetic crude oil. In the early stages of development, diluted bitumen will be produced at the Joslyn Lease. Diluent will be trucked to the Joslyn Lease for SAGD Phase I and a pipeline will be constructed to transport the diluent for SAGD Phase II and future developments. Deer Creek is planning to utilize synthetic crude oil as a diluent, which it expects to purchase from existing oil sands producers. A blend of bitumen and synthetic crude oil is generally referred to as synbit.

Synbit competes in the North American refinery supply market with imported medium sour crude oils. Synbit creates a ready-made medium sour crude oil which could be more readily available to a greater number of U.S. refiners than synthetic crude oil or historical condensate based blends. The netback for bitumen is determined by the price received for the blend less transportation and diluent costs. A major refiner publishes a posted price for an Athabasca synbit at Hardisty, Alberta that, has been, on average in 2004, a premium price to the price posted for the benchmark Lloydminster Blend, a heavy crude oil sold at Hardisty, Alberta.

Although Joslyn Project bitumen netbacks are uncertain at present, Deer Creek believes that adequate markets are available for bitumen production from the Joslyn Lease. Deer Creek is in the final stages of discussions with crude oil purchasers for commitments to purchase bitumen production from SAGD Phase I and SAGD Phase II.

Deer Creek expects that its SAGD Phase I bitumen production will be trucked to third-party terminal facilities. Plans for SAGD Phase II include the construction of a lateral pipeline connected to a major pipeline in the area. The Corporation is currently in negotiations with third parties to construct and operate a lateral pipeline.

Once production from the Joslyn Project nears rates of 100,000 barrels of bitumen per day, Deer Creek will pursue upgrading options and consider the installation of an onsite upgrader, depending on market conditions and technologies at that time.

SAGD Phase II Design and Construction

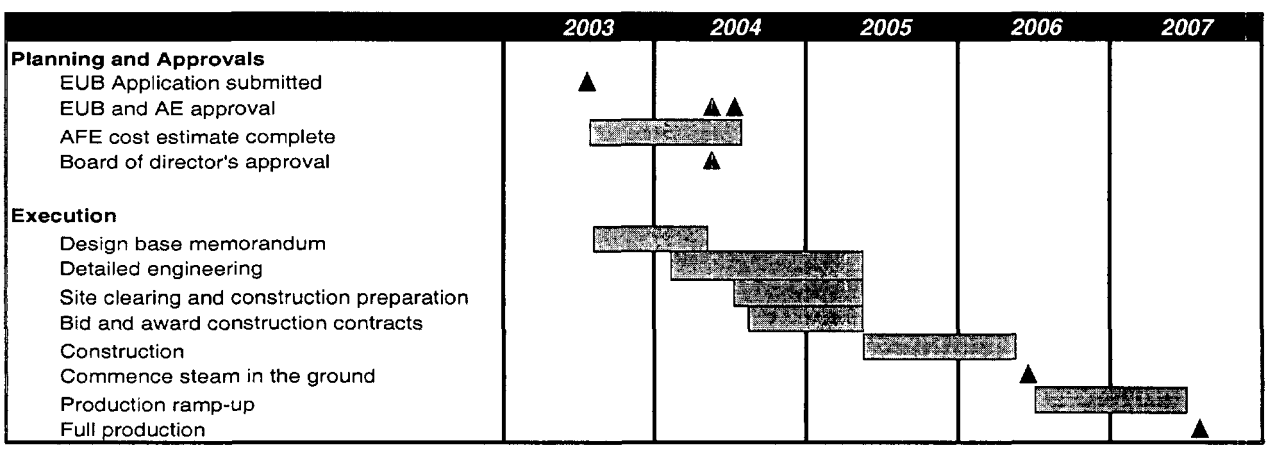
The Corporation plans to continue to use BDR Engineering for the engineering, procurement and construction management of the SAGD Phase II facility, well pad infrastructure and the steam injection and gathering lines. BDR Engineering has experience in the design and construction of projects of this magnitude, and had a similar role in the SAGD Phase I facility. All construction will be contracted on a bid basis and will be awarded based on cost, experience and availability.

The SAGD Phase II construction strategy is being planned in a fashion that should allow Deer Creek to manage and control capital costs. Key elements of this strategy include:

- ensuring Deer Creek staff are accountable for all key aspects of design, costs and scheduling;
- ensuring 60% of up-front project engineering definition is achieved prior to awarding construction contracts and 90% at commencement of construction;
- ensuring a high degree of modular construction occurs offsite to reduce the demand for on-site labour (construction completed in a controlled shop environment is typically completed at lower costs compared to activities in the field);
- using smaller contractors in the field, which should improve productivity; and
- employing adequate logistical and quality inspection supervision both in the shops and in the field to ensure standards are met and to monitor costs and schedules.

SAGD Phase II Project Schedule

The overall schedule for SAGD Phase II development is outlined in the following diagram.



▲ Event   Range of task

Note:

(1) There is not necessarily a consistent level of activity throughout the range of task completion.

EUB application submitted — Completed in 2003.

EUB and Alberta Environment approval — EUB and Alberta Environment approval has been received for SAGD Phase II. See "Joslyn Project Development — Regulatory Affairs".

AFE cost estimate complete — Preliminary engineering includes defining the scope of SAGD Phase II and the associated cost estimates necessary to proceed. Target completion date is the third quarter of 2004.

Board of Directors' approval — This marks the point when the Corporation approved SAGD Phase II in principle, subject to review of the authorizations for expenditure.

Design base memorandum — Preliminary engineering that defines Project scope, key design parameters and assumptions, process flow diagrams and major equipment identification. This was completed in April 2004.

Detailed engineering — Detailed engineering, and a project execution plan, which define the procurement and construction strategies. The engineering of each design package will be completed prior to the start of construction to avoid changes during project execution. These detailed engineering packages will provide the basis for final price quotations and placing of final supply and construction contracts, thereby contributing to the control of capital costs. Target completion date is the second quarter of 2005.

Site clearing and construction preparation — The site will be prepared in the fall and winter months to facilitate final site preparation during the summer months. This work will include tree clearing and site grading. Target completion date is the second quarter of 2005.

Bid and award SAGD construction contracts — Much of the work will be modular construction and will be built in the Calgary and Edmonton regions. Shop construction ensures high quality at a cost effective price. In addition it enables timely and effective inspection of the modules by BDR Engineering, whose staff is located in Calgary. Target completion date is the second quarter of 2005.

Construction — Since the facility will be modular, field erection costs will be reduced due to lower skilled labour requirements in the field and shorter field construction duration. The modules will arrive to the field with structural steel in place, and equipment will be skid mounted and pre-wired where practical. This means that the majority of skilled trade work will be done in a controlled shop environment where costs are significantly lower and quality should be higher. In addition, it will be possible to utilize smaller contractors for this type of field erection, which should reduce the risk of cost overruns and simplify the management of the Joslyn Project. Target completion date is the second quarter of 2006.

Commence steam injection — This phase includes operating all of the process and supporting facilities to ensure their mechanical and operational integrity. The well pads will be started up over a period of time to ensure effective well bore heating. Target date is mid-year 2006.

Production ramp-up and full production — This phase includes the well circulation warm-up phase and the period of time to ramp-up to full production. The period from first steam to peak oil is projected to be 12 to 18 months, with full production occurring from mid-year to the fourth quarter of 2007.

Project Development Costs

On April 1, 2004, BDR Engineering completed a design base memorandum on the facility, gathering and steam injection system plus the well pad surface equipment for SAGD Phase II. The estimate includes a 25% contingency for labour installation costs and a 10% contingency for new equipment costs. The estimate is considered to be accurate within plus or minus 25%. A breakdown of the estimated initial capital costs is as follows:

SAGD Phase II	Estimated Gross Initial Capital Cost
	(MM$)
Main facility	87
Well pads (four)	12
Surface gathering and steam injection lines	17
SAGD wells(1)	44
Infrastructure(1)	6
Commissioning(1)	2
Regulatory and other(1)	3
Total	171

Note:

(1) Costs estimated by Deer Creek outside of the design base memorandum prepared by BDR Engineering.

The facility will have a design capacity of 12,000 barrels per day of bitumen. The cost estimate includes the drilling and completion of 17 well pairs with expected productivity of 600 barrels of bitumen per day per well pair. Drilling of the well pairs will commence in the summer of 2005. Additional well pairs may be drilled if necessary to obtain full capacity production.

With the completion of the design base memorandum, approximately 30% of the total facility engineering budget for SAGD Phase II has been expended.

The final cost estimates are expected to be completed in the third quarter of 2004, with major equipment orders being issued to vendors shortly thereafter.

The following are the current estimates of the initial capital required for each of the phases of the Joslyn Project:

Development Phase of Joslyn Project	Estimated Incremental Bitumen Production	Estimated Gross Initial Capital Cost (2004 $)(1)
	(bbl/d)	(MM$)
SAGD Phase I(2)	600	25
SAGD Phase II	10,000	171
SAGD Phase III(3)	30,000	335
Mine Phase I(3)	50,000	708
Mine Phase II(3)	50,000	643
Mine Phase III(3)(4)	50,000	615
Mine Phase IV(3)(4)	50,000	544

Notes:

(1) Does not include any sustaining capital for any phase of the Joslyn Project.

(2) SAGD Phase I has been constructed and is currently in the first stage of operation.

(3) Based solely on preliminary cost estimates made by Deer Creek and subject to change as project progresses.

(4) Mine Phase III and Mine Phase IV are conceptual only and are dependent on, among other things, economics, future delineation drilling and mine planning. Given the stage of mine development, various changes to the mine plan may be made by the Corporation and the construction and operations schedules may change as further information is obtained and future engineering evaluations are completed.

Capital Expenditures To March 31, 2004

The table below summarizes the gross costs of the Joslyn Project from November 1998 to March 31, 2004:

	Gross Project Cost[1]
	(MM$)
Lease development	38
SAGD Phase I	25
SAGD Phases II and III	5
Mining	1
Total gross Project cost[1]	69

Note:

(1) Before capitalized general and administrative expenses.

SAGD Phase II Operating Costs

Operating costs for a SAGD project consist of fuel and non-fuel costs. It is anticipated that natural gas will be purchased to fire the steam generators for SAGD Phase II. Non-fuel costs include labour, chemical and other materials and services.

The following is an estimate of the SAGD Phase II operating costs for 2008, the first anticipated year of full production from SAGD Phase II, assuming a 2.25 to 1 steam to oil ratio and a $5.00 per GJ natural gas cost.

Natural gas	$4.50/bbl
Non-fuel costs	$3.50/bbl
Total	$8.00/bbl

It is anticipated that the non-fuel operating costs will decline by approximately $1.00 per barrel once full production from SAGD Phase III has been achieved.

Loss Management

The Corporation is committed to a high level of health, safety and environmental protection for employees, contractors, suppliers and the public. This is a key component guiding the Corporation's operations and is central to its success.

Deer Creek promotes safe work practices with established policies and procedures for field operations. The Corporation has a loss management system, which commits to providing safe and healthy operations and includes respect for the interests of the communities in which the Corporation operates. Deer Creek's operations staff communicates regularly with both management and the Board of Directors in accordance with stated policies and procedures and to identify opportunities to reduce risks associated with its field operations.

The Corporation has committed to participating in the Canadian Association of Petroleum Producer's Environmental Health and Safety Stewardship program and has received a bronze recognition level. The Corporation's goal for 2004 is to achieve the silver recognition level by implementing all basic environment and safety programs and other core industry environment, health and safety operating guidelines. The Corporation did not experience any lost-time related injuries or illnesses in 2003.

The Corporation has adopted the ISO (International Organization for Standardization) 9000 quality control standards and is applying these standards to the design aspects of its operations.

Stakeholder Consultation

The Corporation has focused on developing strong relationships with stakeholders interested in its resource development plans. A crucial element of its success and future expansion is its relationships with its neighbours. The Corporation is committed to extensive and open communication with stakeholders. As part of the Joslyn Project development plan, the Corporation has implemented a comprehensive consultation strategy for partnering with stakeholders.

Deer Creek participates in the Cumulative Environmental Management Association, the Regional Aquatics Monitoring Program and the Regional Infrastructure Working Group, and is finalizing participation in the Wood Buffalo Environmental Association. These multi-stakeholder organizations address oil sands development on a regional basis, including cumulative environmental and socio-economic impacts.

Deer Creek's operations in the Athabasca region of northern Alberta are near several First Nations communities. Deer Creek is a party to the Athabasca Tribal Council All Parties Agreement (the "Tribal Council Agreement"). The other parties to the Tribal Council Agreement are the five First Nations located in that part of the Athabasca region impacted by oil sands industry operations and 15 other oil sands industry operators in the area. The Tribal Council Agreement provides for the mechanisms and funding for meaningful consultation in support of oil sands development in the Athabasca region and enhances the ability of the First Nations to build strong economies and self-sustaining communities.

The Corporation has also worked closely with local communities to identify opportunities for local businesses and employment. These elements of the Corporation's commitment to working with local communities, including open communication, constructive response to stakeholder concerns and participating in the socio-economic opportunities of oil sands development, are critical to ongoing operations and future expansion.

The Corporation will continue to focus on building positive relationships in the communities in which it operates to address concerns and interests that its stakeholders may have regarding its development plans and to ensure these issues are understood. As the Corporation's business activities grow in the Wood Buffalo region, the Corporation will become more visible and will increasingly participate in these and other multi-stakeholder processes.

Regulatory Affairs

In November 1998, Deer Creek applied to the EUB and Alberta Environment for approval of the Pilot Project as an experimental multi drain scheme. Approval was received in January 1999. In April 2000, Deer Creek applied for regulatory approval for the second phase of the Pilot Project to operate four additional vertical wells and one additional observation well. Approval was received in July 2000. Deer Creek applied to the EUB for approval of certain amendments made to the Pilot Project in August 2000 and October 2000 for the purpose of testing other technology and recovery techniques. Approvals were received in September 2000 and December 2000, respectively.

In the summer of 2002, Deer Creek applied to the EUB and Alberta Environment for SAGD Phase I, a demonstration SAGD project. Approval was received from EUB and Alberta Environment in January 2003 and December 2002, respectively, for producing up to 2,000 barrels of bitumen per day.

In July 2003, the Corporation filed an integrated application with the EUB and Alberta Environment for approval of the construction and operation of the SAGD Phase II expansion. The integrated application sought amendments to the existing EUB and Alberta Environment approvals to increase daily SAGD bitumen production by 10,000 barrels of bitumen per day. In contemplation of merging the production from SAGD Phase I and SAGD Phase II, the design capacity and associated infrastructure of the SAGD Phase II facility was prepared for 12,000 barrels of bitumen per day. The proposed SAGD Phase II project did not require a full environmental impact assessment. However, the application did include information and analysis relating to all environmental aspects of the development such as air emissions, impacts on water resources, soils, wildlife and traditional land use as well as socio-economic effects. The application was deemed administratively complete in August 2003, at which time Alberta Environment issued a public notice for the proposed project. In response to that notice, statements of concern were submitted to Alberta Environment from three local First Nations and one non-government organization. The key issues were environmental concerns such as regional cumulative impacts by industry on the use of fresh water. The EUB received a letter from one oil industry company identifying issues relating to co-development of oil sands resources. The Corporation provided additional information to regulators and stakeholders in response to supplemental questions raised by EUB and Alberta Environment in November 2003. The statements of concern and other stakeholder issues were addressed by March 2004. In May 2004, the Corporation received an Order in Council approving the amendment to EUB Approval Number 9272 (the original SAGD Phase I EUB approval), increasing the approved production level to 12,000 barrels of bitumen per day on an annual average basis. Alberta Environment issued a set of draft approvals to the parties who filed statements of concern for their review and comment by June 1, 2004. Deer Creek received final EUB approval in May 2004 and Alberta Environment approval in July 2004.

Throughout the construction and initial start-up of operations, there will be additional regulatory approvals and permits required. Deer Creek anticipates that such additional approvals and permits required for SAGD Phase II will be received in the ordinary course.

Deer Creek has designed SAGD Phase II to meet or exceed regulatory standards for control of air emissions, water use and terrestrial disturbance.

Insurance

The Corporation's insurance strategy is to ensure comprehensive physical property and liability coverage through all phases of Project construction and operation. Deer Creek plans to review its insurance coverage through each Joslyn Project phase, in addition to conducting an annual review of such coverage. At this time, Deer Creek believes it is sufficiently insured for liability, boiler and machinery, property, officers' and directors' liability and automobile risks typical for such undertakings.

TALISMAN DEBENTURE

The Corporation acquired Lease 24 from Talisman on December 1, 1999 pursuant to the terms of the Talisman Agreement for an initial payment of $5.3 million plus a commitment to pay an additional amount of up to $21.0 million plus accrued interest pursuant to the Talisman Debenture. Interest is computed, without compounding, at the Bank of Canada's prime rate per annum. The payments under the Talisman Debenture are payable in three installments: (i) $6.0 million plus accrued interest on the earlier of the date average monthly production from Lease 24 first exceeds 10,000 barrels of bitumen per day or when cumulative bitumen production exceeds 5,000,000 barrels; (ii) $7.0 million plus accrued interest on the earlier of the date average monthly production from Lease 24 first exceeds 15,000 barrels of bitumen per day or when cumulative bitumen production exceeds 15,000,000 barrels; and (iii) $8.0 million plus accrued interest on the earlier of the date average monthly production from Lease 24 first exceeds 20,000 barrels of bitumen per day or when cumulative bitumen production exceeds 30,000,000 barrels. Enerplus has assumed its 16% share of the Talisman Debenture and the obligations of the Corporation thereunder. The Talisman Debenture is secured by a fixed and specific mortgage and charge over properties purchased by the Corporation under the Talisman Agreement, as well as after acquired personal and real property. An event of default under either the Existing Credit Facility or the Talisman Debenture triggers a deemed default under the other. The Corporation does not anticipate making a payment under the Talisman Debenture until 2007.

ENERPLUS JOINT VENTURE

In August 2002, Deer Creek sold a 16% working interest in the Joslyn Project to Enerplus. Concurrent with the sale, Deer Creek and a wholly-owned subsidiary of Enerplus entered into the joint venture governed by the Joint Venture Agreement providing for the development of the Project. The Joint Venture Agreement adopts a modified form of the Canadian Association of Petroleum Landmen 1990 Operating Procedure and Petroleum Accountants Society of Canada 1996 Accounting Procedure to govern operations of the joint venture. Deer Creek is appointed as operator of the joint venture and the Joslyn Lease.

The joint venture is divided into two stages with the rights and obligations of Enerplus varying between the stages. During the first stage, Enerplus has, among others, the following rights and obligations:

- the right to annually nominate one person acceptable to Deer Creek to be included in the slate of nominees to be considered for election as directors of Deer Creek at each annual meeting of shareholders;
- the obligation to reimburse Deer Creek for a proportionate share (based on Enerplus working interest in the Project) of Deer Creek's general and administrative expenses, less recoveries from third parties and excluding financing costs and advisory fees, subject to a maximum of $3.0 million per year, unless a larger amount is agreed to by Enerplus, and subject to adjustment in certain events such as Enerplus exchanging all or part of its interest in the Joslyn Project for Common Shares and Deer Creek making capital investments, other than in relation to the Joslyn Project, which Enerplus does not participate in;
- the right to participate with Deer Creek in capital investments other than in relation to the Joslyn Project;

- the right, if Enerplus elects not to pay its proportionate share of any expenditure on the SAGD area of the Project, to assign all of Enerplus' interest in the Project to Deer Creek in exchange for Common Shares based on a value of Enerplus' interest in the Project and the value of the Common Shares, in each case determined by evaluation by a mutually acceptable, qualified, independent expert of the after tax fair market value in accordance with the valuation instructions contained in the Joint Venture Agreement;
- the right, if Enerplus elects not to pay its proportionate share of any expenditure on the mining areas of the Joslyn Lease, to assign all of Enerplus interest in the mining areas only in exchange for Common Shares based on the value of Enerplus interest in the mining areas only and the value of the Common Shares, in each case determined in the same manner as described above;
- the obligation, if Enerplus elects not to or fails to pay its proportionate share of one or more expenditures totaling $10.0 million (net to Enerplus) on the SAGD area of the Joslyn Project, and Deer Creek so elects, to assign Enerplus interest in the SAGD area of the Joslyn Lease to Deer Creek in exchange for Common Shares based on the value of Enerplus interest in the SAGD area and the value of the Common Shares, determined in the same manner as described above; and
- the obligation, if Enerplus elects not to, or fails to pay, its proportionate share of one or more expenditures totaling $10.0 million (net to Enerplus) on the mining area of the Project and Deer Creek so elects, to assign Enerplus interest in the mining areas of the Joslyn Lease to Deer Creek in exchange for Common Shares based on the value of Enerplus interest in the mining areas and the value of the Common Shares, determined in the same manner as described above.

The first stage of the joint venture commenced on August 8, 2002 and will end on December 31, 2007, or earlier in certain events stated in the Joint Venture Agreement.

Substantially the same terms will apply during the second stage of the joint venture, however:

- Enerplus will not have the right to designate a nominee to the Board of Directors;
- Enerplus will not have the right to assign to Deer Creek and Deer Creek will not have the right to require Enerplus to assign to Deer Creek all or part of Enerplus interest in the Joslyn Project in exchange for Common Shares in the events described above; and
- Enerplus will not have the right to participate with Deer Creek in capital investments other than in relation to the Joslyn Project.

Enerplus is required to reimburse Deer Creek for its proportionate share of general and administrative expenses (as described above) and to contribute its proportionate share of expenses of the joint venture until the cumulative amount paid reaches $11.3 million (the "Commitment Amount"). Until the Commitment Amount is paid, Enerplus may not refuse to reimburse Deer Creek for general and administrative expenses or refuse to participate in operations in the Project. Once Enerplus payments reach the Commitment Amount, proposed expenditures will be subject to industry standard authorization for expenditure procedures and Enerplus may elect whether to participate or not. If Enerplus elects not to participate in a proposed expenditure (the "Non-Participating Expenditure"), Deer Creek will be entitled to recover an amount equal to 300% of the amount of the Non-Participating Expenditure (the "Recovery Amount") from net production from: (a) the SAGD area of the Joslyn Lease if the Non-Participating Expenditure relates to the SAGD area; (b) from the mining areas of the Joslyn Lease if the Non-Participating Expenditure relates to the mining areas; or (c) from the net salvage value of materials and equipment if the particular area is surrendered prior to the Recovery Amount being received. Even after Enerplus pays the Commitment Amount, it is required to continue to reimburse Deer Creek for its proportionate share of general and administrative expenses through to the end of the first stage of the joint venture. During the second stage of the joint venture, Enerplus is not required to reimburse Deer Creek for general and administrative expenses, but it will be obligated to pay overhead prescribed by the operating procedure.

Unless Deer Creek becomes bankrupt or insolvent, Enerplus may not replace Deer Creek as operator of the mining areas under the Operating Procedure or initiate operations in the mining areas unless it is appointed operator of the mining areas.

Enerplus may not propose operations on the SAGD area of the Joslyn Lease except in circumstances where the proposed operation has received all necessary regulatory approval and there are no other operations on the SAGD area, Deer Creek fails to timely proceed with the first 30,000 barrels of bitumen per day project after regulatory approval is obtained, or Deer Creek is replaced as operator. If Enerplus becomes operator of a phase of development on the Joslyn Project and Deer Creek does not participate in a proposed operation in that phase, Deer Creek will suffer a 300% penalty similar to that described above for Non-Participating Expenditures.

The Joint Venture Agreement anticipates that as the first stage of the joint venture ends, the parties will define an area of the Joslyn Project capable of a development of approximately 30,000 barrels of bitumen per day production with an estimated life of 30 years. If this goal is accomplished, that area may be segregated from the remainder of the Joslyn Project and may be operated under a separate agreement which may contain additional or different terms. If the activities of the joint venture define additional areas of the Joslyn Project which will support a phase of development of similar parameters, those areas may also be segregated and operated under separate agreements.

If either party receives and is prepared to accept an offer to purchase all or a part of its interest in the mining area, it shall not accept the offer unless the third party buyer has made a similar offer to the other party.

AREA OF MUTUAL INTEREST

Deer Creek is subject to an area of mutual interest under both the Talisman Agreement and the Joint Venture Agreement. Under the Talisman Agreement, each of Talisman and Deer Creek are entitled to participate in any oil sands related investment or project initiated by the other party outside of the Joslyn Lease but within the area of mutual interest for a 25% working interest share. The area of mutual interest under the Talisman Agreement terminates upon satisfaction of the Talisman Debenture. Under the Joint Venture Agreement, Enerplus is entitled to participate as to 16% of Deer Creek's participating interest during the first stage of the Joint Venture Agreement. See "Enerplus Joint Venture".

SELECTED FINANCIAL INFORMATION

The following tables summarize selected financial information of the Corporation as at and for the years ended December 31, 2003, 2002 and 2001 and for each of the first quarter of 2004 and the fiscal quarters of 2003 and 2002 and should be read in conjunction with the consolidated financial statements and accompanying notes of the Corporation included as Appendix A hereto.

Annual Information

	Year Ended December 31		
	2003	2002	2001
	($ thousands, except per share amounts)		
Interest and other revenue	970	533	(806)
Oil sales, net of royalties and operating expenses	—	—	119
General and administrative expenses	1,151	839	1,221
Net loss	(316)	(2,737)	(4,328)
Net loss per share (basic and diluted)[2]	—	(0.04)	(0.16)

	As at December 31		
	2003	2002	2001
	($ thousands)		
Working capital	30,522	40,723	2,971
Property, plant and equipment	28,370	8,564	18,974
Long-term financial liabilities	3,314	—	19,427
Shareholders' equity	56,004	49,486	2,518

Quarterly Information

	Three Months Ended								
	Mar 31 2004	Dec 31 2003	Sep 30 2003(1)	Jun 30 2003(1)	Mar 31 2003(1)	Dec 31 2002	Sep 30 2002	Jun 30 2002	Mar 31 2002
	($ thousands, except per share amounts)								
Net additions to property, plant and equipment	21,096	5,988	4,638	1,240	7,970	1,833	(14,395)	230	1,944
Interest and other revenue	260	235	240	242	253	217	(672)	983	5
Net income (loss)	(374)	(166)	(45)	(77)	(28)	(45)	(2,408)	411	(695)
Net income (loss) per share (basic and diluted)(2)	—	—	—	—	—	—	(0.03)	0.01	(0.03)

Notes:

(1) Net income (loss) has been restated for the prospective adoption of the Canadian Institute of Chartered Accountants' recommendations for stock-based compensation, effective January 1, 2003.

(2) Pre-Consolidation Shares.

DIVIDENDS

The Corporation has not paid any dividends to date. The payment of dividends in the future will be dependent upon the earnings and financial position of the Corporation and on such other factors as the Board of Directors considers appropriate. The Existing Credit Facility restricts the Corporation's ability to pay dividends and it is expected that the terms of the New Credit Facility will impose a similar restriction on the payment of dividends.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis should be read in conjunction with the consolidated financial statements and accompanying notes of the Corporation, which have been prepared in accordance with Canadian generally accepted accounting principles, included as Appendix A hereto. Additional information relating to Deer Creek is available on the SEDAR website at www.sedar.com. Prospective purchasers of Common Shares should carefully consider the information set forth under "Risk Factors" and other information set forth herein before deciding to invest in the Common Shares.

Three Months Ended March 31, 2004 Compared to Three Months Ended March 31, 2003

Results of Operations

Net Additions to Property, Plant and Equipment

Exploration, development and construction activities have been conducted under the Joint Venture Agreement.

	Three Months Ended March 31	
	2004	2003
	($ thousands)	
Joslyn Project		
Project delineation	**8,056**	4,821
SAGD Phase I	**9,870**	2,138
SAGD Phases II and III	**1,901**	714
Mining	**58**	6
Other	**(14)**	128
Asset retirement obligations	**595**	—
Capitalized general and administration	**478**	155
Project costs	**20,944**	7,962
Office equipment	**152**	8
Net additions to property, plant and equipment	**21,096**	7,970

For the three months ended March 31, 2004, net capital expenditures (excluding non-cash items such as asset retirement obligations and capitalized stock-based compensation) were incurred primarily for the construction of the SAGD Phase I facility and gathering system and for the 2004 winter core hole drilling and seismic programs. Net capital expenditures, estimated at $11.7 million, for the remainder of 2004 are focused on the evaluation and analysis of the mine opportunity, identifying synergies between mining and SAGD, and regulatory and engineering costs for the next phases of development. The Corporation anticipates that its future development costs of the Joslyn Project will be financed through a combination of internally generated cash flow, equity financings and debt. The Joslyn Project is planned to be developed using a combination of both SAGD and mining methods. This is expected to allow Deer Creek to first establish SAGD production, which benefits from lower economies of scale. Through SAGD operations, Deer Creek will establish on-site infrastructure and utilities and cash flow as a platform from which to develop the mining phases of the Project.

Financial Results

	Three Months Ended March 31	
	2004	**2003**
	($ thousands)	
Interest and other revenue	**260**	253
General and administrative expenses, net	**610**	255
Net income (loss)	**(374)**	(28)

Interest and Other Revenue

Interest and other revenue was primarily interest earned on cash invested in bankers' acceptances and money market instruments held during the period. Interest and other revenue for the first quarter of 2004 was consistent with the first quarter of 2003 due to comparable average investment balances and interest rates.

General and Administrative Expenses

Net general and administrative expenses increased $0.4 million in the three months ended March 31, 2004 compared to the three months ended March 31, 2003 primarily due to an increase in the number of employees and the recording of stock-based compensation for 2003 and 2004 stock option awards. Deer Creek's general and administrative expenses are expected to increase as the Joslyn Project advances.

	Three Months Ended March 31	
	2004	**2003**
	($ thousands)	
General and administrative expenses, gross	**954**	394
Joint venture recoveries	**(139)**	(55)
	815	339
Stock option compensation costs	**273**	71
Capitalized costs	**(478)**	(155)
General and administrative expenses, net	**610**	255

The increase in gross general and administrative expenses was due to increased activities related to project development including employees, computer services and consulting costs.

Net Income (Loss)

The net loss increased by $0.3 million for the three months ended March 31, 2004 compared to the three months ended March 31, 2003 due to increased general and administrative expenses associated with the advancing development of the Joslyn Project.

Losses are expected to continue during 2004 as the Joslyn Project will remain in the pre-commercial phase. All net revenue and operating costs associated with SAGD Phase I will be capitalized and amortized over the expected life of the associated reserves.

Income Taxes

Large Corporations Tax decreased to $12,000 in the first quarter of 2004 from $22,000 for the same period in 2003 due to the decrease in the statutory rate and the increase in the allowable capital deduction.

Liquidity

Working Capital

Working capital surplus decreased $3.7 million during the first quarter of 2004. This decrease was primarily due to capital expenditures for the development of the Joslyn Project partially offset by net proceeds from the January 28, 2004 issuance of Pre-Consolidation Shares.

	($ thousands)
Working capital, December 31, 2003	30,522
Capital expenditures	(20,369)
Share issuance proceeds, net of costs	16,647
Funds used in operations	(45)
Other	79
Working capital, March 31, 2004	**26,834**

The working capital surplus at March 31, 2004 is sufficient to fund the 2004 expected remaining capital expenditures, general and administrative expenses and pre-commercial operating costs from SAGD Phase I. Working capital surplus is estimated to be $10.0 million at December 31, 2004.

Capital Resources

Equity Financing

On January 28, 2004, the Corporation closed a private placement of 10,100,000 Pre-Consolidation Shares at a price of $1.75 per Pre-Consolidation Share for total gross proceeds of $17.7 million. Proceeds from this share issuance are intended for future development of the Joslyn Project.

Credit Facility

On March 25, 2004, Deer Creek entered into the Existing Credit Facility. The Existing Credit Facility is intended for project development purposes. The Corporation has not drawn any funds under the Existing Credit Facility.

Contingencies and Commitments

The Corporation has an obligation to Talisman to pay $21.0 million, contingent on production from the Joslyn Project. Deer Creek does not anticipate making a payment under the Talisman Agreement until 2007. Additional information on the obligation to Talisman is set forth in the accompanying notes to the consolidated financial statements. Enerplus assumed 16% of the contingent obligations to Talisman when it purchased its 16% interest in the Joslyn Project on August 8, 2002.

Deer Creek has lease obligations until 2007 as follows:

	($ thousands)
2004 remainder	193
2005	253
2006	12
2007	2

Under a SAGD Licence Agreement with the Alberta Research Council Inc., the Corporation is required to pay $0.4 million at the earlier of obtaining sufficient capital resources to develop SAGD Phase II or commencing construction of SAGD Phase II. A final installment of $0.4 million is required to be paid upon commencing steam injection of SAGD Phase II.

Outstanding Share Data

At April 28, 2004, share data consists of the following (before giving effect to the Consolidation):

	(thousands)
Issued and outstanding	
Pre-Consolidation Shares	148,108
Special warrants	1,384
Stock options	10,158
Performance share units (formerly stock rights)	792
Fully diluted number of Pre-Consolidation Shares	160,442

The Board of Directors approved amendments to each of the Stock Option Plan and Performance Share Unit Plan (formerly the stock rights plan of the Corporation) on April 21, 2004 with shareholder approval received at the annual and special meeting of shareholders held on May 20, 2004. The amendments specify the maximum number of Common Shares issuable pursuant to such plans, adopt a revised definition of "Change of Control", consistent with other Canadian issuers and limit the term of exercise of performance share units to seven years.

Critical Accounting Estimates

A comprehensive discussion of the Corporation's significant accounting policies is contained in Note 1 to the consolidated financial statements and attached hereto as Appendix A. The following is a discussion of the accounting estimates that are critical in determining the Corporation's financial results.

Reserves

Deer Creek's oil sands reserves are independently evaluated by petroleum engineering consultants. A reduction in the estimate of reserves could result in a reduction in the net recoverable amount. The estimate of reserves is a subjective process. Forecasts are based on numerous uncertainties such as engineering data, projected future rates of production and commodity pricing, and the timing of future capital expenditures. Upward or downward revisions of reserve estimates can be made based on results of future drilling, testing, production levels and economics of recovery.

Capitalized costs less accumulated depletion and amortization, future taxes and the provision for asset retirement obligations is limited to the estimated future cash flow from the properties. Estimates of future cash flows are subject to significant judgment concerning prices, production quantities, operating costs, future development costs, general and administrative expenses, financing costs and income taxes.

Changes in Accounting Standards

Asset Retirement Obligations

Effective January 1, 2004, the Corporation adopted, retroactively with restatement, the new recommendation of the Canadian Institute of Chartered Accountants with respect to asset retirement obligations. The recommendation requires the recognition of all legal obligations associated with the retirement of an asset. A liability for an asset retirement obligation is to be recognized at its fair value in the period in which it is incurred with a corresponding asset retirement cost added to the carrying value which is then amortized into income. Deer Creek recorded a liability of $0.6 million for future asset retirement obligations. There were no adjustments required to prior periods as substantially all the assets to which an asset retirement obligation exists were completed during the first quarter of 2004.

Oil and Gas Accounting — Full Cost

In September 2003, the Canadian Institute of Chartered Accountants issued a new guideline for petroleum and natural gas operations, Accounting Guideline 16. This guideline is effective for fiscal years beginning January 1, 2004. The adoption of this guideline did not impact the Corporation's operating results as it continues to develop the Joslyn Project.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Results of Operations

Net Additions to Property, Plant and Equipment

Gross capital expenditures in 2003 totaled $23.6 million compared to $6.0 million in 2002. On August 8, 2002, the Corporation sold a 16% working interest in the Joslyn Project to Enerplus for gross proceeds of $16.0 million.

	2003	2002
	($ thousands)	
Joslyn Project		
Exploration	**6,179**	2,041
SAGD Phase I	**9,368**	1,652
SAGD Phases II and III	**2,051**	—
Mining	**501**	—
Other	**446**	655
Capitalized general and administration	**1,198**	561
Project expenditures	**19,743**	4,909
Less proceeds from sale of working interest	**—**	(15,304)
	19,743	(10,395)
Office equipment	**93**	7
Net additions to property, plant and equipment	**19,836**	(10,388)

Financial Results

Deer Creek had no producing assets nor did the Corporation have any other operating activities.

	2003	2002	change
	($ thousands)		(%)
Interest and other revenue	**970**	533	82
General and administrative expenses, net	**1,151**	839	37
Net loss	**(316)**	(2,737)	(88)

Interest and Other Revenue

Interest and other revenue primarily consists of interest earned on cash invested in bankers' acceptances and money market instruments held during 2003. Interest and other revenue increased $0.4 million in 2003, compared to 2002, as a result of higher average balances maintained throughout 2003. In accordance with corporate policies, cash is invested in short-term investment instruments.

General and Administrative Expenses

Net general and administrative expenses increased $0.3 million in 2003, compared to 2002, primarily due to an increase in the number of employees.

Total gross general and administrative expenses for 2003 were $2.4 million. Costs directly related to the project development activities are capitalized. The Corporation capitalized $1.2 million of general and administrative expenses in 2003 compared to $0.6 million in 2002. The increases in gross general and administrative expenses and capitalized costs were due to increased activities related to Project development. Net general and administrative expenses increased as a result of the prospective adoption of the fair value method of accounting for stock options effective January 1, 2003.

	2003	2002	change
	($ thousands)		(%)
General and administrative expenses, gross	**2,364**	1,491	59
Joint venture recoveries	**(324)**	(102)	218
	2,040	1,389	47
Stock option compensation costs	**309**	11	2,709
Capitalized	**(1,198)**	(561)	114
General and administrative expenses, net	**1,151**	839	37

Net Income (Loss)

The net loss decreased for 2003 compared to 2002. In August of 2002, non-recurring interest and amortization costs associated with the conversion of the convertible debentures held by Lime Rock were satisfied by the subscription for Pre-Consolidation Shares. The Corporation recorded charges totaling $3.7 million in respect of the estimated value of these additional shares. Of the total charge, $1.3 million related to the debt portion of the debentures was expensed and the remaining $2.4 million related to the equity portion of the debentures was recorded directly to the deficit.

Income Taxes

Large Corporations Tax increased to $105,000 in 2003 from $59,000 in 2002 directly as a result of the increase to the Corporation's capital base through the issuance of share capital.

Deer Creek was not taxable on net income. As at December 31, 2003, the Corporation had approximately $18.3 million of tax pools, $1.7 million of financing and share issue costs, and $1.1 million of losses to carry forward which can be used to offset future taxable income. Future income tax liabilities of $3.5 million arising from the renunciation of deductions for the November 4, 2003 issuance of flow-through Pre-Consolidation Shares, reduced by the future income tax assets, result in a net future income tax liability of $3.3 million. Share capital has been reduced for the tax effect of the flow-through renunciations.

Annual Information

	2003	2002	2001
	($ thousands, except per share amounts)		
Oil sales, net of royalties	**—**	—	119
Interest and other revenue	**970**	533	(806)
Net loss	**(316)**	(2,737)	(4,328)
Net loss per Pre-Consolidation Share (basic and diluted)	**—**	(0.04)	(0.16)
Total assets	**65,870**	50,761	22,234

Capital expenditures have increased due to the development of the Joslyn Project. In 2001, the Corporation disposed of its producing property at Lloydminster, Alberta and focused on the development of the Joslyn Project. Proceeds from the issuance of Pre-Consolidation Shares contributed to the increase in total assets and interest revenue.

Quarterly Information

	2003				
	Q1	Q2	Q3	Q4	Total
	($ thousands, except per share amounts)				
Net additions to property, plant and equipment	**7,970**	**1,240**	**4,638**	**5,988**	**19,836**
Interest and other revenue	**253**	**242**	**240**	**235**	**970**
Net loss	**(28)**	**(77)**	**(45)**	**(166)**	**(316)**
Net loss per Pre-Consolidation Share (basic and diluted)	—	—	—	—	—

	2002				
	Q1	Q2	Q3	Q4	Total
	($ thousands, except per share amounts)				
Net additions to property, plant and equipment	1,944	230	(14,395)	1,833	(10,388)
Interest and other revenue	5	983	(672)	217	533
Net income (loss)	(695)	411	(2,408)	(45)	(2,737)
Net income (loss) per Pre-Consolidation Share (basic and diluted)	(0.03)	0.01	(0.03)	—	(0.04)

Capital expenditures occurred primarily in the first and fourth quarters when surface conditions provide the Corporation access to the property. The third quarter of 2002 reflects the Corporation's sale of a 16% working interest in the Joslyn Project to Enerplus.

Net loss increased in the fourth quarter of 2003 as a result of recording performance-related expenses earned by employees during 2003. In 2003, the Corporation prospectively adopted the recommendations of the Canadian Institute of Chartered Accountants for stock-based compensation effective January 1, 2003. Net loss for prior quarters was restated for the adoption of this recommendation.

A foreign exchange gain was recognized in the second quarter of 2002. In the third quarter of 2002, the Corporation expensed $1.3 million for the satisfaction of the convertible debentures held by Lime Rock.

Liquidity

Working Capital

Deer Creek had a working capital surplus of $30.5 million at December 31, 2003 compared to $40.7 million at December 31, 2002. The decrease in the working capital surplus was primarily a result of $19.8 million of capital expenditures for the development of the Joslyn Project in 2003 offset by net proceeds of $9.7 million from the November 4, 2003 flow-through Pre-Consolidation Share issuance.

	($ thousands)
Working capital, December 31, 2002	40,723
Capital expenditures	(19,836)
Share issuance proceeds, net of costs	9,661
Funds provided by operations	19
Other	(45)
Working capital, December 31, 2003	**30,522**

Cash and cash equivalents decreased to $35.1 million at December 31, 2003 from $41.2 million at December 31, 2002 as a result of capital expenditures for the development of the Joslyn Project.

Capital Resources

Equity Financing

On November 4, 2003, the Corporation closed a private placement of 5,000,000 flow-through Pre-Consolidation Shares at a price of $2.00 per flow-through Pre-Consolidation Share for total gross proceeds of $10.0 million. The proceeds from this share issuance were used to fund the Corporation's 2004 winter core hole drilling program.

Changes in Accounting Standards

Stock-based Compensation

The new recommendation of the Canadian Institute of Chartered Accountants for stock-based compensation was effective for the Corporation as of January 1, 2002. This new recommendation requires pro forma disclosure of the effect of fair value accounting for stock-based compensation where the fair value method was not applied. The Corporation prospectively adopted the recommendation effective January 1, 2003. All awards granted subsequent to January 1, 2003 have been recorded using the fair value method with the cost being recognized over the estimated vesting periods of the respective stock options. Share options granted prior to January 1, 2003 were not recognized as compensation cost and the Corporation will continue to disclose the pro forma impact of these options.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Financial Results

Revenue

Interest and other revenue increased to $0.4 million in 2002 from $0.1 million in 2001 due to a significant increase in cash and cash equivalents during the fourth quarter of 2002. The increase in cash and cash equivalents resulted from the receipts of proceeds from the sale of a 16% interest in the Joslyn Project to Enerplus and from the net proceeds of the July 25, 2002 issuance of Pre-Consolidation Shares and the November 28, 2002 issuance of flow-through Pre-Consolidation Shares.

The decrease in oil sales revenue and gain on sale of property, plant and equipment was due to the sale of Deer Creek's only producing property, Lloydminster, in the third quarter of 2001.

Foreign Exchange Revenue, Debt Set-Off Expense and Interest on Debenture

On August 8, 2002, the consolidated debenture held by Lime Rock was satisfied by the subscription for Pre-Consolidation Shares. Following this issuance, no further interest expense or foreign exchange revenue was recorded. As a result of the agreement, the debenture agreement was amended to include a number of Pre-Consolidation Shares that exceeded the amount of Pre-Consolidation Shares Lime Rock was entitled to under a voluntary conversion of the debentures pursuant to the original debenture terms. The Corporation recorded charges totaling $3.7 million in respect of the estimated value of the additional Pre-Consolidation Shares issued, of which $1.3 million related to debt and was charged to earnings, and $2.4 million related to equity and was charged directly to the deficit.

General and Administrative Expenses

General and administrative expenses decreased to $0.8 million in 2002 from $1.2 million in 2001 due to recoveries received under the terms of the Joint Venture Agreement.

Income Taxes

Large Corporations Tax increased in 2002, compared to 2001, due to the set-off arrangement and the issuance of Pre-Consolidation Shares increasing the Corporation's capital tax base in 2002.

The Corporation had $8.5 million of expenditure pools and $1.6 million of share issuance costs available for deduction against future income. The Corporation was not taxable on income and the benefits of the tax pools were not recognized in the consolidated financial statements for 2002 and 2001.

Net Income (Loss)

The net loss for the year ended December 31, 2002 was $2.7 million compared to $4.3 million for the year ended December 31, 2001. The net loss for both years was primarily due to the non-recurring interest and amortization costs associated with the convertible debentures held by Lime Rock, which was satisfied by the subscription for Pre-Consolidation Shares in August 2002.

Net Additions to Property, Plant and Equipment

Project expenditures for 2002 totaled $5.0 million compared to $4.0 million for 2001. The 2001 capital program focused on core hole and seismic programs aimed at delineating the Joslyn Lease as well as the construction and operation of a SAGD pilot facility for the Joslyn Project. Capital expenditures in 2002 related to SAGD Phase I development, further delineation of the Joslyn Lease and preparatory expenditures for the regulatory submission for expansion of the Joslyn Project.

Liquidity and Capital Resources

Cash and cash equivalents increased to $41.2 million at December 31, 2002 from $3.1 million at December 31, 2001 due to net proceeds from the issuance of Pre-Consolidation Shares and the sale of a 16% interest in the Joslyn Project to Enerplus.

On August 8, 2002 the Corporation completed a private placement of 26.3 million Pre-Consolidation Shares for net proceeds of $23.9 million and also received net proceeds of $15.3 million from the sale of a 16% interest in the Joslyn Project to Enerplus. In addition to acquiring such 16% interest from the Corporation, Enerplus committed to expending $11.3 million for its share of future development and general and administrative expenses of the Joslyn Project.

On November 28, 2002, the Corporation completed a private placement of 4.5 million flow-through Pre-Consolidation Shares for net proceeds of $4.6 million. These funds were designated for the winter core hole program and the capital expenditures were incurred in early 2003.

Changes in Accounting Standards

Foreign Exchange

Effective January 1, 2002, the Corporation adopted, retroactively with restatement, the Canadian Institute of Chartered Accountants' new recommendations for foreign currency translation whereby gains and losses from translation of foreign denominated debt are charged to current earnings and not deferred. As a result, the accumulated deferred foreign exchange loss of $1.0 million was charged to the deficit, increasing the deficit at December 31, 2001 from $7.1 million to $8.1 million.

USE OF PROCEEDS

The net proceeds of the Offering to the Corporation, after deducting the fees payable to the Underwriters and the expenses of the Offering, are estimated to be $151,122,500 ($166,374,750 in the event the Over-Allotment Option is exercised in full). The net proceeds will be used by the Corporation to fund the Corporation's share of the projected capital costs of SAGD Phase II, the regulatory, engineering design and environmental work related to additional expansions of the Joslyn Project and other related expenses.

FINANCING PLAN

General

The net proceeds of the Offering are expected to be sufficient to complete SAGD Phase II, as well as certain additional work necessary to advance the development of future phases of the Joslyn Project. In addition, Deer Creek has entered into a commitment agreement for a committed credit facility of $65 million with two Canadian chartered banks. This additional financing will assist in funding SAGD Phase II and provide incremental working capital to the Corporation to support the regulatory, engineering design and environmental work related to additional expansions of the Joslyn Project and other related expenses. The Existing Credit Facility will be cancelled upon Deer Creek entering into a credit agreement pursuant to the New Credit Facility.

Bank Financing

On July 16, 2004, Deer Creek entered into a commitment agreement with two Canadian chartered banks for a committed credit facility of $65 million.

The New Credit Facility will be available to the Corporation to assist in funding SAGD Phase II and can be used to provide incremental working capital to the Corporation to support the regulatory, engineering design and environmental work related to additional expansions of the Joslyn Project and other related expenses.

The conditions precedent to closing and making the initial drawdown under the New Credit Facility include, among other conditions, the following:

- execution of satisfactory loan and security documentation;
- receipt by the lenders of evidence that all material government approvals and licenses have been obtained or will be obtained in the normal course of completion for SAGD Phase II;
- satisfactory proof of adequate insurance coverage;
- Deer Creek has issued at least $152 million of common equity and utilized $144 million for the SAGD Phase II project;
- Deer Creek has entered into a marketing agreement for at least 2,500 bbls/d on terms satisfactory to the lenders; and
- Deer Creek has entered into a transportation agreement for a period of not less than seven years on terms satisfactory to the lenders.

The conditions precedent to all drawings under the New Credit Facility include, among other conditions:

- Deer Creek certifying current stage of construction, project costs incurred to date, estimated cost remaining to completion and confirmation that completion will occur prior to December 31, 2008; and
- the independent engineers certifying to the lenders completion costs, analysis of labour utilization costs, productivity and accountability and ability of Deer Creek to achieve project completion by December 31, 2008.

Once SAGD Phase II has been completed, project cashflow (net of, among other things, operating and maintenance expenses) will be directed toward payment of interest and fees, any commitments due to Talisman and the repayment of principal.

The New Credit Facility is expected to restrict Deer Creek's ability to incur additional indebtedness, pay dividends or distributions, encumber or dispose of its interest in the Joslyn Project, change the nature of its business or incur certain capital expenditures for as long as the New Credit Facility is outstanding.

The lenders will take a charge over all the assets of Deer Creek to secure the New Credit Facility and will rank *pari passu* with Talisman over Deer Creek's right, title, estate and interest in the Joslyn Lease.

Sources and Uses of Funds

The following table sets out the estimated expenditures and potential sources of funds for Deer Creek during the period commencing in the fiscal year 2004 and ending upon commencement of positive cash flow from SAGD Phase II, expected at year end 2006. In addition, costs for development work on SAGD Phase III and Mine Phase I and Mine Phase II are included. The Project costs reflect Deer Creek's 84% working interest share in the Joslyn Project.

	For the Years Ended December 31			
	2004	2005	2006	2004-2006
Uses of Capital (MM$)				
SAGD Phase I expenditures	10.6	—	0.3	10.9
SAGD Phase II expenditures	5.3	82.8	55.2	143.3
Other capital expenditures	16.1	9.9	15.5	41.5
General & administrative expenditures	3.2	4.6	5.5	13.3
Operating loss	2.2	1.8	5.0	9.0
Working capital	—	—	3.0	3.0
Financing fees/interest expense	12.5	0.8	1.3	14.6
Total uses	49.9	99.9	85.8	235.6
Sources of Capital (MM$)				
Cash (as at January 1, 2004)	35.1	—	—	35.1
Common equity — January 2004 private placement	17.7	—	—	17.7
Proposed initial public offering	160.6	—	—	160.6
Interest income	2.4	1.6	0.8	4.8
Debt	—	—	17.4	17.4
Total sources	215.8	1.6	18.2	235.6
Excess of available sources over uses	**165.9**	**(98.3)**	**(67.6)**	**0**

CAPITALIZATION

The following table sets forth the capitalization of the Corporation as at the dates indicated:

	Outstanding as at December 31, 2003	Outstanding as at March 31, 2004	Outstanding as at March 31, 2004 before giving effect to the Offering and after giving effect to the Consolidation	Outstanding as at March 31, 2004 after giving effect to the Offering and the Consolidation(6)(7)
Long Term Debt(1)	—	—	—	—
Common Shares(2)(3)(4)(5)	$59,743,213 (137,865,302 Pre-Consolidated Shares)	$76,745,034 (147,965,302 Pre-Consolidated Shares)	$76,745,034 (29,593,079 Common Shares)	$229,802,044 (46,798,458 Common Shares)
Special Warrants(5)	$1,934,510 (1,526,882 warrants)	$1,934,510 (1,526,882 warrants)	$1,934,510 (305,378 warrants)	Nil (Nil warrants)

Notes:

(1) The Corporation has in place the Existing Credit Facility. The Existing Credit Facility is a 364 day revolving facility of $6 million that is repayable on March 24, 2005. In addition, the Corporation has entered into a commitment agreement for a committed credit facility of $65 million. (See "Financing Plan").

(2) Common Shares after giving effect to the Consolidation and Pre-Consolidation Shares before giving effect to the Consolidation.

(3) The Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of First Preferred Shares issuable in one or more series. There are currently no First Preferred Shares outstanding. See "Share Capital".

(4) Does not include up to 8,291,931 Pre-Consolidation Shares as at December 31, 2003 and 10,949,520 Pre-Consolidation Shares as at March 31, 2004 (1,658,398 Common Shares and 2,189,928 Common Shares, respectively) issuable pursuant to the Stock Option Plan and Performance Share Unit Plan of the Corporation.

(5) All of the special warrants were exercised between April 1, 2004 and May 11, 2004 and the Corporation issued 1,526,882 Pre-Consolidation Shares (305,378 Common Shares).

(6) Based on the issuance of 16,900,000 Offered Shares for aggregate gross proceeds of $160,550,000, less the Underwriters' fee of $8,027,500 and expenses of the Offering estimated to be $1,400,000, the net proceeds to the Corporation from the Offering are estimated to be $151,122,500. Assumes the exercise of all of the special warrants.

(7) In certain circumstances, Enerplus may sell all or part of its interest in the Joslyn Project to Deer Creek in exchange for Common Shares (See "Enerplus Joint Venture"). Common Shares issuable to Enerplus in exchange for its interest in the Joslyn Project are not included.

SHARE CAPITAL

The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and First Preferred Shares. As at July 1, 2004, after giving effect to the Consolidation, there were 29,898,458 Common Shares issued and outstanding. No First Preferred Shares are currently issued and outstanding.

Common Shares

The Corporation is authorized to issue an unlimited number of Common Shares. Holders of Common Shares are entitled to one vote per Common Share at meetings of shareholders of the Corporation and are entitled to dividends if, as and when declared by the Board of Directors, subject to prior satisfaction of rights to dividends attached to the First Preferred Shares or any other class or series of shares ranking in priority to the Common Shares. Upon the liquidation, dissolution or winding-up of the Corporation, or other distribution of the assets of the Corporation, holders of Common Shares shall be entitled to receive the remaining property of the Corporation, subject to the prior satisfaction of the rights of holders of First Preferred Shares or shares of any other class or series ranking in priority to the Common Shares to receive property of the Corporation upon its liquidation, dissolution or winding-up or other distribution of its property.

First Preferred Shares

The Corporation is authorized to issue an unlimited number of First Preferred Shares, issuable in one or more series, and having such designation, rights, privileges, restrictions and conditions as the Board of Directors may determine. Holders of First Preferred Shares are entitled to a preference over the holders of Common Shares and any other class or series of shares ranking junior to the First Preferred Shares with respect to receipt of dividends. Upon the liquidation, dissolution or winding-up of the Corporation, or other distribution of the assets of the Corporation, holders of the First Preferred Shares shall be entitled to receive payment of unpaid cumulative dividends and declared but unpaid non-cumulative dividends on the First Preferred Shares and to the return of capital on the First Preferred Shares in priority to the Common Shares or any other class or series of shares ranking junior to the First Preferred Shares with respect to the receipt of dividends or the return of capital on the liquidation, dissolution or winding-up of the Corporation or other distribution of the assets of the Corporation. As at the date hereof, no First Preferred Shares are outstanding.

DIRECTORS, OFFICERS AND MANAGEMENT

The following table lists the names of the directors of the Corporation, their municipalities of residence, positions and offices with the Corporation, principal occupations and the number of securities of the Corporation (after giving effect to the Consolidation) currently held by them.

Name and Municipality of Residence and Position with the Corporation	Principal Occupation	Date Appointed Director of the Corporation	Number of Common Shares Beneficially Owned or Controlled(1)	Number of Securities of the Corporation Owned(2)
S. Barry Jackson . . . . Calgary, Alberta *Chairman of the Board of Directors* *Chair of the Human Resources and Governance Committee* *Member of the Technical Committee*	Independent businessman since November 2000.	April 27, 2001	29,408	235,007
Glen C. Schmidt . . . . Calgary, Alberta *President and Chief Executive Officer* *Member of the Technical Committee*	President and Chief Executive Officer of Deer Creek since July 1, 2001.	March 10, 2000	41,000	564,849
John G. Clarkson . . . . Calgary, Alberta *Chair of the Technical Committee* *Member of the Human Resources and Governance Committee*	Managing Director, Lime Rock Management Ltd. since December 2003.	August 30, 2001	16,000(3)	88,369
Jonathan C. Farber . . . . Westport, Connecticut, USA *Member of the Audit Committee* *Member of the Human Resources and Governance Committee*	Managing Director, Lime Rock Management LP, since June 1998.	December 10, 1998	Nil(3)	63,592
Ronald J. Hiebert . . . . Edmonton, Alberta *Member of the Audit Committee* *Member of the Human Resources and Governance Committee*	Director, Private Client Services ScotiaMcLeod since 1983.	March 28, 2001(4)	4,000	75,409
Gordon J. Kerr(5) . . . . Calgary, Alberta *Member of the Audit Committee*	President and Chief Executive Officer of Enerplus since May 10, 2001.	August 30, 2002	Nil	10,286
Brian K. Lemke . . . . Calgary, Alberta *Chair of the Audit Committee*	President and Chief Executive Officer, Resolute Energy Inc. (successor to Resolute Energy Corporation).	April 27, 2001	29,408	133,777

Notes:

(1) The information as to the number of Common Shares beneficially owned or controlled, not being within the knowledge of the Corporation, has been furnished by the respective nominees or their legal counsel.

(2) This column represents the sum of the Common Shares beneficially owned or controlled by the nominee plus the number of options to acquire Common Shares and performance share units to acquire Common Shares. The Corporation has been advised that all options to acquire Common Shares and performance share units to acquire Common Shares granted to Messrs. Clarkson, Farber and Kerr are for the benefit of their respective employers.

(3) The Beacon Group Energy Investment Fund II, L.P. beneficially owns 15,320,401 Common Shares (which is comprised of 2,276,949 Common Shares owned directly and 13,043,452 Common Shares owned through Riverside Investments LLC on behalf of The Beacon Group Energy Investment Fund II, L.P.) and Friends of Lime Rock LP beneficially owns 656,127 Common Shares. These investments in the Corporation are managed by Lime Rock Management LP, of which Mr. Farber is a Managing Director and Messrs. Farber and Clarkson are limited partners. Mr. Farber also has an indirect ownership interest in The Beacon Group Energy Investment Fund II, L.P., Riverside Investments LLC on behalf The Beacon Group Energy Investment Fund II, L.P. and Friends of Lime Rock LP. Messrs. Farber and Clarkson disclaim beneficial ownership of the subject shares except to the extent of their pecuniary interest, if any, therein.

(4) Mr. Hiebert was a member of the Board of Directors from March 28, 2001 to August 8, 2002 and from August 30, 2002 to the present.

(5) Under the Joint Venture Agreement, Enerplus is entitled to have one representative nominated for election as a director of the Corporation until the earlier of (a) December 31, 2007, (b) the date that there is a Change of Control (as defined in the Joint Venture Agreement) of the Corporation, (c) the date that the Corporation is replaced as operator of the Joslyn Project and (d) the date that the joint venture with Enerplus terminates. While Enerplus is entitled to have its representative nominated, The Beacon Group Energy Investment Fund II, L.P. and Friends of Lime Rock LP have agreed to vote for the election of Enerplus nominee. Mr. Kerr is the Enerplus nominee.

The directors and officers of the Corporation, as a group, own or control, directly or indirectly, 141,216 Common Shares or approximately 0.5% of the issued and outstanding Common Shares.

Board of Directors

The term of office for each director of the Corporation is from the date at which the director is elected or appointed until the next annual meeting of shareholders of the Corporation. Brief biographies for each member of the Board of Directors are set forth below:

S. Barry Jackson

Mr. Jackson is a professional engineer with extensive experience in major exploration and production and energy companies, both in senior management positions and as a director. Mr. Jackson is currently Chairman of the Board of Resolute Energy Inc. He was the President and Chief Executive Officer of Crestar Energy Inc. from 1993 to 2000. Prior to joining Crestar, Mr. Jackson was the President and Chief Operating Officer of Northstar Energy Corporation. Mr. Jackson also serves on the boards of Nexen Inc., TransCanada Pipelines Limited and the Calgary Petroleum Club. Mr. Jackson holds a Bachelor of Science degree (Engineering) from the University of Calgary.

Glen C. Schmidt

Mr. Schmidt has served as President and Chief Executive Officer of Deer Creek since 2001 and has been a director of Deer Creek since 2000. Mr. Schmidt holds both a Master of Business Administration and Bachelor of Science in Chemical Engineering (with Distinction) from the University of Calgary. Mr. Schmidt has more than 20 years oil and gas experience with more than 10 years at the executive level. Formerly, Mr. Schmidt was the President of each of Torex Resources Ltd. and Pioneer Natural Resources Canada Inc. and was previously the Vice President Canada of Chauvco Resources Ltd. and the Vice President Production and Engineering of Mark Resources Inc.

John G. Clarkson

Mr. Clarkson is currently a Managing Director of Lime Rock Management Ltd. and President of Clearwater Capital Corporation, an advisor to Lime Rock Management Inc. Mr. Clarkson previously held various management positions with Renaissance Energy Ltd., including Manager of Oil Development and Manager of Acquisitions and Divestitures. In addition, Mr. Clarkson presently serves on the board of directors of NQL Drilling Tools Inc. and U.S. Exploration Holdings, LLC. Mr. Clarkson has 20 years of oil and gas and energy finance experience. Mr. Clarkson holds a Bachelor of Science in Geological Engineering from the University of Manitoba.

Jonathan C. Farber

Mr. Farber is co-founder and Managing Director of Lime Rock Management LP where he is responsible for originating and monitoring private equity investments in the energy sector. Mr. Farber was previously the Vice

President, Investment Banking of Goldman Sachs. Mr. Farber also serves on the board of directors of U.S. Exploration Holdings, LLC, Venture Production Corporation Ltd. and Crescendo Resources LLC. Mr. Farber is a graduate of the School of Foreign Service of Georgetown University and has more than 14 years of experience in energy research, finance and private equity investment.

Ronald J. Hiebert

Mr. Hiebert has been the Director, Private Client Services of Scotia McLeod since 1983. Mr. Hiebert is a graduate of Ambassador College with a Bachelor of Arts and holds a Master of Science in Administration from California State University, Los Angeles.

Gordon J. Kerr

Mr. Kerr graduated from the University of Calgary in 1976 with a Bachelor of Commerce and thereafter obtained the designation of Chartered Accountant and admission as a member of the Institute of Chartered Accountants of Alberta in 1979. Mr. Kerr commenced employment in the oil and gas industry in 1979 with Petromark Minerals Ltd. and Bluesky Oil & Gas Ltd., Canadian based companies that joint ventured with numerous German drilling funds conducting operations in both Canada and the United States. Mr. Kerr held various positions with Bluesky Oil & Gas Ltd. and its successor, Mark Resources Inc., ultimately holding the position of Vice President Finance, Chief Financial Officer and Corporate Secretary until the company's reorganization into the EnerMark Income Fund in 1996. In 1996, Mr. Kerr commenced employment with the Enerplus group of companies holding positions of increasing responsibility including the position of Executive Vice President for the Enerplus group of companies prior to his recent appointment as President and Chief Executive Officer.

Brian K. Lemke

Mr. Lemke is currently President, Chief Executive Officer and a Director of Resolute Energy Inc. Formerly, Mr. Lemke was Senior Vice-President and Chief Financial Officer of Crestar Energy Inc. and was the former Chief Financial Officer of HCO Energy Ltd. and former Vice-President Finance and Secretary at Northstar Energy Corporation. Mr. Lemke also serves on the board of the Calgary YMCA. Mr. Lemke is a Chartered Accountant and earned a Bachelor of Science degree (Biology) from the University of Calgary.

Committees of the Board of Directors

The Board of Directors has an audit committee, a human resources and governance committee and a technical committee. Each committee consists of a minimum of three directors and there is a requirement that the members of each of the audit committee and the human resources and governance committee be unrelated (non-management). The Board of Directors designates one member of each committee as the Chair of that committee, or, if it does not do so, the members of the committee elect a Chair. Each member of the audit committee is required to possess a basic level of "financial literacy" (i.e. the ability to read and understand basic financial statements). Each member of the technical committee is required to have a general familiarity with health, safety and environmental matters and with petroleum and natural gas reserve and resource matters. The Board of Directors gives consideration to the periodic rotation of membership of each committee and, from time to time as the Board of Directors sees fit, chairmanship of the committee. The Corporation does not have an executive committee.

Officers and Senior Management

Deer Creek has assembled a strong senior management team to maintain the focus on strategy execution and profitable growth. The six members of the senior management team have in excess of 135 years aggregate experience in the oil and gas and mining industry.

Brief biographies for each member of the senior management team are set forth below:

Glen C. Schmidt
President and Chief Executive Officer

Mr. Schmidt has served as President and Chief Executive Officer of Deer Creek since 2001 and has been a director of Deer Creek since 2000. See Mr. Schmidt's biography set forth above under the sub-heading "Board of Directors".

John S. Kowal
Vice President, Finance and Chief Financial Officer

Mr. Kowal joined Deer Creek in 2003 and has nearly 20 years of experience in a variety of senior treasury and financial positions in several multi-national companies. Prior to joining Deer Creek, Mr. Kowal served as Treasurer of Canadian Hunter Exploration Ltd. Additionally, Mr. Kowal's diversified experience includes positions at Noranda Inc., John Labatt Limited, Celestica Inc. and IBM Canada Limited. Mr. Kowal holds a Bachelor of Commerce degree and a Master of Business Administration from McMaster University.

Mark A. Montemurro
Vice President, Thermal

Mr. Montemurro has held his current position with Deer Creek since 2002 and has more than 20 years oil and gas experience, focused primarily on conventional and thermal heavy oil. Formerly, Mr. Montemurro was General Manager at PanCanadian Energy Corporation, responsible for the Heavy Oil Business Unit, and later Information Services. Prior to that, Mr. Montemurro spent eight years in increasing engineering management roles at CS Resources Limited where he focused on conventional and thermal heavy oil development, using both conventional and innovative technologies. Mr. Montemurro holds a Bachelor of Science in Chemical Engineering from the University of Calgary.

Gary R. Purcell
Vice President, Business Development

Mr. Purcell joined Deer Creek in 2003 with over 20 years of experience in the oil and gas business. Mr. Purcell was formerly Vice President, Business Development with Rio Alto Exploration Ltd. Prior to Rio Alto, Mr. Purcell spent several years with Suncor Energy Inc. in various engineering, finance, planning, and business development roles. Mr. Purcell holds a Bachelor of Science in Mechanical Engineering (with Distinction) from the University of Alberta and a Master of Business Administration from Stanford University.

Donald A. Riva
Vice President, Mining

Mr. Riva has held his current position with Deer Creek since 2002. Mr. Riva graduated from the University of Alberta with a degree in Mining Engineering in 1968 and has spent 35 years in the mining industry holding various technical, operations management and senior executive roles. Prior to joining Deer Creek, Mr. Riva was Director of Bitumen Production for both the Steepbank and Millennium Projects and General Manager, International Mineable Oil for Suncor Energy Inc. In addition, Mr. Riva spent 18 years in the oil sands and metallurgical coal business with Shell Canada Ltd. and its mining subsidiary Crows Nest Resources Ltd. where his later positions included Mine General Manager and Vice President of Development.

Karen E. Lillejord
Controller

Ms. Lillejord has 19 years of experience in a variety of functions primarily in the area of corporate reporting. Ms. Lillejord holds a degree in Business Administration from the University of Regina and has obtained the designations of Chartered Accountant, Certified Management Accountant and Certified Public Accountant. Ms. Lillejord has held management positions with Ernst & Young, Wascana Energy Inc. and Nexen Inc. Prior to joining Deer Creek in 2004, Ms. Lillejord was Manager, Corporate Reporting and Control with AltaGas Services Inc.

James D. Thomson
Corporate Secretary

Mr. Thomson is a partner of Parlee McLaws LLP, Barristers and Solicitors. From June 2001 to December 2004, Mr. Thomson was a special associate of Parlee McLaws LLP and from November 1995 to June 2001, he was a partner of McManus Thomson, Barristers & Solicitors. Mr. Thomson has over 25 years of experience in acting as legal counsel in a variety of corporate and securities transactions. From April 1997 to September 2002, Mr. Thomson was a director of Carpatsky Petroleum Corp., a junior issuer whose shares traded on the TSX Venture Exchange. In February 2000, a cease trade order was issued against the company due to failure to timely file financial statements and trading in the company's shares was suspended. The cease trade order was revoked in February 2001 and trading in the company's shares was subsequently reinstated.

INDEBTEDNESS OF DIRECTORS AND SENIOR OFFICERS

There is not, as of the date hereof, nor has there been since the incorporation of the Corporation, any indebtedness owing to the Corporation or any of its subsidiaries by the directors and senior officers of the Corporation, or any of their associates or affiliates.

COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS

Summary Compensation Table

The following table sets forth information concerning the total compensation paid, during each of the last three financial years (as applicable), to the Chief Executive Officer and Chief Financial Officer of the Corporation and the other executive officers of the Corporation (the "Named Executive Officers").

		Annual Compensation			Long Term Compensation	
Name and Principal Position	**Year**	**Salary**	**Bonus[1]**	**Other Annual Compensation[2]**	**Securities Under Options Granted**	**All Other Compensation**
		$	$	$	(#)[3]	$
Glen C. Schmidt[4]	2003	132,057	74,400	45,000	70,000	3,694
President and Chief Executive	2002	141,833	Nil	35,000	90,000	150
Officer	2001	117,215	Nil	19,250	40,000	75
John S. Kowal[5]	2003	71,713	Nil	13,333	120,000	2,824
Vice President, Finance and Chief	2002	N/A	N/A	N/A	N/A	N/A
Financial Officer	2001	N/A	N/A	N/A	N/A	N/A
Mark A. Montemurro[6]	2003	119,951	14,062	20,000	39,000	5,453
Vice President, Thermal	2002	44,189	Nil	8,334	120,000	936
	2001	N/A	N/A	N/A	N/A	N/A
Gary R. Purcell[7]	2003	27,691	Nil	5,000	120,000	1,211
Vice President,	2002	N/A	N/A	N/A	N/A	N/A
Business Development	2001	N/A	N/A	N/A	N/A	N/A
Donald A. Riva[8]	2003	116,547	14,062	20,000	39,000	3,910
Vice President, Mining	2002	44,189	Nil	8,334	120,000	904
	2001	N/A	N/A	N/A	N/A	N/A

Notes:

(1) This column represents the cash amount of the bonus paid to the Named Executive Officer. In lieu of the cash amount of the bonus, each Named Executive Officer receives a number of performance share units equal to the cash amount of the bonus divided by the last price of the Common Shares issued pursuant to a private placement. Accordingly, performance share units (after giving effect to the Consolidation) were issued as part of the bonus paid to the Named Executive Officers as follows: Glen C. Schmidt, 16,000; Mark A. Montemurro, 3,024; and Donald A. Riva, 3,024. Each performance share unit entitles the holder to receive one Common Share upon payment of $0.05 per Common Share.

(2) This column represents the cash amount of the other annual compensation paid to the Named Executive Officer. In lieu of the cash amount of the other annual compensation, each Named Executive Officer receives a number of performance share units equal to the cash amount of the other annual compensation divided by the last price of the Common Shares issued pursuant to a private placement. Accordingly, performance share units (after giving effect to the Consolidation) were issued as part of the other annual compensation to the Named Executive Officers as follows: Glen C. Schmidt, 9,678 (2003), 7,527 (2002), 3,500 (2001); John S. Kowal, 2,868; Mark A. Montemurro, 4,301 (2003), 1,793 (2002); Gary R. Purcell, 1,076; and Donald A. Riva, 4,301 (2003), 1,793 (2002). Each performance share unit entitles the holder to receive one Common Share upon payment of $0.05 per Common Share.

(3) This column represents the number of securities after giving effect to the Consolidation.

(4) Mr. Schmidt commenced employment with the Corporation on July 1, 2001.

(5) Mr. Kowal commenced employment with the Corporation on May 8, 2003.

(6) Mr. Montemurro commenced employment with the Corporation on August 8, 2002.

(7) Mr. Purcell commenced employment with the Corporation on October 1, 2003. In addition, Mr. Purcell received $5,040 in 2002 and $57,097 in 2003 in connection with consulting services provided to the Corporation by White Oak Enterprises Inc. prior to his employment with the Corporation.

(8) Mr. Riva commenced employment with the Corporation on August 8, 2002.

There are no long-term compensation arrangement, benefit or actuarial plans in place.

Employment Agreements

The Corporation has entered into employment agreements with each of the Named Executive Officers (each an "Employment Agreement"). Pursuant to the terms of the Employment Agreements, Mr. Schmidt is entitled to an annual salary of $150,000 for the calendar year 2004 and each of the other Named Executive Officers is entitled to an annual salary of $125,000 for the calendar year 2004. Further, each Named Executive Officer is entitled to additional benefits and performance-based bonuses. The Employment Agreements provide that each Named Executive Officer is subject to certain confidentiality and non-disclosure restrictions during and following the course of their respective employment with the Corporation. Each Employment Agreement shall continue until terminated by either party in accordance with the notice provisions thereof.

Option and Performance Share Unit Grants for the year ended December 31, 2003

Options and performance share units granted to the Named Executive Officers during the financial year ended December 31, 2003 (after giving effect to the Consolidation) were as follows:

	Common Shares Under Securities Granted (#)		% of Total Options/ Performance Share Units Granted in Fiscal Year	Exercise Price of Options/ Performance Share Units ($/security)	Market Value of Common Shares Underlying Options/ Performance Share Units ($/security)	Option Expiry Date[1]
	Options	Performance Share Units				
Glen C. Schmidt	70,000	25,678	11.2/49.1	4.65/0.05	4.65	March 13, 2010
John S. Kowal	120,000	2,868	19.2/ 5.5	4.65/0.05	4.65	May 8, 2010
Mark A. Montemurro	39,000	7,325	6.2/14.0	4.65/0.05	4.65	March 13, 2010
Gary R. Purcell	120,000	1,076	19.2/ 2.1	4.65/0.05	4.65	October 1, 2010
Donald A. Riva	39,000	7,325	6.2/14.0	4.65/0.05	4.65	March 13, 2010

Note:

(1) Performance share units granted prior to April 21, 2004 do not have a scheduled expiry date.

Aggregated Option and Performance Share Unit Exercises During the Year Ended December 31, 2003 and Financial Year-End Option and Performance Share Unit Values

The following table sets forth certain information respecting the numbers and accrued value of unexercised stock options and performance share units as at December 31, 2003 and options and performance share units exercised by the Named Executive Officers during the financial year ended December 31, 2003 (after giving effect to the Consolidation):

	Securities Acquired on Exercise (#)	Aggregate Value Realized ($)	Unexercised Options/Performance Share Units at December 31, 2003 (#)		Value of Unexercised in-the-Money Options/Performance Share Units at December 31, 2003 ($)(1)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Glen C. Schmidt	Nil	Nil	292,500/28,705	107,500/8,000	1,587,125/236,816	388,875/66,000
John S. Kowal	Nil	Nil	30,000/2,868	90,000/Nil	109,500/23,661	328,500/Nil
Mark A. Montemurro . .	Nil	Nil	69,750/7,606	89,250/1,512	254,588/62,750	325,762/12,474
Gary R. Purcell	Nil	Nil	30,000/1,076	90,000/Nil	109,500/8,877	328,500/Nil
Donald A. Riva	Nil	Nil	69,750/7,606	89,250/1,512	254,588/62,750	325,762/12,474

Note:

(1) The values of the unexercised "in-the-money" options and performance share units have been determined by subtracting the exercise price of the options or performance share units, as applicable, from the equity component of the flow-through Common Shares issue (calculated to equal $8.30), being the last price of the Common Shares issued pursuant to a private placement on November 4, 2003, and multiplying by the number of Common Shares that may be acquired upon the exercise of the options and performance share units.

Termination of Employment or Change of Control

Pursuant to each Employment Agreement, if at any time during the term of the Employment Agreement, the Named Executive Officer is terminated for other than "Just Cause" (as defined in the Employment Agreement) all options, rights, warrants or other entitlements for the purchase or acquisition of Common Shares, whether or not then vested, will immediately become exercisable and the Corporation shall pay a lump sum equal to (i) one times annual base salary (two times annual base salary for Mr. Schmidt), (ii) 15% of annual base salary to compensate for lost benefits and (iii) one times the value of the most recent grant of base performance share units granted to the Named Executive Officer (two times the value of base performance share units granted to Mr. Schmidt) pursuant to the PSU Plan and the prior stock rights plan of the Corporation.

Pursuant to the Employment Agreement with Mr. Schmidt, if at any time during the term of the Employment Agreement, there is a "change of control" (as defined in the Employment Agreement), then Mr. Schmidt shall be entitled to elect, within a period of six months, to terminate his employment services with the Corporation and all options, rights, warrants, or other entitlements for the purchase or acquisition of Common Shares, whether or not then vested, will immediately become exercisable and the Corporation shall pay a lump sum in an amount equal to the amount set forth in the foregoing paragraph.

Compensation of Directors

Directors of Deer Creek are also eligible to be granted options pursuant to the Stock Option Plan. During the financial year ended December 31, 2003, options to purchase an aggregate of 58,000 Common Shares at an exercise price of $4.65 per Common Share were granted to non-employee directors, other than Mr. Kerr. As at December 31, 2003, non-employee directors held options to purchase an aggregate of 414,000 Common Shares with a weighted average exercise price of $4.84 per Common Share.

For the 2004 financial year, the Chairman of the Board of Directors will receive an annual fee of $50,000 and shall be granted options to acquire 18,000 Common Shares, each Committee Chair will receive an annual fee of $30,000 and shall be granted options to acquire 12,000 Common Shares and each other member of the Board of Directors will receive an annual fee of $20,000 and shall be granted options to acquire 8,000 Common Shares. Directors currently do not receive meeting fees. The annual fees payable in 2004 will be paid entirely by the granting of performance share units pursuant to the PSU Plan.

In addition to being a director of the Corporation, Mr. Schmidt was also an executive officer of Deer Creek during 2003 and, as such, received no compensation as a director.

STOCK OPTIONS AND PERFORMANCE SHARE UNITS

The Corporation has adopted the Stock Option Plan and the PSU Plan (formerly the stock rights plan of the Corporation), under which the Board of Directors may allocate non-transferable options and performance share units to acquire Common Shares to directors, officers, employees and providers of services of the Corporation and its subsidiaries. Options granted pursuant to the Stock Option Plan are for a maximum term of seven years, subject to earlier termination in certain events, with the exercise price equal to the issue price of the Common Shares issued by the Corporation pursuant to the most recent equity financing undertaken by the Corporation. Options granted pursuant to the Stock Option Plan after the closing of the Offering will not be lower than the closing price of the Common Shares on the TSX on the trading day prior to the date of grant. Performance share units granted pursuant to the PSU Plan are for a maximum term of seven years, subject to earlier termination in certain events, have a nominal exercise price equal to $0.05 per Common Share for performance share units granted prior to the Consolidation and $0.01 thereafter. The number of Common Shares reserved for issuance under the Stock Option Plan has been fixed at 8% of the total number of issued and outstanding Common Shares after giving effect to the Offering and the number of Common Shares reserved for issuance under the PSU Plan has been fixed at 2% of the total number of issued and outstanding Common Shares after giving effect to the Offering. No grantee under the Stock Option Plan and PSU Plan may receive options or performance share units, as the case may be, entitling the grantee to purchase more than 5% of the aggregate outstanding Common Shares.

The following table summarizes the outstanding options to acquire Common Shares granted pursuant to the Stock Option Plan as of the date hereof:

Group (Number)	Date Options Granted	Shares Under Options	Exercise Price	Closing Price On Day Prior to Grant[(1)]	Expiry Date
Executive Officers (5)	Mar/00-Mar/04	1,184,000	$2.00-$8.75	$2.00-$8.75	Mar/07-Mar/11
Directors (6)	Apr/01-Mar/04	480,000	$4.65-$8.75	$4.65-$8.75	Apr/08-Mar/11
Employees (14)	Apr/03-May/04	645,600	$4.65-$8.75	$4.65-$8.75	Apr/10-May/11
Consultants (3)	Jul/01-/May/04	39,000	$4.65-$8.75	$4.65-$8.75	Jul/08-May/11
Total		2,348,600			

Note:

(1) There is currently no public market for the Common Shares. The value ascribed to the closing price of the Common Shares on the day prior to grant is equal to the last price prior to the grant of the options that the Common Shares were issued pursuant to a private placement.

The following table summarizes the outstanding performance share units to acquire Common Shares granted pursuant to the PSU Plan as of the date hereof:

Group (Number)	Date Performance Share Units Granted	Shares Under Performance Share Units	Exercise Price	Expiry Date[(1)]
Executive Officers (5)	Dec/01-Mar/04	102,972	$0.05	N/A
Directors (6)	Dec/01-Mar/04	47,624	$0.05	N/A
Employees (11)	Apr/03-Apr/04	20,518	$0.05	Apr/11
Total		171,114		

Note:

(1) The PSU Plan was preceded by the Corporation's stock rights plan, which granted share units with no expiry period. Such stock rights plan was amended to become the PSU Plan and outstanding stock rights have been grandfathered and do not have an expiry date. All performance share units granted on or after April 21, 2004 have been granted under the PSU Plan and have an expiry date no later than seven years from the date of grant. A total of 11,928 performance share units were granted on or after April 21, 2004.

PRIOR SALES

The following table sets forth the Common Shares that have been issued by the Corporation during the 12 months preceding the date of this prospectus.

	Nature of Transaction	Number of Common Shares	Issue Price per Common Share	Aggregate Issue Price
September 12, 2003	Exercise of stock options	166,667	$ 0.75	$ 125,000
September 12, 2003	Exercise of stock options	75,000	$ 1.11	$ 83,025
November 4, 2003	Private placement	1,000,000[(1)]	$10.00	$10,000,000
January 28, 2004.	Private placement	2,020,000	$ 8.75	$17,675,000
April 14, 2004 to May 11, 2004 .	Exercise of special warrants	305,378	Nil	Nil

Notes:

(1) Common Shares issued on a flow-through basis.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal holder of securities (as described under "Principal Shareholders") or any associate or affiliate of the foregoing has, or has had, any material interest in any transaction prior to the date hereof or any proposed transaction that has materially affected or will material affect the Corporation or any of its affiliates, except as disclosed elsewhere in this prospectus.

CONFLICTS OF INTERESTS

Certain directors of the Corporation are associated with other companies or entities, which may give rise to conflicts of interest. In accordance with the ABCA, directors who have a material interest in any person who is a party to a material contract or proposed material contract with the Corporation are required, subject to certain exceptions, to disclose that interest and abstain from voting on any resolution to approve that contract. In addition, the directors are required to act honestly and in good faith with a view to the best interest of the Corporation.

INDUSTRY REGULATION

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 related to oil and gas generally. Outlined below are some of the more significant aspects of the legislation and regulations governing the recovery and marketing of bitumen from oil sands.

Regulation of Operations

In Alberta, the regulation of oil sands operations, pipelines, upgraders and cogeneration facilities is undertaken jointly by the EUB pursuant to various statutes, including the *Oil Sands Conservation Act* (Alberta), and by Alberta Environment pursuant to Alberta's *Environmental Protection and Enhancement Act* ("EPEA"). In addition to requiring certain approvals prior to the construction and operation of oil sands recovery projects, pipelines, upgraders and cogeneration facilities, the legislation allows the EUB to inspect and investigate and, where a practice employed or a facility used is hazardous to human health or the environment, to make remedial orders. Similar powers are available to the Alberta Environment. Certain changes to oil sands recovery operations, pipelines, upgraders and cogeneration facilities also require the approval of the EUB, the Alberta Environment, or both.

Additionally, the construction, operation, decommissioning and reclamation of facilities as part of a scheme to recover bitumen from oil sands, extract and upgrade products therefrom, and transport those products to market, may invoke regulation by the federal government under various federal statutes and regulations, including the *Canadian Environmental Assessment Act*, the *Canadian Environmental Protection Act* (Canada), the *Fisheries Act* (Canada) and the *Navigable Waters Protection Act* (Canada). Certain approvals or authorizations may be needed prior to construction, operation or modification of facilities or operational practices. Inspections and investigations may result in remedial orders.

Land Tenure

Oil produced from oil sands owned by the Province of Alberta is produced under provincial Crown oil sands leases. While such leases may historically have had initial terms which varied in length, continuations beyond the initial terms are now subject to standardized criteria as provided for in the *Oil Sands Tenure Regulation* (Alberta). A lease may generally be continued after the initial term provided certain minimum levels of exploration or production have been achieved and all lease rentals (including escalating rentals) have been timely paid, subject to certain exceptions. The surface rights required for pipelines, upgraders and co-generation facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

Royalties

The Province of Alberta imposes royalties of varying rates on the production of crude oil from lands in which it owns the mineral rights. Alberta's current royalty system for oil sands, introduced in September 1997, is designed to support the development of the oil sands industry. An initial royalty of 1% of the quantity of oil sands product that is recovered and delivered to the royalty calculation point is payable until the owners have recovered specified allowed costs, including certain exploration and development costs, operating costs, a return allowance (based on the monthly federal long-term bond rate) and royalties paid to the Crown. Subsequent thereto, the royalty payable will be the greater of the aforesaid 1% royalty and 25% of net revenue from the Project. The foregoing royalty will approximate a 1% royalty on gross revenue before payout and a 25% royalty on net revenue after payout.

Environmental Regulation

Oil sands extraction operations, pipelines, upgraders and cogeneration plants 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 used in association with such 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 EPEA. The EPEA imposes certain environmental responsibilities on the operators of oil sands *in-situ* extraction projects, pipelines, upgraders and cogeneration plants. In certain instances EPEA imposes significant penalties for violations.

Pricing and Marketing of Crude Oil

In Canada, producers of crude oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of crude oil. The price depends in part on crude oil quality, prices of competing fuels, distance to market and the value of refined products. Oil exports from Canada may be made pursuant to export contracts with terms not exceeding one year in the case of light crude oil, and not exceeding two years in the case of heavy crude oil provided that an export order has been obtained from the NEB. Any crude oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

RISK FACTORS

The following are certain risk factors related to the business of the Corporation which prospective investors should carefully consider, in addition to those discussed elsewhere in this prospectus, before deciding whether to purchase Common Shares. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this prospectus.

An investment in securities of the Corporation is speculative due to the Corporation's present stage of development and certain other factors and will be subject to all of the risks inherent in the Joslyn Project, including construction and operation risks and the overall feasibility and viability of the Joslyn Project.

Status of the Joslyn Project and Stage of Development of the Corporation

The Joslyn Project is currently in the development stage. There is a risk that the Joslyn Project will not be completed on time or on budget or at all. Additionally, there is a risk that the Joslyn Project may have delays, interruption of operations or increased costs due to many factors, including, without limitation:

- breakdown or failure of equipment or processes;
- construction performance falling below expected levels of output or efficiency;
- design errors;
- contractor or operator errors;
- non-performance by third-party contractors;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- inability to attract sufficient numbers of qualified workers;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- changes in Project scope;
- violation of permit requirements;
- disruption in the supply of energy;
- availability of drilling rigs and services;
- catastrophic events such as fires, earthquakes, storms or explosions; and
- challenges to the proprietary technology of the Corporation and/or its affiliates.

Given the stage of development of the Joslyn Project, various changes to the Joslyn Project may be made by the Corporation during implementation of or prior to completing the Joslyn Project. The information contained in this prospectus, including, without limitation, reserve and economic evaluations is conditional upon receipt of all regulatory approvals and no material changes being made to the Joslyn Project or its scope.

The current construction and operations schedules may not proceed as planned, there may be delays and the Joslyn Project may not be completed on budget. Any such delays will likely increase the costs of the Joslyn Project and may require additional financing, which financing may not be available.

Actual costs to construct and develop the Joslyn Project will vary from the estimates set forth in this prospectus and such variances may be significant.

Reliance on Management

Subscribers for securities of the Corporation must rely on the ability, expertise, judgment, discretion and good faith of the management of the Corporation.

Insufficient Funding

Significant amounts of financing will be required to develop the Joslyn Project. The Corporation intends to finance the Joslyn Project from internally generated cash flow and the sales of securities and borrowings. Capital requirements are subject to oil and natural gas prices and capital market risks, primarily the availability and cost of capital. There can be no assurance that sufficient capital will be available to the Corporation, or available to the Corporation on acceptable terms or on a timely basis, to fund its capital obligations in respect of the Joslyn Project or any other capital obligation it may have. See also "Debt Service".

Debt Service

Under the terms of both the Existing Credit Facility and the New Credit Facility, the Corporation may utilize the funds available to it to develop the Joslyn Project. The Existing Credit Facility will terminate upon the Corporation entering into a credit agreement pursuant to the New Credit Facility. See "Financing Plan". Variations in interest rates could result in significant changes in the amount required to be applied to debt service and would affect the financial results of operations of the Corporation. If the Corporation does not earn sufficient income from the Joslyn Project to meet its debt service obligations, the lenders may be able to foreclose on the Corporation's ownership interest.

Pursuant to the Talisman Debenture, the Corporation is obligated to pay up to $21.0 million plus accrued interest to Talisman in part satisfaction of the consideration payable to Talisman for the acquisition of Lease 24 pursuant to the Talisman Agreement. The payments under the Talisman Debenture are payable by the Corporation in three installments upon the Corporation meeting certain production milestones on Lease 24. If the Corporation achieves the production milestones under the Talisman Debenture and does not meet its payment obligations thereunder, Talisman may foreclose on the Corporation's ownership interest in the Joslyn Project.

The Talisman Debenture is secured by a fixed and specific mortgage and charge over properties purchased by the Corporation under the Talisman Agreement, as well as after acquired personal and real property. An event of default under either the Existing Credit Facility or the Talisman Debenture triggers a deemed default under the other. See "Talisman Debenture".

Government Regulation

The oil and gas industry in Canada, including the oil sands industry, operates under federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, income, the exportation of crude oil, natural gas and other products, as well as other matters. See "Risk Factors — Environmental Considerations; Abandonment and Reclamation Costs". The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase the Corporation's costs and have a material adverse impact on the Corporation.

Before proceeding with any phase of development in the Joslyn Project the Corporation must obtain all required regulatory approvals. Each phase of development will require separate regulatory approvals which are uncertain. The regulatory approval process can involve stakeholder consultation, environmental impact assessments and public hearings, among other things. In addition, regulatory approvals may be subject to conditions including security deposit obligations and other commitments. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays, abandonment or restructuring of the Joslyn Project and increased costs, all of which could have a material adverse affect on the Corporation.

Royalty Regime

In the event that the Joslyn Project is developed and becomes operational, the Corporation's revenue and expenses will be directly affected by the royalty regime applicable to the Joslyn Project. The economic benefit of future capital expenditures for the Joslyn Project is, in many cases, dependent on a satisfactory royalty regime. There can be no assurance that the federal government and the Province of Alberta will not adopt a new royalty regime which will make capital expenditures uneconomic or that the regime currently in place will remain unchanged.

Sales of Additional Securities

The Corporation may issue additional Common Shares or other securities to finance the Joslyn Project and certain of the Corporation's other capital expenditures. The articles of the Corporation permit the Corporation to issue an unlimited number of Common Shares and First Preferred Shares without the approval of the holders thereof. Subscribers for Common Shares will have no pre-emptive or participation rights in connection with such additional issues. The Board of Directors has discretion in connection with the price and the terms of issue of Common Shares. Such future issuances may be dilutive to investors.

Future access by the Corporation to equity markets may from time to time be affected by the timing of sales of Common Shares by Lime Rock, if Lime Rock should determine to sell Common Shares controlled by it.

Reserves and Resources

There are numerous uncertainties inherent in estimating quantities of reserves and resources, including many factors beyond the Corporation's control, and no assurance can be given that the indicated level of reserves or recovery of bitumen will be realized. In general, estimates of economically recoverable bitumen reserves and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

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

Reserve and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil prices and operating costs. Market price fluctuations of oil prices may render uneconomic the recovery of certain grades of bitumen. Moreover, short term factors relating to oil sands resources may impair the profitability of the Joslyn Project in any particular period.

No assurance can be provided as to the gravity or quality of bitumen produced from the Joslyn Project.

Independent Reviews

Although third parties have prepared reviews, reports and projections relating to the viability and expected performance of the Joslyn Project, it cannot be assured that these reports, reviews and projections and the assumptions on which they are based will, over time, prove to be accurate.

Title Risks

The Corporation is satisfied that it has good and proper right, title and interest in and to the Joslyn Lease. However, the Corporation has not obtained title opinions in respect of the Joslyn Lease and, accordingly, the

Corporation's ownership of the Joslyn Lease could be subject to prior unregistered agreements or interests or undetected claims or interests.

Changes in Government Regulation

Lease 24 is subject to the *Oil Sands Tenure Regulation* (Alberta) which was introduced in 2000. This legislation deems Lease 24 to continue beyond its primary term to the extent that the lessee has attained the minimum level of evaluation of the oil sands in Lease 24 or Lease 24 is producing. There can be no assurance that the Corporation will be able to comply with the requirements of the *Oil Sands Tenure Regulation* (Alberta). In addition, the Minister, in certain circumstances, may change the designation of any lease subject to the legislation and provide notice requiring the Corporation to commence production or recovery of, or to increase existing production or recovery of bitumen or other oil sands products within the time specified in such notice. There can be no assurance that if such a notice is given, the Corporation will be able to comply with its terms to maintain Lease 24. Additionally, the *Oil Sands Tenure Regulation* (Alberta) expires on December 1, 2008 and, if such legislation is not renewed in its present or similarly favourable form, the status of Lease 24 may be in question.

SAGD Bitumen Recovery Process

The recovery of bitumen using the SAGD process is subject to uncertainty. The SAGD process has had limited production history in commercial projects. Although the Corporation conducted a SAGD pilot test on the Joslyn Lease, there can be no assurance that the Joslyn Project will achieve the same or similar results as the Pilot Project or produce bitumen at the expected levels or costs, on schedule or at all. See "The Business — Historical Development — Pilot Project".

Infrastructure for Project Facilities

The Corporation will depend, to a large extent, on third party designers, contractors and suppliers to design and construct each phase of the Joslyn Project. The Joslyn Project will also depend on certain infrastructure owned and operated or to be constructed by others, including, without limitation, pipelines for the transportation of diluent and produced bitumen to the market, natural gas, water source and disposal pipelines, electrical grid transmission lines for the provision and/or sale of electricity to Deer Creek and roadways providing access to various areas of the Joslyn Lease. The failure of any or all of these third parties to supply utilities, services or construct the infrastructure required for future phases of the Joslyn Project on a timely basis and on acceptable commercial terms will negatively impact Deer Creek's operation of the Joslyn Project.

Dependence on Third Parties

The business of the Corporation, and the Joslyn Project in particular, is also subject to the risk that Enerplus may change its business strategies and determine not to proceed with future phases of the Joslyn Project. The Corporation will be subject to the risk of default by Enerplus in meeting its obligations to pay its proportionate share of expenditures of the Joslyn Project prior to its payments under the Joint Venture Agreement reaching the Commitment Amount. Such default by Enerplus may adversely affect the continuation of the Joslyn Project, the construction or operations of the Joslyn Project or other facets of the Joslyn Project, any of which may adversely affect the Corporation.

The success and ability of the Corporation to compete depends to a significant extent on the proprietary technology of third parties that has been, or is required to be, licensed by the Corporation. Further, others may develop technologies that are similar or superior to the technology that the Corporation licenses from third parties or design around the patents owned by such third parties. Despite the efforts of such third parties, the intellectual property rights licensed by the Corporation may be invalidated, circumvented, challenged, infringed or required to be licensed to others. It cannot be assured that any steps the Corporation or such third parties may take to protect the intellectual property rights of such third parties will prevent the termination of licenses from third parties.

Commodity Prices

The Corporation's financial results will be dependent upon the prevailing price of crude oil and natural gas. Oil prices, natural gas prices and heavy oil differentials fluctuate significantly in response to regional, national and global supply and demand factors beyond the control of the Corporation. Political and economic developments around the world can affect world oil supply and oil and natural gas prices.

Any prolonged period of low oil prices, high natural gas prices and/or high heavy oil differentials could result in a decision by the Corporation to suspend or reduce production. Any such suspension or reduction of production would result in a corresponding substantial decrease in the Corporation's revenues and earnings and could materially impact the Corporation's ability to meet its debt servicing obligations and could expose the Corporation to significant additional expense as a result of any future long-term contracts. If production was not suspended or reduced during such period, the sale of the petroleum products produced by the Joslyn Project at such reduced prices would lower the Corporation's revenues.

At present, the Corporation has not entered into any marketing or transportation agreements. Failure to achieve acceptable terms for such agreements could negatively effect the Corporation's financial results.

Operating Costs

The cost of natural gas, which has the potential to vary considerably, is a significant component of the cost of production of the bitumen produced by the Joslyn Project. The availability and cost of diluent also has the potential to vary considerably. The Corporation's earnings may be reduced if significant increases in natural gas or diluent prices are incurred.

Environmental Considerations

The construction, operation and decommissioning of the Joslyn Project and reclamation of the Joslyn Project's land are conditional upon various environmental and regulatory approvals issued by governmental authorities. There is no assurance such approvals will be issued, or once issued renewed, or that they will not contain terms and conditions which make the Joslyn Project uneconomic or cause the Corporation to significantly alter the Joslyn Project. See "Risk Factors — Government Regulation". Further, the construction, operation and decommissioning of the Joslyn Project and reclamation of the Joslyn Project's lands will be subject to approvals and laws and regulations relating to environmental protection and operational safety. Although the Corporation believes that the Joslyn Project will be in general compliance with applicable environmental and safety approvals, laws and regulations, risks of substantial costs and liabilities are inherent in oil sands recovery and there can be no assurance that substantial costs and liabilities will not be incurred or that the Joslyn Project will be permitted to carry on operations. Moreover, it is possible that other developments, such as increasingly strict environmental and safety laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the Joslyn Project's operations, could result in substantial costs and liabilities to the Corporation or delays to or abandonment of the Joslyn Project.

Canada is a signatory to, and has ratified, the Kyoto Protocol established under the United Nations Framework Convention on Climate Change to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide greenhouse gases. The Project will be a significant producer of some greenhouse gases covered by the Convention. The Government of Canada has put forward a Climate Change Plan for Canada which suggested further legislation that will set carbon dioxide and other greenhouse gases emission reduction requirements for various industrial activities, including oil sands. Future federal legislation, together with provincial emission reduction requirements, such as those proposed in Alberta's *Climate Change and Emissions Management Act* (unproclaimed), may require the reduction of emissions or emissions intensity from the Corporation's operations and facilities. The reductions may not be technically or economically feasible and the failure to meet such emission reduction requirement may materially adversely affect the Corporation's business and result in fines, penalties and the suspension of operations. No assurance can be given that future environmental approvals, laws or regulations will not adversely impact the ability to operate the Joslyn Project or increase or maintain production or will not increase unit costs of production. Equipment from suppliers which can meet future emission standards may not be available on an economic basis and other methods of reducing emissions to required levels in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass legislation which would tax such emissions or require, directly or indirectly, reductions in such emissions produced by energy industry participants, including the Joslyn Project, for which the Joslyn Project may be unable to mitigate. Mitigation of the risk of future legislative or regulatory limits on the emission of greenhouse gases may include the acquisition of emission reduction or off-set credits from third parties. However, emission reduction or off-set credits may not be available for acquisition by the Joslyn Project or may not be available on an economic basis and may not be recognized or qualify under future legislative or regulatory regimes as mitigation for the emission of greenhouse gases by the Joslyn Project.

Operational Hazards

The operation of the Joslyn Project will be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. The Corporation will not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that the Corporation's insurance will be sufficient to cover any such casualty occurrences or disruptions. The Project could be interrupted by natural disasters or other events beyond the control of Deer Creek and Enerplus. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the Joslyn Project and on the Corporation's business, financial condition and results of operations.

Recovering bitumen from oil sands involves particular risks and uncertainties. The Project is susceptible to loss of production or slowdowns. Severe climatic conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. Equipment failures could result in damage to the Joslyn Project's facilities or wells, and liability to third parties against which the Corporation may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Abandonment and Reclamation Costs

The Corporation will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment of the Joslyn Project and reclamation of its lands at the end of its economic life, which abandonment and reclamation costs may be substantial. A breach of such legislation and/or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made. It is not possible to estimate the abandonment and reclamation costs since they will be a function of regulatory requirements at the time and the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. In addition, in the future the Corporation may determine it prudent or be required by applicable laws or regulations to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs.

Human Resources

Deer Creek has assembled a management and field operations team for SAGD Phase I. However, the labour force in Fort McMurray and surrounding area is limited and the inability to staff future projects could have an adverse affect on the Corporation's development plans. In addition, rising personnel costs could result in increases in general and administrative expenses.

Principal Shareholder

As a result of its shareholdings and after giving effect to the Offering and the Over-Allotment Offering, Lime Rock will effectively be in a position to defeat any matters requiring the passing of a special resolution of the shareholders of the Corporation.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of oil interests and the distribution and marketing of petroleum products. The Joslyn Project competes with other producers of bitumen. Some of the conventional producers have lower operating costs than the Corporation is anticipated to have. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than the Corporation have announced plans to enter the oil sands business, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of bitumen in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices.

Foreign Exchange

Crude oil prices are generally based on a U.S. dollar market price, while certain operating and capital costs will be primarily in Canadian dollars. Fluctuations in exchange rates between the U.S. and Canadian dollar will therefore give rise to foreign currency exchange exposure. The Corporation may mitigate the impact of exchange rate fluctuations on the revenue from the Joslyn Project by hedging. There is no assurance that any hedging which may be undertaken by the Corporation will be successful and, if not successful, could result in serious adverse effects on the Corporation's financial condition and business.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the Joslyn Project and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the Corporation and the Joslyn Project.

Hedging Risks

The nature of the Corporation's operations will result in exposure to fluctuations in commodity prices. The Corporation may use financial instruments and physical delivery contracts to hedge its exposure to these risks. If the Corporation engages in hedging it will be exposed to credit-related losses in the event of non-performance by counterparties to the financial instruments. Additionally, if product prices increase above those levels specified in any future hedging agreements, the Corporation could lose the cost of floors or ceilings or a fixed price could limit the Corporation from receiving the full benefit of commodity price increases. If the Corporation enters into hedging arrangements, it may suffer financial loss if it is unable to commence operations on schedule or is unable to produce sufficient quantities of oil to fulfill its obligations.

The Corporation may also hedge its exposure to the costs of inputs to the Joslyn Project. If the prices of these inputs falls below the levels specified in any future hedging agreements, the Corporation could lose the cost of ceilings or a fixed price could limit it from receiving the full benefit of commodity price decreases.

Project Expansions

The Corporation plans to participate in one or more additional phases of the Joslyn Project beyond SAGD Phase II. The Corporation is expected to require additional debt and equity financing in order to fund its share of costs associated with such expansions. The Corporation's participation in any additional phases of the Joslyn Project will be subject to many of the same risks as SAGD Phase II.

PLAN OF DISTRIBUTION

Pursuant to an underwriting agreement dated July 21, 2004 (the "Underwriting Agreement") between the Corporation and the Underwriters, the Corporation has agreed to issue and sell, and the Underwriters have severally agreed to purchase, as principals, on July 29, 2004, or such other date as may be agreed but not later than September 1, 2004, subject to the terms and conditions stated therein, the 16,900,000 Offered Shares offered hereby at a price of $9.50 per Offered Share payable in cash for aggregate consideration of $160,550,000 against delivery of a certificate representing the Offered Shares. In consideration for their services in connection with the Offering, the Underwriters will be paid a fee of $0.475 per Offered Share for an aggregate fee of $8,027,500.

The Corporation has granted to the Underwriters the Over-Allotment Option, exercisable in whole or in part for a period of 30 days from closing of the Offering, to purchase up to an additional 1,690,000 Over-Allotment Shares at a price of $9.50 per Over-Allotment Share to cover over-allotments, if any, and for market stabilization purposes. If the Over-Allotment Option is exercised in full, the Corporation will be obligated to issue such Over-Allotment Shares to the Underwriters and will receive net proceeds of $15,252,250, after deducting fees payable by the Corporation to the Underwriters of $802,750. This prospectus also qualifies the distribution of the Over-Allotment Shares issuable upon exercise of the Over-Allotment Option.

There is presently no market for the Common Shares. Accordingly, the terms of the Offering were established through negotiation between the Corporation and the Underwriters.

The obligations of the Underwriters under the Underwriting Agreement are conditional and may be terminated at their discretion on the basis of their assessment of the state of the financial markets and may also be terminated upon the occurrence of certain stated events. The Underwriters are, however, severally obligated to take up and pay for all such Offered Shares if any such Offered Shares are purchased under the Underwriting Agreement. The Corporation has agreed to indemnify the Underwriters, their directors, officers, employees and agents against certain liabilities including civil liabilities under Canadian provincial securities legislation or will contribute to payments the Underwriters may be required to make in respect thereof.

Pursuant to policy statements of the Ontario Securities Commission and l'Agence nationale d'encadrement du secteur financier, the Underwriters may not, throughout the period of distribution under this prospectus, bid for or purchase Common Shares. The foregoing restriction is subject to certain exceptions, including a bid or purchase permitted under the by-laws and rules of the TSX relating to market stabilization and passive market-making activities and a bid or purchase made for and on behalf of a customer where the order was not solicited during the period of distribution, provided that the bid or purchase is not engaged in for the purpose of creating actual or apparent active trading in, or raising the price of, the Common Shares. In connection with this Offering, and subject to the foregoing, the Underwriters may effect transactions, which stabilize or maintain the market price for the Common Shares at levels other than those, which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Common Shares have not been and will not be registered under the 1933 Act or any state securities laws. Accordingly, the Offered Shares and the Over-Allotment Shares may not be offered or sold within the United States (as such term is defined in Regulation S under the 1933 Act) except in transactions exempt from the registration requirements of the 1933 Act. The Underwriting Agreement enables the Underwriters to offer and resell the Offered Shares and the Over-Allotment Shares that they have acquired pursuant to the Underwriting Agreement to certain qualified institutional buyers in the United States, provided such offers and sales are made in compliance with Rule 144A under the 1933 Act. The Underwriting Agreement also enables the Underwriters to offer Offered Shares and Over-Allotment Shares for sale to certain institutional "accredited investors" that satisfy the requirements of Rule 501(a)(1), (2), (3) or (7) under the 1933 Act, provided such offers and sales are made in compliance with Rule 506 of Regulation D under the 1933 Act. The obligation of the Underwriters to purchase Offered Shares in the Offering will be reduced by the number of Offered Shares and Over-Allotment Shares, if any, being sold by the Corporation pursuant to Rule 506 of Regulation D under the 1933 Act.

In addition, until 40 days after the commencement of the Offering, an offer or sale of additional Common Shares within the United States by any dealer (whether or not participating in the Offering) may violate the registration requirements of the 1933 Act if such offer or sale is made otherwise than in accordance with available exemptions under the 1933 Act.

The Corporation has agreed that it will not, without the prior written consent of Peters & Co. Limited and RBC Dominion Securities Inc. on behalf of the Underwriters pursuant to the Underwriting Agreement, which consent may not be unreasonably withheld, authorize, issue or sell any Common Shares or any securities giving the right to acquire Common Shares, except with respect to conversion of existing outstanding convertible securities, to give effect to the Over-Allotment Option and the issuance from treasury of up to $15 million of Common Shares to be issued on a flow-through basis, or agree or announce any intention to do so, at any time prior to 180 days after closing of the Offering.

In connection with the Offering, Lime Rock and the officers and directors of Deer Creek will execute lock-up agreements pursuant to which they will each agree with the Underwriters that (except in certain circumstances), without the prior written consent of Peters & Co. Limited and RBC Dominion Securities Inc. on behalf of the Underwriters pursuant to the Underwriting Agreement, which consent may not be unreasonably withheld, they will not, during the period ending 180 days after the closing of the Offering, directly or indirectly (i) offer, secure, pledge, sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase, or otherwise lend, transfer or dispose of, directly or indirectly, any Common Shares or any securities convertible into or exercisable or exchangeable for Common Shares, (ii) enter into any swap or other arrangement that transfers to another party, in whole or in part, any of the economic consequences of ownership of the Common Shares, regardless of whether any such transaction described in (i) or (ii) is to be settled by the delivery of Common Shares, other securities or cash or otherwise, or (iii) announce publicly any intention to effect any of the foregoing.

The TSX has conditionally approved the listing of the Common Shares. Listing is subject to the Corporation fulfilling all of the requirements of the TSX on or before October 17, 2004, including the distribution of Common Shares to a minimum number of public shareholders.

RELATIONSHIP BETWEEN THE CORPORATION AND CERTAIN UNDERWRITERS

Each of RBC Dominion Securities Inc. and CIBC World Markets Inc. is a subsidiary of a Canadian financial institution which is a lender to the Corporation. Consequently, the Corporation may be considered a "connected issuer" of each of RBC Dominion Securities Inc. and CIBC World Markets Inc. under applicable Canadian securities legislation. No advances have been made at this time under the Existing Credit Facility. The debt arrangements are secured by a security interest over all of the assets of the Corporation.

The terms and conditions of the Offering were negotiated by the Underwriters and the Corporation without the involvement of the applicable financial institutions. None of the Underwriters described above will derive any benefit from the Offering other than the remuneration described above which is payable by the Corporation.

PRINCIPAL SHAREHOLDERS

The following table sets forth those persons who own of record or are known by the Corporation to own beneficially, directly or indirectly, or to exercise control or direction over, equity voting shares of the Corporation as at the date hereof in an amount equal to or greater than 10% of the presently outstanding Common Shares:

Name of Shareholder	Common Shares Held	Percentage of Common Shares Held
Lime Rock[1]	15,976,528	53.4%

Note:

(1) The Beacon Group Energy Investment Fund II, L.P. beneficially owns 15,320,401 Common Shares (which is comprised of 2,276,949 Common Shares held directly and 13,043,452 Common Shares held through Riverside Investments LLC on behalf of The Beacon Group Energy Investment Fund II, L.P.) and Friends of Lime Rock LP beneficially owns 656,127 Common Shares. These investments in the Corporation are managed by Lime Rock Management LP, of which Mr. Farber is a Managing Director and Messrs. Farber and Clarkson are limited partners. Mr. Farber also has an indirect ownership interest in The Beacon Group Energy Investment Fund II, L.P., Riverside Investments LLC and Friends of Lime Rock LP. Messrs. Farber and Clarkson disclaim beneficial ownership of the subject shares except to the extent of their pecuniary interest, if any, therein.

LEGAL PROCEEDINGS

The Corporation is not aware of any material legal proceedings involving the Corporation or its property, nor are any such proceedings known by the Corporation to be contemplated.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are PricewaterhouseCoopers LLP, Chartered Accountants, Calgary, Alberta and the registrar and transfer agent for the Common Shares is Valiant Trust Company at its principal offices in Calgary, Alberta and its sub-agency office in Toronto, Ontario.

LEGAL MATTERS

Certain legal matters relating to the Offering and Over-Allotment Offering will be passed upon by Bennett Jones LLP on behalf of the Corporation and by Stikeman Elliott LLP on behalf of the Underwriters. As of the date hereof, the partners and associates of Bennett Jones LLP as a group and Stikeman Elliott LLP as a group each own less than 1% of the outstanding Common Shares.

EXPERTS

As of the date hereof, the partners or principals, as the case may be, of GLJ Associates as a group, Norwest as a group and Washington Group as a group, respectively, each own less than 1% of the outstanding Common Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only contracts entered into by the Corporation which may be regarded as presently material are the following:

1. Underwriting Agreement, as more particularly described under the heading "Plan of Distribution";
2. Joint Venture Agreement, as more particularly described under the heading "Enerplus Joint Venture"; and
3. Talisman Debenture as more particularly described under the heading "Talisman Debenture".

A copy of each of the material contracts listed above may be inspected at the offices of Bennett Jones LLP, 4500 Bankers Hall East, 855 - 2nd Street S.W., Calgary, Alberta T2P 4K7, during normal business hours at any time during the period of distribution to the public of the Offered Shares and the Over-Allotment Shares offered hereby and for a period of 30 days thereafter.

PURCHASERS' STATUTORY RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, damages where the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that such remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the applicable province. The purchaser should refer to the securities legislation in the province in which the purchaser resides for the particulars of these rights or consult with a legal advisor.

APPENDIX A

AUDITORS' CONSENT

We have read the prospectus of Deer Creek Energy Limited (the "Corporation") dated July 21, 2004 relating to the issue and sale of common shares of the Corporation. We have complied with Canadian generally accepted standards for auditors' involvement with offering documents.

We consent to the use in the above-mentioned prospectus of our report to the directors of the Corporation on the consolidated balance sheets of the Corporation as at December 31, 2003 and December 31, 2002 and the consolidated statements of income and deficit and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2003. Our report is dated March 5, 2004, except as to note 12, which is as of July 21, 2004.

Calgary, Canada
July 21, 2004

(Signed) PRICEWATERHOUSECOOPERS LLP
Chartered Accountants

AUDITORS' REPORT

To the Directors of Deer Creek Energy Limited:

We have audited the consolidated balance sheets of Deer Creek Energy Limited as at December 31, 2003 and 2002 and the consolidated statements of income and deficit and cash flows for each of the years in the three year period then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for each of the years in the three year period then ended in accordance with Canadian generally accepted accounting principles.

(Signed) PRICEWATERHOUSECOOPERS LLP
Chartered Accountants

Calgary, Canada
March 5, 2004 (except as to
note 12, which is as of July 21, 2004)

DEER CREEK ENERGY LIMITED

CONSOLIDATED BALANCE SHEETS

(thousands of dollars)

	March 31 2004 (unaudited)	December 31 2003	December 31 2002
Assets			
Current assets			
Cash and cash equivalents	**$ 39,458**	**$ 35,132**	$ 41,221
Accounts receivable	**4,304**	**1,828**	701
Prepaid expenses and deposits	**100**	**114**	76
	43,862	**37,074**	41,998
Abandonment deposits (note 7)	**429**	**426**	199
Property, plant and equipment (note 2)	**49,454**	**28,370**	8,564
	$ 93,745	**$ 65,870**	$ 50,761
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**$ 17,028**	**$ 6,552**	$ 1,275
Asset retirement obligations (note 4)	**595**	**—**	—
Future income tax liability (note 9)	**2,958**	**3,314**	—
	20,581	**9,866**	1,275
Shareholders' equity			
Share capital (note 5)	**78,680**	**61,677**	55,381
Contributed surplus (note 6)	**8,413**	**7,882**	7,344
Deficit	**(13,929)**	**(13,555)**	(13,239)
	73,164	**56,004**	49,486
	$ 93,745	**$ 65,870**	$ 50,761

Contingencies and commitments (note 7)

Approved by the Board,

(Signed) BRIAN K. LEMKE
Director

(Signed) GLEN C. SCHMIDT
Director

See accompanying notes to the consolidated financial statements

DEER CREEK ENERGY LIMITED

CONSOLIDATED STATEMENTS OF INCOME AND DEFICIT
(thousands of dollars, except per share amounts)

	For the Three Months ended March 31		For the Years Ended December 31		
	2004	2003	2003	2002	2001
	(unaudited)	(unaudited) (restated)			(restated)
Revenue					
Interest and other	$ **260**	$ 253	$ **970**	$ 376	$ 115
Oil sales, net of royalties	**—**	—	**—**	—	119
Gain on sale of property, plant and equipment	**—**	—	**—**	—	148
Foreign exchange gain (loss)	**—**	—	**—**	157	(1,069)
	260	253	**970**	533	(687)
Expenses					
General and administrative	**610**	255	**1,151**	839	1,221
Operating	**—**	—	**—**	—	109
Debt component of debenture set-off (note 8)	**—**	—	**—**	1,300	—
Interest on debenture	**—**	—	**—**	1,050	1,653
Depletion and amortization	**12**	4	**30**	22	642
	622	259	**1,181**	3,211	3,625
Income (loss) before Large Corporations Tax	**(362)**	(6)	**(211)**	(2,678)	(4,312)
Large Corporations Tax (note 9)	**12**	22	**105**	59	16
Net income (loss)	**(374)**	(28)	**(316)**	(2,737)	(4,328)
Deficit, beginning of period	**(13,555)**	(13,239)	**(13,239)**	(8,102)	(3,774)
Equity component of debenture set-off (note 8)	**—**	—	**—**	(2,400)	—
Deficit, end of period	**$(13,929)**	$(13,267)	**$(13,555)**	$(13,239)	$(8,102)
Net income (loss) per common share (note 5)					
Basic and diluted	**$ —**	$ —	**$ —**	$ (0.04)	$ (0.16)

See accompanying notes to the consolidated financial statements

DEER CREEK ENERGY LIMITED

CONSOLIDATED STATEMENTS OF CASH FLOWS

(thousands of dollars)

	For the Three Months ended March 31		For the Years Ended December 31		
	2004	2003	2003	2002	2001
	(unaudited)	(unaudited) (restated)			(restated)
Operating activities					
Net income (loss)	**$ (374)**	$ (28)	**$ (316)**	$(2,737)	$(4,328)
Add (deduct) items not affecting cash:					
Stock-based compensation	**317**	82	**305**	93	48
Depletion and amortization	**12**	4	**30**	22	642
Debenture set-off	**—**	—	**—**	1,300	—
Interest on debenture	**—**	—	**—**	1,050	1,653
Gain on sale of property, plant and equipment	**—**	—	**—**	—	(148)
Foreign exchange (gain) loss	**—**	—	**—**	(157)	1,069
Funds provided by (used in) operations	**(45)**	58	**19**	(429)	(1,064)
Changes in non-cash working capital (note 10)	**168**	(37)	**(94)**	99	(533)
	123	21	**(75)**	(330)	(1,597)
Investing activities					
Acquisition of property, plant and equipment	**(20,369)**	(7,944)	**(19,654)**	(5,016)	(4,073)
Disposition of property, plant and equipment	**—**	—	**—**	15,304	566
Abandonment deposit	**(3)**	—	**(227)**	(199)	24
Site restoration costs	**—**	—	**—**	—	(53)
Changes in non-cash working capital (note 10)	**7,928**	2,494	**4,074**	475	(148)
	(12,444)	(5,450)	**(15,807)**	10,564	(3,684)
Financing activities					
Share issues, net of share issuance costs	**16,647**	—	**9,661**	28,092	2,684
Changes in non-cash working capital (note 10)	**—**	(94)	**132**	(242)	109
	16,647	(94)	**9,793**	27,850	2,793
Increase (decrease) in cash and cash equivalents	**4,326**	(5,523)	**(6,089)**	38,084	(2,488)
Cash and cash equivalents, beginning of period	**35,132**	41,221	**41,221**	3,137	5,625
Cash and cash equivalents, end of period	**$ 39,458**	$35,698	**$ 35,132**	$41,221	$ 3,137
Cash and cash equivalents is comprised of:					
Deposits with banks	**$ 276**	$ 6,341	**$ 292**	$ 5,603	$ 1,558
Money market funds and bankers' acceptances	**39,182**	29,357	**34,840**	35,618	1,579
	$ 39,458	$35,698	**$ 35,132**	$41,221	$ 3,137

See accompanying notes to the consolidated financial statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles. Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements, and revenue and expenses during the reporting period. Actual results may differ from those estimates.

Basis of Presentation

The consolidated financial statements include the accounts of Deer Creek Energy Limited ("Deer Creek" or the "Company") and its wholly-owned subsidiary. Currently, the principal business of Deer Creek is an eighty-four percent interest in the Joslyn oil sands property (the "Joslyn Project"). Deer Creek is engaged in the development and construction of the Joslyn Project and does not anticipate commercial operations to commence until 2006.

The Company's exploration and development activities are conducted jointly with others and the accounts reflect only Deer Creek's proportionate interest.

Cash Equivalents

Cash equivalents consist of bankers' acceptances and investments in money market instruments with a maturity at the time of purchase of three months or less. Cash equivalents are stated at cost, which approximates market value.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost.

Effective January 1, 2004, the Company adopted the new Canadian Institute of Chartered Accountants' guideline for petroleum and natural gas operations, Accounting Guideline 16. The adoption of this guideline did not affect the Company's results.

The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs relating to the acquisition, exploration and development of reserves are capitalized. Such costs include land acquisition costs, annual carrying costs of non-producing properties, geological and geophysical costs, costs of drilling and equipping both productive and non-productive wells, and net costs relating to production during the development phase.

Expenditures to develop mining operations are capitalized. Net costs related to operating activities during the development of large capital projects are capitalized until commercial production has commenced. General and administrative costs directly related to the activities of these projects are also capitalized until commercial production commences.

The carrying amount of capitalized costs are limited to an amount equal to the estimated future net revenue from proved reserves based on current prices and costs, plus the lower of cost and estimated fair value of unproved properties (the "ceiling test"). The Joslyn Project is reviewed at each financial statement date for impairment or conditions which would indicate that capitalized costs are not recoverable through expected future cash flows.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Proceeds from the sale of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly change the rate of depletion.

Depletion and Amortization

Capital costs related to the Joslyn Project will be amortized on the unit-of-production method based on the estimated proved reserves, commencing when the facilities are substantially complete and after commercial production has begun. No amortization has been recorded with respect to the Joslyn Project as production has not commenced.

Office equipment is amortized on a 30 percent declining balance basis with one half of a year's amortization recorded in the year of acquisition.

Asset Retirement Obligations

Effective January 1, 2004, Deer Creek adopted the new accounting standard of the Canadian Institute of Chartered Accountants for asset retirement obligations. The new standard requires that a liability be recognized for retirement obligations associated with long-lived assets. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and allocated to expense on a basis consistent with the related depletion and amortization policy. The liability is increased due to the passage of time until the retirement obligation is settled.

Applying this change in accounting policy retroactively has no effect on the Company's prior year consolidated financial statements as substantially all the long-lived assets for which a retirement obligation exists were completed in early 2004. Accretion of the retirement obligation, prior to commercial production, is capitalized.

Financial Instruments

Financial instruments of the Company consist of cash, cash equivalents, accounts receivable, accounts payable and accrued liabilities. As at March 31, 2004, December 31, 2003 and December 31, 2002, there were no significant differences between the carrying values of these amounts and their estimated market values due to the short term maturity of the instruments.

Revenue Recognition

Revenue is recognized when products have been delivered and title passes. Revenue is not recognized on large capital projects until commercial production has commenced. Revenue earned prior to commercial production is netted against operating costs during the development phase and capitalized.

Stock-based Compensation

Effective January 1, 2003, the Company prospectively adopted the new recommendation of the Canadian Institute of Chartered Accountants with respect to stock-based compensation. The recommendation requires that the fair value method of accounting be applied for stock options and performance share units awarded to directors, officers and employees after January 1, 2003. Compensation is recorded based on the estimated fair value of the option or share unit on the grant date. Consideration paid by directors, officers or employees on the exercise of stock options and performance share units is recorded as share capital.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

The adoption of this recommendation decreased net income for the three months ended March 31, 2003 by $45 thousand.

Stock options that have been granted to non-employees of the Company in exchange for the receipt of services are recorded using the fair value method of accounting for the stock option under which compensation cost is recorded based on the estimated fair value of the options at the grant date.

Flow-through Shares

A portion of the Company's exploration activities have been financed through the issue of flow-through shares. Under the terms of the share issues, the related resource expenditure deductions are renounced to the shareholders for income tax purposes. When the expenditures are renounced and the related income tax deductions are transferred to the shareholders, future income tax liability will increase and the share capital will be reduced.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted on the consolidated balance sheet date.

Earnings per Share

Basic earnings per share is computed by dividing net earnings or net loss by the weighted average number of common shares outstanding during the year. Diluted earnings per share is computed as if the proceeds obtained upon exercise of stock options, stock rights or other dilutive instruments were used to purchase common shares at the latest market transaction price.

Foreign Exchange

Effective January 1, 2002, the Company adopted the Canadian Institute of Chartered Accountants' recommendations for foreign currency translation. As a result, the accumulated deferred foreign exchange loss of $1.0 million was retroactively charged to deficit, increasing the deficit at December 31, 2001 from $7.1 million to $8.1 million.

The Company translates foreign currency denominated monetary assets and liabilities at the rate of exchange in effect at the balance sheet date. Any gains or losses are recognized in net income.

(tabular amounts in thousands of dollars, unless otherwise noted)

2. PROPERTY, PLANT AND EQUIPMENT

	March 31 2004	December 31 2003	December 31 2002
Joslyn Project			
Cost	$49,259	$28,254	$8,511
Accumulated depletion	—	—	—
	49,259	28,254	8,511
Office equipment			
Cost	347	256	163
Accumulated amortization	152	140	110
	195	116	53
Leasehold improvements			
Cost	—	—	22
Accumulated amortization	—	—	22
	—	—	—
	$49,454	$28,370	$8,564

The Company capitalized general and administrative expenditures of $0.5 million for the three months ended March 31, 2004 ($1.2 million for the year ended December 31, 2003; $0.6 million for the year ended December 31, 2002)

3. CREDIT FACILITY

On March 25, 2004, Deer Creek entered into a $6.0 million, 364-day revolving committed credit facility with a Canadian chartered bank. This facility is intended for project development purposes. The Company has not received any advances on this facility.

4. ASSET RETIREMENT OBLIGATIONS

	March 31 2004	December 31 2003	December 31 2002
Balance, beginning of period	$—	$—	$—
Liabilities incurred	586	263	41
Liabilities settled	—	(263)	(41)
Accretion	9	—	—
Balance, end of period	$595	$—	$—

At March 31, 2004, the estimated undiscounted amount of cash flows required to settle the asset retirement obligations was $1.3 million and have been discounted at rates between 5.9 percent and 7.2 percent. The costs are expected to be incurred between 2008 and 2040.

(tabular amounts in thousands of dollars, unless otherwise noted)

5. SHARE CAPITAL

Authorized

Unlimited number of common shares without par value
Unlimited number of first preferred shares without par value, issuable in series.

Issued

	Number of Shares (thousands)	Amount
Common Shares		
December 31, 2001	27,990	$ 6,554
Issued for cash and commissions	31,184	29,774
Set-off of debenture (note 8)	71,809	26,143
Exercise of stock rights	7	5
Exercise of stock options	667	100
Stated capital reduction	—	(7,208)
Issue costs	—	(1,922)
December 31, 2002	131,657	53,446
Issued for cash	5,000	10,000
Exercise of stock options	1,208	208
Renunciation of flow-through share offering	—	(3,462)
Issue costs, net of tax	—	(450)
December 31, 2003	137,865	59,742
Issued for cash	10,100	17,675
Issue costs, net of tax	—	(672)
March 31, 2004	147,965	76,745
Special Warrants		
March 31, 2004 and December 31, 2001, 2002 and 2003	1,527	1,935
	149,492	$78,680

On January 28, 2004, the Company closed a private placement of 10,100,000 common shares at a price of $1.75 per common share for total gross proceeds of $17.7 million.

On November 4, 2003, the Company closed a private placement of 5,000,000 flow-through common shares at a price of $2.00 per common share for total gross proceeds of $10.0 million. In accordance with the terms of the offering and pursuant to the Income Tax Act, the Company renounced, for income tax purposes, exploration expenditures of $10.0 million to the holders of the flow-through common shares effective December 31, 2003. The Company is required to incur the associated qualifying exploration expenditures by December 31, 2004.

On November 28, 2002, the Company closed a private placement of 4,545,455 flow-through common shares at a price of $1.10 per common share for total gross proceeds of $5.0 million. The Company renounced exploration expenditures of $5.0 million to the holders of the flow-through common shares effective

5. SHARE CAPITAL (Continued)

December 31, 2002. The Company incurred the associated qualifying exploration expenditures by December 31, 2003.

On August 30, 2002, the shareholders approved a special resolution to reduce the stated capital of the common shares, pursuant to Section 36 of the Business Corporations Act (Alberta), to an amount equal to $0.343 per issued common share. The resolution further stipulated that the reduction amount be added to contributed surplus (see note 6).

The Company issued 184,086 common shares as part of commissions payable on the disposition of 16 percent of its total interest in the Joslyn Project to EnerMark Inc. ("EnerMark") on August 8, 2002. Under the terms of the joint venture agreement with EnerMark, after the initial capital commitment is satisfied, certain performance conditions become operative, which if unsatisfied, could result in EnerMark exchanging part or all of its working interest in the Joslyn Project for common shares of the Company. Any exchange would be based on the fair value of the property interest and shares.

On August 8, 2002, the Company closed a private placement of 26,321,407 common shares at a price of $0.93 per common share for total gross proceeds of $24.5 million. The agency agreement, entered into in connection with this issuance, provided for commission to the agents in the amount of $0.7 million. Pursuant to the agency agreement, the Company paid $0.6 million in cash and issued 133,102 common shares to the agents.

During the year ended December 31, 2001, the Company issued 1,526,882 flow-through special warrants for gross proceeds of $1.9 million. Each special warrant is convertible into one common share at the earlier of (i) the fifth business day following the date upon which a receipt for a final prospectus qualifying the distribution of the common shares issuable upon exercise of the special warrants has been obtained from the Alberta Securities Commission; (ii) the day prior to the effective date of any amalgamation or any plan of arrangement involving the Company pursuant to which, among other things, a holder of a special warrant would be entitled to a freely trading security in the Company, or the corporation resulting from the amalgamation or plan of arrangement, in exchange for each special warrant held; (iii) the first business day that is twelve months after the date the Company becomes a reporting issuer or the equivalent thereof in the province of residence of the holder of the special warrant; and (iv) October 18, 2004. The Company renounced expenditures of $1.9 million to the holders of the special warrants effective December 31, 2001.

At March 31, 2004, the Company had 14,949,000 common shares reserved for issuance under the stock option and performance share unit plans.

Performance Share Units

The Company has a performance share unit plan under which directors, officers, employees and providers of services of the Company are eligible to receive grants. Each performance share unit permits the holder to purchase one common share of Deer Creek at an exercise price of $0.01 per common share. Performance

(tabular amounts in thousands of dollars, unless otherwise noted)

5. SHARE CAPITAL (Continued)

share units under the plan have a term and vesting dates determined by the Board of Directors of the Company at the time of grant. The following performance share units have been granted:

	March 31 2004	December 31 2003	December 31 2002
	(thousands)	(thousands)	(thousands)
Outstanding, beginning of period	382	120	43
Granted	410	262	88
Exercised	—	—	(7)
Cancelled	—	—	(4)
Outstanding, end of period	792	382	120
Exercisable, end of period	460	327	120

Compensation cost of $0.3 million has been credited to contributed surplus for the three months ended March 31, 2004 ($0.2 million for the year ended December 31, 2003; $0.1 million for the year ended December 31, 2002).

Stock Options

The Company has a stock option plan under which directors, officers, employees and providers of services of the Company are eligible to receive grants. Each option permits the holder to purchase one common share of Deer Creek at the stated exercise price. The exercise price of options granted is determined by the Board of Directors of the Company at the time of grant. Stock options under the plan have a term not exceeding seven years from the date of grant and vest at terms to be determined by the directors at the time of grant. The following stock options have been granted:

	March 31, 2004		December 31, 2003		December 31, 2002	
	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
	(thousands)	($/option)	(thousands)	($/option)	(thousands)	($/option)
Outstanding, beginning of year	7,910	$0.88	6,603	$ 0.71	5,600	$ 0.59
Granted	2,248	1.74	3,125	0.94	2,570	0.93
Exercised	—	—	(1,208)	(0.17)	(667)	(0.15)
Cancelled	—	—	(610)	(0.79)	(900)	(1.00)
Outstanding, end of year	10,158	$1.07	7,910	$ 0.88	6,603	$ 0.71
Exercisable, end of year	4,830	$0.93	4,011	$ 0.82	3,713	$ 0.55

(tabular amounts in thousands of dollars, unless otherwise noted)

5. SHARE CAPITAL (Continued)

The following table is an analysis of outstanding and exercisable stock options as at March 31, 2004:

	Outstanding			Exercisable	
Exercise Price	Number	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
($/option)	(thousands)	(years)	($/option)	(thousands)	($/option)
$0.40	1,000	3.4	$0.40	1,000	$0.40
$0.93	5,515	5.8	$0.93	2,245	$0.93
$1.00	1,350	4.2	$1.00	1,013	$1.00
$1.66	170	6.7	$1.66	42	$1.66
$1.75	2,123	7.0	$1.75	530	$1.75
	10,158	5.6	$1.07	4,830	$0.93

Compensation cost of $0.3 million has been recognized for the three months ended March 31, 2004 ($0.3 million for the year ended December 31, 2003) for stock options granted after January 1, 2003. No compensation cost has been recorded for stock options granted in 2002.

The following shows pro forma net loss and loss per common share had the fair value method of accounting been applied for stock options granted during 2002:

	For the Three Months Ended March 31		For the Years Ended December 31	
	2004	2003	**2003**	2002
Net income (loss)				
As reported	**$(374)**	$(28)	**$(316)**	$(2,737)
Less fair value of stock options	**18**	17	**70**	106
Pro forma	**$(392)**	$(45)	**$(386)**	$(2,843)
Basic and diluted net income (loss) per share				
As reported	**$—**	$—	**$—**	$ (0.04)
Pro forma	**$—**	$—	**$—**	$ (0.04)

The estimated fair value of stock options granted was determined by computing the minimum value. The following estimates were used in the calculation of the present value of the exercise price:

	March 31 2004	December 31 2003	December 31 2002
Weighted average fair value ($/option)	$0.38	$0.25	$0.24
Risk free interest rate, average for year (percent)	3.5	4.3	4.2
Expected life (years)	7	7	7

(tabular amounts in thousands of dollars, unless otherwise noted)

5. SHARE CAPITAL (Continued)

Earnings per share

Basic and diluted net income (loss) per share have been calculated using the weighted average number of common shares and special warrants outstanding for the three months ended March 31, 2004 of 146,384,000 (131,657,000 weighted average common shares for the three months ended March 31, 2003; 132,829,000 weighted average common shares for the year ended December 31, 2003; 69,362,000 weighted average common shares for the year ended December 31, 2002; 27,583,000 weighted average common shares for the year ended December 31, 2001). The calculation of diluted net income (loss) per share does not include stock options or stock rights as the effect would be anti-dilutive.

6. CONTRIBUTED SURPLUS

	March 31 2004	December 31 2003	December 31 2002
Balance, beginning of period	$7,882	$7,344	$ 48
Reduction of stated capital	—	—	7,208
Stock rights granted	258	229	82
Stock rights exercised	—	—	(5)
Stock options granted	273	309	11
Balance, end of period	$8,413	$7,882	$7,344

7. CONTINGENCIES AND COMMITMENTS

Abandonment deposits

The Company is required to provide cash deposits to the Alberta Energy and Utilities Board to be held as security against the estimated future abandonment and site reclamation costs for the Joslyn Project wells and facilities. A further deposit estimated at $0.1 million is required to be made in May 2004 to satisfy the total current obligation of approximately $0.6 million as at March 31, 2004. Once production is achieved in 2004, the Company's requirement to provide cash deposits will be reduced.

Joslyn Project Development

The Company's principal business consists of the exploration and development of its oil sands property at Joslyn Creek, Alberta. Pursuant to an agreement ("the Talisman Agreement") with Talisman Energy Inc., the Company acquired the Joslyn oil sands property for an initial payment of $5.3 million plus a commitment to pay an additional amount of up to $21.0 million, contingent on production from the property. In addition, interest is computed, without compounding, at the Bank of Canada's prime rate per annum from November 1, 1998 to the date of the installment payments. At March 31, 2004, interest on the total contingent amount was $6.5 million ($6.3 million at December 31, 2003; $5.3 million at December 31, 2002).

On August 8, 2002, Deer Creek sold 16 percent of its total interest in the Joslyn Project to EnerMark for proceeds of $16.0 million plus the assumption by EnerMark of 16 percent of the contingent obligations to Talisman Energy Inc.

(tabular amounts in thousands of dollars, unless otherwise noted)

7. CONTINGENCIES AND COMMITMENTS (Continued)

As continuing security for the due performance and discharge of its covenants, obligations and liabilities under the Talisman Agreement, the Company granted a debenture in the principal amount of $21.0 million to Talisman Energy Inc. which is contingently payable by reference to reaching certain production thresholds. EnerMark has assumed its proportionate share of the debenture and Deer Creek has guaranteed all amounts assumed by EnerMark. EnerMark has also agreed to indemnify Deer Creek for its obligations. The debenture is secured by a fixed and specific mortgage and charge over properties purchased in the Talisman Agreement and certain other acquired personal and real property.

Contingent amounts payable to Talisman Energy Inc. by both the Company and EnerMark under the terms of the debenture granted pursuant to the Talisman Agreement are as follows:

Production Barrels of Bitumen Per Day	Cumulative Bitumen Production In Barrels	Amount Payable by Deer Creek	Amount Payable by EnerMark	Total Amount Payable
(thousands)	(thousands)			
10	5,000	$ 5,040	$ 960	$ 6,000
15	15,000	5,880	1,120	7,000
20	30,000	6,720	1,280	8,000
		$17,640	$3,360	$21,000

	March 31 2004	December 31 2003	December 31 2002
Contingent production payment:			
Deer Creek	$17,640	$17,640	$17,640
EnerMark	3,360	3,360	3,360
	$21,000	$21,000	$21,000

	March 31 2004	December 31 2003	December 31 2002
Contingent interest payment:			
Deer Creek	$ 5,443	$ 5,258	$ 4,431
EnerMark	1,037	1,002	844
	$ 6,480	$ 6,260	$ 5,275

As at March 31, 2004, development of the Joslyn Project had not advanced sufficiently to establish commercial production and positive operating cash flows. Additional investment is projected to be required to complete development of the property and to pay contingent consideration to Talisman Energy Inc. when the associated production levels are reached.

(tabular amounts in thousands of dollars, unless otherwise noted)

7. CONTINGENCIES AND COMMITMENTS (Continued)

Other Obligations

Future minimum amounts payable under operating leases for office space, office equipment and automotive equipment were as follows:

	Amount
2004 remainder	$193
2005	$253
2006	$ 12
2007	$ 2

Under a Steam Assisted Gravity Drainage Licence Agreement with the Alberta Research Council Inc., the Company is required to pay $0.4 million at the earlier of obtaining sufficient capital resources to develop SAGD Phase II or commencing construction of SAGD Phase II. A final installment of $0.4 million is required to be paid upon commencing steam injection of SAGD Phase II.

8. DEBENTURE AND SUBSCRIPTION AGREEMENT

On August 8, 2002, the Company completed an agreement with the holders of the six percent subordinated debenture to set-off the debenture and all accrued interest against a subscription for 71,809,000 common shares. Prior to this transaction the debenture holders, through a combination of common share ownership and other debenture terms, effectively controlled the Company. The total adjustment to share capital to record the set-off is as follows:

	Amount
Debenture principal amount, net of unamortized issue discount	$16,761
Accrued interest payable	3,299
Set-off expense	3,700
	23,760
Equity component of debenture recorded on issuance	2,383
Stated capital attributed to common shares	$26,143

The number of common shares issued under the terms of the set-off agreement exceeded the number of common shares that the debenture holders would have been entitled to under a voluntary conversion of the debenture pursuant to the original debenture terms. The Company has recorded an estimated $3.7 million for the value of common shares issued under the set-off arrangement. Of this amount, $1.3 million related to the debt component of the debenture and recorded as an expense. The balance of $2.4 million related to the equity component of the debenture and was recorded directly to the deficit. Fees paid in connection with this transaction were recorded as share issuance costs.

(tabular amounts in thousands of dollars, unless otherwise noted)

9. INCOME TAXES

The provision for income taxes is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the differences are as follows:

	For the Three Months Ended March 31		For the Years Ended December 31		
	2004	2003	2003	2002	2001
Income (loss) before Large Corporations Tax	**$ (362)**	$ (6)	**$ (211)**	$(2,678)	$(4,312)
Canadian statutory income tax rate (percent)	**38.87**	40.74	**40.74**	42.12	42.62
Income tax provision at statutory rates	**(141)**	(2)	**(86)**	(1,128)	(1,838)
Effect on income taxes of:					
Large Corporations Tax	**12**	22	**105**	59	16
Resource allowance	**47**	16	**64**	436	136
Non-deductible costs	**175**	34	**130**	47	1,489
Set-off expense of debenture	**—**	—	**—**	548	—
Amortization of discount on debenture	**—**	—	**—**	128	213
Other	**(81)**	(48)	**(108)**	(31)	—
Large Corporations Tax	**$ 12**	$ 22	**$ 105**	$ 59	$ 16

The following summarizes the temporary differences that give rise to the future income tax liability:

	March 31 2004	December 31 2003	December 31 2002
Future income tax liabilities			
Property, plant and equipment	**$4,336**	**$4,288**	$ 17
Future income tax assets			
Share issue costs	**(880)**	**(589)**	(679)
Non-capital losses	**(498)**	**(385)**	—
Capital losses	**(189)**	**(195)**	(237)
Future income tax liability (asset)	**2,769**	**3,119**	(899)
Valuation allowance	**189**	**195**	899
Future income tax liability	**$2,958**	**$3,314**	$ —

Prior to 2003, the future income taxes related to the renouncement of resource expenditure deductions and share issue costs were not recognized as a result of future income tax assets exceeding the future income tax liabilities. The future income tax liability related to the 2003 renouncement of the resource expenditure deductions has been recognized in 2003 to the extent that the future income tax liabilities exceed future tax assets related to share issue costs and non-capital losses.

(tabular amounts in thousands of dollars, unless otherwise noted)

10. CASH FLOWS

Changes in Non-Cash Working Capital

	For the Three Months Ended March 31		For the Years Ended December 31		
	2004	**2003**	**2003**	**2002**	**2001**
Operating activities					
Accounts receivable	**(6)**	$ 8	**$ (82)**	$ (644)	143
Prepaid expenses and deposits	**13**	9	**31**	(10)	6
Accounts payable and accrued liabilities	**161**	(54)	**(43)**	753	(682)
	168	(37)	**(94)**	99	(533)
Investing activities					
Accounts receivable	**(2,428)**	(1,421)	**(1,271)**	—	—
Prepaid expenses and deposits	**1**	—	**(69)**	—	—
Accounts payable and accrued liabilities	**10,355**	3,915	**5,414**	475	(148)
	7,928	2,494	**4,074**	475	(148)
Financing activities					
Accounts receivable	**—**	—	**226**	—	—
Accounts payable and accrued liabilities	**—**	(94)	**(94)**	(242)	109
	—	(94)	**132**	(242)	109
	$8,096	$2,363	**$4,112**	$ 332	$ (572)

Other Cash Flow Information

	For the Three Months Ended March 31		For the Years Ended December 31		
	2004	**2003**	**2003**	**2002**	**2001**
Interest paid	**$ —**	$ —	**$ —**	$ —	$ —
Large Corporations Tax paid	**$ 28**	$ 42	**$ 115**	$ 24	$ 21

11. GUARANTEES

The Company has guaranteed all amounts assumed by EnerMark under the Talisman Agreement (see Note 7).

Deer Creek has entered into indemnification agreements with its directors and officers to indemnify them, to the extent permitted by law, against any and all charges, costs, expenses, amounts paid in settlement and damages incurred by the directors and officers as a result of any lawsuit or any other judicial, administrative or investigative proceeding in which the directors and officers are sued as a result of their service. The nature of the indemnification agreements prevents the Company from making a reasonable estimate of the

11. GUARANTEES (Continued)

maximum potential liability. The Company purchases directors' and officers' liability insurance and there are currently no claims outstanding.

12. SUBSEQUENT EVENTS

On May 20, 2004, the shareholders approved a special resolution authorizing the Board of Directors to amend the Articles of Amendment of the Company to consolidate the issued and outstanding common shares on a five for one basis. This consolidation is not reflected in these consolidated financial statements and accompanying notes.

On July 21, 2004, the Company entered into an underwriting agreement in relation to an initial offering of 16,900,000 Common Shares at $9.50 per Common Share.

APPENDIX B

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the board of directors of Deer Creek Energy Ltd. (the "Company"):

1. We have prepared an evaluation of the Company's reserves and resources data as at January 1, 2004. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at January 1, 2004, using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2003, using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Description and Preparation Date of Evaluation/Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (million) (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
March 16, 2004	Canada	$0	$194.7	$0	$194.7

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

6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation dates.

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

Executed as to our report referred to above:

Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta, Canada — Dated June 11, 2004

ORIGINALLY SIGNED BY
Dana B. Laustsen, P. Eng.

APPENDIX C

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Deer Creek Energy Limited (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

(ii) the related estimated future new revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Technical Committee of the board of directors of the Corporation has

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Technical Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Technical Committee, approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

(Signed) GLEN C. SCHMIDT
President and Chief Executive Officer

(Signed) GARY R. PURCELL
Vice President, Business Development

(Signed) S. BARRY JACKSON
Chairman and Director

(Signed) JOHN G. CLARKSON
Director

June 11, 2004

CERTIFICATE OF THE CORPORATION

July 21, 2004

The foregoing constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 9 of the *Securities Act* (British Columbia), by Part 9 of the *Securities Act* (Alberta), by Part XI of *The Securities Act, 1988* (Saskatchewan), by Part VII of the *Securities Act* (Manitoba), by Part XV of the *Securities Act* (Ontario), by section 63 of the *Securities Act* (Nova Scotia), by Part II of the *Securities Act* (Prince Edward Island), by section 13 of the *Securities Fraud Prevention Act* (New Brunswick) and by Part XIV of the *Securities Act, 1990* (Newfoundland and Labrador) and the respective regulations thereunder. This prospectus does not contain any misrepresentation likely to affect the value or market price of the securities to be distributed within the meaning of the *Securities Act* (Quebec) and the regulations thereunder.

(Signed) GLEN C. SCHMIDT
President and Chief Executive Officer

(Signed) JOHN S. KOWAL
Vice President and Chief Financial Officer

On Behalf of the Board of Directors

(Signed) S. BARRY JACKSON
Director

(Signed) BRIAN K. LEMKE
Director

CERTIFICATE OF THE UNDERWRITERS

July 21, 2004

To the best of our knowledge, information and belief, the foregoing constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 9 of the *Securities Act* (British Columbia), by Part 9 of the *Securities Act* (Alberta), by Part XI of *The Securities Act, 1988* (Saskatchewan), by Part VII of the *Securities Act* (Manitoba), by Part XV of the *Securities Act* (Ontario), by section 64 of the Securities Act (Nova Scotia), by Part II of the *Securities Act* (Prince Edward Island), by section 13 of the *Securities Fraud Prevention Act* (New Brunswick) and by Part XIV of the *Securities Act, 1990* (Newfoundland and Labrador) and the respective regulations thereunder. For the purposes of the Province of Quebec, to our knowledge, this prospectus does not contain any misrepresentation likely to affect the value or market price of the securities to be distributed within the meaning of the *Securities Act* (Quebec) and the regulations thereunder.

PETERS & CO. LIMITED	RBC DOMINION SECURITIES INC.
(Signed) IAN D. BRUCE	(Signed) EVAN J. HAZELL

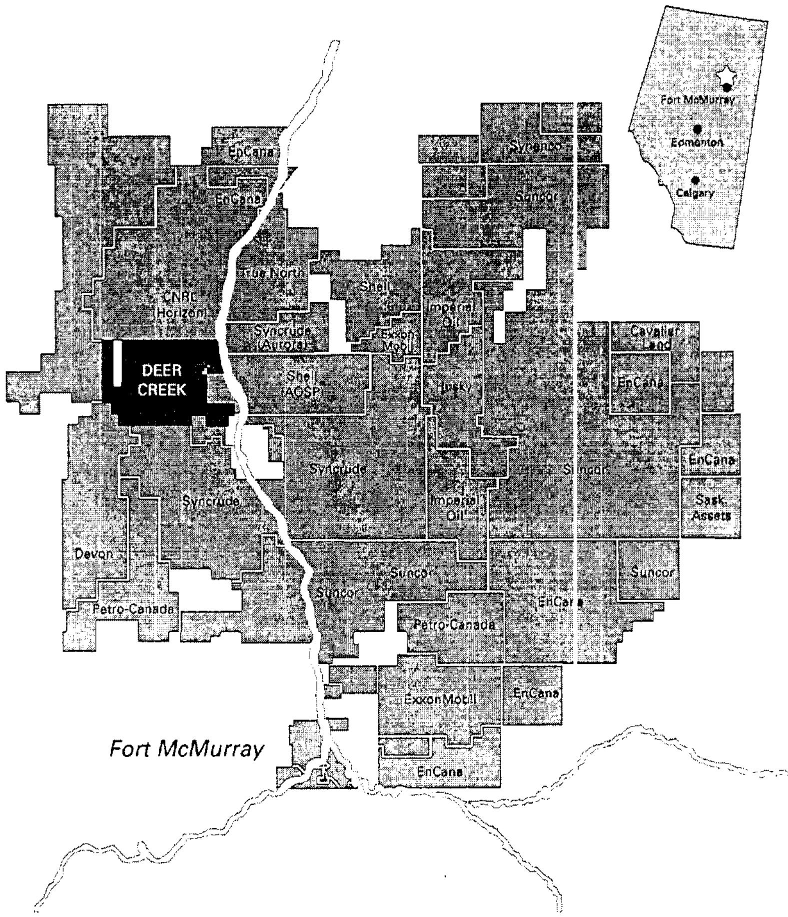
MERRILL LYNCH CANADA INC.

(Signed) DREW M. ROSS

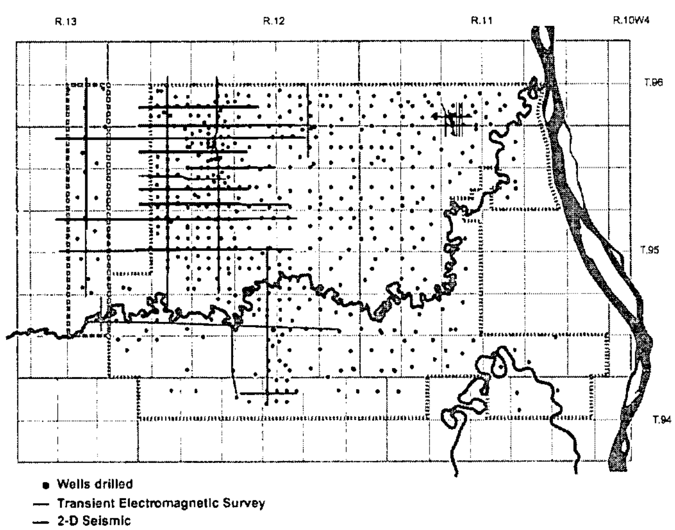
CIBC WORLD MARKETS INC.	SCOTIA CAPITAL INC.
(Signed) T. TIMOTHY KITCHEN	(Signed) MARK HERMAN

CANACCORD CAPITAL CORPORATION	FIRST ASSOCIATES INVESTMENTS INC.	FIRSTENERGY CAPITAL CORP.	RAYMOND JAMES LTD.	SALMAN PARTNERS INC.
(Signed) KARL B. STADDON	(Signed) CHARLES A.V. PENNOCK	(Signed) M. SCOTT BRATT	(Signed) EDWARD J. BEREZNICKI	(Signed) FRANCESCO MELE

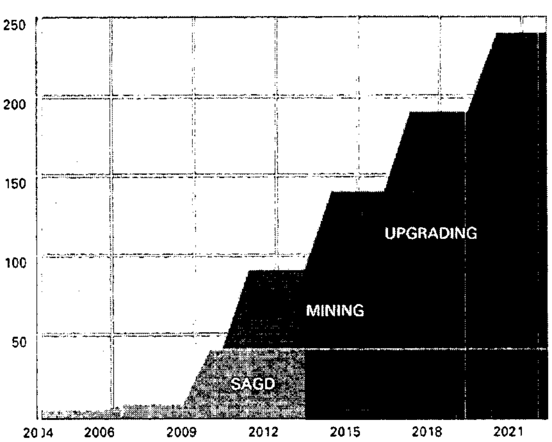
Athabasca Oil Sands Area



Delineation of Joslyn Project



Forecast Production (mmbbl/d)



DEER CREEK

Energy Limited

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