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News release via Canada NewsWire, Calgary 403-269-7605

Attention Business Editors:
Deer Creek Energy Limited Announces Financings Totaling $225 Million and Alberta Environment Approval for SAGD Phase II

/NOT FOR DISSEMINATION IN THE UNITED STATES OR TO U.S. PERSONS/

CALGARY, July 22 /CNW/ - Deer Creek Energy Limited ("Deer Creek" or the "Company") is pleased to announce that it has filed and obtained a receipt for a final prospectus with the securities regulatory authorities in each of the provinces of Canada with respect to its initial public offering ("IPO") of 16,900,000 common shares at a price of $9.50 per common share, for total proceeds of $160,550,000 (the "Offered Shares"). The closing of the offering and the listing of the common shares of Deer Creek on the Toronto Stock Exchange under the trading symbol "DCE" is expected to occur on or about July 29, 2004.

The syndicate of underwriters was co-led by Peters & Co. Limited and RBC Capital Markets and included 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.

In connection with the IPO, Deer Creek has granted to the underwriters an over-allotment option, exercisable in whole or in part, for a period of 30 days from the closing of the IPO, to purchase up to 10% of the number of Offered Shares at the offering price, to cover over-allotments, if any, and for market stabilization purposes. If the over-allotment option is exercised in full, additional gross proceeds of $16,055,000 will be realized by the Company.

Deer Creek is also pleased to announce that it has executed a commitment agreement for a $65,000,000 credit facility with two Canadian chartered banks. The credit facility will be available to the Company to assist in funding Deer Creek's share of the capital costs of phase two of the steam assisted gravity drainage ("SAGD Phase II") development of its Joslyn Project.

The Company also announces that it has received Alberta Environment approval for the applications it made under the Environmental Protection and Enhancement Act and the Water Act in respect of the SAGD Phase II expansion. In May 2004, Deer Creek received approval from the Alberta Energy and Utilities Board for SAGD Phase II. SAGD Phase II, which will be funded by the net proceeds of the IPO and the credit facility, is designed to expand the production level of the Joslyn Project by 10,000 barrels of bitumen per day. Deer Creek's operational plans for SAGD Phase II are firmly on track.

The securities offered have not been and will not be registered under the United States Securities Act of 1933, as amended (the "1933 Act"), and may not be offered or sold within the United States or to, or for the account or benefit of, U.S. persons except in certain transactions exempt from the registration requirement of the 1933 Act.

Deer Creek is a Calgary-based, oil sands company engaged in the development of its Athabasca oil sands deposits through SAGD and mining extraction methods. The Company 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. Deer Creek has an 84% working interest in and is operator of the Joslyn Project.

Certain statements contained in this document are "forward-looking statements". The projections, estimates and beliefs contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results or events to differ materially from those anticipated in any forward-looking statements. Deer Creek believes the expectations reflected in those forward-looking statements are reasonable;

however Deer Creek cannot provide any assurance that these expectations will prove to be correct.

%SEDAR: 00010187E

/For further information: Deer Creek Energy Limited: Mr. Glen C. Schmidt, President & CEO, (403) 264-3777, (403) 264-3700 (fax), E-mail: glen.schmidt(at)deercreekenergy.com, Website: www.deercreekenergy.com; OR Deer Creek Energy Limited, Mr. John S. Kowal, VP Finance & CFO, (403) 264-3777, (403) 264-3700 (fax), E-mail: john.kowal(at)deercreekenergy.com, Website: www.deercreekenergy.com/

CO: Deer Creek Energy Limited

CNW 08:01e 22-JUL-04

News release via Canada NewsWire, Calgary 403-269-7605

Attention Business Editors:
Deer Creek Energy Limited Announces the Completion of a $65,000,000 Committed Credit Facility.

/NOT FOR DISSEMINATION IN THE UNITED STATES OR TO U.S. PERSONS/

CALGARY, July 23 /CNW/ - Deer Creek Energy Limited ("Deer Creek" or the "Company") is pleased to announce that it has executed a credit agreement and all other loan and security documentation related to the previously announced $65,000,000 committed credit facility with two Canadian chartered banks.

The credit facility will be available to the Company to assist in funding Deer Creek's share of the capital costs of phase two of the steam assisted gravity drainage development of its Joslyn Project.

"Securing the credit facility with two Canadian chartered banks is an important endorsement of our project" said John Kowal, Deer Creek's Vice President, Finance & Chief Financial Officer. "This facility is a key component of the financing required to implement the commercial development of the Joslyn Project."

Deer Creek is a Calgary-based, oil sands company engaged in the development of its Athabasca oil sands deposits through SAGD and mining extraction methods. The Company 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. Deer Creek has an 84% working interest in and is operator of the Joslyn Project.

Certain statements contained in this document are "forward-looking statements". The projections, estimates and beliefs contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results or events to differ materially from those anticipated in any forward-looking statements. Deer Creek believes the expectations reflected in those forward-looking statements are reasonable; however Deer Creek cannot provide any assurance that these expectations will prove to be correct.

%SEDAR: 00010187E

/For further information: please contact: Deer Creek Energy Limited, Mr. Glen C. Schmidt, President & CEO or Mr. John S. Kowal, VP Finance & CFO, at (403) 264-3777, (403) 264-3700 (fax), E-mail: deercrk(at)deercreekenergy.com, Website: www.deercreekenergy.com/

CO: Deer Creek Energy Limited

CNW 08:00e 23-JUL-04

News release via Canada NewsWire, Calgary 403-269-7605

Attention Business Editors:
Deer Creek Energy Limited (TSX:DCE) Announces Completion Of $160 Million Initial Public Offering and Commences Trading on the Toronto Stock Exchange

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/NOT FOR DISSEMINATION IN THE UNITED STATES OR TO U.S. PERSONS/

CALGARY, July 29 /CNW/ - Deer Creek Energy Limited is pleased to announce the closing of its initial public offering (the "IPO") of 16.9 million common shares at a price of $9.50 per share, for gross proceeds of $160.6 million. The common shares will commence trading on the Toronto Stock Exchange at the opening of the market today under the symbol "DCE".

The net proceeds of the IPO, together with the previously-announced committed credit facility of $65 million, will fully fund Deer Creek's share of the capital costs for phase two of the steam assisted gravity drainage ("SAGD") development, a 10,000 barrels of bitumen per day expansion of the Joslyn Project. The net proceeds will also be used to advance the engineering, regulatory application and approval stages of SAGD Phase III, a 30,000 barrels of bitumen per day expansion and the first 100,000 barrels of bitumen per day mining development through 2006.

Mr. Glen Schmidt, President and CEO of Deer Creek, commented, "We are very excited about the opportunity this capital provides to execute our development plans and commence commercial operations. These financings support the next stage in Deer Creek's evolution as we launch as a public company and progress on our goal of becoming a significant oil sands producer."

Peters & Co. Limited and RBC Capital Markets co-led a syndicate of underwriters including 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. in connection with the IPO.

Deer Creek is a Calgary-based oil sands company engaged in the development of its Athabasca oil sands deposits through SAGD and mining extraction methods. The Company 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. Deer Creek has an 84% working interest in, and is operator of, the Joslyn Project.

After giving effect to the IPO, the Company has 46,798,458 common shares outstanding. In addition, the Company has granted the underwriters of the IPO the right to purchase, on or before August 28, 2004, up to 1,690,000 common shares at the IPO issue price of $9.50 per share.

This news release shall not constitute an offer to sell or the solicitation of an offer to buy the offered shares in any jurisdiction. Such offered shares have not been and will not be registered under the United States Securities Act of 1933, as amended, and subject to certain exemptions, may not be offered or sold in the United States or to U.S. persons.

Certain statements contained in this document are "forward-looking statements". The projections, estimates and beliefs contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results or events to differ materially from those anticipated in any forward-looking statements. Deer Creek believes the expectations reflected in those forward-looking statements are reasonable; however Deer Creek cannot provide any assurance that these expectations will prove to be correct.

%SEDAR: 00010187E

/For further information: please contact: Deer Creek Energy Limited, Mr. Glen C. Schmidt, President & CEO or Mr. John S. Kowal, VP Finance & CFO at

(403) 264-3777, (403) 264-3700 (fax) E-mail: deercrk(at)deercreekenergy.com
Website: www.deercreekenergy.com/
(DCE.)

CO: Deer Creek Energy Limited

CNW 08:50e 29-JUL-04

News release via Canada NewsWire, Calgary 403-269-7605

Attention Business/Financial Editors:
Deer Creek Energy Limited - Second Quarter 2004 Results Conference Call

CALGARY, Aug. 10 /CNW/ - Deer Creek Energy Limited ("Deer Creek") released its second quarter 2004 results today before the markets opened on August 10, 2004. A conference call has been scheduled for 2:30PM MST (4:30PM EST) on Thursday, August 12, 2004. To participate in the conference call, the dial in number is 1-800-796-7558 or 1-416-640-4127.

An archived recording of the conference call will be available until August 19, 2004 by dialing 1-877-289-8525 or 1-416-640-1917 and entering passcode : 21090816 followed by the pound key.

Deer Creek is a Calgary-based oil sands company engaged in the development of its Athabasca oil sands deposits through SAGD and mining extraction methods. The Company 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. Deer Creek has an 84% working interest in and is operator of the Joslyn Project.

Trading Symbol - TSX: DCE
%SEDAR: 00010187E

/For further information: please contact: Deer Creek Energy Limited, Mr. Glen C. Schmidt, President & CEO or Mr. John S. Kowal, VP Finance & CFO, at (403) 264-3777, (403) 264-3700 (fax), E-mail: deercrk(at)deercreekenergy.com, Website: www.deercreekenergy.com/
(DCE.)

CO: Deer Creek Energy Limited

CNW 16:13e 10-AUG-04

News release via Canada NewsWire, Calgary 403-269-7605

Attention Business/Financial Editors:
Deer Creek Announces Second Quarter 2004 Financial and Operating Results

CALGARY, Aug. 10 /CNW/ - Deer Creek Energy Limited (TSX:DCE) announced today its financial and operating results for the quarter ended June 30, 2004.

Continued progress on the Joslyn Project positioned Deer Creek's successful initial public offering

This is Deer Creek's first quarterly report as a public company following the closing of its initial public offering ("IPO") on July 29, 2004 and listing on the Toronto Stock Exchange ("TSX").

Quarterly Highlights

- Start up of SAGD Phase I facility and steaming of initial well pair
- Completed design base memorandum for SAGD Phase II
- Received AEUB approval of SAGD Phase II
- Expanded thermal and mining teams
- Filed public disclosure documents and terms of reference for SAGD Phase III and first two mine phases
- Subsequent to the second quarter, Deer Creek:
    - Completed a $160.6 million IPO and began trading on the TSX
    - Secured a $65.0 million committed credit facility
    - Received Alberta Environment approval for SAGD Phase II

Deer Creek's operational plans for 2004 are firmly on track and are supported by the successful closing of its IPO.

Steaming of the SAGD Phase I well pair began in April, 2004 and circulation performance is as expected. Deer Creek anticipates change over from steam circulation mode to production mode to occur during the third quarter. Production response from the well is forecasted to ramp up over the next 12 months and reach its peak rate of approximately 600 barrels of bitumen per day by mid 2005.

Early in the quarter, the Company completed a design base memorandum on the facility, gathering and steam injection system plus the well pad surface equipment for SAGD Phase II. The gross cost estimate, including wells and well pads and contingencies is projected to be approximately $171 million.

In May 2004, Deer Creek received approval from the Alberta Energy and Utilities Board for the 10,000 barrels of bitumen per day SAGD Phase II expansion. This is a significant milestone for Deer Creek. The approval is a result of a comprehensive process including environmental assessment, detailed technical design, regulatory review and stakeholder consultation. Subsequently, Deer Creek's board of directors and its joint venture partner, EnerMark Inc., a wholly owned subsidiary of Enerplus Resources Fund, approved going forward with the commercial development.

During the quarter, work continued on advancing future phases of the Joslyn Project. The Company submitted a public disclosure document, which marks the first step in the regulatory process, for the 30,000 barrels of bitumen per day SAGD Phase III expansion and the first 100,000 barrels of bitumen per day mining development. Deer Creek plans to submit an application for regulatory approval of the SAGD Phase III project in early 2005 and the first two mine phases in late 2005 or early 2006. To support the applications, an environmental impact assessment report will be prepared together with the conceptual engineering design, business analysis and socio-economic assessment. A companion document containing the proposed terms of reference for the environmental impact assessment report required for the SAGD Phase III and the mining developments has also been prepared to initiate the regulatory process.

Deer Creek also expanded its management team with three additions to its mining and thermal areas during the second quarter. These additions will greatly assist the Company as it expands operations and implements its plan of developing a world class growth opportunity in the Athabasca oil sands. Current staffing consists of 23 employees in the Calgary Office and a total of 12 employees and contract operators located in Fort McMurray.

In June, Deer Creek commenced activities for the IPO of its common shares. Subsequent to the quarter end, the Company successfully completed these financing activities raising gross proceeds of $225.6 million through a $65.0 million committed credit facility from two Canadian chartered banks and a $160.6 million IPO.

These financings signify the beginning of the next stage in Deer Creek's evolution and fully fund the Company's initial commercial operations.

2004 Outlook

- Change over SAGD Phase I well pair to production mode
- Advance engineering and initiate procurement of major equipment for SAGD Phase II
- Award construction contracts and commence site construction of SAGD Phase II
- Complete licensing applications for the 2005 winter core-hole program of approximately 200 wells

Success from implementing Deer Creek's phased approach reinforces our strategy of a step wise development. The positive engineering construction and start up results from the initial SAGD Phase I facility and well pair, position the Company favourably to execute its development plans for SAGD Phase II.

Subsequent to quarter end, the Company announced that it has received Alberta Environment approval for SAGD Phase II. With regulatory approvals and financing in hand, Deer Creek will continue to complete the engineering for SAGD Phase II with major equipment tenders expected to be awarded in the third quarter of 2004. By the end of September, engineering will exceed 60 percent on the facility. Costs will be firm, supported by completed equipment orders on the steam generation, water treatment, oil treating and other key components. Site construction is expected to begin in the last quarter of 2004 following the awarding of construction contracts. Deer Creek's detailed development plan for SAGD Phase II is on schedule with a target date to commence steam injection of mid 2006.

Geological modeling of Deer Creek's extensive 2004 winter drilling program will continue in the second half of 2004. Deer Creek expects to participate in over 200 delineation wells in the first quarter of 2005 to enhance the Company's project design data.

Deer Creek's one step at a time strategy matches its unique opportunity to establish commercial SAGD production as a platform from which to develop the mining phases of the Joslyn Project.

Management's Discussion and Analysis

The Management's Discussion and Analysis for Deer Creek Energy Limited ("Deer Creek" or the "Company") should be read in conjunction with the accompanying unaudited interim consolidated financial statements and accompanying notes for the six months ended June 30, 2004 and the audited consolidated financial statements and the Management's Discussion and Analysis contained in the Company's annual report for the year ended December 31, 2003. Additional information relating to Deer Creek is available on the SEDAR website at www.sedar.com. This Management's Discussion and Analysis is dated August 9, 2004.

The following information offers Management's analysis of the financial and operating results of the Company and may contain forward-looking statements that are based on estimates and assumptions that are subject to uncertainties. Actual results or events may vary materially from those anticipated.

Results of Operations

Joslyn Project (oil sands lease 24 and permit 70)

Following the successful completion of the SAGD Phase I facility, on schedule and under budget, steam injection and circulation of the SAGD Phase I well pair began in early April and continued throughout the second quarter of 2004. Production is anticipated to commence in the third quarter of 2004. During this pre-commercial phase of the initial SAGD development, all net revenue and operating costs will be capitalized.

During the quarter ended June 30, 2004, the Company received approval from the Alberta Energy and Utilities Board for SAGD Phase II, a 10,000 barrels of bitumen per day expansion. Deer Creek also made advancements in the regulatory process for SAGD Phase III and the first two phases of the mining development by submitting a public disclosure document in June 2004.

Net Additions to Property, Plant and Equipment

Core-hole drilling, development and construction activities have been conducted under a joint venture agreement with EnerMark Inc. ("EnerMark").

<<

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	2004	2003	2004	2003
Joslyn Project, net				
Project delineation	256	663	8,312	5,484
SAGD Phase I	274	(214)	10,144	1,924
SAGD Phase II and III	1,331	434	3,232	1,148
Mining	44	8	102	14
Other	430	135	416	263
Asset retirement obligations	15	-	610	-
Capitalized general and administration	506	205	984	360
Project costs	2,856	1,231	23,800	9,193
Office equipment	124	9	276	17
Net additions to property, plant and equipment	2,980	1,240	24,076	9,210

For the three months ended June 30, 2004, net capital expenditures (excluding non-cash items such as asset retirement obligations and capitalized stock-based compensation) were primarily incurred for the regulatory and engineering costs related to SAGD Phase II of the Joslyn Project. During the second quarter of 2004, the Company completed a design base memorandum on the SAGD Phase II facility, gathering and steam injection system and the surface equipment.

During the six months ended June 30, 2004, the Company has incurred capital expenditures primarily for the construction of the SAGD Phase I facility, gathering and steam injection system and for the 2004 winter drilling and seismic program.

Net capital expenditures, are expected to be approximately $21.0 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 Company 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.

Financial Results

($ thousands)	Three Months Ended June 30 2004	Three Months Ended June 30 2003	Six Months Ended June 30 2004	Six Months Ended June 30 2003
Interest income and other revenue	158	242	418	495
General and administrative expenses, net	576	291	1,186	546
Net income (loss)	(450)	(77)	(824)	(105)

Interest Income and Other Revenue

Interest income and other revenue is primarily interest earned on cash invested in bankers' acceptances and money market instruments held during the periods. Interest income and other revenue is lower for the three and six month periods ended June 30, 2004 when compared to the same periods of 2003 due to lower average investment balances and lower interest rates realized in the second quarter of 2004. The decrease in the average investment balances is a result of the increased capital expenditures incurred during the first six months of 2004 when compared to the first six months of 2003.

It is expected that interest income and other revenue will increase in the last six months of 2004 due to higher investment balances resulting from the proceeds of Deer Creek's initial public offering which closed in late July 2004.

General and Administrative Expenses

Net general and administrative expenses increased $0.3 million for the three months ended June 30, 2004 compared to the three months ended June 30, 2003 and $0.6 million for the first six months of 2004 compared to the first six months of 2003. These increases were 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.

($ thousands)	Three Months Ended June 30 2004	Three Months Ended June 30 2003	Six Months Ended June 30 2004	Six Months Ended June 30 2003
General and administrative expenses, gross	1,069	493	2,023	887
Joint venture recoveries	(180)	(84)	(319)	(139)
	889	409	1,704	748
Stock option compensation costs	193	87	466	158
Capitalized costs	(506)	(205)	(984)	(360)
General and administrative				

expenses, net	576	291	1,186	546

The increase in gross general and administrative expenses was due to a higher level of activity related to the progression of the Company which resulted in higher employee, consulting and computer services costs. During the first six months of 2004, six employees have joined Deer Creek in planned positions.

For 2004, the gross general and administrative expenses are expected to be approximately $4.2 million. A portion of these expenditures will be offset by EnerMark's 16 percent share pursuant to the joint venture agreement and a portion will be capitalized. Stock option compensation costs are expected to be approximately $0.7 million for 2004.

Net Income (Loss)

The net loss increased by $0.4 million and $0.7 million for the three and six months ended June 30, 2004, respectively, when compared to the same periods of 2003. The increases were due to increased general and administrative expenses associated with the advancing development of the Joslyn Project and a decrease in interest income earned on investments.

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 of the Joslyn Project will be capitalized and amortized over the expected life of the associated reserves.

Income Taxes

Large Corporations Tax decreased to $26,000 in the first six months of 2004 from $44,000 for the same period in 2003 due to the decrease in the statutory rate and the increase in the allowable capital deduction. The Company's Large Corporations Tax is expected to increase from the issuance of capital through the initial public offering.

Quarterly Information

($ thousands, except per share amounts)	Q2 04	Q1 04	Q4 03	Q3 03	Q2 03	Q1 03	Q4 02	Q3 02
Net additions to property, plant and equipment	2,980	21,096	5,988	4,638	1,240	7,970	1,833	(14,395)
Interest and other revenue	158	260	235	240	242	253	217	(672)
Net loss	(450)	(374)	(166)	(45)	(77)	(28)	(45)	(2,408)
Net loss per share (basic and diluted) (1)	(0.02)	(0.01)	-	-	-	-	(0.01)	(0.14)

(1) restated for the consolidation of common shares on a five to one basis

Capital expenditures have occurred primarily in the first and fourth quarters when the Company had planned core-hole drilling and SAGD Phase I construction. Drilling activity for the purpose of delineating the lease occurs during the winter season with analysis of the data occurring during the following six months. In the third quarter of 2002, the Company sold its 16 percent working interest in the Joslyn Project to EnerMark.

Net loss increased in the first quarter of 2004 and the fourth quarter of 2003 as a result of recording performance related expenses. In the fourth quarter of 2003, the Company 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. In the third quarter of 2002, the Company expensed $1.3 million for the set-off of the convertible debenture.

Liquidity

Working Capital

Working capital surplus decreased $6.9 million during the first six months of 2004. This decrease is primarily due to capital expenditures for the development of the Joslyn Project partially offset by net proceeds from the January 28, 2004 common share issuance.

($ thousands)

Working capital, December 31, 2003	30,522
Capital expenditures	(23,225)
Share issuance proceeds, net of costs	16,647
Funds used in operations	(372)
Abandonment deposits	(151)
Other	174
Working capital, June 30, 2004	23,595

The working capital surplus at June 30, 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 will significantly increase in the third quarter of 2004 with the proceeds from Deer Creek's initial public offering. It is anticipated that the proceeds will be invested in short term money market securities.

Capital Resources

Equity Financing

On January 28, 2004, the Company closed a private placement of 2,020,000 common shares at a price of $8.75 per common share for total gross proceeds of $17.7 million. Proceeds from this share issuance are intended for future development of the Joslyn Project.

On July 29, 2004, the Company closed its initial public offering for 16,900,000 common shares at $9.50 per common share. The estimated proceeds of $152.5 million, net of commissions, are to be used to complete SAGD Phase II, as well as certain additional work necessary to advance the development of future phases of the Joslyn Project.

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 drawn any funds under this facility.

On July 22, 2004, the Company cancelled the $6.0 million revolving committed credit facility and entered into an agreement with two Canadian chartered banks for a committed credit facility of $65.0 million. The new credit facility will assist in funding SAGD Phase II and provide incremental working capital to the Company to support the regulatory, engineering design and environmental work related to additional expansions of the Joslyn Project and other related expenses.

Commitments

The Company did not enter into any additional material commitments from that set forth in Note 5 of the accompanying notes to the unaudited consolidated financial statements.

Outstanding Share Data

At July 31, 2004, share capital consists of the following:

(thousands)	
Issued and outstanding	
Common shares	46,798
Stock options	2,349
Performance share units (formerly stock rights)	171
Fully diluted number of shares	49,318

The Board of Directors approved amendments to each of the Stock Option Plan and Performance Share Unit Plan (formerly the Stock Rights Plan) 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, adopted a revised definition of Change of Control, consistent with other Canadian issuers and limited the term of exercise of performance share units to seven years.

At the annual and special meeting of shareholders held on May 20, 2004, the shareholders approved a resolution to consolidate the issued and outstanding common shares on a five to one basis, effective June 1, 2004. The shareholders also approved, pursuant to section 36 of the Business Corporations Act (Alberta), to reduce the stated capital account for the common shares in the amount of $18.2 million.

Changes in Accounting Standards

Asset Retirement Obligations

Effective January 1, 2004, the Company 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.

Risk Management and Success Factors

Reference is made to the "Risk Management and Success Factors" section of Management's Discussion and Analysis in Deer Creek's 2003 Annual Report. The nature of the Company's risk exposure and methods of managing risk remain substantially unchanged since December 31, 2003.

Outlook

Initial production from SAGD Phase I is expected during the third quarter of 2004 with production levels reaching 600 barrels per day over the subsequent 12 months.

During the remainder of 2004, the Company plans to finalize the engineering for SAGD Phase II and begin the process of procuring major equipment tenders. Construction contracts will also be awarded and site work will begin late in 2004.

Consolidated Balance Sheets

(Unaudited)

(thousands of dollars)	June 30 2004	December 31 2003
Assets		
Current assets		
Cash and cash equivalents	$ 24,838	$ 35,132
Accounts receivable	1,946	1,828
Prepaid expenses and deposits	233	114
	27,017	37,074
Abandonment deposits	578	426
Property, plant and equipment	52,416	28,370
	$ 80,011	$ 65,870
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 3,422	$ 6,552
Future income tax liability	2,958	3,314
Asset retirement obligations (note 2)	610	-
	6,990	9,866
Shareholders' equity		
Share capital (note 3)	60,452	61,677
Contributed surplus	26,948	7,882

Deficit	(14,379)	(13,555)
	73,021	56,004
	$ 80,011	$ 65,870

Contingencies and Commitments (note 5)

See accompanying notes to the consolidated financial statements

Consolidated Statements of Income and Deficit

(Unaudited)

(thousands of dollars except per share amounts)	Three months ended June 30 2004	Three months ended June 30 2003	Six months ended June 30 2004	Six months ended June 30 2003
		(restated - Note 1)		(restated - Note 1)
Revenue				
Interest and other	$ 158	$ 242	$ 418	$ 495
Expenses				
General and administrative	576	291	1,186	546
Amortization	18	6	30	10
	594	297	1,216	556
Income (loss) before Large Corporations Tax	(436)	(55)	(798)	(61)
Large Corporations Tax	14	22	26	44
Net income (loss)	(450)	(77)	(824)	(105)
Deficit, beginning of period	(13,929)	(13,267)	(13,555)	(13,239)
Deficit, end of period	$(14,379)	$(13,344)	$(14,379)	$(13,344)
Net income (loss) per common share (note 3) Basic and diluted	$ (0.02)	$ -	$ (0.03)	$ -

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

(Unaudited)

(thousands of dollars)	Three months ended June 30 2004	Three months ended June 30 2003 (restated - Note 1)	Six months ended June 30 2004	Six months ended June 30 2003 (restated - Note 1)
Operating activities				
Net income (loss)	$ (450)	$ (77)	$ (824)	$ (105)
Add (deduct) items not affecting cash:				
Stock-based compensation	105	94	422	176
Amortization	18	6	30	10
Funds provided by (used in) operations	(327)	23	(372)	81
Changes in non-cash working capital	(66)	(67)	102	(104)
	(393)	(44)	(270)	(23)
Investing activities				
Acquisition of property, plant and equipment	(2,856)	(1,175)	(23,225)	(9,119)
Abandonment deposit	(148)	(218)	(151)	(218)
Changes in non-cash working capital	(11,073)	(1,829)	(3,145)	665
	(14,077)	(3,222)	(26,521)	(8,672)
Financing activities				
Share issues, net of share issuance costs	-	-	16,647	-
Changes in non-cash working capital	(150)	-	(150)	(94)
	(150)	-	16,497	(94)
Increase (decrease) in cash and cash equivalents	(14,620)	(3,266)	(10,294)	(8,789)
Cash and cash equivalents, beginning of period	39,458	35,698	35,132	41,221
Cash and cash equivalents, end of period	$ 24,838	$ 32,432	$ 24,838	$ 32,432
Cash and cash equivalents is comprised of:				
Deposits with banks and others	$ 59	$ 1,437	$ 59	$ 1,437
Money market funds and bankers' acceptances	24,779	30,995	24,779	30,995
	$ 24,838	$ 32,432	$ 24,838	$ 32,432

See accompanying notes to the consolidated financial statements

Notes to the Consolidated Financial Statements - June 30, 2004

(Unaudited)
(tabular amounts in thousands of dollars except per share amounts and otherwise noted)

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1. Summary of Significant Accounting Policies

The interim consolidated financial statements of Deer Creek Energy Limited ("Deer Creek" or "the Company") 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.

The accounting policies applied are consistent with those outlined in the Company's annual consolidated financial statements for the fiscal year ended December 31, 2003. These consolidated financial statements for the six months ended June 30, 2004 do not include all disclosures required in the annual consolidated financial statements and should be read in conjunction with the audited consolidated financial statements included in Deer Creek's 2003 Annual Report.

Certain comparative figures have been reclassified to conform with current financial statement presentation.

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 stock option or performance 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.

The adoption of this recommendation decreased the net income for the six months ended June 30, 2003 by $0.1 million.

Asset Retirement Obligation

Effective January 1, 2004, Deer Creek adopted, retroactively without restatement, 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.

2. Asset Retirement Obligations

	Amount
Balance, December 31, 2003	$ -
Liabilities incurred	586
Accretion	24
Balance, June 30, 2004	$ 610

The estimated undiscounted amount of the asset retirement obligations is $1.3 million and has been discounted at rates between 5.9 percent and 7.2 percent. The costs are expected to be incurred between 2008 and 2040.

3. 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, 2003	27,573	$ 59,742
Issued for cash	2,020	17,675
Conversion of special warrants	305	1,935
Issue costs, net of tax		(672)
Stated capital reduction		(18,228)
June 30, 2004	29,898	$ 60,452

On January 28, 2004, the Company closed a private placement of 2,020,000 common shares at a price of $8.75 per common share for total gross proceeds of $17.7 million.

On May 20, 2004, the shareholders of the Company approved a special resolution to reduce the stated capital of the common shares, pursuant to the Business Corporations Act (Alberta), in the aggregate amount of $18.2 million and to contribute such amount to the Company's contributed surplus. The shareholders of the Company also approved a special resolution consolidating the outstanding common shares on a five for one basis, effective June 1, 2004.

At June 30, 2004, there were 2,989,800 common shares reserved for issuance under the Stock Option and Performance Share Unit Plans.

Subsequent to June 30, 2004, the Company closed an initial public offering (see Note 6).

Performance Share Units

The Company has a performance share unit plan under which directors, employees and select providers of services of the Company are eligible to receive grants.

	Number (thousands)	Exercise Price ($/unit)
Outstanding, December 31, 2003	76	$ 0.05
Granted	95	0.05
Outstanding, June 30, 2004	171	$ 0.05
Exercisable, June 30, 2004	104	$ 0.05

For the six months ended June 30, 2004, compensation cost of $0.4 million for performance share units granted has been credited to contributed surplus.

Stock Options

The Company has a stock option plan under which directors, employees and select providers of services of the Company are eligible to receive grants.

	Number (thousands)	Weighted Average Exercise Price ($/option)
Outstanding, December 31, 2003	1,582	$ 4.40
Granted	767	8.73
Outstanding, June 30, 2004	2,349	$ 5.81
Exercisable, June 30, 2004	1,091	$ 4.80

For the six months ended June 30, 2004, compensation cost of $0.5 million has been recognized 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:

	Three months ended June 30		Six months ended June 30	
	2004	2003	2004	2003
Net income (loss)				

As reported	$ (450)	$ (77)	$ (824)	$ (105)
Less fair value of stock options	19	19	37	36
Pro forma	$ (469)	$ (96)	$ (861)	$ (141)
Basic and diluted net income (loss) per share				
As reported	$ (0.02)	$ -	$ (0.03)	$ -
Pro forma	$ (0.02)	$ -	$ (0.03)	$ -

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:

	June 30 2004
Weighted average fair value ($/option)	$ 2.08
Risk free interest rate, average for the period (percent)	4.1
Expected life (in years)	7

Earnings per share

Basic and diluted net income (loss) per share has been calculated using the weighted average number of common shares outstanding during the period of 29,811,824 (26,331,400 in 2003). The calculation of diluted net income (loss) per share does not include stock options or performance share units as the effect would be anti-dilutive.

4. 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 (see Note 6).

5. Contingencies and Commitments

Joslyn Project Development

The Company has agreements with Talisman Energy Inc. (the "Talisman Agreement") and EnerMark Inc. ("EnerMark") related to the development of the Joslyn Project. Details of these agreements are provided in Note 5 to the annual consolidated financial statements for the fiscal year ended December 31, 2003.

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:

June 30 December 31

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

Contingent interest payment:		
Deer Creek	$ 5,609	$ 5,258
EnerMark	1,069	1,002
	$ 6,678	$ 6,260

As at June 30, 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.

6. Subsequent Events

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 for total gross proceeds of $160.0 million.

This initial offering closed on July 29, 2004 and shares of the Company began trading on the Toronto Stock Exchange.

On July 22, 2004, Deer Creek entered into an agreement with two Canadian chartered banks for a committed credit facility of $65.0 million. The $6.0 million existing credit facility was cancelled upon entering into the new credit facility agreement.

Deer Creek is a Calgary-based oil sands company engaged in the development of its Athabasca oil sands deposits through SAGD and mining extraction methods. The Company 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. Deer Creek has an 84% working interest in and is operator of the Joslyn Project.

Certain statements contained in this document are "forward-looking statements". The projections, estimates and beliefs contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results or events to differ materially from those anticipated in any forward-looking statements. Deer Creek believes the expectations reflected in those forward-looking statements are reasonable; however Deer Creek cannot provide any assurance that these expectations will prove to be correct.

All reference to the Joslyn Project are gross numbers unless otherwise noted.

Trading Symbol - TSX: DCE

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%SEDAR: 00010187E

/For further information: Deer Creek Energy Limited, Mr. Glen C. Schmidt, President & CEO or Mr. John S. Kowal, VP Finance & CFO, at (403) 264-3777, (403) 264-3700 (fax), E-mail: deercrk(at)deercreekenergy.com; Website: www.deercreekenergy.com/
(DCE.)

CO: Deer Creek Energy Limited

CNW 08:01e 10-AUG-04

News release via Canada NewsWire, Calgary 403-269-7605

Attention Business Editors:
Deer Creek Energy Limited (TSX:DCE) Announces a Joslyn Project Update and Accelerated Capital Spending

Joslyn Project Update

CALGARY, Sept. 14 /CNW/ - Deer Creek Energy Limited is pleased to announce it has ordered the major equipment for the central processing facility of its 10,000 barrel of bitumen per day SAGD Phase II expansion of the Joslyn Project. The Joslyn Project is a steam assisted gravity drainage (SAGD) and mining oil sands development located north of Fort McMurray, Alberta. A definitive cost estimate for the facility has been completed and by the end of September, upwards of 70% of the facility engineering will be finished. The overall SAGD Phase II cost estimate remains at $171 million as previously reported. Clearing of the facility site has commenced and construction contracts are being awarded.

The central facility will include steam generation, water and oil treating equipment. Deer Creek has chosen to utilize an evaporative based water treatment process for this expansion of the project. The evaporator process allows for incorporation of higher efficiency boilers for steam generation and has a proven performance record in North America. This process is expected to increase reliability and reduce operating costs compared to warm lime water treatment processes previously installed in other SAGD operations.

Deer Creek is also pleased to announce the signing of an agreement with Ensign Resource Service Group Inc. to drill the 17 well pairs required for the SAGD Phase II expansion. This commitment will allow Ensign to construct a specialized slant hole rig designed to efficiently drill SAGD well pairs. Construction of the rig will begin shortly and will be available for drilling operations after the spring of 2005.

Progress on the SAGD Phase I of the Joslyn Project is continuing and the dual well pair has recently been converted to production mode. Steaming of the reservoir and circulation performance have been as expected.

Accelerated Capital Spending

With the closing of Deer Creek's initial public offering and credit facility in July, all major regulatory approvals in place, and the completion of the definitive facility cost estimate, Deer Creek has the opportunity to accelerate its capital program for the development of its oil sands assets. Budgeted capital expenditures for 2004 have been increased to $45 million from the previously announced $32 million.

"Deer Creek is at a major project milestone," stated Mr. Mark Montemurro, Vice President, Thermal. "With the definitive facility cost estimate and major equipment ordered, Deer Creek is well on schedule for our goal of SAGD Phase II start-up by mid 2006."

Deer Creek is a publicly traded, (TSX:DCE), Calgary-based oil sands company engaged in the development of its Athabasca oil sands deposits through SAGD and mining extraction methods. The Company 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. Deer Creek has an 84% working interest in and is operator of the Joslyn Project.

All reference to the Joslyn Project are gross numbers unless otherwise noted.

Certain statements contained in this document are "forward-looking statements." The projections, estimates and beliefs contained in such forward-looking statements involve known and unknown risks, uncertainties and other factors which may cause actual results or events to differ materially from those anticipated in any forward-looking statements. Deer Creek believes the expectations reflected in those forward-looking statements are reasonable; however Deer Creek cannot provide any assurance that these expectations will prove to be correct.

Trading Symbol - TSX: DCE
%SEDAR: 00010187E

/For further information: please contact Deer Creek Energy Limited, Mr. Glen C. Schmidt, President & CEO or Mr. John S. Kowal, VP Finance & CFO at (403) 264-3777, (403) 264-3700 (fax), E-mail: deercrk(at)deercreekenergy.com, Website: www.deercreekenergy.com/
(DCE.)

CO: Deer Creek Energy Limited

CNW 18:14e 14-SEP-04

News release via Canada NewsWire, Calgary 403-269-7605

Attention Business/Financial Editors:
Deer Creek Announces Third Quarter 2004 Financial and Operating Results

CALGARY, Nov. 10 /CNW/ - Deer Creek Energy Limited (TSX:DCE) announced today its financial and operating results for the quarter ended September 30, 2004.

First bitumen production from SAGD Phase I and acceleration of SAGD Phase II deliver positive results and steady progress

Quarterly Highlights

- Completed financings totaling $225 million and began trading on the TSX
- SAGD Phase I well pair on production
- Accelerated SAGD Phase II capital spending and project schedule
- Advanced the design for SAGD Phase III in two parts
- Subsequent to the third quarter, Deer Creek:
  - Awarded engineering services contract for the mining project
  - Approved a 2005 net capital program totaling $146 million

On July 29, Deer Creek commenced trading on the Toronto Stock Exchange under the trading symbol "DCE" with the successful closing of its initial public offering for 16.9 million common shares at $9.50 per common share. In addition, the Company entered into a committed credit facility of $65 million with two Canadian chartered banks. These financings, totaling $225 million, support Deer Creek's commercial development of the Joslyn Project.

As planned, the SAGD Phase I well pair was completed for production in mid-September. The average field production during the month of October was approximately 125 barrels of bitumen per day, in line with expectations. The ramp-up to the full production rate of 600 barrels of bitumen per day is expected to occur linearly over the next 12 months.

The steam-oil-ratio in the first six weeks of production has consistently declined over the period to reach 3.5 at the end of October and averaged 3.7 for the month. The steam-oil-ratio is currently better than the expected range of 6 to 7 at this point of the well life. The original Joslyn Pilot Project well pair in 2001 tested at a steam-oil-ratio of 2.4 when shut-in and continues to support the expected production profile. Additionally, the level of water loss to the reservoir is corresponding to forecast. Deer Creek is pleased the well is performing as expected.

During the quarter, Deer Creek accelerated its capital program for SAGD Phase II, which is expected to produce 10,000 barrels of bitumen per day. As a result, the project schedule for SAGD Phase II has been advanced up to six months sooner than previously forecast with first steam now expected early 2006. Progress in the quarter included ordering all of the major equipment for the central processing facility, completion of site access and clearing of the facility site as well as completion of a drilling rig commitment. As of the end of September, more than 70% of the facility engineering has been complete. On-site foundation construction is scheduled to begin in early 2005.

Deer Creek is also pleased to announce the decision to accelerate the growth of the Joslyn Project and advance SAGD Phase III in two parts. The first approximate 15,000 barrels of bitumen per day expansion (SAGD Phase IIIA) is expected to begin steaming operations in late 2007, closely followed by a second expansion of approximately 15,000 barrels of bitumen per day (SAGD Phase IIIB) scheduled for first steam in 2009. Deer Creek anticipates filing the regulatory application for SAGD Phase IIIA in the first quarter of 2005. This optimized plan allows Deer Creek to develop its SAGD opportunities earlier than originally planned with less execution and cost risk, due to its smaller project size and complexity. In addition, this allows SAGD and mining synergies to be explored by designing SAGD Phase IIIB concurrently with the first two phases of the mining development.

Subsequent to quarter end, Deer Creek awarded a major engineering contract to AMEC Americas Ltd. to supply engineering support services for the completion of a regulatory application for the first two phases of the Joslyn mining development for total approved production of 100,000 barrels of bitumen per day. Deer Creek intends to file the regulatory application in late 2005 or early 2006 in combination with SAGD Phase IIIB. Deer Creek's portion of contracts currently entered into for the mining development total approximately $30 million in engineering and environmental commitments and $20 million in resource delineation over the next 3 year period, at which time regulatory approval is expected to be received.

With these objectives, the board of directors approved a net capital program totaling approximately $146 million for 2005. The capital program advances approximately $40 million of expenditures originally planned in 2006 and reflects the previously announced acceleration of SAGD Phase II.

The focus of the majority of the 2005 capital program will be on SAGD Phase II where Deer Creek will invest approximately $118 million primarily on facilities completion and the initial drilling program. The overall SAGD Phase II cost estimate is projected to be $149 million net to Deer Creek and is within 4% of previously reported estimates. Deer Creek's SAGD Phase IIIA and mining expenditures, totaling $8 million, will continue to advance these phases through regulatory application and support engineering and technical studies.

In 2005, Deer Creek's net core-hole program expense is expected to be $12 million, split approximately 40% to the SAGD and 60% to the mining areas. Deer Creek expects to drill more than 250 gross delineation wells which will increase the Joslyn well database to more than 800 wells.

The balance of the capital program supports general corporate studies and initiatives.

2004 Outlook

- Advance SAGD Phase II design and construction
- Prepare for the 2005 winter core-hole program of more than 250 wells
- Advance SAGD Phase IIIA regulatory application

Deer Creek will focus the balance of 2004 on preparing for site construction and installation for SAGD Phase II and an active winter core-hole drilling program. Work will continue on the regulatory application for SAGD Phase IIIA with the preparation of environmental reports. Significant progress on the regulatory application is expected to be made to achieve a target filing date of the first quarter of 2005. Deer Creek's primary goal is to deliver on our plans as scheduled and within budget. The results for 2004 to date have delivered on that goal successfully.

A conference call has been scheduled for 2:30 p.m. MST (4:30 p.m. EST) on November 11, 2004 to discuss Deer Creek's third quarter financial and operating results. To participate in the conference call please dial 1-416-640-4127 or toll-free 1-800-814-4860. An archived recording of the conference call will be available until Thursday, November 18, 2004 by dialing 1-416-640-1917 or 1-877-289-8525 and entering pass code 210999220 followed by the pound key.

Management's Discussion and Analysis

The Management's Discussion and Analysis for Deer Creek Energy Limited ("Deer Creek" or the "Company") should be read in conjunction with the accompanying unaudited interim consolidated financial statements and accompanying notes for the nine months ended September 30, 2004 and the audited consolidated financial statements and the Management's Discussion and Analysis contained in the Company's annual report for the year ended December 31, 2003. Additional information relating to Deer Creek is available on the SEDAR website at www.sedar.com. This Management's Discussion and Analysis is dated November 10, 2004.

The following information offers Management's analysis of the financial and operating results of the Company and may contain forward-looking statements that are based on estimates and assumptions that are subject to uncertainties. Actual results or events may vary materially from those anticipated.

Results of Operations

Joslyn Project (oil sands lease 24 and permit 70)

The SAGD Phase I facility was successfully completed in the first quarter of 2004, on schedule and under budget. Steam injection and circulation of the SAGD Phase I well pair began in early April and continued throughout the second quarter of 2004. During the third quarter of 2004, the well pair was converted to production mode. During this pre-commercial phase of the initial SAGD development, all net revenue and operating costs will be capitalized.

Subsequent to receiving approval from the Alberta Energy and Utilities Board and Alberta Environment for SAGD Phase II, a 10,000 barrels of bitumen per day expansion, the Company has made significant commitments for major equipment, including steam generators, water treatment and oil treating. Facility engineering for SAGD Phase II has advanced to approximately 70%. SAGD Phase II site construction and access commenced in October 2004.

Deer Creek has completed the oil sands exploration permitting for its 2005 winter core-hole program. It is anticipated that more than 250 new core-holes will be drilled during the winter season.

Net Additions to Property, Plant and Equipment

Core-hole drilling, development and construction activities have been conducted under a joint venture agreement with EnerMark Inc. ("EnerMark").

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	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	2004	2003	2004	2003
Joslyn Project, net				
Project delineation	588	610	8,900	6,094
SAGD Phase I	906	2,833	10,250	4,757
SAGD Phase II and III	4,628	637	7,860	1,785
SAGD Operations	1,493	-	2,293	-
Mining	209	77	311	91
Other	617	247	1,033	510
Asset retirement obligations	10	-	620	-
Capitalized general and administration	738	194	1,722	554
Project costs	9,189	4,598	32,989	13,791
Office equipment	(40)	40	236	57
Net additions to property, plant and equipment	9,149	4,638	33,225	13,848

For the three months ended September 30, 2004, net capital expenditures (excluding non-cash items such as asset retirement obligations and capitalized stock-based compensation) were primarily incurred for the engineering costs and the initial procurement of major equipment related to SAGD Phase II of the Joslyn Project.

During the nine months ended September 30, 2004, the Company has incurred capital expenditures primarily for the construction and operation of the SAGD Phase I facility, gathering and steam injection system, completion and equipping of the SAGD well pair and for the 2004 winter core-hole drilling and seismic program. Deer Creek completed a design base memorandum on the SAGD Phase II facility, gathering and steam injection system and the surface equipment and has proceeded to make commitments for major equipment of this phase of development.

Net capital expenditures, expected to be approximately $15.0 million for the remainder of 2004, are focused primarily on continuing the acceleration of SAGD Phase II, mine engineering and studies to support a regulatory application in late 2005 or early 2006, and studies to identify synergies between mining and SAGD operations. The Company 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.

Financial Results

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	2004	2003	2004	2003
Interest income and other revenue	656	240	1,074	735
General and administrative expenses, net	819	248	2,005	794
Net income (loss)	(458)	(45)	(1,282)	(150)

Interest Income and Other Revenue

Interest income and other revenue is related to interest earned on cash invested in interest bearing instruments held during the periods. Interest income and other revenue is higher for the three and nine month periods ended September 30, 2004 when compared to the same periods of 2003 due to higher average investment balances resulting from the proceeds of Deer Creek's initial public offering which closed in late July 2004.

General and Administrative Expenses

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	2004	2003	2004	2003
General and administrative expenses, gross	1,583	492	3,606	1,379
Joint venture recoveries	(259)	(82)	(578)	(221)
	1,324	410	3,028	1,158
Stock option compensation costs	233	32	699	190
Capitalized costs	(738)	(194)	(1,722)	(554)
General and administrative expenses, net	819	248	2,005	794

The increase in gross general and administrative expenses from the prior year was due to a higher level of activity related to the progression of the Company and the advancement of the Joslyn Project which has resulted in higher employee, consulting and information services costs. During the first nine months of 2004, seven employees have joined Deer Creek in planned positions bringing the total number of employees to 24 as at September 30, 2004.

Net general and administrative expenses increased $0.6 million for the three months ended September 30, 2004 compared to the three months ended September 30, 2003 and $1.2 million for the first nine months of 2004 compared to the first nine months of 2003. These increases were primarily due to an increase in the number of employees, the recording of stock-based compensation for 2003 and 2004 stock option awards and employee costs related to the initial public offering. Deer Creek's general and administrative expenses are expected to increase as the Joslyn Project advances.

For 2004, the gross general and administrative expenses are expected to be approximately $5.1 million. A portion of these expenditures will be offset by EnerMark's 16% share pursuant to the joint venture agreement and a portion will be capitalized. Deer Creek's stock option compensation costs are expected to be approximately $0.9 million for 2004.

Amortization

Amortization increased in the three months ended September 30, 2004 when compared to prior quarters due to the amortization of deferred financing charges related to the Company's $65.0 million credit facility. These costs will be amortized over the five year term of the credit facility.

Net Income (Loss)

The net loss increased by $0.4 million and $1.1 million for the three and nine months ended September 30, 2004, respectively, when compared to the same periods of 2003. The increases were due to increased general and administrative expenses associated with advancing the development of the Joslyn Project, offset by an increase in interest income earned on investments.

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 of the Joslyn Project will be capitalized and amortized over the expected life of the associated reserves.

Income Taxes

Large Corporations Tax increased to $0.3 million in the first nine months of 2004 from $0.1 million for the same period in 2003 due to an increase in the capital tax base resulting from the issuance of capital through the initial public offering, offset by the decrease in the statutory rate and the increase in the allowable capital deduction.

Quarterly Information

($ thousands, except per share amounts)	Q3 04	Q2 04	Q1 04	Q4 03	Q3 03	Q2 03	Q1 03	Q4 02
Net additions to property, plant and equipment	9,149	2,980	21,096	5,988	4,638	1,240	7,970	1,833

Interest and other revenue	656	158	260	235	240	242	253	217
Net loss	(458)	(450)	(374)	(166)	(45)	(77)	(28)	(45)
Net loss per share (basic and diluted)(1)	(0.01)	(0.02)	(0.01)	-	-	-	-	(0.01)

(1) restated for the consolidation of common shares on a five for one basis

Drilling activity for the purpose of delineating the lease occurs during the winter season with analysis of the data occurring during the following six months.

Net loss increased in the first quarter of 2004 and the fourth quarter of 2003 as a result of recording performance related expenses. In the fourth quarter of 2003, the Company 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.

Liquidity

Working Capital

Working capital surplus increased $134.0 million during the first nine months of 2004. This increase is primarily due to net proceeds from the initial public offering and the January 28, 2004 common share issuance offset by capital expenditures for the development of the Joslyn Project.

($ thousands)	
Working capital, December 31, 2003	30,522
Share issuance proceeds, net of costs	167,751
Capital expenditures	(32,152)
Deferred financing charges	(963)
Funds used in operations	(630)
Other	39
Working capital, September 30, 2004	164,567

The working capital surplus at September 30, 2004 will fund the 2004 expected remaining capital expenditures, general and administrative expenses and operating costs for SAGD Phase I, and is sufficient to complete the construction of SAGD Phase II, and the planned 2005 regulatory and engineering costs for SAGD Phase IIIA and the mine project.

Capital Resources

Equity Financing

On January 28, 2004, the Company closed a private placement of 2,020,000 common shares at a price of $8.75 per common share for total gross proceeds of $17.7 million. Proceeds from this share issuance are intended for future development of the Joslyn Project.

On July 29, 2004, the Company closed its initial public offering for 16,900,000 common shares at a price of $9.50 per common share. The gross proceeds of $160.6 million are to be used to complete SAGD Phase II, as well as certain additional work necessary to advance the development of future phases of the Joslyn Project.

Credit Facility

On July 22, 2004, the Company entered into an agreement with two Canadian chartered banks for a committed credit facility of $65.0 million. The new credit facility will assist in funding SAGD Phase II and provide incremental working capital to the Company to support the regulatory, engineering design and environmental work related to additional expansions of the Joslyn Project and other related expenses. At September 30, 2004, no funds had been advanced under this credit facility.

Commitments

The Company has entered into certain commitments for equipment and engineering services for SAGD Phase II approximating $20.7 million representing the Company's share of commitments. These commitments will be realized over time as work is completed.

All other commitments are set forth in Note 5 of the accompanying notes to the unaudited consolidated financial statements and in Note 5 of the audited consolidated financial statements for the year ended December 31, 2003.

Outstanding Share Data

At October 31, 2004, share capital consists of the following:

(thousands)	
Issued and outstanding	
Common shares	46,798
Stock options	2,310
Performance share units (formerly stock rights)	171
Fully diluted number of shares	49,279

Changes in Accounting Standards and Estimates

Asset Retirement Obligations

Effective January 1, 2004, the Company 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.

Risk Management and Success Factors

Reference is made to the "Risk Management and Success Factors" section of Management's Discussion and Analysis in Deer Creek's 2003 Annual Report. The nature of the Company's risk exposure and methods of managing risk remain substantially unchanged since December 31, 2003.

Outlook

Production levels from SAGD Phase I are expected to reach 600 barrels per day within the subsequent 12 months.

During the remainder of 2004, the Company plans to finalize the engineering for SAGD Phase II and continue procuring major equipment components. On-site installation of equipment is scheduled to begin in early 2005. Contracts to provide engineering services for the mine project regulatory process will be completed to allow filing for the first 100,000 barrels of bitumen per day in late 2005 or early 2006. These contracts will provide for engineering services through 2007 when mine regulatory approval is expected.

Consolidated Balance Sheets

(Unaudited)

(thousands of dollars)	September 30 2004	December 31 2003
Assets		
Current assets		
Cash and cash equivalents	$ 171,798	$ 35,132
Accounts receivable	1,520	1,828
Prepaid expenses and deposits	185	114
	173,503	37,074
Abandonment deposits	584	426
Deferred charges	931	-
Property, plant and equipment	61,542	28,370
	$ 236,560	$ 65,870
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 8,936	$ 6,552
Future income tax liability	-	3,314
Asset retirement obligations (note 2)	620	-
	9,556	9,866
Shareholders' equity		
Share capital (note 3)	214,514	61,677
Contributed surplus	27,327	7,882
Deficit	(14,837)	(13,555)
	227,004	56,004
	$ 236,560	$ 65,870

Contingencies and Commitments (note 5)

See accompanying notes to the consolidated financial statements

Consolidated Statements of Income and Deficit

(Unaudited)

(thousands of dollars except per share amounts)	Three months ended September 30 2004	Three months ended September 30 2003	Nine months ended September 30 2004	Nine months ended September 30 2003
		(restated - Note 1)		(restated - Note 1)
Revenue				
Interest and other	$ 656	$ 240	$ 1,074	$ 735
Expenses				
General and administrative	819	248	2,005	794
Amortization	55	14	85	24
	874	262	2,090	818
Income (loss) before Large Corporations Tax	(218)	(22)	(1,016)	(83)
Large Corporations Tax	240	23	266	67
Net income (loss)	(458)	(45)	(1,282)	(150)
Deficit, beginning of period	(14,379)	(13,344)	(13,555)	(13,239)
Deficit, end of period	$ (14,837)	$ (13,389)	$ (14,837)	$ (13,389)
Net income (loss) per common share (note 3) Basic and diluted	$ (0.01)	$ -	$ (0.04)	$ -

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

(Unaudited)

(thousands of dollars)	Three months ended September 30 2004	Three months ended September 30 2003	Nine months ended September 30 2004	Nine months ended September 30 2003

		(restated - Note 1)		(restated - Note 1)
Operating activities				
Net income (loss)	$ (458)	$ (45)	$ (1,282)	$ (150)
Add (deduct) items not affecting cash:				
Stock-based compensation	145	67	567	243
Amortization	55	14	85	24
Funds provided by (used in) operations	(258)	36	(630)	117
Changes in non-cash working capital	223	(205)	325	(309)
	(35)	(169)	(305)	(192)
Investing activities				
Acquisition of property, plant and equipment	(8,927)	(4,612)	(32,152)	(13,731)
Abandonment deposit	(7)	(6)	(158)	(224)
Changes in non-cash working capital	5,466	1,917	2,321	2,582
	(3,468)	(2,701)	(29,989)	(11,373)
Financing activities				
Share issues, net of share issuance costs	151,104	209	167,751	209
Deferred charges	(963)	-	(963)	-
Changes in non-cash working capital	322	-	172	(94)
	150,463	209	166,960	115
Increase (decrease) in cash and cash equivalents	146,960	(2,661)	136,666	(11,450)
Cash and cash equivalents, beginning of period	24,838	32,432	35,132	41,221
Cash and cash equivalents, end of period	$ 171,798	$ 29,771	$ 171,798	$ 29,771
Cash and cash equivalents is comprised of:				
Deposits with banks and others	$ 120	$ 1,142	$ 120	$ 1,142
Interest bearing instruments	171,678	28,629	171,678	28,629
	$ 171,798	$ 29,771	$ 171,798	$ 29,771

See accompanying notes to the consolidated financial statements

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1. Summary of Significant Accounting Policies

The interim consolidated financial statements of Deer Creek Energy Limited ("Deer Creek" or the "Company") 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.

The accounting policies applied are consistent with those outlined in the Company's annual consolidated financial statements for the fiscal year ended December 31, 2003. These consolidated financial statements for the nine months ended September 30, 2004 do not include all disclosures required in the annual consolidated financial statements and should be read in conjunction with the audited consolidated financial statements included in Deer Creek's 2003 Annual Report.

Certain comparative figures have been reclassified to conform with current financial statement presentation.

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 stock option or performance 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.

The adoption of this recommendation decreased the net income for the nine months ended September 30, 2003 by $0.1 million.

Asset Retirement Obligation

Effective January 1, 2004, Deer Creek adopted, retroactively without restatement, 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 material effect on the Company's prior year consolidated financial statements as substantially all of the Company's obligations with respect to 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.

Property, plant and equipment

Interest and standby charges in relation to the credit facility are capitalized until commercial activities commence.

2. Asset Retirement Obligations

	Amount
Balance, December 31, 2003	$ -
Liabilities incurred	586
Accretion	34
Balance, September 30, 2004	$ 620

The estimated undiscounted amount of the asset retirement obligations is $1.3 million and has been discounted at rates between 5.9 percent and 7.2 percent. The costs are expected to be incurred between 2008 and 2040.

3. 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, 2003	27,573	$ 59,742
Issued for cash	18,920	178,225
Conversion of special warrants	305	1,935
Issue costs, net of tax		(7,160)
Stated capital reduction		(18,228)
September 30, 2004	46,798	$ 214,514

On January 28, 2004, the Company closed a private placement of 2,020,000 common shares at a price of $8.75 per common share for total gross proceeds of $17.7 million.

On May 20, 2004, the shareholders of the Company approved a special resolution to reduce the stated capital of the common shares, pursuant to the Business Corporations Act (Alberta), in the aggregate amount of $18.2 million and to contribute such amount to the Company's contributed surplus. The shareholders of the Company also approved a special resolution consolidating the outstanding common shares on a five for one basis, effective June 1, 2004.

On July 29, 2004, the Company closed an initial offering of 16,900,000 common shares at $9.50 per common share for total gross proceeds of $160.6 million. The shares of Deer Creek immediately began trading on the Toronto Stock Exchange under the symbol DCE.

At September 30, 2004, there were 4,679,845 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, employees and select providers of services of the Company are eligible to receive grants.

	Number (thousands)	Exercise Price ($/unit)
Outstanding, December 31, 2003	76	$ 0.05
Granted	95	0.05
Outstanding, September 30, 2004	171	$ 0.05
Exercisable, September 30, 2004	104	$ 0.05

For the nine months ended September 30, 2004, compensation cost of $0.5 million for performance share units granted has been credited to contributed surplus.

Stock Options

The Company has a stock option plan under which directors, employees and select providers of services of the Company are eligible to receive grants.

	Number (thousands)	Weighted Average Exercise Price ($/option)
Outstanding, December 31, 2003	1,582	$ 4.40
Granted	728	8.73
Outstanding, September 30, 2004	2,310	$ 5.76
Exercisable, September 30, 2004	1,275	$ 4.90

For the nine months ended September 30, 2004, compensation cost of $0.7 million has been recognized 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:

	Three months ended September 30 2004	2003	Nine months ended September 30 2004	2003
Net income (loss)				
As reported	$ (458)	$ (45)	$ (1,282)	$ (150)
Less fair value of stock options	19	20	56	56
Pro forma	$ (477)	$ (65)	$ (1,338)	$ (206)
Basic and diluted net income (loss) per share				
As reported	$ (0.01)	$ -	$ (0.04)	$ -
Pro forma	$ (0.01)	$ -	$ (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:

	September 30 2004
Expected volatility (percent)	30.0
Risk free interest rate, average for the period (percent)	4.4
Expected life (in years)	7

Earnings per share

Basic and diluted net income (loss) per share has been calculated using the weighted average number of common shares outstanding during the nine months ended September 30, 2004 of 33,509,286 (26,378,800 in 2003) and 41,654,980 for the three months ended September 30, 2004 (26,389,200 in 2003). The calculation of diluted net income (loss) per share does not include stock options or performance share units as the effect would be anti-dilutive.

4. Credit Facility

On July 22, 2004, Deer Creek entered into an agreement with two Canadian chartered banks for a committed credit facility of $65.0 million. The lenders have a charge over all the assets of Deer Creek to secure the credit facility and will rank pari passu with Talisman over Deer Creek's right, title, estate and interest in the Joslyn Lease. As at September 30, 2004, no amounts had been advanced under this credit facility. Fees incurred in relation to the credit facility are included in deferred financing charges and will be amortized over the term of the agreement which expires on June 30, 2009. Standby fees of $0.1 million in relation to the credit facility have been capitalized during the nine and three month periods ended September 30, 2004.

5. Contingencies and Commitments

Joslyn Project Development

The Company has agreements with Talisman Energy Inc. (the "Talisman Agreement") and EnerMark Inc. ("EnerMark") related to the development of the Joslyn Project. Details of these agreements are provided in Note 5 to the annual consolidated financial statements for the fiscal year ended December 31, 2003.

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:

	September 30 2004	December 31 2003
Contingent production payment:		
Deer Creek	$ 17,640	$ 17,640
EnerMark	3,360	3,360
	$ 21,000	$ 21,000
Contingent interest payment:		
Deer Creek	$ 5,779	$ 5,258
EnerMark	1,101	1,002
	$ 6,880	$ 6,260

As at September 30, 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.

Deer Creek is a Calgary-based oil sands company engaged in the development of its Athabasca oil sands deposits through SAGD and mining extraction methods. The Company 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. Deer Creek has an 84% working interest in and is operator of the Joslyn Project.

This report contains certain "forward-looking statements" within the meaning of such statements under applicable securities law. Forward-looking statements are frequently characterized by words such as "plan", "expect", "estimate", "believe" and other similar words, or statements that certain events or conditions "may" or "will" occur. By their nature, forward-looking statements involve assumptions and are subject to a variety of risks and uncertainties, including, but not limited to, those associated with resource definition, the timeline to production, the possibility of project cost overruns or unanticipated costs and expenses, regulatory approvals, fluctuating oil and gas prices, and the ability to access sufficient capital to finance future development. Although the Company believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct.

Deer Creek does not undertake any obligation to update publicly or to revise any of the included forward-looking statements as a result of new information, future events or otherwise, subsequent to the date of this report. The reader is cautioned not to place undue reliance on forward-looking statements.

All reference to the Joslyn Project are gross numbers unless otherwise noted.

Trading Symbol - TSX: DCE

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%SEDAR: 00010187E

/For further information: Deer Creek Energy Limited, Mr. Glen C. Schmidt, President & CEO or Mr. John S. Kowal, VP Finance & CFO at (403) 264-3777, (403) 264-3700 (fax), E-mail: deercrk(at)deercreekenergy.com, Website: www.deercreekenergy.com/
(DCE.)

CO: Deer Creek Energy Limited

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AS AT NOVEMBER 15, 2004, NO DOCUMENT HAS BEEN FILED BY DEER CREEK ENERGY LIMITED UNDER THIS TAB

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DEER CREEK
Energy Limited

Building a Pure Oil Sands Company

ONE STEP AT A TIME

For the 6 months ended June 30, 2004

Continued progress on the Joslyn Project positioned Deer Creek's successful initial public offering

This is Deer Creek's first quarterly report as a public company following the closing of its initial public offering ("IPO") on July 29, 2004 and listing on the Toronto Stock Exchange ("TSX").

Quarterly Highlights

- Start up of SAGD Phase I facility and steaming of initial well pair
- Completed design base memorandum for SAGD Phase II
- Received AEUB approval of SAGD Phase II
- Expanded thermal and mining teams
- Filed public disclosure documents and terms of reference for SAGD Phase III and first two mine phases
- Subsequent to the second quarter, Deer Creek:
    - Completed a $160.6 million IPO and began trading on the TSX
    - Secured a $65.0 million committed credit facility
    - Received Alberta Environment approval for SAGD Phase II

Deer Creek's operational plans for 2004 are firmly on track and are supported by the successful closing of its IPO.

Steaming of the SAGD Phase I well pair began in April, 2004 and circulation performance is as expected. Deer Creek anticipates change over from steam circulation mode to production mode to occur during the third quarter. Production response from the well is forecasted to ramp up over the next 12 months and reach its peak rate of approximately 600 barrels of bitumen per day by mid 2005.

Early in the quarter, the Company completed a design base memorandum on the facility, gathering and steam injection system plus the well pad surface equipment for SAGD Phase II. The gross cost estimate, including wells and well pads and contingencies is projected to be approximately $171 million.

In May 2004, Deer Creek received approval from the Alberta Energy and Utilities Board for the 10,000 barrels of bitumen per day SAGD Phase II expansion. This is a significant milestone for Deer Creek. The approval is a result of a comprehensive process including environmental assessment, detailed technical design, regulatory review and stakeholder consultation. Subsequently, Deer Creek's board of directors and its joint venture partner, EnerMark Inc., a wholly owned subsidiary of Enerplus Resources Fund, approved going forward with the commercial development.

During the quarter, work continued on advancing future phases of the Joslyn Project. The Company submitted a public disclosure document, which marks the first step in the regulatory process, for the 30,000 barrels of bitumen per day SAGD Phase III expansion and the first 100,000 barrels of bitumen per day mining development. Deer Creek plans to submit an application for regulatory approval of the SAGD Phase III project in early 2005 and the first two mine phases in late 2005 or early 2006. To support the applications, an environmental impact assessment report will be prepared together with the conceptual engineering design, business analysis and socio-economic assessment. A companion document containing the proposed terms of reference for the environmental impact assessment report required for the SAGD Phase III and the mining developments has also been prepared to initiate the regulatory process.

Deer Creek also expanded its management team with three additions to its mining and thermal areas during the second quarter. These additions will greatly assist the Company as it expands operations and implements *its plan of developing a world class growth opportunity in the Athabasca oil sands.* Current staffing consists of 23 employees in the Calgary office and a total of 12 employees and contract operators located in Fort McMurray.

In June, Deer Creek commenced activities for the IPO of its common shares. Subsequent to the quarter end, the Company successfully completed these financing activities raising gross proceeds of $225.6 million through a $65.0 million committed credit facility from two Canadian chartered banks and a $160.6 million IPO.

These financings signify the beginning of the next stage in Deer Creek's evolution and fully fund the Company's initial commercial operations.

2004 Outlook

- Change over SAGD Phase I well pair to production mode
- Advance engineering and initiate procurement of major equipment for SAGD Phase II
- Award construction contracts and commence site construction of SAGD Phase II
- Complete licensing applications for the 2005 winter core-hole program of approximately 200 wells

Success from implementing Deer Creek's phased approach reinforces our strategy of a step wise development. The positive engineering construction and start up results from the initial SAGD Phase I facility and well pair, position the Company favourably to execute its development plans for SAGD Phase II.

Subsequent to quarter end, the Company announced that it has received Alberta Environment approval for SAGD Phase II. With regulatory approvals and financing in hand, Deer Creek will continue to complete the engineering for SAGD Phase II with major equipment tenders expected to be awarded in the third quarter of 2004. By the end of September, engineering will exceed 60% on the facility. Costs will be firm, supported by completed equipment orders on the steam generation, water treatment, oil treating and other key components. Site construction is expected to begin in the last quarter of 2004 following the awarding of construction contracts. Deer Creek's detailed development plan for SAGD Phase II is on schedule with a target date to commence steam injection of mid 2006.

Geological modeling of Deer Creek's extensive 2004 winter drilling program will continue in the second half of 2004. Deer Creek expects to participate in over 200 delineation wells in the first quarter of 2005 to enhance the Company's project design data.

Deer Creek's one step at a time strategy matches its unique opportunity to establish commercial SAGD production as a platform from which to develop the mining phases of the Joslyn Project.

We are excited about Deer Creek's evolution into a public company and look forward to our growth as we become a significant oil sands producer.

On behalf of the Board of Directors,

(signed) *Glen C. Schmidt*

President and Chief Executive Officer

The foregoing message contains forward-looking statements. Readers are directed to the Management's Discussion and Analysis, "Advisory" on page 7, which also applies to the forward-looking statements in this message. All reference to the Joslyn Project are gross numbers unless otherwise noted.

Management's Discussion and Analysis

The Management's Discussion and Analysis for Deer Creek Energy Limited ("Deer Creek" or the "Company") should be read in conjunction with the accompanying unaudited interim consolidated financial statements and accompanying notes for the six months ended June 30, 2004 and the audited consolidated financial statements and the Management's Discussion and Analysis contained in the Company's annual report for the year ended December 31, 2003. Additional information relating to Deer Creek is available on the SEDAR website at www.sedar.com. This Management's Discussion and Analysis is dated August 9, 2004.

The following information offers Management's analysis of the financial and operating results of the Company and may contain forward-looking statements that are based on estimates and assumptions that are subject to uncertainties. Actual results or events may vary materially from those anticipated.

Results of Operations

Joslyn Project (oil sands lease 24 and permit 70)

Following the successful completion of the SAGD Phase I facility, on schedule and under budget, steam injection and circulation of the SAGD Phase I well pair began in early April and continued throughout the second quarter of 2004. Production is anticipated to commence in the third quarter of 2004. During this pre-commercial phase of the initial SAGD development, all net revenue and operating costs will be capitalized.

During the quarter ended June 30, 2004, the Company received approval from the Alberta Energy and Utilities Board for SAGD Phase II, a 10,000 barrels of bitumen per day expansion. Deer Creek also made advancements in the regulatory process for SAGD Phase III and the first two phases of the mining development by submitting a public disclosure document in June 2004.

Net Additions to Property, Plant and Equipment

Core-hole drilling, development and construction activities have been conducted under a joint venture agreement with EnerMark Inc. ("EnerMark").

($ thousands)	**Three Months Ended June 30 2004**	2003	**Six Months Ended June 30 2004**	2003
Joslyn Project, net				
Project delineation	**256**	663	**8,312**	5,484
SAGD Phase I	**274**	(214)	**10,144**	1,924
SAGD Phase II and III	**1,331**	434	**3,232**	1,148
Mining	**44**	8	**102**	14
Other	**430**	135	**416**	263
Asset retirement obligations	**15**	-	**610**	-
Capitalized general and administration	**506**	205	**984**	360
Project costs	**2,856**	1,231	**23,800**	9,193
Office equipment	**124**	9	**276**	17
Net additions to property, plant and equipment	**2,980**	1,240	**24,076**	9,210

For the three months ended June 30, 2004, net capital expenditures (excluding non-cash items such as asset retirement obligations and capitalized stock-based compensation) were primarily incurred for the regulatory and engineering costs related to SAGD Phase II of the Joslyn Project. During the second quarter of 2004, the Company completed a design base memorandum on the SAGD Phase II facility, gathering and steam injection system and the surface equipment.

During the six months ended June 30, 2004, the Company has incurred capital expenditures primarily for the construction of the SAGD Phase I facility, gathering and steam injection system and for the 2004 winter drilling and seismic program.

Net capital expenditures, are expected to be approximately $21.0 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 Company 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.

Financial Results

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2004**	2003	**2004**	2003
Interest income and other revenue	**158**	242	**418**	495
General and administrative expenses, net	**576**	291	**1,186**	546
Net income (loss)	**(450)**	(77)	**(824)**	(105)

Interest Income and Other Revenue

Interest income and other revenue is primarily interest earned on cash invested in bankers' acceptances and money market instruments held during the periods. Interest income and other revenue is lower for the three and six month periods ended June 30, 2004 when compared to the same periods of 2003 due to lower average investment balances and lower interest rates realized in the second quarter of 2004. The decrease in the average investment balances is a result of the increased capital expenditures incurred during the first six months of 2004 when compared to the first six months of 2003.

It is expected that interest income and other revenue will increase in the last six months of 2004 due to higher investment balances resulting from the proceeds of Deer Creek's initial public offering which closed in late July 2004.

General and Administrative Expenses

Net general and administrative expenses increased $0.3 million for the three months ended June 30, 2004 compared to the three months ended June 30, 2003 and $0.6 million for the first six months of 2004 compared to the first six months of 2003. These increases were 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 June 30		Six Months Ended June 30	
($ thousands)	**2004**	2003	**2004**	2003
General and administrative expenses, gross	**1,069**	493	**2,023**	887
Joint venture recoveries	**(180)**	(84)	**(319)**	(139)
	889	409	**1,704**	748
Stock option compensation costs	**193**	87	**466**	158
Capitalized costs	**(506)**	(205)	**(984)**	(360)
General and administrative expenses, net	**576**	291	**1,186**	546

The increase in gross general and administrative expenses was due to a higher level of activity related to the progression of the Company which resulted in higher employee, consulting and computer services costs. During the first six months of 2004, six employees have joined Deer Creek in planned positions.

For 2004, the gross general and administrative expenses are expected to be approximately $4.2 million. A portion of these expenditures will be offset by EnerMark's 16 percent share pursuant to the joint venture agreement and a portion will be capitalized. Stock option compensation costs are expected to be approximately $0.7 million for 2004.

Net Income (Loss)

The net loss increased by $0.4 million and $0.7 million for the three and six months ended June 30, 2004, respectively, when compared to the same periods of 2003. The increases were due to increased general and administrative expenses associated with the advancing development of the Joslyn Project and a decrease in interest income earned on investments.

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 of the Joslyn Project will be capitalized and amortized over the expected life of the associated reserves.

Income Taxes

Large Corporations Tax decreased to $26,000 in the first six months of 2004 from $44,000 for the same period in 2003 due to the decrease in the statutory rate and the increase in the allowable capital deduction. The Company's Large Corporations Tax is expected to increase from the issuance of capital through the initial public offering.

Quarterly Information

($ thousands, except per share amounts)	**Q2 04**	Q1 04	Q4 03	Q3 03	Q2 03	Q1 03	Q4 02	Q3 02
Net additions to property, plant and equipment	**2,980**	21,096	5,988	4,638	1,240	7,970	1,833	(14,395)
Interest and other revenue	**158**	260	235	240	242	253	217	(672)
Net loss	**(450)**	(374)	(166)	(45)	(77)	(28)	(45)	(2,408)
Net loss per share (basic and diluted)(1)	**(0.02)**	(0.01)	-	-	-	-	(0.01)	(0.14)

(1)restated for the consolidation of common shares on a five to one basis

Capital expenditures have occurred primarily in the first and fourth quarters when the Company had planned core-hole drilling and SAGD Phase I construction. Drilling activity for the purpose of delineating the lease occurs during the winter season with analysis of the data occurring during the following six months. In the third quarter of 2002, the Company sold its 16 percent working interest in the Joslyn Project to EnerMark.

Net loss increased in the first quarter of 2004 and the fourth quarter of 2003 as a result of recording performance related expenses. In the fourth quarter of 2003, the Company 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. In the third quarter of 2002, the Company expensed $1.3 million for the set-off of the convertible debenture.

Liquidity

Working Capital

Working capital surplus decreased $6.9 million during the first six months of 2004. This decrease is primarily due to capital expenditures for the development of the Joslyn Project partially offset by net proceeds from the January 28, 2004 common share issuance.

($ thousands)	
Working capital, December 31, 2003	30,522
Capital expenditures	(23,225)
Share issuance proceeds, net of costs	16,647
Funds used in operations	(372)
Abandonment deposits	(151)
Other	174
Working capital, June 30, 2004	**23,595**

The working capital surplus at June 30, 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 will significantly increase in the third quarter of 2004 with the proceeds from Deer Creek's initial public offering. It is anticipated that the proceeds will be invested in short term money market securities.

Capital Resources

Equity Financing

On January 28, 2004, the Company closed a private placement of 2,020,000 common shares at a price of $8.75 per common share for total gross proceeds of $17.7 million. Proceeds from this share issuance are intended for future development of the Joslyn Project.

On July 29, 2004, the Company closed its initial public offering for 16,900,000 common shares at $9.50 per common share. The estimated proceeds of $152.5 million, net of commissions, are to be used to complete SAGD Phase II, as well as certain additional work necessary to advance the development of future phases of the Joslyn Project.

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 drawn any funds under this facility.

On July 22, 2004, the Company cancelled the $6.0 million revolving committed credit facility and entered into an agreement with two Canadian chartered banks for a committed credit facility of $65.0 million. The new credit facility will assist in funding SAGD Phase II and provide incremental working capital to the Company to support the regulatory, engineering design and environmental work related to additional expansions of the Joslyn Project and other related expenses.

Commitments

The Company did not enter into any additional material commitments from that set forth in Note 5 of the accompanying notes to the unaudited consolidated financial statements.

Outstanding Share Data

At July 31, 2004, share capital consists of the following:

(thousands)	
Issued and outstanding	
Common shares	46,798
Stock options	2,349
Performance share units (formerly stock rights)	171
Fully diluted number of shares	49,318

The Board of Directors approved amendments to each of the Stock Option Plan and Performance Share Unit Plan (formerly the Stock Rights Plan) 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, adopted a revised definition of Change of Control, consistent with other Canadian issuers and limited the term of exercise of performance share units to seven years.

At the annual and special meeting of shareholders held on May 20, 2004, the shareholders approved a resolution to consolidate the issued and outstanding common shares on a five to one basis, effective June 1, 2004. The shareholders also approved, pursuant to section 36 of the Business

Corporations Act (Alberta), to reduce the stated capital account for the common shares in the amount of $18.2 million.

Changes in Accounting Standards

Asset Retirement Obligations

Effective January 1, 2004, the Company 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.

Risk Management and Success Factors

Reference is made to the "Risk Management and Success Factors" section of Management's Discussion and Analysis in Deer Creek's 2003 Annual Report. The nature of the Company's risk exposure and methods of managing risk remain substantially unchanged since December 31, 2003.

Outlook

Initial production from SAGD Phase I is expected during the third quarter of 2004 with production levels reaching 600 barrels per day over the subsequent 12 months.

During the remainder of 2004, the Company plans to finalize the engineering for SAGD Phase II and begin the process of procuring major equipment tenders. Construction contracts will also be awarded and site work will begin late in 2004.

Advisory

This report contains certain "forward-looking statements" within the meaning of such statements under applicable securities law. Forward-looking statements are frequently characterized by words such as "plan", "expect", "estimate", "believe" and other similar words, or statements that certain events or conditions "may" or "will" occur. By their nature, forward-looking statements involve assumptions and are subject to a variety of risks and uncertainties, including, but not limited to, those associated with resource definition, the timeline to production, the possibility of project cost overruns or unanticipated costs and expenses, regulatory approvals, fluctuating oil and gas prices, and the ability to access sufficient capital to finance future development. Although the Company believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Deer Creek does not undertake any obligation to update publicly or to revise any of the included forward-looking statements as a result of new information, future events or otherwise, subsequent to the date of this report. The reader is cautioned not to place undue reliance on forward-looking statements.

Consolidated Balance Sheets

(Unaudited)

(thousands of dollars)	June 30 2004	December 31 2003
Assets		
Current assets		
Cash and cash equivalents	$ **24,838**	$ 35,132
Accounts receivable	**1,946**	1,828
Prepaid expenses and deposits	**233**	114
	27,017	37,074
Abandonment deposits	**578**	426
Property, plant and equipment	**52,416**	28,370
	$ **80,011**	$ 65,870
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ **3,422**	$ 6,552
Future income tax liability	**2,958**	3,314
Asset retirement obligations (note 2)	**610**	-
	6,990	9,866
Shareholders' equity		
Share capital (note 3)	**60,452**	61,677
Contributed surplus	**26,948**	7,882
Deficit	**(14,379)**	(13,555)
	73,021	56,004
	$ **80,011**	$ 65,870

Contingencies and Commitments (note 5)

See accompanying notes to the consolidated financial statements

Consolidated Statements of Income and Deficit

(Unaudited)

(thousands of dollars except per share amounts)	Three months ended June 30 **2004**	2003 (restated – Note 1)	Six months ended June 30 **2004**	2003 (restated – Note 1)
Revenue				
Interest and other	**$ 158**	$ 242	**$ 418**	$ 495
Expenses				
General and administrative	**576**	291	**1,186**	546
Amortization	**18**	6	**30**	10
	594	297	**1,216**	556
Income (loss) before Large Corporations Tax	**(436)**	(55)	**(798)**	(61)
Large Corporations Tax	**14**	22	**26**	44
Net income (loss)	**(450)**	(77)	**(824)**	(105)
Deficit, beginning of period	**(13,929)**	(13,267)	**(13,555)**	(13,239)
Deficit, end of period	**$ (14,379)**	$ (13,344)	**$ (14,379)**	$ (13,344)
Net income (loss) per common share (note 3) Basic and diluted	**$ (0.02)**	$ -	**$ (0.03)**	$ -

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

(Unaudited)

(thousands of dollars)	Three months ended June **2004**	Three months ended June 2003 (restated – Note 1)	Six months ended June 30 **2004**	Six months ended June 30 2003 (restated – Note 1)
Operating activities				
Net income (loss)	**$ (450)**	$ (77)	**$ (824)**	$ (105)
Add (deduct) items not affecting cash:				
Stock-based compensation	**105**	94	**422**	176
Amortization	**18**	6	**30**	10
Funds provided by (used in) operations	**(327)**	23	**(372)**	81
Changes in non-cash working capital	**(66)**	(67)	**102**	(104)
	(393)	(44)	**(270)**	(23)
Investing activities				
Acquisition of property, plant and equipment	**(2,856)**	(1,175)	**(23,225)**	(9,119)
Abandonment deposit	**(148)**	(218)	**(151)**	(218)
Changes in non-cash working capital	**(11,073)**	(1,829)	**(3,145)**	665
	(14,077)	(3,222)	**(26,521)**	(8,672)
Financing activities				
Share issues, net of share issuance costs	**-**	-	**16,647**	-
Changes in non-cash working capital	**(150)**	-	**(150)**	(94)
	(150)	-	**16,497**	(94)
Increase (decrease) in cash and cash equivalents	**(14,620)**	(3,266)	**(10,294)**	(8,789)
Cash and cash equivalents, beginning of period	**39,458**	35,698	**35,132**	41,221
Cash and cash equivalents, end of period	**$ 24,838**	$ 32,432	**$ 24,838**	$ 32,432
Cash and cash equivalents is comprised of:				
Deposits with banks and others	**$ 59**	$ 1,437	**$ 59**	$ 1,437
Money market funds and bankers' acceptances	**24,779**	30,995	**24,779**	30,995
	$ 24,838	$ 32,432	**$ 24,838**	$ 32,432

See accompanying notes to the consolidated financial statements

Notes to the Consolidated Financial Statements – June 30, 2004

(Unaudited)
(tabular amounts in thousands of dollars except per share amounts and otherwise noted)

1. Summary of Significant Accounting Policies

The interim consolidated financial statements of Deer Creek Energy Limited ("Deer Creek" or "the Company") 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.

The accounting policies applied are consistent with those outlined in the Company's annual consolidated financial statements for the fiscal year ended December 31, 2003. These consolidated financial statements for the six months ended June 30, 2004 do not include all disclosures required in the annual consolidated financial statements and should be read in conjunction with the audited consolidated financial statements included in Deer Creek's 2003 Annual Report.

Certain comparative figures have been reclassified to conform with current financial statement presentation.

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 stock option or performance 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.

The adoption of this recommendation decreased the net income for the six months ended June 30, 2003 by $0.1 million.

Asset Retirement Obligation

Effective January 1, 2004, Deer Creek adopted, retroactively without restatement, 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.

2. Asset Retirement Obligations

		Amount
Balance, December 31, 2003	$	-
Liabilities incurred		586
Accretion		24
Balance, June 30, 2004	**$**	**610**

The estimated undiscounted amount of the asset retirement obligations is $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.

3. 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, 2003	**27,573**	**$**	**59,742**
Issued for cash	2,020		17,675
Conversion of special warrants	305		1,935
Issue costs, net of tax			(672)
Stated capital reduction			(18,228)
June 30, 2004	**29,898**	**$**	**60,452**

On January 28, 2004, the Company closed a private placement of 2,020,000 common shares at a price of $8.75 per common share for total gross proceeds of $17.7 million.

On May 20, 2004, the shareholders of the Company approved a special resolution to reduce the stated capital of the common shares, pursuant to the Business Corporations Act (Alberta), in the aggregate amount of $18.2 million and to contribute such amount to the Company's contributed surplus. The shareholders of the Company also approved a special resolution consolidating the outstanding common shares on a five for one basis, effective June 1, 2004.

At June 30, 2004, there were 2,989,800 common shares reserved for issuance under the Stock Option and Performance Share Unit Plans.

Subsequent to June 30, 2004, the Company closed an initial public offering (see Note 6).

Performance Share Units

The Company has a performance share unit plan under which directors, employees and select providers of services of the Company are eligible to receive grants.

	Number (thousands)	Exercise Price ($/unit)
Outstanding, December 31, 2003	**76**	$ 0.05
Granted	**95**	0.05
Outstanding, June 30, 2004	**171**	**$ 0.05**
Exercisable, June 30, 2004	**104**	**$ 0.05**

For the six months ended June 30, 2004, compensation cost of $0.4 million for performance share units granted has been credited to contributed surplus.

Stock Options

The Company has a stock option plan under which directors, employees and select providers of services of the Company are eligible to receive grants.

	Number (thousands)	**Weighted Average Exercise Price** ($/option)
Outstanding, December 31, 2003	1,582	$ 4.40
Granted	767	8.73
Outstanding, June 30, 2004	**2,349**	**$ 5.81**
Exercisable, June 30, 2004	**1,091**	**$ 4.80**

For the six months ended June 30, 2004, compensation cost of $0.5 million has been recognized 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:

	Three months ended June 30		**Six months ended June 30**	
	2004	2003	**2004**	2003
Net income (loss)				
As reported	**$ (450)**	$ (77)	**$ (824)**	$ (105)
Less fair value of stock options	**19**	19	**37**	36
Pro forma	**$ (469)**	$ (96)	**$ (861)**	$ (141)
Basic and diluted net income (loss) per share				
As reported	**$ (0.02)**	$ -	**$ (0.03)**	$ -
Pro forma	**$ (0.02)**	$ -	**$ (0.03)**	$ -

3. Share Capital (continued)

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:

		June 30 2004
Weighted average fair value ($/option)	$	2.08
Risk free interest rate, average for the period (percent)		4.1
Expected life (in years)		7

Earnings per share

Basic and diluted net income (loss) per share has been calculated using the weighted average number of common shares outstanding during the period of 29,811,824 (26,331,400 in 2003). The calculation of diluted net income (loss) per share does not include stock options or performance share units as the effect would be anti-dilutive.

4. 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 (see Note 6).

5. Contingencies and Commitments

Joslyn Project Development

The Company has agreements with Talisman Energy Inc. (the "Talisman Agreement") and EnerMark Inc. ("EnerMark") related to the development of the Joslyn Project. Details of these agreements are provided in Note 5 to the annual consolidated financial statements for the fiscal year ended December 31, 2003.

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:

		June 30 2004		December 31 2003
Contingent production payment:				
Deer Creek	$	17,640	$	17,640
EnerMark		3,360		3,360
	$	21,000	$	21,000
Contingent interest payment:				
Deer Creek	$	5,609	$	5,258
EnerMark		1,069		1,002
	$	6,678	$	6,260

As at June 30, 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.

6. Subsequent Events

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 for total gross proceeds of $160.0 million.

This initial offering closed on July 29, 2004 and shares of the Company began trading on the Toronto Stock Exchange.

On July 22, 2004, Deer Creek entered into an agreement with two Canadian chartered banks for a committed credit facility of $65.0 million. The $6.0 million existing credit facility was cancelled upon entering into the new credit facility agreement.

Corporate Information

Directors

John Clarkson [3, 4C]
President, Clearwater Capital Corporation

Jonathan C. Farber [2, 3]
Managing Director, Lime Rock Partners

Ronald Hiebert [2, 3]
Director, Scotia McLeod

S. Barry Jackson [1, 3C, 4]
Chairman, Resolute Energy Inc.

Gordon Kerr [2]
President and CEO, Enerplus Resources Fund

Brian Lemke [2C]
President and CEO, Resolute Energy Inc.

Glen Schmidt [4]
President and CEO, Deer Creek Energy Limited

[1] Chairman of the Board
[2] Audit Committee
[3] Human Resources & Governance Committee
[4] Technical Committee
[C] Committee Chairman

Officers

Glen Schmidt
President and CEO

John Kowal
Vice President, Finance and CFO

Mark Montemurro
Vice President, Thermal

Gary Purcell
Vice President, Business Development

Don Riva
Vice President, Mining

Karen Lillejord
Controller

Jim Thomson
Corporate Secretary

Toronto Stock Exchange
Trading Symbol – DCE

DEER CREEK
Energy Limited

For more information, please contact

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Toll Free: 1-888-264-3777
E-Mail: deercrk@deercreekenergy.com

Deer Creek's annual report and other documents are available online at www.deercreekenergy.com.

FORM 52-109FT2

CERTIFICATION OF INTERIM FILINGS DURING TRANSITION PERIOD

I, Glen C. Schmidt, President and Chief Executive Officer of Deer Creek Energy Limited, certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Deer Creek Energy Limited (the issuer), for the interim period ending June 30, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

August 9, 2004

(signed) *Glen C. Schmidt*
Glen C. Schmidt
President and Chief Executive Officer

FORM 52-109FT2

CERTIFICATION OF INTERIM FILINGS DURING TRANSITION PERIOD

I, John S. Kowal, Vice President, Finance and Chief Financial Officer of Deer Creek Energy Limited, certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Deer Creek Energy Limited (the issuer), for the interim period ending June 30, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

August 9, 2004

(signed) *John S. Kowal*
John S. Kowal
Vice President, Finance and
Chief Financial Officer

DEER CREEK
Energy Limited

Building a Pure Oil Sands Company

ONE STEP AT A TIME

For the 9 months ended September 30, 2004

First bitumen production from SAGD Phase I and acceleration of SAGD Phase II deliver positive results and steady progress

Quarterly Highlights

- Completed financings totaling $225 million and began trading on the TSX
- SAGD Phase I well pair on production
- Accelerated SAGD Phase II capital spending and project schedule
- Advanced the design for SAGD Phase III in two parts
- Subsequent to the third quarter, Deer Creek:
  - Awarded engineering services contract for the mining project
  - Approved a 2005 net capital program totaling $146 million

On July 29, Deer Creek commenced trading on the Toronto Stock Exchange under the trading symbol "DCE" with the successful closing of its initial public offering for 16.9 million common shares at $9.50 per common share. In addition, the Company entered into a committed credit facility of $65 million with two Canadian chartered banks. These financings, totaling $225 million, support Deer Creek's commercial development of the Joslyn Project.

As planned, the SAGD Phase I well pair was completed for production in mid-September. The average field production during the month of October was approximately 125 barrels of bitumen per day, in line with expectations. The ramp-up to the full production rate of 600 barrels of bitumen per day is expected to occur linearly over the next 12 months.

The steam-oil-ratio in the first six weeks of production has consistently declined over the period to reach 3.5 at the end of October and averaged 3.7 for the month. The steam-oil-ratio is currently better than the expected range of 6 to 7 at this point of the well life. The original Joslyn Pilot Project well pair in 2001 tested at a steam-oil-ratio of 2.4 when shut-in and continues to support the expected production profile. Additionally, the level of water loss to the reservoir is corresponding to forecast. Deer Creek is pleased the well is performing as expected.

During the quarter, Deer Creek accelerated its capital program for SAGD Phase II, which is expected to produce 10,000 barrels of bitumen per day. As a result, the project schedule for SAGD Phase II has been advanced up to six months sooner than previously forecast with first steam now expected early 2006. Progress in the quarter included ordering all of the major equipment for the central processing facility, completion of site access and clearing of the facility site as well as completion of a drilling rig commitment. As of the end of September, more than 70% of the facility engineering has been complete. On-site foundation construction is scheduled to begin in early 2005.

Q3

Deer Creek is also pleased to announce the decision to accelerate the growth of the Joslyn Project and advance SAGD Phase III in two parts. The first approximate 15,000 barrels of bitumen per day expansion (SAGD Phase IIIA) is expected to begin steaming operations in late 2007, closely followed by a second expansion of approximately 15,000 barrels of bitumen per day (SAGD Phase IIIB) scheduled for first steam in 2009. Deer Creek anticipates filing the regulatory application for SAGD Phase IIIA in the first quarter of 2005. This optimized plan allows Deer Creek to develop its SAGD opportunities earlier than originally planned with less execution and cost risk, due to its smaller project size and complexity. In addition, this allows SAGD and mining synergies to be explored by designing SAGD Phase IIIB concurrently with the first two phases of the mining development.

Subsequent to quarter end, Deer Creek awarded a major engineering contract to AMEC Americas Ltd. to supply engineering support services for the completion of a regulatory application for the first two phases of the Joslyn mining development for total approved production of 100,000 barrels of bitumen per day. Deer Creek intends to file the regulatory application in late 2005 or early 2006 in combination with SAGD Phase IIIB. Deer Creek's portion of contracts currently entered into for the mining development total approximately $30 million in engineering and environmental commitments and $20 million in resource delineation over the next 3 year period, at which time regulatory approval is expected to be received.

With these objectives, the board of directors approved a net capital program totaling approximately $146 million for 2005. The capital program advances approximately $40 million of expenditures originally planned in 2006 and reflects the previously announced acceleration of SAGD Phase II.

The focus of the majority of the 2005 capital program will be on SAGD Phase II where Deer Creek will invest approximately $118 million primarily on facilities completion and the initial drilling program. The overall SAGD Phase II cost estimate is projected to be $149 million net to Deer Creek and is within 4% of previously reported estimates. Deer Creek's SAGD Phase IIIA and mining expenditures, totaling $8 million, will continue to advance these phases through regulatory application and support engineering and technical studies.

In 2005, Deer Creek's net core-hole program expense is expected to be $12 million, split approximately 40% to the SAGD and 60% to the mining areas. Deer Creek expects to drill more than 250 gross delineation wells which will increase the Joslyn well database to more than 800 wells.

The balance of the capital program supports general corporate studies and initiatives.

2004 Outlook

- Advance SAGD Phase II design and construction
- Prepare for the 2005 winter core-hole program of more than 250 wells
- Advance SAGD Phase IIIA regulatory application

Deer Creek will focus the balance of 2004 on preparing for site construction and installation for SAGD Phase II and an active winter core-hole drilling program. Work will continue on the regulatory application for SAGD Phase IIIA with the preparation of environmental reports. Significant progress on the regulatory application is expected to be made to achieve a target filing date of the first quarter of 2005. Deer Creek's primary goal is to deliver on our plans as scheduled and within budget. The results for 2004 to date have delivered on that goal successfully.

We look forward to continuing to report to you on our steady progress.

On behalf of the Board of Directors,

(signed) *Glen C. Schmidt*

President and Chief Executive Officer

The foregoing message contains forward-looking statements. Readers are directed to the Management's Discussion and Analysis, "Advisory" on page 7, which also applies to the forward-looking statements in this message. All reference to the Joslyn Project are gross interest unless stated otherwise.

Management's Discussion and Analysis

The Management's Discussion and Analysis for Deer Creek Energy Limited ("Deer Creek" or the "Company") should be read in conjunction with the accompanying unaudited interim consolidated financial statements and accompanying notes for the nine months ended September 30, 2004 and the audited consolidated financial statements and the Management's Discussion and Analysis contained in the Company's annual report for the year ended December 31, 2003. Additional information relating to Deer Creek is available on the SEDAR website at www.sedar.com. This Management's Discussion and Analysis is dated November 10, 2004.

The following information offers Management's analysis of the financial and operating results of the Company and may contain forward-looking statements that are based on estimates and assumptions that are subject to uncertainties. Actual results or events may vary materially from those anticipated.

Results of Operations

Joslyn Project (oil sands lease 24 and permit 70)

The SAGD Phase I facility was successfully completed in the first quarter of 2004, on schedule and under budget. Steam injection and circulation of the SAGD Phase I well pair began in early April and continued throughout the second quarter of 2004. During the third quarter of 2004, the well pair was converted to production mode. During this pre-commercial phase of the initial SAGD development, all net revenue and operating costs will be capitalized.

Subsequent to receiving approval from the Alberta Energy and Utilities Board and Alberta Environment for SAGD Phase II, a 10,000 barrels of bitumen per day expansion, the Company has made significant commitments for major equipment, including steam generators, water treatment and oil treating. Facility engineering for SAGD Phase II has advanced to approximately 70%. SAGD Phase II site construction and access commenced in October 2004.

Deer Creek has completed the oil sands exploration permitting for its 2005 winter core-hole program. It is anticipated that more than 250 new core-holes will be drilled during the winter season.

Net Additions to Property, Plant and Equipment

Core-hole drilling, development and construction activities have been conducted under a joint venture agreement with EnerMark Inc. ("EnerMark").

	Three Months Ended September 30		**Nine Months Ended September 30**	
($ thousands)	**2004**	2003	**2004**	2003
Joslyn Project, net				
Project delineation	**588**	610	**8,900**	6,094
SAGD Phase I	**906**	2,833	**10,250**	4,757
SAGD Phase II and III	**4,628**	637	**7,860**	1,785
SAGD Operations	**1,493**	-	**2,293**	-
Mining	**209**	77	**311**	91
Other	**617**	247	**1,033**	510
Asset retirement obligations	**10**	-	**620**	-
Capitalized general and administration	**738**	194	**1,722**	554
Project costs	**9,189**	4,598	**32,989**	13,791
Office equipment	**(40)**	40	**236**	57
Net additions to property, plant and equipment	**9,149**	4,638	**33,225**	13,848

For the three months ended September 30, 2004, net capital expenditures (excluding non-cash items such as asset retirement obligations and capitalized stock-based compensation) were primarily incurred for the engineering costs and the initial procurement of major equipment related to SAGD Phase II of the Joslyn Project.

During the nine months ended September 30, 2004, the Company has incurred capital expenditures primarily for the construction and operation of the SAGD Phase I facility, gathering and steam injection system, completion and equipping of the SAGD well pair and for the 2004 winter core-hole drilling and seismic program. Deer Creek completed a design base memorandum on the SAGD Phase II facility, gathering and steam injection system and the surface equipment and has proceeded to make commitments for major equipment of this phase of development.

Net capital expenditures, expected to be approximately $15.0 million for the remainder of 2004, are focused primarily on continuing the acceleration of SAGD Phase II, mine engineering and studies to support a regulatory application in late 2005 or early 2006, and studies to identify synergies between mining and SAGD operations. The Company 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.

Financial Results

	Three Months Ended September 30		**Nine Months Ended September 30**	
($ thousands)	**2004**	2003	**2004**	2003
Interest income and other revenue	**656**	240	**1,074**	735
General and administrative expenses, net	**819**	248	**2,005**	794
Net income (loss)	**(458)**	(45)	**(1,282)**	(150)

Interest Income and Other Revenue

Interest income and other revenue is related to interest earned on cash invested in interest bearing instruments held during the periods. Interest income and other revenue is higher for the three and nine month periods ended September 30, 2004 when compared to the same periods of 2003 due to higher average investment balances resulting from the proceeds of Deer Creek's initial public offering which closed in late July 2004.

General and Administrative Expenses

	Three Months Ended September 30		**Nine Months Ended September 30**	
($ thousands)	**2004**	2003	**2004**	2003
General and administrative expenses, gross	**1,583**	492	**3,606**	1,379
Joint venture recoveries	**(259)**	(82)	**(578)**	(221)
	1,324	410	**3,028**	1,158
Stock option compensation costs	**233**	32	**699**	190
Capitalized costs	**(738)**	(194)	**(1,722)**	(554)
General and administrative expenses, net	**819**	248	**2,005**	794

The increase in gross general and administrative expenses from the prior year was due to a higher level of activity related to the progression of the Company and the advancement of the Joslyn Project which has resulted in higher employee, consulting and information services costs. During the first nine months of 2004, seven employees have joined Deer Creek in planned positions bringing the total number of employees to 24 as at September 30, 2004.

Net general and administrative expenses increased $0.6 million for the three months ended September 30, 2004 compared to the three months ended September 30, 2003 and $1.2 million for the first nine months of 2004 compared to the first nine months of 2003. These increases were primarily due to an increase in the number of employees, the recording of stock-based compensation for 2003 and 2004 stock option awards and employee costs related to the initial public offering. Deer Creek's general and administrative expenses are expected to increase as the Joslyn Project advances.

For 2004, the gross general and administrative expenses are expected to be approximately $5.1 million. A portion of these expenditures will be offset by EnerMark's 16% share pursuant to the joint venture agreement and a portion will be capitalized. Deer Creek's stock option compensation costs are expected to be approximately $0.9 million for 2004.

Amortization

Amortization increased in the three months ended September 30, 2004 when compared to prior quarters due to the amortization of deferred financing charges related to the Company's $65.0 million credit facility. These costs will be amortized over the five year term of the credit facility.

Net Income (Loss)

The net loss increased by $0.4 million and $1.1 million for the three and nine months ended September 30, 2004, respectively, when compared to the same periods of 2003. The increases were due to increased general and administrative expenses associated with advancing the development of the Joslyn Project, offset by an increase in interest income earned on investments.

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 of the Joslyn Project will be capitalized and amortized over the expected life of the associated reserves.

Income Taxes

Large Corporations Tax increased to $0.3 million in the first nine months of 2004 from $0.1 million for the same period in 2003 due to an increase in the capital tax base resulting from the issuance of capital through the initial public offering, offset by the decrease in the statutory rate and the increase in the allowable capital deduction.

Quarterly Information

($ thousands, except per share amounts)	**Q3 04**	Q2 04	Q1 04	Q4 03	Q3 03	Q2 03	Q1 03	Q4 02
Net additions to property, plant and equipment	**9,149**	2,980	21,096	5,988	4,638	1,240	7,970	1,833
Interest and other revenue	**656**	158	260	235	240	242	253	217
Net loss	**(458)**	(450)	(374)	(166)	(45)	(77)	(28)	(45)
Net loss per share (basic and diluted) [1]	**(0.01)**	(0.02)	(0.01)	-	-	-	-	(0.01)

[1] restated for the consolidation of common shares on a five for one basis

Drilling activity for the purpose of delineating the lease occurs during the winter season with analysis of the data occurring during the following six months.

Net loss increased in the first quarter of 2004 and the fourth quarter of 2003 as a result of recording performance related expenses. In the fourth quarter of 2003, the Company 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.

Liquidity

Working Capital

Working capital surplus increased $134.0 million during the first nine months of 2004. This increase is primarily due to net proceeds from the initial public offering and the January 28, 2004 common share issuance offset by capital expenditures for the development of the Joslyn Project.

($ thousands)	
Working capital, December 31, 2003	30,522
Share issuance proceeds, net of costs	167,751
Capital expenditures	(32,152)
Deferred financing charges	(963)
Funds used in operations	(630)
Other	39
Working capital, September 30, 2004	**164,567**

The working capital surplus at September 30, 2004 will fund the 2004 expected remaining capital expenditures, general and administrative expenses and operating costs for SAGD Phase I, and is sufficient to complete the construction of SAGD Phase II, and the planned 2005 regulatory and engineering costs for SAGD Phase IIIA and the mine project.

Capital Resources

Equity Financing

On January 28, 2004, the Company closed a private placement of 2,020,000 common shares at a price of $8.75 per common share for total gross proceeds of $17.7 million. Proceeds from this share issuance are intended for future development of the Joslyn Project.

On July 29, 2004, the Company closed its initial public offering for 16,900,000 common shares at a price of $9.50 per common share. The gross proceeds of $160.6 million are to be used to complete SAGD Phase II, as well as certain additional work necessary to advance the development of future phases of the Joslyn Project.

Credit Facility

On July 22, 2004, the Company entered into an agreement with two Canadian chartered banks for a committed credit facility of $65.0 million. The new credit facility will assist in funding SAGD Phase II and provide incremental working capital to the Company to support the regulatory, engineering design and environmental work related to additional expansions of the Joslyn Project and other related expenses. At September 30, 2004, no funds had been advanced under this credit facility.

Commitments

The Company has entered into certain commitments for equipment and engineering services for SAGD Phase II approximating $20.7 million representing the Company's share of commitments. These commitments will be realized over time as work is completed.

All other commitments are set forth in Note 5 of the accompanying notes to the unaudited consolidated financial statements and in Note 5 of the audited consolidated financial statements for the year ended December 31, 2003.

Outstanding Share Data

At October 31, 2004, share capital consists of the following:

(thousands)	
Issued and outstanding	
Common shares	46,798
Stock options	2,310
Performance share units (formerly stock rights)	171
Fully diluted number of shares	49,279

Changes in Accounting Standards and Estimates

Asset Retirement Obligations

Effective January 1, 2004, the Company 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.

Risk Management and Success Factors

Reference is made to the "Risk Management and Success Factors" section of Management's Discussion and Analysis in Deer Creek's 2003 Annual Report. The nature of the Company's risk exposure and methods of managing risk remain substantially unchanged since December 31, 2003.

Outlook

Production levels from SAGD Phase I are expected to reach 600 barrels per day within the subsequent 12 months.

During the remainder of 2004, the Company plans to finalize the engineering for SAGD Phase II and continue procuring major equipment components. On-site installation of equipment is scheduled to begin in early 2005. Contracts to provide engineering services for the mine project regulatory process will be completed to allow filing for the first 100,000 barrels of bitumen per day in late 2005 or early 2006. These contracts will provide for engineering services through 2007 when mine regulatory approval is expected.

Advisory
This report contains certain "forward-looking statements" within the meaning of such statements under applicable securities law. Forward-looking statements are frequently characterized by words such as "plan", "expect", "estimate", "believe" and other similar words, or statements that certain events or conditions "may" or "will" occur. By their nature, forward-looking statements involve assumptions and are subject to a variety of risks and uncertainties, including, but not limited to, those associated with resource definition, the timeline to production, the possibility of project cost overruns or unanticipated costs and expenses, regulatory approvals, fluctuating oil prices, and the ability to access sufficient capital to finance future development. Although the Company believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Deer Creek does not undertake any obligation to update publicly or to revise any of the included forward-looking statements as a result of new information, future events or otherwise, subsequent to the date of this report. The reader is cautioned not to place undue reliance on forward-looking statements.

Consolidated Balance Sheets

(Unaudited)

(thousands of dollars)	September 30 2004	December 31 2003
Assets		
Current assets		
Cash and cash equivalents	$ 171,798	$ 35,132
Accounts receivable	1,520	1,828
Prepaid expenses and deposits	185	114
	173,503	37,074
Abandonment deposits	584	426
Deferred charges	931	-
Property, plant and equipment	61,542	28,370
	$ 236,560	$ 65,870
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 8,936	$ 6,552
Future income tax liability	-	3,314
Asset retirement obligations (note 2)	620	-
	9,556	9,866
Shareholders' equity		
Share capital (note 3)	214,514	61,677
Contributed surplus	27,327	7,882
Deficit	(14,837)	(13,555)
	227,004	56,004
	$ 236,560	$ 65,870

Contingencies and Commitments (note 5)

See accompanying notes to the consolidated financial statements

Consolidated Statements of Income and Deficit

(Unaudited)

(thousands of dollars except per share amounts)	Three months ended September 30 **2004**	Three months ended September 30 2003 (restated – Note 1)	Nine months ended September 30 **2004**	Nine months ended September 30 2003 (restated – Note 1)
Revenue				
Interest and other	**$ 656**	$ 240	**$ 1,074**	$ 735
Expenses				
General and administrative	**819**	248	**2,005**	794
Amortization	**55**	14	**85**	24
	874	262	**2,090**	818
Income (loss) before Large Corporations Tax	**(218)**	(22)	**(1,016)**	(83)
Large Corporations Tax	**240**	23	**266**	67
Net income (loss)	**(458)**	(45)	**(1,282)**	(150)
Deficit, beginning of period	**(14,379)**	(13,344)	**(13,555)**	(13,239)
Deficit, end of period	**$ (14,837)**	$ (13,389)	**$ (14,837)**	$ (13,389)
Net income (loss) per common share (note 3)				
Basic and diluted	**$ (0.01)**	$ -	**$ (0.04)**	$ -

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

(Unaudited)

(thousands of dollars)	Three months ended September 30 2004	Three months ended September 30 2003 (restated – Note 1)	Nine months ended September 30 2004	Nine months ended September 30 2003 (restated – Note 1)
Operating activities				
Net income (loss)	**$ (458)**	$ (45)	**$ (1,282)**	$ (150)
Add (deduct) items not affecting cash:				
Stock-based compensation	**145**	67	**567**	243
Amortization	**55**	14	**85**	24
Funds provided by (used in) operations	**(258)**	36	**(630)**	117
Changes in non-cash working capital	**223**	(205)	**325**	(309)
	(35)	(169)	**(305)**	(192)
Investing activities				
Acquisition of property, plant and equipment	**(8,927)**	(4,612)	**(32,152)**	(13,731)
Abandonment deposit	**(7)**	(6)	**(158)**	(224)
Changes in non-cash working capital	**5,466**	1,917	**2,321**	2,582
	(3,468)	(2,701)	**(29,989)**	(11,373)
Financing activities				
Share issues, net of share issuance costs	**151,104**	209	**167,751**	209
Deferred charges	**(963)**	-	**(963)**	-
Changes in non-cash working capital	**322**	-	**172**	(94)
	150,463	209	**166,960**	115
Increase (decrease) in cash and cash equivalents	**146,960**	(2,661)	**136,666**	(11,450)
Cash and cash equivalents, beginning of period	**24,838**	32,432	**35,132**	41,221
Cash and cash equivalents, end of period	**$ 171,798**	$ 29,771	**$ 171,798**	$ 29,771
Cash and cash equivalents is comprised of:				
Deposits with banks and others	**$ 120**	$ 1,142	**$ 120**	$ 1,142
Interest bearing instruments	**171,678**	28,629	**171,678**	28,629
	$ 171,798	$ 29,771	**$ 171,798**	$ 29,771

See accompanying notes to the consolidated financial statements

(Unaudited)
(tabular amounts in thousands of dollars except per share amounts and otherwise noted)

1. Summary of Significant Accounting Policies

The interim consolidated financial statements of Deer Creek Energy Limited ("Deer Creek" or the "Company") 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.

The accounting policies applied are consistent with those outlined in the Company's annual consolidated financial statements for the fiscal year ended December 31, 2003. These consolidated financial statements for the nine months ended September 30, 2004 do not include all disclosures required in the annual consolidated financial statements and should be read in conjunction with the audited consolidated financial statements included in Deer Creek's 2003 Annual Report.

Certain comparative figures have been reclassified to conform with current financial statement presentation.

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 stock option or performance 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.

The adoption of this recommendation decreased the net income for the nine months ended September 30, 2003 by $0.1 million.

Asset Retirement Obligation

Effective January 1, 2004, Deer Creek adopted, retroactively without restatement, 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 material effect on the Company's prior year consolidated financial statements as substantially all of the Company's obligations with respect to 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.

1. Summary of Significant Accounting Policies (continued)

Property, plant and equipment

Interest and standby charges in relation to the credit facility are capitalized until commercial activities commence.

2. Asset Retirement Obligations

		Amount
Balance, December 31, 2003	$	-
Liabilities incurred		586
Accretion		34
Balance, September 30, 2004	**$**	**620**

The estimated undiscounted amount of the asset retirement obligations is $1.3 million and has been discounted at rates between 5.9 percent and 7.2 percent. The costs are expected to be incurred between 2008 and 2040.

3. 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, 2003	**27,573**	**$**	**59,742**
Issued for cash	18,920		178,225
Conversion of special warrants	305		1,935
Issue costs, net of tax			(7,160)
Stated capital reduction			(18,228)
September 30, 2004	**46,798**	**$**	**214,514**

On January 28, 2004, the Company closed a private placement of 2,020,000 common shares at a price of $8.75 per common share for total gross proceeds of $17.7 million.

On May 20, 2004, the shareholders of the Company approved a special resolution to reduce the stated capital of the common shares, pursuant to the Business Corporations Act (Alberta), in the aggregate amount of $18.2 million and to contribute such amount to the Company's contributed surplus. The shareholders of the Company also approved a special resolution consolidating the outstanding common shares on a five for one basis, effective June 1, 2004.

On July 29, 2004, the Company closed an initial offering of 16,900,000 common shares at $9.50 per common share for total gross proceeds of $160.6 million. The shares of Deer Creek immediately began trading on the Toronto Stock Exchange under the symbol DCE.

At September 30, 2004, there were 4,679,845 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, employees and select providers of services of the Company are eligible to receive grants.

	Number (thousands)		**Exercise Price** ($/unit)
Outstanding, December 31, 2003	76	$	0.05
Granted	95		0.05
Outstanding, September 30, 2004	**171**	**$**	**0.05**
Exercisable, September 30, 2004	**104**	**$**	**0.05**

For the nine months ended September 30, 2004, compensation cost of $0.5 million for performance share units granted has been credited to contributed surplus.

Stock Options

The Company has a stock option plan under which directors, employees and select providers of services of the Company are eligible to receive grants.

	Number (thousands)		**Weighted Average Exercise Price** ($/option)
Outstanding, December 31, 2003	1,582	$	4.40
Granted	728		8.73
Outstanding, September 30, 2004	**2,310**	**$**	**5.76**
Exercisable, September 30, 2004	**1,275**	**$**	**4.90**

For the nine months ended September 30, 2004, compensation cost of $0.7 million has been recognized for stock options granted after January 1, 2003.

3. Share Capital (continued)

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:

	Three months ended September 30		Nine months ended September 30	
	2004	2003	**2004**	2003
Net income (loss)				
As reported	**$ (458)**	$ (45)	**$ (1,282)**	$ (150)
Less fair value of stock options	**19**	20	**56**	56
Pro forma	**$ (477)**	$ (65)	**$ (1,338)**	$ (206)
Basic and diluted net income (loss) per share				
As reported	**$ (0.01)**	$ -	**$ (0.04)**	$ -
Pro forma	**$ (0.01)**	$ -	**$ (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:

	September 30 **2004**
Expected volatility (percent)	**30.0**
Risk free interest rate, average for the period (percent)	**4.4**
Expected life (in years)	**7**

Earnings per share

Basic and diluted net income (loss) per share has been calculated using the weighted average number of common shares outstanding during the nine months ended September 30, 2004 of 33,509,286 (26,378,800 in 2003) and 41,654,980 for the three months ended September 30, 2004 (26,389,200 in 2003). The calculation of diluted net income (loss) per share does not include stock options or performance share units as the effect would be anti-dilutive.

4. Credit Facility

On July 22, 2004, Deer Creek entered into an agreement with two Canadian chartered banks for a committed credit facility of $65.0 million. The lenders have a charge over all the assets of Deer Creek to secure the credit facility and will rank *pari passu* with Talisman over Deer Creek's right, title, estate and interest in the Joslyn Lease. As at September 30, 2004, no amounts had been advanced under this credit facility. Fees incurred in relation to the credit facility are included in deferred financing charges and will be amortized over the term of the agreement which expires on June 30, 2009. Standby fees of $0.1 million in relation to the credit facility have been capitalized during the nine and three month periods ended September 30, 2004.

5. Contingencies and Commitments

Joslyn Project Development

The Company has agreements with Talisman Energy Inc. (the "Talisman Agreement") and EnerMark Inc. ("EnerMark") related to the development of the Joslyn Project. Details of these agreements are provided in Note 5 to the annual consolidated financial statements for the fiscal year ended December 31, 2003.

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:

	September 30 2004	December 31 2003
Contingent production payment:		
Deer Creek	**$ 17,640**	$ 17,640
EnerMark	**3,360**	3,360
	$ 21,000	$ 21,000
Contingent interest payment:		
Deer Creek	**$ 5,779**	$ 5,258
EnerMark	**1,101**	1,002
	$ 6,880	$ 6,260

As at September 30, 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.

Supplemental Information

Joslyn Project Development Plan

Project Phase	Expected Production Bbls of bitumen per day	Start up*	Full Production*
SAGD Phase I	600	Q2 2004	2005
SAGD Phase II	10,000	Q1 2006	2007
SAGD Phase IIIA	15,000	2007	2008
SAGD Phase IIIB	15,000	2009	2010
Mine Phase I/II	100,000	2011	2014
Mine Phase III/IV	100,000	2017	2020
Total	**240,600**		

* Start up for the SAGD phases of the Joslyn Project refers to initial steaming, with full production expected 12-18 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.

Corporate Information

Directors

John Clarkson [3, 4C]
President, Clearwater Capital Corporation

Jonathan C. Farber [2, 3]
Managing Director, Lime Rock Partners

Ronald Hiebert [2, 3]
Director, Scotia McLeod

S. Barry Jackson [1, 3C, 4]
Chairman, Resolute Energy Inc.

Gordon Kerr [2]
President and CEO, Enerplus Resources Fund

Brian Lemke [2C]
President and CEO, Resolute Energy Inc.

Glen Schmidt [4]
President and CEO, Deer Creek Energy Limited

[1] Chairman of the Board
[2] Audit Committee
[3] Human Resources & Governance Committee
[4] Technical Committee
[C] Committee Chairman

Officers

Glen Schmidt
President and CEO

John Kowal
Vice President, Finance and CFO

Mark Montemurro
Vice President, Thermal

Gary Purcell
Vice President, Business Development

Don Riva
Vice President, Mining

Karen Lillejord
Controller

Jim Thomson
Corporate Secretary

Toronto Stock Exchange
Trading Symbol – DCE

DEER CREEK
Energy Limited

For more information, please contact

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E-Mail: deercrk@deercreekenergy.com

Deer Creek's annual report and other documents are available online at www.deercreekenergy.com.

FORM 52-109FT2
Certificate of Interim Filings during Transition Period

I, Glen C. Schmidt, President and Chief Executive Officer of Deer Creek Energy Limited, certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings)* of **Deer Creek Energy Limited** for the interim period ending September 30, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

November 10, 2004

(signed) *Glen C. Schmidt*
Glen C. Schmidt
President and Chief Executive Officer

FORM 52-109FT2
Certificate of Interim Filings during Transition Period

I, John S. Kowal, Vice President, Finance and Chief Financial Officer of Deer Creek Energy Limited, certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings)* of **Deer Creek Energy Limited** for the interim period ending September 30, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

November 10, 2004

(signed) *John S. Kowal*
John S. Kowal
Vice President, Finance and Chief Financial Officer

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July 21, 2004

VIA SEDAR

Alberta Securities Commission
British Columbia Securities Commission
Saskatchewan Securities Commission
The Manitoba Securities Commission
Ontario Securities Commission
Autorité des marchés financiers
Office of the Administrator, New Brunswick
Nova Scotia Securities Commission
Securities Commission of Newfoundland and Labrador
Registrar of Securities, Prince Edward Island

Dear Sirs/Mesdames:

Re: Final Prospectus of Deer Creek Energy Limited

We refer to the final prospectus of Deer Creek Energy Limited (the "Issuer") dated July 21, 2004 (the "Prospectus"), relating to the offering of common shares of the Issuer.

We hereby consent to being named in the Prospectus as counsel for the Issuer under the heading "Legal Matters", and on the face page of the Prospectus, and to the references to and use of our opinions under the headings "Prospectus Summary – The Offering" and "Eligibility for Investment" in the Prospectus, and on the face page of the Prospectus.

We have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained therein that are derived from our opinions referred to above or that are within our knowledge as a result of our participation in the preparation of such opinions.

This letter is provided solely for the purpose of assisting you in discharging your responsibilities and may not be relied on by any other person for any other purpose.

Yours truly,

(signed) *Bennett Jones LLP*

STIKEMAN ELLIOTT

Stikeman Elliott LLP Barristers & Solicitors

4300 Bankers Hall West, 888-3rd Street S.W., Calgary, Canada T2P 5C5
Tel: (403) 266-9000 Fax: (403) 266-9034 www.stikeman.com

July 21, 2004

RECEIVED
2004 NOV 16 P 12:13

Alberta Securities Commission
British Columbia Securities Commission
Saskatchewan Financial Services Commission
The Manitoba Securities Commission
Ontario Securities Commission
Autorité des marchés financiers
New Brunswick Securities Administration
Nova Scotia Securities Commission
Prince Edward Island Securities Office
Securities Commission of Newfoundland and Labrador

Dear Sirs/Mesdames:

Re: Deer Creek Energy Limited - Final Prospectus

We refer to the (final) prospectus of Deer Creek Energy Limited (the "Issuer") dated July 21, 2004 (the "Prospectus") relating to the offering of common shares of the Issuer.

We hereby consent to being named in the Prospectus as counsel for the Underwriters under the heading "Legal Matters" and on the face page of the Prospectus, and to the references to and use of our opinions under the headings "Prospectus Summary – The Offering" and "Eligibility for Investment" in the Prospectus and on the face page of the Prospectus.

We confirm that we have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained in the Prospectus that are derived from our opinions referred to above or that are within our knowledge as a result of services we have performed to render such opinions.

This letter is solely for the private information of the addressees and is not to be used, quoted or referred to, in whole or in part, in the Prospectus or any other document or to any other person or company, nor should it be relied upon by any other person.

Yours truly,

"Stikeman Elliott LLP"

CALGARY
VANCOUVER
TORONTO
MONTREAL
OTTAWA
NEW YORK
LONDON
HONG KONG
SYDNEY

PRICEWATERHOUSECOOPERS

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2004 NOV 16 P 12: 14

OFFICE OF INTERNATIONAL CORPORATE FINANCE

PricewaterhouseCoopers LLP
Chartered Accountants
111 5th Avenue SW, Suite 3100
Calgary, Alberta
Canada T2P 5L3
Telephone +1 (403) 509 7500
Facsimile +1 (403) 781 1825

July 21, 2004

British Columbia Securities Commission
Alberta Securities Commission
Saskatchewan Securities Commission
Manitoba Securities Commission
Ontario Securities Commission
Autorité des Marchés Financiers
New Brunswick Securities Branch
Nova Scotia Securities Commission
Prince Edward Island Department of Community Affairs and Attorney General
Securities Commission of Newfoundland and Labrador

Re: Deer Creek Energy Limited

We refer to the preliminary prospectus of Deer Creek Energy Limited (the "Company") dated July 21, 2004 relating to the sale and issue of $160,550,000 in common shares (the "Prospectus").

We consent to the use, through inclusion in the Prospectus of our report dated March 5, 2004, except for note 12, which is as at July 21, 2004 to the directors of the Company on the following financial statements:

- Consolidated balance sheets as at December 31, 2003 and 2002;
- Consolidated statements of income, deficit and cash flows for each of the years in the three-year period ended December 31, 2003.

We report that we have read the Prospectus and all information specifically incorporated by reference therein and have no reason to believe that there are any misrepresentations in the information contained therein that are derived from the financial statements upon which we have reported or that are within our knowledge as a result of our audit of such financial statements.

This letter is provided solely for the purpose of assisting the securities regulatory authorities to which it is addressed in discharging their responsibilities and should not be used for any other

PRICEWATERHOUSECOOPERS

purpose. Any use that a third party makes of this letter, or any reliance or decisions made based on it, are the responsibility of such third parties. We accept no responsibility for loss or damages, if any, suffered by any third party as a result of decisions made or actions taken based on this letter.

Yours very truly,

Chartered Accountants

Gilbert Laustsen Jung
Associates Ltd. Petroleum Consultants
4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada T2P 4H2 (403) 266-9500 Fax (403) 262-1855

July 21, 2004

British Columbia Securities Commission
Alberta Securities Commission
Saskatchewan Securities Commission
The Manitoba Securities Commission
Ontario Securities Commission
Autorité des marchés financiers
Office of the Administrator, New Brunswick
Registrar of Securities, Prince Edward Island
Nova Scotia Securities Commission
Securities Commission of Newfoundland

Dear Sirs/Mesdames:

Re: Deer Creek Energy Limited (the "Corporation")

Reference is made to the prospectus of the Corporation dated July 21, 2004 (the "Prospectus") relating to the initial public offering of common shares in the capital of the Corporation.

We hereby consent to the reference in the Prospectus to our firm name and to the use in the Prospectus of our report entitled "Reserves and Resource Assessment and Evaluation of Canadian Oil and Gas Properties" dated March 16, 2004 and effective January 1, 2004 (the "Report").

We have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from the Report or that is within our knowledge as a result of the services we provided in preparing the Report.

Sincerely,

**GILBERT LAUSTSEN JUNG
ASSOCIATES LTD.**

ORIGINALLY SIGNED BY
Dana B. Laustsen, P. Eng.
Executive Vice-President

NORWEST
CORPORATION

SUITE 400, 205 – 9TH AVE SE
CALGARY, ALBERTA CANADA T2G OR3
TEL (403) 237-7763
FAX (403) 263-4086

RECEIVED
2004 NOV 16 P 12: 14
OFFICE OF INTERNATIONAL CORPORATE FINANCE

July 21, 2004

British Columbia Securities Commission
Alberta Securities Commission
Saskatchewan Securities Commission
The Manitoba Securities Commission
Ontario Securities Commission
Autorité des marchés financiers
Office of the Administrator, New Brunswick
Registrar of Securities, Prince Edward Island
Nova Scotia Securities Commission
Securities Commission of Newfoundland

Dear Sirs/Mesdames:

Re: Deer Creek Energy Limited (the "Corporation")

Reference is made to the final prospectus of the Corporation to be dated on or about July 20, 2004 (the "Prospectus") relating to the initial public offering of common shares in the capital of the Corporation.

We hereby consent to the reference in the Prospectus to our firm name and to the use in the Prospectus of our report entitled "Lease 24/Permit 70 Geological Modeling and Evaluation of Bitumen Potential" (the "Report") dated December 2, 2003 (updated April 2004) and the table under the heading "Mining and Extraction Operations – Oil Sands Mining Comparisons", located on page 35 of the Prospectus, prepared by us and comparing certain of the key resource attributes of certain oil sands projects that are being developed by competitors of the Corporation.

We have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from the Report or that is within our knowledge as a result of the services we provided in preparing the Report.

Sincerely,

NORWEST CORPORATION

ORIGINAL SIGNED BY:
Joseph Aiello, P.Eng.
President

JPA/njw

Washington Group International
Integrated Engineering, Construction, and Management Solutions

July 21, 2004

British Columbia Securities Commission
Alberta Securities Commission
Saskatchewan Securities Commission
The Manitoba Securities Commission
Ontario Securities Commission
Autorité des marchés financiers
Office of the Administrator, New Brunswick
Registrar of Securities, Prince Edward Island
Nova Scotia Securities Commission
Securities Commission of Newfoundland

Dear Sirs/Mesdames:

Re: Deer Creek Energy Limited (the "Corporation")

Reference is made to the final prospectus of the Corporation to be dated on or about July 21, 2004 (the "Prospectus") relating to the initial public offering of common shares in the capital of the Corporation.

We hereby consent to the reference in the Prospectus to our firm name and to the references in the Prospectus of our report entitled Joslyn Oil Sands Project Preliminary Feasibility Study dated March, 2004 (the "Report").

We have read the Prospectus and have no reason to believe that there are any misrepresentations in the information contained therein that is derived from the Report or that is within our knowledge as a result of the services we provided in preparing the Report.

Sincerely,

WASHINGTON GROUP INTERNATIONAL INC.

Gil Clausen
Executive Vice President – Business Development
Washington Group International - Mining

DEER CREEK ENERGY LTD.

RESERVES & RESOURCE ASSESSMENT
AND
EVALUATION OF
CANADIAN OIL AND GAS PROPERTIES

CORPORATE SUMMARY

Effective January 01, 2004

1046350

Gilbert Laustsen Jung Associates Ltd.

SUMMARY REPORT

TABLE OF CONTENTS

Gilbert Laustsen Jung
Associates Ltd. Petroleum Consultants
4100,400 - 3rd Avenue S.W.,Calgary,Alberta,Canada T2P 4H2 (403) 266-9500 Fax (403) 262-1855

May 18, 2004

Project 1046350

Mr. Gary Purcell
Deer Creek Energy Ltd.
2600, 205 – 5th Avenue S.W.
Calgary, Alberta
T2P 2V7

Dear Sir:

Re: Deer Creek Energy Ltd.
Corporate Evaluation
<u>Effective January 1, 2004</u>

Gilbert Laustsen Jung Associates Ltd. (GLJ) has completed an independent reserves and resources assessment and evaluation of the oil and gas properties of Deer Creek Energy Ltd. (the "Company"). The effective date of this evaluation is January 1, 2004. The report has been revised from the previous March 23, 2004 report to reflect new income tax regulations.

The Company's activities entail development of bitumen reserves and resources in the Joslyn Creek property. Development of the bitumen volumes by Steam Assisted Gravity Drainage (SAGD) techniques in the near future have been classified as reserves, whereas the future development of the bitumen volumes by mining have been classified as resources.

This report has been prepared for the Company for the purpose of annual disclosure and other financial requirements. This evaluation has been prepared in accordance with reserves definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook.

It was GLJ's primary mandate in this evaluation to provide an independent evaluation of the oil and gas reserves of the Company in aggregate. Accordingly it may not be appropriate to extract individual property or entity estimates for other purposes. Our engagement letter notes these limitations on the use of this report.

It is trusted that this evaluation meets your current requirements. Should you have any questions regarding this analysis, please contact the undersigned.

Yours very truly,

GILBERT LAUSTSEN JUNG
ASSOCIATES LTD.

ORIGINALLY SIGNED BY

Dana B. Laustsen, P. Eng.
Executive Vice-President

DBL/jem
Attachments

INDEPENDENT PETROLEUM CONSULTANTS' CONSENT

The undersigned firm of Independent Petroleum Consultants of Calgary, Alberta, Canada has prepared an independent evaluation of the **Deer Creek Energy Ltd.** Canadian oil and gas properties and hereby gives consent to the use of its name and to the said estimates. The effective date of the evaluation is **January 1, 2004.**

In the course of the evaluation, Deer Creek Energy Ltd. provided Gilbert Laustsen Jung Associates Ltd. personnel with basic information which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which this report is based, were obtained from public records, other operators and from Gilbert Laustsen Jung Associates Ltd. nonconfidential files. Deer Creek Energy Ltd. has provided a representation letter confirming that all information provided to Gilbert Laustsen Jung Associates Ltd. is correct and complete to the best of its knowledge. Procedures recommended in the Canadian Oil and Gas Evaluation (COGE) Handbook to verify certain interests and financial information were applied in this evaluation. In applying these procedures and tests, nothing came to Gilbert Laustsen Jung Associates Ltd.'s attention that would suggest that information provided by Deer Creek Energy Ltd. was not complete and accurate. Gilbert Laustsen Jung Associates Ltd. reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this report.

The accuracy of any reserves and production estimate is a function of the quality and quantity of available data and of engineering interpretation and judgment. While reserves and production estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

Revenue projections presented in this report are based in part on forecasts of market prices, currency exchange rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future, differ materially from the forecasts utilized herein. Present values of revenues documented in this report do not necessarily represent the fair market value of the reserves evaluated herein.

PERMIT TO PRACTICE
GILBERT LAUSTSEN JUNG ASSOCIATES LTD.

Signature: ORIGINALLY SIGNED BY KEITH M. BRAATEN

Date: May 18, 2004

PERMIT NUMBER: P 2066
The Association of Professional Engineers, Geologists and Geophysicists of Alberta

ORIGINALLY SIGNED BY
DARYL H. GILBERT
Gilbert Laustsen Jung Associates Ltd.

INTRODUCTION

Gilbert Laustsen Jung Associates Ltd. (GLJ) was commissioned by Deer Creek Energy Ltd. (the "Company") to prepare an independent evaluation of its oil and gas reserves and resources. The location of the Joslyn Creek property is indicated on the attached index map.

The evaluation was initiated in November 2003 and completed by March 2004. The Company provided land, accounting data and other technical information not available in the public domain to approximately January 31, 2004. The Company has confirmed that, to the best of its knowledge, all information provided to GLJ is correct and complete as of the effective date.

This evaluation has been prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook. The reserves definitions used in preparing this report (included herein under "Reserves Definitions") are those contained in the COGE Handbook and the Canadian Securities Administrators National Instrument 51-101 (NI 51-101).

The Company's activities entail development of bitumen reserves and resources in its Joslyn Creek property. Development of the bitumen volumes have been classified as reserves, whereas the future development of bitumen volumes by mining have been classified as resources.

The evaluation was conducted on the basis of the Gilbert Laustsen Jung Associates Ltd. April 1, 2004 Price Forecast which is summarized in the Product Price and Market Forecasts section of this report.

Tables summarizing production, royalties, costs, revenue projections, reserves and present value estimates for various reserves categories for individual properties and the Company total are provided in the tabbed sections of this Summary Report.

The Evaluation Procedure section outlines general procedures used in preparing this evaluation. The individual property reports, provided under separate cover, provide additional evaluation details. The following summarizes evaluation matters that have been included/excluded in cash flow projections:

- Alberta Royalty Tax Credits (ARTC) have been included,
- the Company has no reported hedging activity,
- the Company has no reported processing income,

- provisions for the abandonment of all of the Company's future wells have been included,
- general and administrative (G&A) costs and overhead recovery have not been included,
- undeveloped land values have not been included in this evaluation.

A constant price analysis was performed by rerunning the evaluation database using fixed last day (December 31, 2003) posted pricing and no cost escalations.

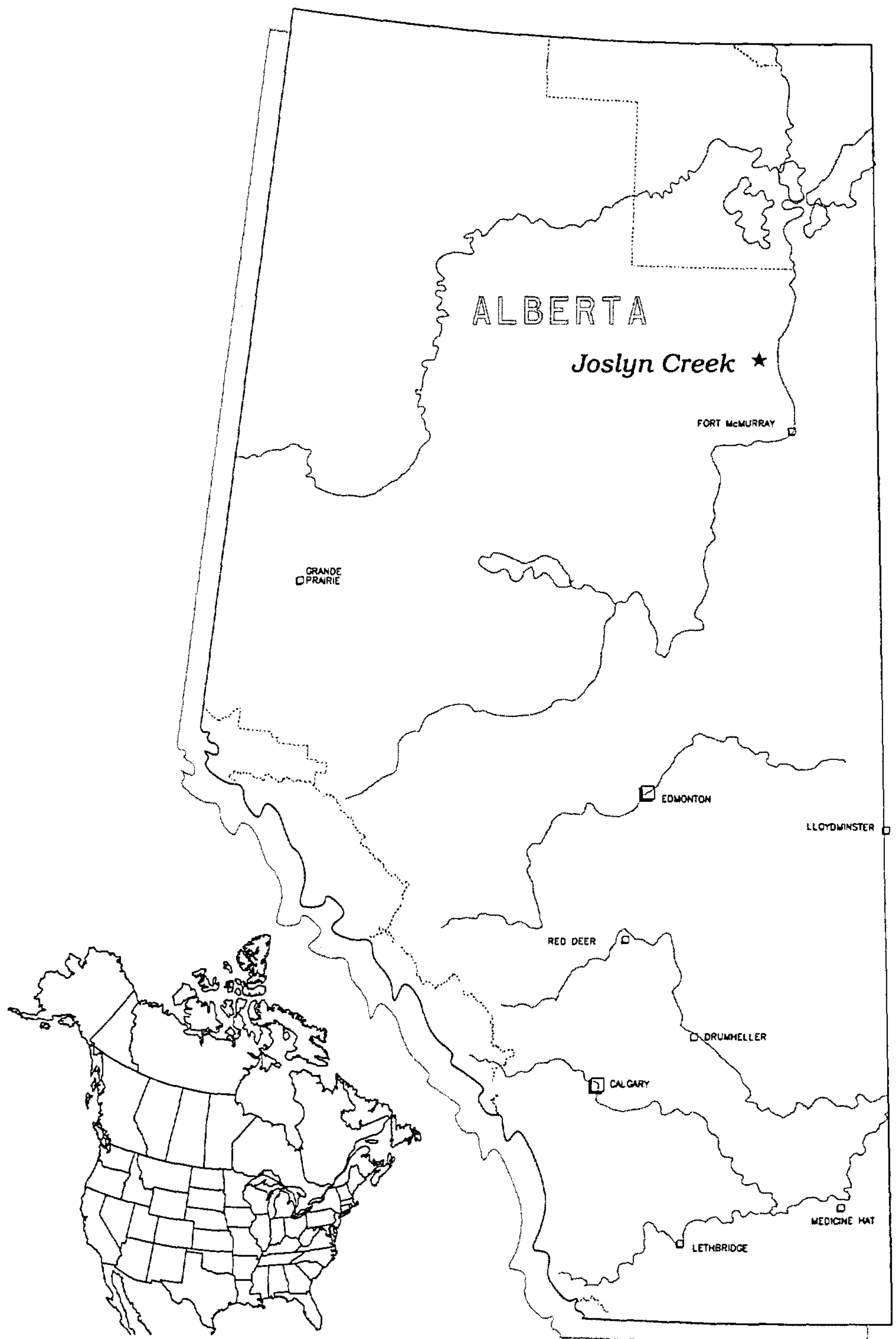
A summary of reference prices and resulting reserves data under the constant pricing scenario are provided in the "Constant Price Analysis" section.

The Securities Reporting section of this report provides reserves data in a format that is consistent with the disclosure requirements set out in NI 51-101.

Map 1
Index Map
Property Locations

Company: Deer Creek Energy Ltd.
Property: Alberta

Effective Date: January 1, 2004
Scale: 1:6,500,000 s1046350/indm01



SUMMARY

TABLE OF CONTENTS

TABLE 1

Summary of Reserves and Values

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total With Adjustments**

Pricing: **GLJ (2004-04) Full Year**
Effective Date: **January 01, 2004**

	Probable Undeveloped	PPP Undeveloped
MARKETABLE RESERVES		
Heavy Oil - MMSTB		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
Oil Equivalent - MMBOE		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
BEFORE TAX PRESENT VALUE - $M		
0.0%	1742695	2871677
5.0%	626186	1056871
8.0%	322548	575921
10.0%	194669	375113
12.0%	104608	234091
15.0%	16050	95200
20.0%	-60419	-26602
AFTER TAX PRESENT VALUE - $M		
0.0%	1143699	1878290
5.0%	368176	634331
8.0%	159059	308446
10.0%	71790	173764
12.0%	10968	80182
15.0%	-47749	-10379
20.0%	-96022	-86447

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

Project 1046350
Run date Fri May 21 2004 10:42:51

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TABLE 2

Summary of Resources and Values

Company: **Deer Creek Energy Ltd.** Pricing: **GLJ (2004-04) Full Year**

Property: **Joslyn Creek Mining Resources** Effective Date: **January 1, 2004**

	Best Estimate
MARKETABLE REOURCES	
Heavy Oil - MMSTB	
Total Company Interest	1235
Working Interest	1235
Net After Royalty	1120
Oil Equivalent - MMBOE	
Total Company Interest	1235
Working Interest	1235
Net After Royalty	1120
BEFORE TAX PRESENT VALUE - $M	
0.00%	10164436
5.00%	2612470
8.00%	1128010
10.00%	607279
12.00%	287998
15.00%	23167
20.00%	-147107
AFTER TAX PRESENT VALUE - $M	
0.00%	6623946
5.00%	1598145
8.00%	614536
10.00%	272556
12.00%	65610
15.00%	-101233
20.00%	-198017

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

Project 1046350

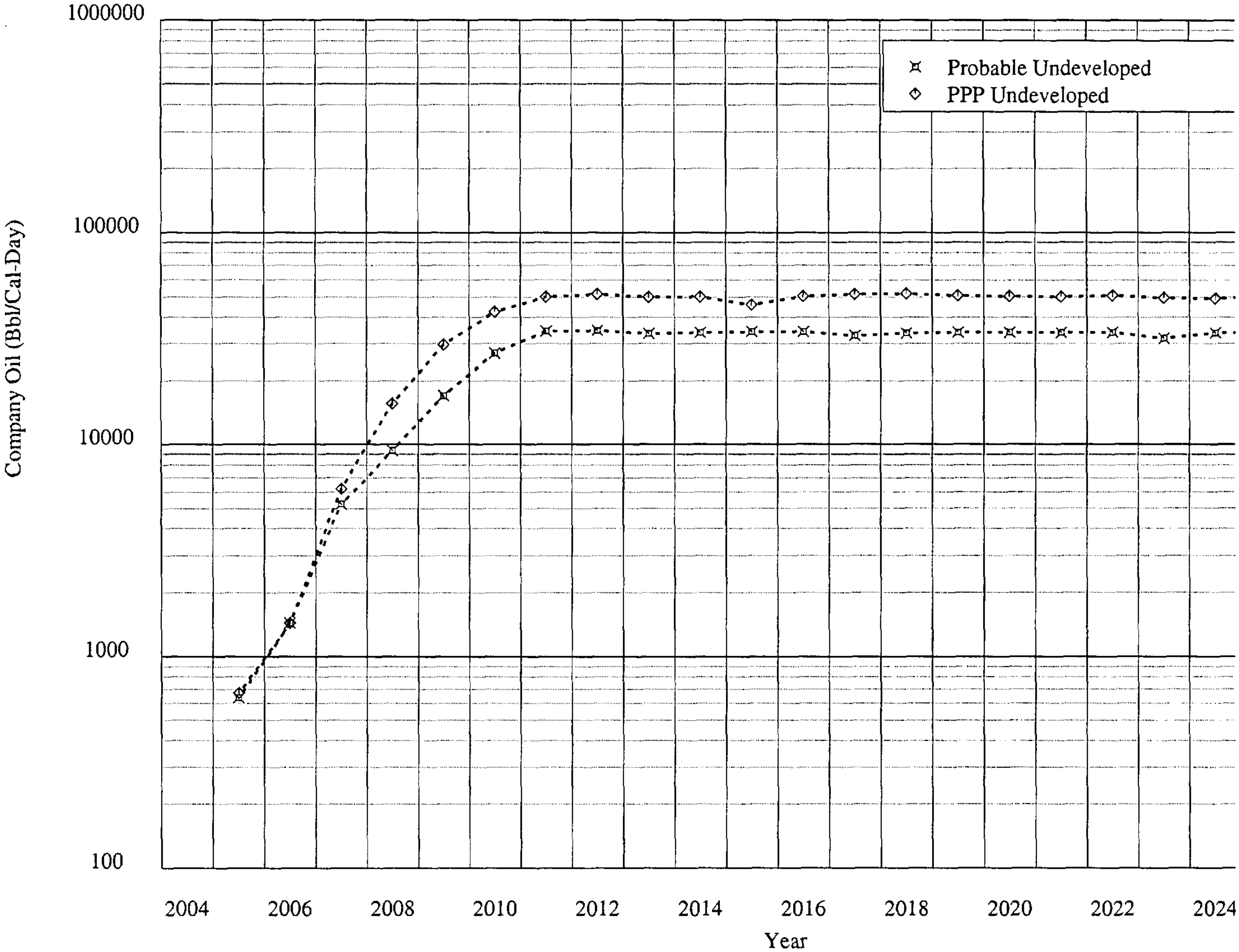
aftertaxpsum.xls

p:\s1046350\rems\econ\Posted (2003-12-31 Constant) \Joslyn_Creek_Mining_Resources_RC38_psum.htm

Company: Deer Creek Energy Ltd.
Property: Corporate
Description: Total With Adjustments

Forecast Production
Company Oil

Pricing: Gl
Effective Date: Ja



Drawing No: 1

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Run

Gilbert Laust

RESERVES

TABLE OF CONTENTS

Summary of Reserves and Values

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total With Adjustments**

Pricing: **GLJ (2004-04) Full Year**
Effective Date: **January 01, 2004**

	Probable Undeveloped	PPP Undeveloped
MARKETABLE RESERVES		
Heavy Oil - MMSTB		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
Oil Equivalent - MMBOE		
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15.0%	16050	95200
20.0%	-60419	-26602
AFTER TAX PRESENT VALUE - $M		
0.0%	1143699	1878290
5.0%	368176	634331
8.0%	159059	308446
10.0%	71790	173764
12.0%	10968	80182
15.0%	-47749	-10379
20.0%	-96022	-86447

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

Project 1046350
Run date Fri May 21 2004 10:42:51

Company Production, Reserves and Present Value Summary

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2004-04) Full Year**
Effective Date: **January 01, 2004**

	2004 Company Interest Prod'n				Company Interest Reserves					Net After Royalty Reserves					I
Entity Description	Gas mcf/d	Oil bbl/d	NGL bbl/d	BOE bbl/d	Gas Mmcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	BOE Mbbl	Gas Mmcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	BOE Mbbl	
Probable Undeveloped															
Total Joslyn Creek															
Joslyn Creek Mining Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Joslyn Creek SAGD	0	0	0	0	0	250195	0	0	250195	0	228258	0	0	228258	
Total Total Joslyn Creek	0	0	0	0	0	250195	0	0	250195	0	228258	0	0	228258	
ARTC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Probable Undeveloped	0	0	0	0	0	250195	0	0	250195	0	228258	0	0	228258	
PPP Undeveloped															
Total Joslyn Creek															
Joslyn Creek Mining Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Joslyn Creek SAGD	0	0	0	0	0	402442	0	0	402442	0	364296	0	0	364296	
Total Total Joslyn Creek	0	0	0	0	0	402442	0	0	402442	0	364296	0	0	364296	
ARTC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
PPP Undeveloped	0	0	0	0	0	402442	0	0	402442	0	364296	0	0	364296	

BOE Factors:								
	OIL	1.00000	RES GAS	6.00000	PROPANE	1.00000	ETHANE	1.00000
	COND	1.00000	SLN GAS	6.00000	BUTANE	1.00000	SULPHUR	0.00000

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Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Reserve Class:	**Probable**
Property:	**Corporate**	Development Class:	**Undeveloped**
Description:	**Total With Adjustments**	Pricing:	**GLJ (2004-04) Full Year**
		Effective Date:	**January 01, 2004**

PRODUCTION FORECAST

	Heavy Oil Production				
Year	Compny Oil Wells	Compny Daily Stb	Compny Yearly Mstb	Net Yearly Mstb	Price $/Bbl
2004	0	0	0	0	0.00
2005	3	638	233	231	20.50
2006	3	1428	521	516	19.25
2007	19	5250	1916	1897	16.50
2008	19	9345	3411	3377	16.50
2009	45	17052	6224	6162	16.50
2010	61	26943	9834	9736	17.00
2011	61	34251	12502	12377	17.50
2012	61	34476	12584	12458	18.00
2013	66	33369	12180	12058	18.50
2014	79	33676	12292	12169	19.00
2015	84	34020	12417	12293	19.50
Sub.	42	19204	84114	83272	18.06
Rem.	62	26766	166082	144986	23.47
Tot.	**54**	**23637**	**250195**	**228258**	**21.65**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses			Other Expenses			Net Prod'n Revenue
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	MM$	MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	4.8	0.0	4.8	0.0	0.0	0.0	0.0	0.0	4.7	4.8	0.0	4.8	0.0	0.0	0.0	0.0
2006	10.0	0.0	10.0	0.1	0.0	0.0	0.0	0.1	9.9	9.1	0.0	9.1	0.0	0.0	0.0	0.8
2007	31.6	0.0	31.6	0.3	0.0	0.0	0.0	0.3	31.3	17.5	2.2	19.7	0.0	0.0	0.0	11.6
2008	56.3	0.0	56.3	0.6	0.0	0.0	0.0	0.6	55.7	29.3	3.9	33.2	0.0	0.0	0.0	22.5
2009	102.7	0.0	102.7	1.0	0.0	0.0	0.0	1.0	101.7	42.0	6.7	48.7	0.0	0.0	0.0	53.0
2010	167.2	0.0	167.2	1.7	0.0	0.0	0.0	1.7	165.5	56.3	11.2	67.4	0.0	0.0	0.0	98.1
2011	218.8	0.0	218.8	2.2	0.0	0.0	0.0	2.2	216.6	61.4	13.2	74.6	0.0	0.0	0.0	142.0
2012	226.5	0.0	226.5	2.3	0.0	0.0	0.0	2.3	224.2	60.4	13.0	73.5	0.0	0.0	0.0	150.8
2013	225.3	0.0	225.3	2.3	0.0	0.0	0.0	2.3	223.1	64.2	13.4	77.5	0.0	0.0	0.0	145.5
2014	233.5	0.0	233.5	2.3	0.0	0.0	0.0	2.3	231.2	72.2	14.6	86.7	0.0	0.0	0.0	144.5
2015	242.1	0.0	242.1	2.4	0.0	0.0	0.0	2.4	239.7	82.9	16.2	99.1	0.0	0.0	0.0	140.6
Sub.	1518.9	0.0	1518.9	15.2	0.0	0.0	0.0	15.2	1503.7	500.0	94.4	594.3	0.0	0.0	0.0	909.4
Rem.	3897.5	0.0	3897.5	505.6	0.0	0.0	0.0	505.6	3391.8	1146.3	227.1	1373.5	0.0	0.0	0.0	2018.4
Tot.	**5416.3**	**0.0**	**5416.3**	**520.8**	**0.0**	**0.0**	**0.0**	**520.8**	**4895.5**	**1646.3**	**321.5**	**1967.8**	**0.0**	**0.0**	**0.0**	**2927.7**
Disc	1353.7	0.0	1353.7	85.8	0.0	0.0	0.0	85.8	1267.9	430.8	81.7	512.5	0.0	0.0	0.0	755.4

	Other Income		Aband. Costs	Oper. Income	Net Capital Investment				Before Tax Cash Flow			Income Tax	After Tax Cash Flow		
Year	Other MM$	ARTC MM$	MM$	MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	10.6	10.6	-10.6	-10.6	-10.1	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	0.0	8.5	0.0	0.0	8.5	-8.5	-19.1	-17.5	0.0	-8.5	-19.1	-17.5
2006	0.0	0.0	0.0	0.9	41.1	0.0	103.0	144.1	-143.2	-162.4	-130.4	0.0	-143.2	-162.4	-130.4
2007	0.0	0.1	0.0	11.6	0.0	0.0	52.7	52.7	-41.1	-203.4	-159.8	0.0	-41.1	-203.5	-159.8
2008	0.0	0.1	0.0	22.7	66.9	0.0	98.1	164.9	-142.3	-345.7	-252.4	0.0	-142.3	-345.8	-252.5
2009	0.0	0.3	0.0	53.3	45.2	0.0	153.8	199.1	-145.8	-491.5	-338.8	0.1	-145.9	-491.6	-338.8
2010	0.0	0.4	0.0	98.5	0.0	0.0	27.6	27.6	70.9	-420.6	-300.6	0.1	70.8	-420.8	-300.7
2011	0.0	0.5	0.0	142.5	0.0	0.0	0.0	0.0	142.5	-278.1	-230.9	10.0	132.5	-288.3	-235.9
2012	0.0	0.5	0.0	151.3	23.7	0.0	9.5	33.1	118.1	-160.0	-178.3	20.4	97.8	-190.5	-192.4
2013	0.0	0.5	0.0	146.0	36.0	0.0	14.4	50.4	95.6	-64.4	-139.7	22.1	73.5	-117.1	-162.7
2014	0.0	0.5	0.0	145.0	60.9	0.0	24.4	85.3	59.7	-4.7	-117.7	21.3	38.4	-78.7	-148.6
2015	0.0	0.5	0.0	141.1	0.0	0.0	0.0	0.0	141.1	136.4	-70.6	26.7	114.3	35.6	-110.4
Sub.	0.0	3.4	0.0	912.8	282.3	0.0	494.1	776.4	136.4	136.4	-70.6	100.7	35.6	35.6	-110.4
Rem.	0.0	8.5	13.3	2013.5	290.7	0.0	116.5	407.2	1606.3	1742.7	194.7	498.3	1108.1	1143.7	71.8
Tot.	**0.0**	**11.9**	**13.3**	**2926.3**	**573.0**	**0.0**	**610.6**	**1183.6**	**1742.7**	**1742.7**	**194.7**	**599.0**	**1143.7**	**1143.7**	**71.8**
Disc	0.0	2.9	1.8	756.5	219.3	0.0	342.5	561.8	194.7	194.7	194.7	122.9	71.8	71.8	71.8

AFTER TAX ANALYSIS

Year Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2005	4.8	0.0	0.0	0.0	4.8	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2006	10.0	0.0	0.0	0.0	9.1	0.0	0.0	0.0	113.6	0.0	0.0	0.0	0.0
2007	31.6	0.0	0.0	0.2	19.7	0.0	0.0	0.0	166.3	0.0	0.0	0.0	0.0
2008	56.3	0.0	0.0	0.4	33.2	0.0	0.0	0.0	264.4	0.0	0.0	0.0	0.0
2009	102.7	0.0	0.0	0.8	48.7	0.0	0.0	0.0	418.2	9.5	0.0	0.0	9.5
2010	167.2	0.0	0.0	1.3	67.4	0.0	0.0	0.0	436.2	67.7	0.0	0.0	67.7
2011	218.8	0.0	0.0	1.7	74.6	0.0	0.0	0.0	368.6	92.1	0.0	0.0	92.1
2012	226.5	0.0	0.0	1.8	73.5	0.0	0.0	0.0	285.9	70.3	0.0	0.0	70.3
2013	225.3	0.0	0.0	1.8	77.5	0.0	0.0	0.0	230.0	55.7	0.0	0.0	55.7
2014	233.5	0.0	0.0	1.8	86.7	0.0	0.0	0.0	198.7	46.6	0.0	0.0	46.6
2015	242.1	0.0	0.0	1.9	99.1	0.0	0.0	0.0	152.1	38.0	0.0	0.0	38.0
Sub.	1518.9	0.0	0.0	11.7	594.3	0.0	0.0	0.0	152.1	380.0	0.0	0.0	380.0
Rem.	3897.5	0.0	0.0	497.1	1386.8	0.0	0.0	0.0	7.0	225.3	0.0	0.0	225.3
Tot.	**5416.3**	**0.0**	**0.0**	**508.8**	**1981.1**	**0.0**	**0.0**	**0.0**	**7.0**	**605.3**	**0.0**	**0.0**	**605.3**
Disc	1353.7	0.0	0.0	82.9	514.3	0.0	0.0	0.0	146.0	216.3	0.0	0.0	216.3

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write -off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.5	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.9	0.1	0.0	0.0	0.0	0.0	67.6	0.8	0.0	0.0	0.8	0.0
2007	0.0	11.6	0.0	0.0	0.0	0.0	0.0	66.8	11.6	0.0	0.0	11.6	0.1
2008	0.0	22.7	0.0	0.0	0.0	0.0	0.0	122.1	22.5	0.0	0.0	22.5	0.1
2009	0.0	43.7	0.0	0.0	0.0	0.0	0.0	144.8	43.5	0.0	0.0	43.5	0.3
2010	0.0	30.8	0.0	0.0	0.0	0.0	0.0	101.4	30.4	0.0	0.0	30.4	0.4
2011	0.0	50.3	0.0	0.0	0.0	0.0	0.0	71.0	21.3	0.0	0.0	21.3	29.0
2012	0.0	81.0	0.0	0.0	0.0	0.0	0.0	73.3	22.0	0.0	0.0	22.0	59.0
2013	0.0	90.3	0.0	0.0	0.0	0.0	0.0	87.4	26.2	0.0	0.0	26.2	64.1
2014	0.0	98.4	0.0	0.0	0.0	0.0	0.0	122.1	36.6	0.0	0.0	36.6	61.7
2015	0.0	103.0	0.0	0.0	0.0	0.0	0.0	85.5	25.6	0.0	0.0	25.6	77.4
Sub.	0.0	532.8	0.1	0.0	0.0	0.0	0.0	85.5	240.5	0.0	0.0	240.5	292.2
Rem.	0.0	1788.3	0.0	0.0	0.0	0.0	0.0	6.5	346.0	0.0	0.0	346.0	1442.3
Tot.	**0.0**	**2321.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**6.5**	**586.5**	**0.0**	**0.0**	**586.5**	**1734.5**
Disc	0.0	540.2	0.1	0.0	0.0	0.0	0.0	69.1	184.2	0.0	0.0	184.2	356.0

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest -ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	Net Cash Flow After Income Tax 10% Dcf Cum. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-8.5	-19.1	-17.5
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-143.2	-162.4	-130.4
2007	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-41.1	-203.5	-159.8
2008	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-142.3	-345.8	-252.5
2009	0.0	0.0	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-145.9	-491.6	-338.8
2010	0.0	0.0	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.1	70.8	-420.8	-300.7
2011	0.0	0.0	29.0	29.0	6.4	0.0	0.0	28.5	3.6	0.0	10.0	132.5	-288.3	-235.9
2012	0.0	0.0	59.0	59.0	13.0	0.0	0.0	58.5	7.3	0.0	20.4	97.8	-190.5	-192.4
2013	0.0	0.0	64.1	64.1	14.2	0.0	0.0	63.6	8.0	0.0	22.1	73.5	-117.1	-162.7
2014	0.0	0.0	61.7	61.7	13.7	0.0	0.0	61.2	7.7	0.0	21.3	38.4	-78.7	-148.6
2015	0.0	0.0	77.4	77.4	17.1	0.0	0.0	76.9	9.6	0.0	26.7	114.3	35.6	-110.4
Sub.	0.0	0.0	292.2	292.2	64.6	0.1	0.0	288.8	36.1	0.0	100.7	35.6	35.6	-110.4
Rem.	0.0	0.0	1442.3	1442.3	319.0	0.0	0.0	1433.8	179.2	0.0	498.3	1108.1	1143.7	71.8
Tot.	**0.0**	**0.0**	**1734.5**	**1734.5**	**383.7**	**0.1**	**0.0**	**1722.6**	**215.3**	**0.0**	**599.0**	**1143.7**	**1143.7**	**71.8**
Disc	0.0	0.0	356.0	356.0	78.7	0.1	0.0	353.1	44.1	0.0	122.9	71.8	71.8	71.8

RESERVE SUMMARY

Product	Units	Remaining Reserves at January 1, 2004: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: BOE Factor	Company Mstb	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	250195	0	250195	228258	1.000	250195	100	29.0	100.0	15.4
Total Oil Eq.	Mstb	250195	0	250195	228258		250195	100	29.0	0.0	15.4

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4895528	100	1267851	100
Total Oil Eq.	$/BOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4895528	100	1267851	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)	Initial	Average	Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Net Present Value After Tax: Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
Crown Royalty	0.0000	9.6157	0.0	2927715	2926316	1183621	1742695	6.97	2327320	1183621	1143699	4.57
Non-crown Royalty	0.0000	0.0000	5.0	1407668	1408549	782363	626186	2.50	1150539	782363	368176	1.47
Mineral Tax	0.0000	0.0000	8.0	957518	958639	636091	322548	1.29	795150	636091	159059	0.64
NPI Payment	0.0000	0.0000	10.0	755365	756491	561823	194669	0.78	633613	561823	71790	0.29
			12.0	604449	605525	500917	104608	0.42	511885	500917	10968	0.04
			15.0	443181	444139	428089	16050	0.06	380340	428089	-47749	-0.19
			20.0	279009	279756	340175	-60419	-0.24	244153	340175	-96022	-0.38

Project.......1046350
Entity.......Total With Adjustments (Probable Undeveloped)
Run date....Fri May 21 2004 10:42:50
Evaluator...Laustsen, Dana B.

Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Reserve Class:	**PPP**
Property:	**Corporate**	Development Class:	**Undeveloped**
Description:	**Total With Adjustments**	Pricing:	**GLJ (2004-04) Full Year**
		Effective Date:	**January 01, 2004**

PRODUCTION FORECAST

		Heavy Oil Production			
Year	Compny Oil Wells	Compny Daily Stb	Compny Yearly Mstb	Net Yearly Mstb	Price $/Bbl
2004	0	0	0	0	0.00
2005	3	672	245	243	20.50
2006	3	1428	521	516	19.25
2007	24	6212	2267	2245	16.50
2008	45	15662	5717	5659	16.50
2009	70	29501	10768	10660	16.50
2010	87	42395	15474	15319	17.00
2011	87	49938	18227	18045	17.50
2012	87	51450	18779	18591	18.00
2013	87	49832	18189	18007	18.50
2014	102	49984	18244	18062	19.00
2015	106	45830	16728	16561	19.50
Sub.	58	28575	125160	123908	18.01
Rem.	104	39983	277282	240388	23.90
Tot.	**86**	**35567**	**402442**	**364296**	**22.07**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total	Net	Operating Expenses			Other Expenses			Net
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	Royalty After Process. MM$	Revenue After Royalty MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	Prod'n Revenue MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	5.0	0.0	5.0	0.1	0.0	0.0	0.0	0.1	5.0	4.8	0.0	4.8	0.0	0.0	0.0	0.1
2006	10.0	0.0	10.0	0.1	0.0	0.0	0.0	0.1	9.9	9.1	0.0	9.1	0.0	0.0	0.0	0.8
2007	37.4	0.0	37.4	0.4	0.0	0.0	0.0	0.4	37.0	20.1	2.7	22.8	0.0	0.0	0.0	14.2
2008	94.3	0.0	94.3	0.9	0.0	0.0	0.0	0.9	93.4	45.4	6.9	52.3	0.0	0.0	0.0	41.1
2009	177.7	0.0	177.7	1.8	0.0	0.0	0.0	1.8	175.9	66.2	11.9	78.1	0.0	0.0	0.0	97.8
2010	263.1	0.0	263.1	2.6	0.0	0.0	0.0	2.6	260.4	79.8	16.6	96.4	0.0	0.0	0.0	164.1
2011	319.0	0.0	319.0	3.2	0.0	0.0	0.0	3.2	315.8	85.7	18.6	104.3	0.0	0.0	0.0	211.4
2012	338.0	0.0	338.0	3.4	0.0	0.0	0.0	3.4	334.6	84.9	18.8	103.7	0.0	0.0	0.0	230.9
2013	336.5	0.0	336.5	3.4	0.0	0.0	0.0	3.4	333.1	88.4	19.1	107.5	0.0	0.0	0.0	225.6
2014	346.6	0.0	346.6	3.5	0.0	0.0	0.0	3.5	343.2	103.7	21.4	125.1	0.0	0.0	0.0	218.1
2015	326.2	0.0	326.2	3.3	0.0	0.0	0.0	3.3	322.9	106.7	21.1	127.7	0.0	0.0	0.0	195.2
Sub.	2253.9	0.0	2253.9	22.5	0.0	0.0	0.0	22.5	2231.3	694.8	137.2	832.0	0.0	0.0	0.0	1399.4
Rem.	6628.4	0.0	6628.4	887.8	0.0	0.0	0.0	887.8	5740.6	1977.3	385.9	2363.2	0.0	0.0	0.0	3377.4
Tot.	**8882.2**	**0.0**	**8882.2**	**910.3**	**0.0**	**0.0**	**0.0**	**910.3**	**7971.9**	**2672.1**	**523.1**	**3195.2**	**0.0**	**0.0**	**0.0**	**4776.7**
Disc	2092.2	0.0	2092.2	149.8	0.0	0.0	0.0	149.8	1942.4	641.6	125.2	766.7	0.0	0.0	0.0	1175.7

	Other Income				Net Capital Investment				Before Tax Cash Flow				After Tax Cash Flow		
Year	Other MM$	ARTC MM$	Aband. Costs MM$	Oper. Income MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	Income Tax MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	10.6	10.6	-10.6	-10.6	-10.1	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	0.1	8.5	0.0	0.0	8.5	-8.4	-19.0	-17.4	0.0	-8.4	-19.0	-17.4
2006	0.0	0.0	0.0	0.9	51.9	0.0	90.0	141.9	-141.1	-160.0	-128.5	0.0	-141.1	-160.0	-128.5
2007	0.0	0.1	0.0	14.3	54.9	0.0	74.7	129.6	-115.3	-275.3	-211.1	0.0	-115.3	-275.3	-211.1
2008	0.0	0.2	0.0	41.3	66.9	0.0	115.9	182.8	-141.5	-416.8	-303.2	0.1	-141.5	-416.9	-303.3
2009	0.0	0.4	0.0	98.2	45.2	0.0	153.8	199.1	-100.9	-517.7	-363.0	0.1	-101.0	-517.8	-363.1
2010	0.0	0.5	0.0	164.6	0.0	0.0	137.8	137.8	26.8	-490.9	-348.5	2.2	24.6	-493.3	-349.8
2011	0.0	0.5	0.0	211.9	0.0	0.0	74.6	74.6	137.4	-353.5	-281.3	23.8	113.6	-379.7	-294.3
2012	0.0	0.5	0.0	231.4	0.0	0.0	0.0	0.0	231.4	-122.1	-178.4	40.2	191.3	-188.5	-209.2
2013	0.0	0.5	0.0	226.1	55.2	0.0	22.1	77.3	148.8	26.7	-118.2	41.9	106.8	-81.6	-166.0
2014	0.0	0.5	0.0	218.6	68.2	0.0	27.3	95.5	123.0	149.7	-73.0	39.7	83.3	1.7	-135.4
2015	0.0	0.5	0.0	195.7	74.2	0.0	29.7	103.9	91.8	241.5	-42.3	31.3	60.5	62.2	-115.2
Sub.	0.0	3.8	0.0	1403.2	425.1	0.0	736.5	1161.7	241.5	241.5	-42.3	179.3	62.2	62.2	-115.2
Rem.	0.0	9.5	30.8	3356.1	518.4	0.0	207.6	725.9	2630.2	2871.7	375.1	814.1	1816.1	1878.3	173.8
Tot.	**0.0**	**13.3**	**30.8**	**4759.3**	**943.5**	**0.0**	**944.1**	**1887.6**	**2871.7**	**2871.7**	**375.1**	**993.4**	**1878.3**	**1878.3**	**173.8**
Disc	0.0	3.2	3.3	1175.5	322.7	0.0	477.7	800.4	375.1	375.1	375.1	201.3	173.8	173.8	173.8

AFTER TAX ANALYSIS

Year Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2005	5.0	0.0	0.0	0.0	4.8	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2006	10.0	0.0	0.0	0.0	9.1	0.0	0.0	0.0	100.6	0.0	0.0	0.0	0.0
2007	37.4	0.0	0.0	0.3	22.8	0.0	0.0	0.0	175.3	0.0	0.0	0.0	0.0
2008	94.3	0.0	0.0	0.7	52.3	0.0	0.0	0.0	291.2	0.0	0.0	0.0	0.0
2009	177.7	0.0	0.0	1.3	78.1	0.0	0.0	0.0	445.0	41.0	0.0	0.0	41.0
2010	263.1	0.0	0.0	2.1	96.4	0.0	0.0	0.0	541.8	118.2	0.0	0.0	118.2
2011	319.0	0.0	0.0	2.7	104.3	0.0	0.0	0.0	498.2	115.2	0.0	0.0	115.2
2012	338.0	0.0	0.0	2.9	103.7	0.0	0.0	0.0	383.0	95.7	0.0	0.0	95.7
2013	336.5	0.0	0.0	2.9	107.5	0.0	0.0	0.0	309.3	74.6	0.0	0.0	74.6
2014	346.6	0.0	0.0	3.0	125.1	0.0	0.0	0.0	262.1	62.1	0.0	0.0	62.1
2015	326.2	0.0	0.0	2.8	127.7	0.0	0.0	0.0	229.7	53.7	0.0	0.0	53.7
Sub.	2253.9	0.0	0.0	18.7	832.0	0.0	0.0	0.0	229.7	560.6	0.0	0.0	560.6
Rem.	6628.4	0.0	0.0	878.3	2390.1	0.0	0.0	0.0	11.4	375.0	0.0	0.0	375.0
Tot.	**8882.2**	**0.0**	**0.0**	**897.0**	**3222.0**	**0.0**	**0.0**	**0.0**	**11.4**	**935.5**	**0.0**	**0.0**	**935.5**
Disc	2092.2	0.0	0.0	146.6	769.9	0.0	0.0	0.0	180.3	327.2	0.0	0.0	327.2

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write -off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.2	0.0	0.0	0.0	0.0	0.0	26.5	0.1	0.0	0.0	0.1	0.0
2006	0.0	0.9	0.1	0.0	0.0	0.0	0.0	78.3	0.8	0.0	0.0	0.8	0.0
2007	0.0	14.3	0.0	0.0	0.0	0.0	0.0	132.4	14.2	0.0	0.0	14.2	0.1
2008	0.0	41.3	0.0	0.0	0.0	0.0	0.0	185.1	41.1	0.0	0.0	41.1	0.2
2009	0.0	57.2	0.0	0.0	0.0	0.0	0.0	189.2	56.8	0.0	0.0	56.8	0.4
2010	0.0	46.3	0.0	0.0	0.0	0.0	0.0	132.5	39.7	0.0	0.0	39.7	6.6
2011	0.0	96.7	0.0	0.0	0.0	0.0	0.0	92.7	27.8	0.0	0.0	27.8	68.9
2012	0.0	135.7	0.0	0.0	0.0	0.0	0.0	64.9	19.5	0.0	0.0	19.5	116.2
2013	0.0	151.6	0.0	0.0	0.0	0.0	0.0	100.7	30.2	0.0	0.0	30.2	121.4
2014	0.0	156.5	0.0	0.0	0.0	0.0	0.0	138.7	41.6	0.0	0.0	41.6	114.9
2015	0.0	142.0	0.0	0.0	0.0	0.0	0.0	171.3	51.4	0.0	0.0	51.4	90.6
Sub.	0.0	842.7	0.1	0.0	0.0	0.0	0.0	171.3	323.2	0.0	0.0	323.2	519.3
Rem.	0.0	2985.1	0.0	0.0	0.0	0.0	0.0	11.5	630.2	0.0	0.0	630.2	2354.9
Tot.	**0.0**	**3827.7**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**11.5**	**953.4**	**0.0**	**0.0**	**953.4**	**2874.2**
Disc	0.0	848.5	0.1	0.0	0.0	0.0	0.0	98.5	265.7	0.0	0.0	265.7	582.7

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest -ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	Net Cash Flow After Income Tax 10% Dcf Cum. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-8.4	-19.0	-17.4
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-141.1	-160.0	-128.5
2007	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-115.3	-275.3	-211.1
2008	0.0	0.0	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-141.5	-416.9	-303.3
2009	0.0	0.0	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-101.0	-517.8	-363.1
2010	0.0	0.0	6.6	6.6	1.5	0.0	0.0	6.1	0.8	0.0	2.2	24.6	-493.3	-349.8
2011	0.0	0.0	68.9	68.9	15.2	0.0	0.0	68.4	8.6	0.0	23.8	113.6	-379.7	-294.3
2012	0.0	0.0	116.2	116.2	25.7	0.0	0.0	115.7	14.5	0.0	40.2	191.3	-188.5	-209.2
2013	0.0	0.0	121.4	121.4	26.8	0.0	0.0	120.9	15.1	0.0	41.9	106.8	-81.6	-166.0
2014	0.0	0.0	114.9	114.9	25.4	0.0	0.0	114.4	14.3	0.0	39.7	83.3	1.7	-135.4
2015	0.0	0.0	90.6	90.6	20.0	0.0	0.0	90.1	11.3	0.0	31.3	60.5	62.2	-115.2
Sub.	0.0	0.0	519.3	519.3	114.9	0.1	0.1	515.5	64.4	0.0	179.3	62.2	62.2	-115.2
Rem.	0.0	0.0	2354.9	2354.9	520.9	0.0	0.0	2345.4	293.2	0.0	814.1	1816.1	1878.3	173.8
Tot.	**0.0**	**0.0**	**2874.2**	**2874.2**	**635.8**	**0.1**	**0.1**	**2860.9**	**357.6**	**0.0**	**993.4**	**1878.3**	**1878.3**	**173.8**
Disc	0.0	0.0	582.7	582.7	128.9	0.1	0.1	579.6	72.4	0.0	201.3	173.8	173.8	173.8

RESERVE SUMMARY

Product	Units	Remaining Reserves at January 1, 2004 Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents BOE Factor	Company Mstb	% of Total	Reserve Life Indic. (yr) Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	402442	0	402442	364296	1.000	402442	100	31.0	100.0	16.1
Total Oil Eq.	Mstb	402442	0	402442	364296		402442	100	31.0	0.0	16.1

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7971916	100	1942376	100
Total Oil Eq.	$/BOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7971916	100	1942376	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)	Initial	Average	Disc. Rate %	Net Present Value Before Income Tax Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Net Present Value After Tax Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
Crown Royalty	0.0000	10.2488	0.0	4776723	4759265	1887587	2871677	7.14	3765878	1887587	1878290	4.67
Non-crown Royalty	0.0000	0.0000	5.0	2227183	2223694	1166823	1056871	2.63	1801154	1166823	634331	1.58
Mineral Tax	0.0000	0.0000	8.0	1497929	1496975	921053	575921	1.43	1229499	921053	308446	0.77
NPI Payment	0.0000	0.0000	10.0	1175656	1175507	800394	375113	0.93	974158	800394	173764	0.43
			12.0	937475	937767	703677	234091	0.58	783859	703677	80182	0.20
			15.0	685402	685990	590789	95200	0.24	580410	590789	-10379	-0.03
			20.0	431392	432057	458660	-26602	-0.07	372212	458660	-86447	-0.21

Project.......1046350
Entity.......Total With Adjustments (PPP Undeveloped)
Run date....Fri May 21 2004 10:42:51
Evaluator...Laustsen, Dana B.

RESOURCES

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Summary of Resources and Values

Company: **Deer Creek Energy Ltd.**
Property: **Joslyn Creek Mining Resources**

Pricing: **GLJ (2004-04) Full Year**
Effective Date: **January 1, 2004**

	Best Estimate	Low Estimate	High Estimate
MARKETABLE RESOURCES			
Heavy Oil - MMSTB			
Total Company Interest	1235	605	1865
Working Interest	1235	605	1865
Net After Royalty	1120	*	*
Oil Equivalent - MMBOE			
Total Company Interest	1235		
Working Interest	1235		
Net After Royalty	1120		
BEFORE TAX PRESENT VALUE - $M			
0.00%	10164436	*	*
5.00%	2612470		
8.00%	1128010		
10.00%	607279		
12.00%	287998		
15.00%	23167		
20.00%	-147107		
AFTER TAX PRESENT VALUE - $M			
0.00%	6623946		
5.00%	1598145		
8.00%	614536		
10.00%	272556		
12.00%	65610		
15.00%	-101233		
20.00%	-198017		

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

* - Low and High economic forecasts were not prepared.

Project 1046350 (aftertaxpsum2.xls)

p:\s1046350\rems\econ\Posted (2003-12-31 Constant) \Joslyn_Creek_Mining_Resources_RC38_psum.htm

Company Production, Reserves and Present Value Summary

Company: **Deer Creek Energy Ltd.**
Property: **Joslyn Creek Mining Resources**

Reserve Class: **Best Estimate**
Development Class: **Total**
Pricing: **GLJ (2004-04) Full Year**
Effective Date: **January 01, 2004**

	2004 Company Interest Prod'n				Company Interest Reserves					Net After Royalty Reserves					F
Entity Description	Gas mcf/d	Oil bbl/d	NGL bbl/d	BOE bbl/d	Gas Mmcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	BOE Mbbl	Gas Mmcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	BOE Mbbl	
Joslyn Creek Mining Resources	0	0	0	0	0	1234800	0	0	1234800	0	1119936	0	0	1119936	

BOE Factors:								
	OIL	1.00000	RES GAS	6.00000	PROPANE	1.00000	ETHANE	1.00000
	COND	1.00000	SLN GAS	6.00000	BUTANE	1.00000	SULPHUR	0.00000

p:/s1046350/rems/econ/GLJ_2004-04_Full_Year/Joslyn_Creek_Mining_Resources_RC38_crv.htm

Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Resource Class:	**Best Estimate**
Property:	**Corporate**	Development Class:	**Total**
Description:	**Total Joslyn Creek**	Pricing:	**GLJ (2004-04) Full Year**
		Effective Date:	**1-Jan-04**

PRODUCTION FORECAST

Year	Heavy Oil Production Compny Daily Stb	Compny Yearly Mmb	Net Yearly Mmb	Price $/Bbl
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	25200	9	9	17
2011	42000	15	15	17.5
2012	42000	15	15	18
2013	75600	28	27	18.5
2014	84000	31	30	19
2015	84000	31	30	19.5
Sub.	29400	129	127	18.57
Rem.	121209	1106	992	26.73
Tot.	**91433**	**1235**	**1120**	**25.88**

REVENUE AND EXPENSE FORECAST

Year	Revenue Before Burdens: Working Interest Oil MM$	Gas MM$	NGL+Sul MM$	Total MM$	Royalty Interest MM$	Company Total MM$	Royalty Burdens Pre-Processing: Crown MM$	Other MM$	Gas Processing Allowance: Crown MM$	Other MM$	Total Royalty After Process. MM$	Net Revenue After Royalty MM$	Operating Expenses: Fixed MM$	Variable MM$	Total MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	156	0	0	156	0	156	2	0	0	0	2	155	71	38	108
2011	268	0	0	268	0	268	3	0	0	0	3	266	119	46	165
2012	276	0	0	276	0	276	3	0	0	0	3	273	122	46	168
2013	510	0	0	510	0	510	5	0	0	0	5	505	218	84	303
2014	583	0	0	583	0	583	6	0	0	0	6	577	223	86	308
2015	598	0	0	598	0	598	6	0	0	0	6	592	270	87	357
Sub.	2391	0	0	2391	0	2391	24	0	0	0	24	2368	1022	387	1409
Rem.	29567	0	0	29567	0	29567	3213	0	0	0	3213	26354	9964	3398	13362
Tot.	**31959**	**0**	**0**	**31959**	**0**	**31959**	**3237**	**0**	**0**	**0**	**3237**	**28722**	**10986**	**3785**	**14771**
Disc	4271	0	0	4271	0	4271	283	0	0	0	283	3988	1571	556	2127

Year	Other Expenses: Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	Net Prod'n Revenue MM$	Other Income: Other MM$	ARTC MM$	Aband. Costs MM$	Oper. Income MM$	Net Capital Investment: Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Before Tax Cash Flow: Annual MM$	Cum. MM$	10% Dcf MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	9	9	-9	-9	-7
2007	0	0	0	0	0	0	0	0	0	0	14	14	-14	-23	-17
2008	0	0	0	0	0	0	0	0	0	0	315	315	-315	-338	-223
2009	0	0	0	0	0	0	0	0	0	0	300	300	-300	-639	-400
2010	0	0	0	46	0	0	0	46	0	0	74	74	-27	-666	-415
2011	0	0	0	101	0	0	0	101	0	0	330	330	-229	-895	-527
2012	0	0	0	105	0	0	0	105	0	0	314	314	-209	-1104	-620
2013	0	0	0	203	0	0	0	203	0	0	87	87	115	-989	-573
2014	0	0	0	268	0	0	0	268	38	0	345	383	-114	-1103	-615
2015	0	0	0	235	0	0	0	235	39	0	329	367	-132	-1235	-660
Sub.	0	0	0	959	0	0	0	959	77	0	2117	2194	-1235	-1235	-132
Rem.	0	0	0	12993	0	0	0	12993	1518	0	75	1593	11399	10164	10164
Tot.	**0**	**0**	**0**	**13951**	**0**	**0**	**0**	**13951**	**1595**	**0**	**2192**	**3787**	**10164**	**10164**	**607**
Disc	0	0	0	1861	0	0	0	1861	218	0	1036	1254	607	607	607

RESOURCE SUMMARY

Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	BOE Factor	Company Mstb	% of Total	Reserve Life	Life Index	Half Life
		Remaining Resources at January 1, 2004					Oil Equivalents		Resource Life Indic. (yr)		
Heavy Oil	Mstb	1234800	0	1234800	1119936	1	1234800	100	37	100	22.7
Total Oil Eq.	Mstb	1234800	0	1234800	1119936		1234800	100	37	0	22.7

PRODUCT REVENUE AND EXPENSES

Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
		Average First Year Unit Values							Net Revenue After Royalties			
Heavy Oil	$/Stb	0	0	0	0	0	0	0	28721748	100	3988123	100
Total Oil Eq.	$/BOE	0	0	0	0	0	0	0	28721748	100	3988123	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)

	Initial	Average
Crown Royalty	0	10.1291
Non-crown Royalty	0	0
Mineral Tax	0	0
NPI Payment	0	0

Net Present Value Before Income Tax

Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
0	13951221	13951221	3786788	10164434	8.23
5	4642361	4642361	2029892	2612469	2.12
8	2629097	2629097	1501086	1128010	0.91
10	1860941	1860941	1253662	607278	0.49
12	1349005	1349005	1061007	287998	0.23
15	865932	865932	842765	23167	0.02
20	450801	450801	597908	-147107	-0.12

Project.......1046350
Entity.......Total Joslyn Creek (Best Estimate)
Run date....Mon Mar 22 2004 11:02:34
Evaluator...Laustsen, Dana B.
p:\s1046350\rems\econ\GLJ_2004-04_Full_Year_Corporate_Total_Joslyn_Creek_RC38_pri.htm

RESERVES DEFINITIONS

Reserves estimates have been prepared by Gilbert Laustsen Jung Associates Ltd. (GLJ) in accordance with standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook with necessary modifications to reflect definitions and standards under the U.S. Financial Standards Board (FSB) standards and the legal requirements of the U.S. Securities and Exchange Commission (SEC). Both the SEC definitions of proved reserves (the SEC does not permit disclosure of probable reserves) and the COGE definitions follow.

SEC DEFINITIONS

REGULATION S-X
UNITED STATES SECURITIES EXCHANGE COMMISSION

1) **Proved oil and gas reserves.** Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

   (i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

   (ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

   (iii) Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

2) **Proved developed oil and gas reserves.** Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

3) **Proved undeveloped reserves.** Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

COGE HANDBOOK DEFINITIONS

The following reserves definitions are set out by the Canadian Securities Administrators in National Instrument 51-101 (NI 51-101; in Part 2 of Appendix 1 to Companion Policy 51-101CP) with reference to the COGE Handbook.

Reserves Categories

Reserves are 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, and engineering data;
- the use of established technology;
- specified economic conditions[1], which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

Proved Reserves
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.

Probable 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 than the sum of the estimated proved plus probable reserves.

Possible Reserves
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.

Other criteria that must also be met for the categorization of reserves are provided in [Section 5.5 of the COGE Handbook].

[1] *For the purposes of NI 51-101, the key economic assumptions will be the prices and costs used in the estimate, namely:*
(a) ***constant prices and costs*** *as at the last day of a reporting issuer's financial year; or*
(b) ***forecast prices and costs.***

Development and Production Status

Each of the reserves categories (proved, probable, and possible) may be divided into developed and undeveloped categories.

Developed Reserves
Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves
Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-producing Reserves
Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

Undeveloped Reserves
Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves estimates are presented). Reported Reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves;
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with *reserves* estimates and the effect of aggregation is provided in Section 5.5.3 [of the *COGE Handbook*].

Incorporation of the COGE Handbook guidelines means that total corporate proved reserves reflect a conservative estimate and proved plus probable reserves reflect a current "best estimate" of the oil and gas quantities which will be recovered. In the evaluated properties, there is no material difference between proved reserves determined applying COGE and SEC standards versus estimates which would result under application of only one of these standards.

CONTINGENT RESOURCES

Resource estimates derived herein have been classified as contingent resources. 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 COGEH. 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, we believe this volume will likely be economic to develop some time in the future. Over time with additional drilling and financial commitment we 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. Low and high estimates have also been prepared.

DOCUMENTED RESERVES CATEGORIES

Production and revenue projections are prepared for each of the following main reserves categories:

Reserves Category
Proved
Proved Plus Probable

Production and Development Status
Developed Producing*
Developed Non-producing
Undeveloped
Total (sum of developed producing, developed non-producing and undeveloped)

* *As producing reserves are inherently developed, GLJ simply refers to "developed producing" reserves as "producing."*

Reserves and revenue projections are available in GLJ's evaluation database for any reserves and development subcategory including those determined by difference (e.g., probable producing).

The following reserves categories are documented in this Executive Summary Volume:

Proved Producing
Proved Developed Non-producing
Proved Undeveloped
Total Proved
Total Probable
Total Proved Plus Probable

In addition, total reserves and resources volumes are summarized on Table 3.

The individual property evaluation report contains detailed documentation of reserves estimation methodology and evaluation procedures.

When evaluating reserves, GLJ evaluators generally first identify the producing situation and assign proved, proved plus probable and proved plus probable plus possible reserves in recognition of the existing level of development and the existing depletion strategy. Incremental non-producing (developed non-producing or undeveloped) reserves are subsequently assigned recognizing future development opportunities and enhancements to the depletion mechanism. It should be recognized that future developments may result in accelerated recovery of producing reserves.

EVALUATION PROCEDURE

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EVALUATION PROCEDURE

The following outlines the methodology employed by Gilbert Laustsen Jung Associates Ltd. (GLJ) in conducting the evaluation of the Company's oil and gas properties. GLJ evaluation procedures are in compliance with standards contained in the Canadian Oil and Gas Evaluation (COGE) Handbook.

INTEREST DESCRIPTIONS

The Company provided GLJ with current land interest information. The Company provided a representation letter confirming accuracy of land information. Certain cross-checks of land and cost information were undertaken by GLJ as recommended in the COGE Handbook. In this process, nothing came to GLJ's attention that indicated that information provided by the Company was incomplete or unreliable.

In GLJ's reports, "Company Interest" reserves and values refer to the sum of royalty interest* and working interest reserves before deduction of royalty burdens payable. "Working Interest" reserves equate to those reserves that are referred to as "Company Gross" reserves by the Canadian Securities Administrators (CSA) in NI 51-101.

In the Securities Reporting section, working interest (or Company Gross) volumes are presented in tables to correspond to NI 51-101 disclosure requirements.

**Royalty interest reserves include lessor royalty and overriding royalty volumes derived only from other working interest owners.*

WELL DATA

Pertinent interest and offset well data such as drill stem tests, workovers, pressure surveys, cores, production tests, etc., were provided by the Company or were obtained from other operators, public records or GLJ nonconfidential files.

ACCOUNTING SUMMARY

As the existing properties are not on production, accounting data was not relevant to the evaluations. Operating and capital cost estimates were from the Company's development studies modified to reflect GLJ's experience with similar properties in the area.

PRODUCTION FORECASTS

In establishing all production forecasts, consideration was given to the operator's plans for development drilling and to reserves and well capability. Generally, development drilling in an area was not considered unless there was some indication from the operator that drilling could be expected.

The on-stream date for currently shut-in reserves was estimated with consideration given to the following:

- proximity to existing facilities
- plans of the operator
- economics

ECONOMIC PARAMETERS

Pertinent economic parameters are listed as follows:

a) The effective date is January 1, 2004.

b) Operating and capital costs were estimated in 2004 dollars and then escalated as summarized in the Product Price and Market Forecasts section of this report.

c) Economic forecasts were prepared for each property on a before income tax basis. Detailed discounting of future cash flow was performed using a mid-year discount factor of 10.0 percent with all values discounted annually to January 1, 2004, on a mid-calendar-year basis.

d) Alberta gas cost allowance (AGCA) and Jumping Pound allowances were not applicable.

e) Mineral taxes on freehold interests are not applicable.

f) Royalty credits under the Alberta Royalty Tax Credit (ARTC) plan have been included in this analysis at the summary level.

g) Field level overhead charges have been included; recovery of overhead expenses has not been included.

h) The Company's office G&A costs have not been included.

i) Well abandonment and lease reclamation costs have been included in property evaluation reports only for wells which are forecast to be drilled in the future. Abandonment costs for existing wells and facilities have not been included.

INCOME TAX

Canadian income taxes were calculated based on currently legislated federal and provincial tax rates, tax regulations and tax pool information provided by the Company. After tax values are not shown for reserves development status subcategories (i.e. developed, undeveloped). After tax values and economic forecasts for reserves production status subcategories (i.e. producing, non-producing) are determined by difference between the total reserves and developed producing categories.

Tax Pools

The following tax pools as of the effective date, were included in the income tax calculations:

Tax Pool Classification	Write-Off Rate (%)	Tax Pool (M$)
Canadian Oil and Gas Property Expense	10	-
Canadian Exploration Expense	100	-
Canadian Development Expense	30	18,000
Capital Cost Allowance:		
Class 41	25	-
Class 10	30	-
Class 8	20	-

Tax Rates

Federal income tax legislation has undergone recent changes including:

- A reduction in the general corporate income tax rate on resource income over a five-year period from 2003-2007,
- The introduction of the deductibility of Crown royalty paid,
- The phasing out of the existing 25% resource allowance,
- The phasing in of the federal taxation of Alberta Royalty Tax Credits (ARTC).

These changes have been incorporated into the after tax economic forecasts as follows:

	Federal Income Tax Rates							
			Resource Comp.					
Year	General Basic Tax Rate	General Surtax Rate	Tax Reduction	Reduced Tax Rate	General Tax Rate	Deductible Federal Res. All.	Deductible % of Crown Payments	Tax Inclusion Of ARTC
2004	28.00%	4.00%	2.00%	26.00%	27.12%	75.0%	25.0%	25.0%
2005	28.00%	4.00%	3.00%	25.00%	26.12%	65.0%	35.0%	35.0%
2006	28.00%	4.00%	5.00%	23.00%	24.12%	35.0%	65.0%	65.0%
2007+	28.00%	4.00%	7.00%	21.00%	22.12%	0.0%	100.0%	100.0%

Allocation of revenues to Canadian provinces for income tax purposes depends on several factors in addition to the provincial origin of the resource revenues. The average future annual provincial tax rate has been calculated based on an allocation of provincial resource revenues and their respective tax rate as follows:

Year	Alberta Tax Rate	Alberta Allocation	B.C. Tax Rate	B.C. Allocation	Sask. Tax Rate	Sask. Allocation	Avg. Ann. Tax Rate
2004	12.50%	100%	13.50%	0	17.00%	0	12.50%
2005	12.50%	100%	13.50%	0	17.00%	0	12.50%
2006	12.50%	100%	13.50%	0	17.00%	0	12.50%
2007+	12.50%	100%	13.50%	0	17.00%	0	12.50%

Company total after tax economic forecasts for all reserves categories are provided in Appendix II.

CONSTANT PRICE ANALYSIS

In the constant price analysis, individual property economic forecasts were rerun using zero inflation and with a fixed price that reflects reference pricing at December 31, 2003. Additional clarification and results are presented in the Constant Price Analysis section of this report.

LIST OF ABBREVIATIONS

AOF	absolute open flow
ARTC	Alberta Royalty Tax Credit
BBL	barrels
BCF	billion cubic feet of gas at standard conditions
BOE	barrel of oil equivalent, in this evaluation determined using 6 MCF/BOE for gas, 1 BBL/BOE for all liquids, and 0 BOE for sulphur
BOPD	barrels of oil per day
BTU	British thermal units

BWPD	barrels of water per day
DSU	drilling spacing unit
GCA	gas cost allowance
GOC	gas-oil contact
GOR	gas-oil ratio
GORR	gross overriding royalty
GWC	gas-water contact
MBBL	thousand barrels
MBOE	thousand BOE
MCF	thousand cubic feet of gas at standard conditions
MLT	thousand long tons
M$	thousand Canadian dollars
MM$	million Canadian dollars
MMBBL	million barrels
MMBOE	million BOE
MMBTU	million British thermal units
MMCF	million cubic feet of gas at standard conditions
MRL	maximum rate limitation
MSTB	thousand stock tank barrels
MMSTB	million stock tank barrels
NGL	natural gas liquids (ethane, propane, butane and condensate)
NPI	net profits interest
OGIP	original gas-in-place
OOIP	original oil-in-place
ORRI	overriding royalty interest
OWC	oil-water contact
P&NG	petroleum and natural gas
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PVT	pressure-volume-temperature
RLI	reserves life index, calculated by dividing reserves by the forecast of first year production
SCF	standard cubic feet
STB	stock tank barrel
WI	working interest
WTI	West Texas Intermediate

PRODUCT PRICE AND MARKET FORECASTS
April 1, 2004

Gilbert Laustsen Jung Associates Ltd. has prepared its April 1, 2004, price and market forecasts as summarized in the attached Tables 1 and 2 after a comprehensive review of information. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The forecasts presented herein are based on an informed interpretation of currently available data. While these forecasts are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change. These future revisions may be significant.

Table 1
Gilbert Laustsen Jung Associates Ltd.
Crude Oil and Natural Gas Liquids
Price Forecast
Effective April 1, 2004

		Bank of Canada Average Noon	West Texas Intermediate Crude Oil at Cushing Oklahoma		Brent Blend Crude Oil FOB North Sea		Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton		Bow River Crude Oil Stream Quality at Hardisty		Heavy Crude Oil Proxy (12 API) at Hardisty		Medium Crude Oil (29 API, 2.0%S) at Cromer		
Year	Inflation %	Exchange Rate $US/$Cdn	Constant 2004 $ $US/bbl	Then Current $US/bbl	Constant 2004 $ $US/bbl	Then Current $US/bbl	Constant 2004 $ $Cdn/bbl	Then Current $Cdn/bbl	Constant 2004 $ $Cdn/bbl	Then Current $Cdn/bbl	Constant 2004 $ $Cdn/bbl	Then Current $Cdn/bbl	Constant 2004 $ $Cdn/bbl	Then Current $Cdn/bbl	Spec Ethane $Cdn/bbl
1993	1.8	0.775	22.56	18.46	20.81	17.03	26.81	21.94	20.44	16.73	16.20	13.26	21.49	17.59	n/a
1994	0.2	0.732	20.62	17.18	18.99	15.82	26.67	22.22	22.17	18.47	18.03	15.02	23.17	19.30	n/a
1995	2.2	0.729	22.03	18.39	20.41	17.04	29.03	24.23	24.92	20.80	20.70	17.28	25.98	21.69	n/a
1996	1.6	0.733	25.78	21.99	23.95	20.43	34.46	29.39	29.47	25.13	23.52	20.06	30.60	26.10	n/a
1997	1.6	0.722	23.79	20.61	22.14	19.18	32.14	27.85	24.43	21.17	16.63	14.41	27.37	23.72	n/a
1998	0.9	0.675	16.38	14.42	14.57	12.83	23.13	20.36	16.63	14.64	10.73	9.45	19.25	16.95	n/a
1999	1.7	0.673	21.72	19.29	20.05	17.81	31.17	27.69	26.84	23.84	22.14	19.67	28.62	25.42	n/a
2000	2.7	0.673	33.45	30.22	31.38	28.35	49.33	44.56	39.02	35.25	30.26	27.34	44.18	39.91	n/a
2001	2.6	0.646	27.99	25.97	26.27	24.37	42.47	39.40	29.86	27.70	18.26	16.94	34.02	31.56	n/a
2002	2.2	0.637	27.40	26.08	26.25	24.99	42.37	40.33	33.44	31.83	27.91	26.57	37.27	35.48	n/a
2003	2.8	0.721	31.93	31.07	29.74	28.93	44.88	43.66	33.01	32.11	26.99	26.26	38.60	37.55	n/a
2004 Q1 (e)	1.5	0.757	34.50	34.50	33.00	33.00	44.50	44.50	34.25	34.25	28.00	28.00	40.50	40.50	n/a
2004 Q2	1.5	0.750	36.00	36.00	34.50	34.50	47.25	47.25	37.75	37.75	31.75	31.75	43.75	43.75	22.00
2004 Q3	1.5	0.750	34.00	34.00	32.50	32.50	44.50	44.50	35.25	35.25	29.50	29.50	41.00	41.00	22.25
2004 Q4	1.5	0.750	32.75	32.75	31.25	31.25	43.00	43.00	32.50	32.50	26.25	26.25	39.00	39.00	23.25
2004 Full Yea	1.5	0.750	34.25	34.25	32.75	32.75	44.75	44.75	35.00	35.00	29.00	29.00	41.00	41.00	22.50
2004 Q2-Q4	0.0	0.750	34.25	34.25	32.75	32.75	44.75	44.75	35.00	35.00	29.00	29.00	41.00	41.00	22.50
2005	1.5	0.750	28.50	29.00	27.00	27.50	37.25	37.75	29.75	30.25	24.75	25.00	33.25	33.75	18.50
2006	1.5	0.750	26.25	27.00	24.75	25.50	34.25	35.25	28.00	28.75	23.00	23.75	30.25	31.25	17.25
2007	1.5	0.750	24.00	25.00	22.50	23.50	31.00	32.50	24.75	26.00	20.00	21.00	27.25	28.50	16.50
2008	1.5	0.750	23.50	25.00	22.25	23.50	30.50	32.50	24.50	26.00	19.75	21.00	26.75	28.50	16.50
2009	1.5	0.750	23.25	25.00	21.75	23.50	30.25	32.50	24.25	26.00	19.50	21.00	26.50	28.50	16.50
2010	1.5	0.750	23.25	25.50	22.00	24.00	30.25	33.00	24.25	26.50	19.75	21.50	26.50	29.00	17.00
2011	1.5	0.750	23.25	25.75	21.75	24.25	30.25	33.50	24.25	27.00	19.75	22.00	26.50	29.50	17.25
2012	1.5	0.750	23.25	26.25	22.00	24.75	30.25	34.00	24.50	27.50	20.00	22.50	26.75	30.00	17.50
2013	1.5	0.750	23.25	26.50	21.75	25.00	30.25	34.50	24.50	28.00	20.00	23.00	26.75	30.50	18.00
2014	1.5	0.750	23.25	27.00	22.00	25.50	30.25	35.00	24.50	28.50	20.25	23.50	26.75	31.00	18.00
2015+	1.5	0.750	23.25	+1.5%/yr	22.00	+1.5%/yr	30.25	+1.5%/yr	24.50	+1.5%/yr	20.25	+1.5%/yr	26.75	+1.5%/yr	

Revised March 3, 2004 11:39 AM

Table 2
Gilbert Laustsen Jung Associates Ltd.
Natural Gas and Sulphur
Price Forecast
Effective April 1, 2004

	US Gulf Coast Gas Price @ Henry Hub		Midwest Price @ Chicago	AECO-C Spot	Alberta Plant Gate					Saskatchewan Plant Gate			British Colu	
					Spot									
	Constant	Then	Then	Then	Constant	Then							CanWest	
	2004 $	Current	Current	Current	2004 $	Current	ARP	Aggregator	Alliance	SaskEnergy	Spot	Sumas Spot	Plant Gate	P
Year	$US/mmbtu	$US/mmbtu	$US/mmbtu	$Cdn/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$US/mmbtu	$/mmbtu	:
1993	2.58	2.11	2.31	2.26	2.64	2.16	1.71	n/a	n/a	1.48	2.07	1.89	1.73	
1994	2.33	1.94	2.11	1.98	2.23	1.86	1.81	n/a	n/a	1.88	1.87	1.59	1.81	
1995	2.04	1.70	1.69	1.15	1.22	1.02	1.31	n/a	n/a	1.35	0.98	1.03	1.29	
1996	2.95	2.52	2.73	1.39	1.48	1.26	1.63	n/a	n/a	1.52	1.28	1.32	1.50	
1997	2.85	2.47	2.75	1.84	1.95	1.69	1.96	n/a	n/a	1.84	1.74	1.70	1.80	
1998	2.45	2.16	2.20	2.03	2.14	1.88	1.94	n/a	n/a	2.05	2.13	1.60	1.94	
1999	2.61	2.32	2.34	2.92	3.10	2.75	2.48	n/a	n/a	2.83	2.97	2.15	2.51	
2000	4.79	4.33	4.38	5.08	5.45	4.92	4.50	4.60	n/a	4.79	5.16	4.17	5.27	
2001	4.37	4.05	4.17	6.21	6.54	6.07	5.41	5.30	5.61	5.71	6.20	4.56	6.76	
2002	3.53	3.36	3.30	4.04	4.08	3.88	3.88	3.83	3.82	4.04	4.08	2.68	3.64	
2003	5.65	5.50	5.60	6.66	6.67	6.49	6.13	5.89	6.69	6.40	6.68	4.66	5.71	
2004 Q1 (e)	5.70	5.70	5.85	6.55	6.30	6.30	6.20	5.90	6.30	6.35	6.45	5.10	5.55	
2004 Q2	5.60	5.60	5.65	6.55	6.30	6.30	6.20	5.90	6.15	6.35	6.45	4.95	5.60	
2004 Q3	5.70	5.70	5.75	6.65	6.40	6.40	6.30	6.00	6.20	6.45	6.55	5.05	5.65	
2004 Q4	5.85	5.85	6.00	6.90	6.65	6.65	6.55	6.20	6.55	6.70	6.80	5.35	5.85	
2004 Full Year	5.70	5.70	5.80	6.65	6.40	6.40	6.30	6.00	6.30	6.45	6.55	5.10	5.65	
2004 Q2-Q4	5.70	5.70	5.80	6.70	6.45	6.45	6.35	6.05	6.30	6.50	6.60	5.10	5.70	
2005	4.75	4.80	5.00	5.55	5.20	5.30	5.25	5.15	5.30	5.40	5.45	4.30	5.15	
2006	4.35	4.50	4.75	5.20	4.80	4.95	4.95	4.95	4.95	5.10	5.10	4.05	4.95	
2007	4.15	4.35	4.60	5.00	4.55	4.75	4.75	4.75	4.75	4.90	4.90	3.90	4.75	
2008	4.10	4.35	4.60	5.00	4.50	4.75	4.75	4.75	4.75	4.90	4.90	3.90	4.75	
2009	4.05	4.35	4.60	5.00	4.45	4.75	4.75	4.75	4.75	4.90	4.90	3.90	4.75	
2010	4.05	4.40	4.65	5.10	4.45	4.85	4.85	4.85	4.85	5.00	5.00	3.95	4.85	
2011	4.05	4.50	4.75	5.20	4.45	4.95	4.95	4.95	4.95	5.10	5.10	4.05	4.95	
2012	4.05	4.55	4.80	5.25	4.45	5.05	5.05	5.05	5.05	5.20	5.15	4.10	5.05	
2013	4.05	4.60	4.90	5.35	4.50	5.15	5.15	5.15	5.15	5.30	5.25	4.20	5.15	
2014	4.05	4.70	4.95	5.45	4.50	5.20	5.20	5.20	5.20	5.35	5.35	4.25	5.20	
2015+	4.05	+1.5%/yr	+1.5%/yr	+1.5%/yr	4.50	+1.5%/yr				Escalate at 1.5 % per year				

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering and processing charges are deducted.
Spot refers to weighted average one month price.

Revised March 3, 2004 11:39 AM

CONSTANT PRICE ANALYSIS

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Summary of Reserves and Values

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total With Adjustments**

Pricing: **Posted (2003-Dec-31) Constant**
Effective Date: **January 01, 2004**

	Probable Undeveloped	PPP Undeveloped
MARKETABLE RESERVES		
Heavy Oil - MMSTB		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
Oil Equivalent - MMBOE		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
BEFORE TAX PRESENT VALUE - $M		
0.0%	1394956	2256430
5.0%	531215	890909
8.0%	286209	510345
10.0%	180237	346402
12.0%	103990	228394
15.0%	26951	108552
20.0%	-42747	-1984
AFTER TAX PRESENT VALUE - $M		
0.0%	916838	1477701
5.0%	311864	533712
8.0%	141899	274048
10.0%	69088	163409
12.0%	17250	84641
15.0%	-34200	6032
20.0%	-78702	-63608

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

Project 1046350
Run date Fri May 21 2004 10:43:31

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Summary of Resources and Values

Company: **Deer Creek Energy Ltd.** Pricing: **Posted (2003-Dec-31) Constant**

Property: **Joslyn Creek Mining Resources** Effective Date: **January 1, 2004**

	Best Estimate
MARKETABLE RESOURCES	
Heavy Oil - MMSTB	
Total Company Interest	1235
Working Interest	1235
Net After Royalty	1107
Oil Equivalent - MMBOE	
Total Company Interest	1235
Working Interest	1235
Net After Royalty	1107
BEFORE TAX PRESENT VALUE - $M	
0.00%	7386178
5.00%	2142530
8.00%	1029394
10.00%	617911
12.00%	354049
15.00%	121193
20.00%	-49073
AFTER TAX PRESENT VALUE - $M	
0.00%	4816345
5.00%	1330083
8.00%	592420
10.00%	321422
12.00%	149160
15.00%	-163
20.00%	-103385

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

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Company Production, Reserves and Present Value Summary

Company:	**Deer Creek Energy Ltd.**		Reserve Class:	**Various**
Property:	**Corporate**		Development Class:	**Classifications**
			Pricing:	**Posted (2003-Dec-31) Co**
			Effective Date:	**January 01, 2004**

	2004 Company Interest Prod'n				Company Interest Reserves					Net After Royalty Reserves					F
Entity Description	Gas mcf/d	Oil bbl/d	NGL bbl/d	BOE bbl/d	Gas Mmcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	BOE Mbbl	Gas Mmcf	Oil Mbbl	NGL Mbbl	Sulphur Mlt	BOE Mbbl	
Probable Undeveloped															
Joslyn Creek SAGD	0	0	0	0	0	250195	0	0	250195	0	228100	0	0	228100	
Joslyn Creek Mining Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
ARTC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Probable Undeveloped	0	0	0	0	0	250195	0	0	250195	0	228100	0	0	228100	
PPP Undeveloped															
Joslyn Creek SAGD	0	0	0	0	0	402442	0	0	402442	0	364460	0	0	364460	
Joslyn Creek Mining Resources	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
ARTC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
PPP Undeveloped	0	0	0	0	0	402442	0	0	402442	0	364460	0	0	364460	
Best Estimate															
Joslyn Creek SAGD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Joslyn Creek Mining Resources	0	0	0	0	0	1234800	0	0	1234800	0	1108151	0	0	1108151	
Best Estimate	0	0	0	0	0	1234800	0	0	1234800	0	1108151	0	0	1108151	

BOE Factors:	OIL	1.00000	RES GAS	6.00000	PROPANE	1.00000	ETHANE	1.00000
	COND	1.00000	SLN GAS	6.00000	BUTANE	1.00000	SULPHUR	0.00000

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Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Reserve Class:	**Probable**
Property:	**Corporate**	Development Class:	**Undeveloped**
Description:	**Total With Adjustments**	Pricing:	**Posted (2003-Dec-31) Constant**
		Effective Date:	**January 01, 2004**

PRODUCTION FORECAST

		Heavy Oil Production			
Year	Compny Oil Wells	Compny Daily Stb	Compny Yearly Mstb	Net Yearly Mstb	Price $/Bbl
2004	0	0	0	0	0.00
2005	3	638	233	231	18.81
2006	3	1428	521	516	18.81
2007	19	5250	1916	1897	18.81
2008	19	9345	3411	3377	18.81
2009	45	17052	6224	6162	18.81
2010	61	26943	9834	9736	18.81
2011	61	34251	12502	12377	18.81
2012	61	34476	12584	12458	18.81
2013	66	33369	12180	12058	18.81
2014	79	33676	12292	12169	18.81
2015	84	34020	12417	12148	18.81
Sub.	42	19204	84114	83127	18.81
Rem.	62	26766	166082	144973	18.81
Tot.	**54**	**23637**	**250195**	**228100**	**18.81**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses			Other Expenses			Net Prod'n Revenue
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	MM$	MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	4.4	0.0	4.4	0.0	0.0	0.0	0.0	0.0	4.3	4.8	0.0	4.8	0.0	0.0	0.0	-0.5
2006	9.8	0.0	9.8	0.1	0.0	0.0	0.0	0.1	9.7	9.3	0.0	9.3	0.0	0.0	0.0	0.4
2007	36.0	0.0	36.0	0.4	0.0	0.0	0.0	0.4	35.7	19.1	2.1	21.2	0.0	0.0	0.0	14.4
2008	64.2	0.0	64.2	0.6	0.0	0.0	0.0	0.6	63.5	31.8	3.6	35.5	0.0	0.0	0.0	28.1
2009	117.1	0.0	117.1	1.2	0.0	0.0	0.0	1.2	115.9	46.2	6.2	52.4	0.0	0.0	0.0	63.5
2010	185.0	0.0	185.0	1.8	0.0	0.0	0.0	1.8	183.1	63.5	10.2	73.7	0.0	0.0	0.0	109.4
2011	235.2	0.0	235.2	2.4	0.0	0.0	0.0	2.4	232.8	68.1	11.9	80.0	0.0	0.0	0.0	152.8
2012	236.7	0.0	236.7	2.4	0.0	0.0	0.0	2.4	234.3	65.7	11.6	77.3	0.0	0.0	0.0	157.1
2013	229.1	0.0	229.1	2.3	0.0	0.0	0.0	2.3	226.8	68.4	11.7	80.1	0.0	0.0	0.0	146.7
2014	231.2	0.0	231.2	2.3	0.0	0.0	0.0	2.3	228.9	76.2	12.5	88.7	0.0	0.0	0.0	140.2
2015	233.6	0.0	233.6	5.1	0.0	0.0	0.0	5.1	228.5	86.4	13.8	100.2	0.0	0.0	0.0	128.3
Sub.	1582.2	0.0	1582.2	18.5	0.0	0.0	0.0	18.5	1563.6	539.6	83.7	623.3	0.0	0.0	0.0	940.3
Rem.	3124.0	0.0	3124.0	397.1	0.0	0.0	0.0	397.1	2726.9	1059.9	172.1	1232.0	0.0	0.0	0.0	1494.9
Tot.	**4706.2**	**0.0**	**4706.2**	**415.6**	**0.0**	**0.0**	**0.0**	**415.6**	**4290.6**	**1599.6**	**255.8**	**1855.4**	**0.0**	**0.0**	**0.0**	**2435.2**
Disc	1278.3	0.0	1278.3	76.4	0.0	0.0	0.0	76.4	1201.9	440.3	68.4	508.7	0.0	0.0	0.0	693.2

	Other Income				Net Capital Investment				Before Tax Cash Flow				After Tax Cash Flow		
Year	Other MM$	ARTC MM$	Aband. Costs MM$	Oper. Income MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	Income Tax MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	10.6	10.6	-10.6	-10.6	-10.1	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	-0.5	8.4	0.0	0.0	8.4	-8.9	-19.5	-17.8	0.0	-8.9	-19.5	-17.8
2006	0.0	0.0	0.0	0.4	39.9	0.0	100.0	139.9	-139.5	-158.9	-127.7	0.0	-139.5	-159.0	-127.7
2007	0.0	0.1	0.0	14.5	0.0	0.0	50.4	50.4	-35.9	-194.8	-153.4	0.0	-35.9	-194.8	-153.4
2008	0.0	0.2	0.0	28.2	63.0	0.0	92.4	155.4	-127.2	-322.0	-236.2	0.0	-127.2	-322.1	-236.3
2009	0.0	0.3	0.0	63.8	42.0	0.0	142.8	184.8	-121.0	-443.0	-307.9	0.1	-121.1	-443.2	-308.0
2010	0.0	0.5	0.0	109.9	0.0	0.0	25.2	25.2	84.7	-358.4	-262.3	0.1	84.6	-358.6	-262.4
2011	0.0	0.5	0.0	153.3	0.0	0.0	0.0	0.0	153.3	-205.1	-187.3	19.1	134.2	-224.4	-196.8
2012	0.0	0.5	0.0	157.6	21.0	0.0	8.4	29.4	128.2	-76.9	-130.3	27.0	101.2	-123.3	-151.8
2013	0.0	0.5	0.0	147.2	31.5	0.0	12.6	44.1	103.1	26.2	-88.6	26.4	76.6	-46.6	-120.8
2014	0.0	0.5	0.0	140.7	52.5	0.0	21.0	73.5	67.2	93.3	-63.9	23.8	43.4	-3.2	-104.9
2015	0.0	0.5	0.0	128.8	0.0	0.0	0.0	0.0	128.8	222.1	-20.9	25.5	103.3	100.0	-70.4
Sub.	0.0	3.5	0.0	943.8	258.3	0.0	463.4	721.7	222.1	222.1	-20.9	122.1	100.0	100.0	-70.4
Rem.	0.0	8.2	9.7	1493.5	228.9	0.0	91.7	320.6	1172.9	1395.0	180.2	356.0	816.8	916.8	69.1
Tot.	**0.0**	**11.8**	**9.7**	**2437.3**	**487.2**	**0.0**	**555.2**	**1042.4**	**1395.0**	**1395.0**	**180.2**	**478.1**	**916.8**	**916.8**	**69.1**
Disc	0.0	3.0	1.3	694.8	195.1	0.0	319.5	514.6	180.2	180.2	180.2	111.1	69.1	69.1	69.1

AFTER TAX ANALYSIS

Year Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2005	4.4	0.0	0.0	0.0	4.8	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2006	9.8	0.0	0.0	0.0	9.3	0.0	0.0	0.0	110.6	0.0	0.0	0.0	0.0
2007	36.0	0.0	0.0	0.3	21.2	0.0	0.0	0.0	161.0	0.0	0.0	0.0	0.0
2008	64.2	0.0	0.0	0.5	35.5	0.0	0.0	0.0	253.4	0.0	0.0	0.0	0.0
2009	117.1	0.0	0.0	0.9	52.4	0.0	0.0	0.0	396.2	25.0	0.0	0.0	25.0
2010	185.0	0.0	0.0	1.4	73.7	0.0	0.0	0.0	396.4	82.5	0.0	0.0	82.5
2011	235.2	0.0	0.0	1.9	80.0	0.0	0.0	0.0	314.0	78.5	0.0	0.0	78.5
2012	236.7	0.0	0.0	1.9	77.3	0.0	0.0	0.0	243.9	59.9	0.0	0.0	59.9
2013	229.1	0.0	0.0	1.8	80.1	0.0	0.0	0.0	196.6	47.6	0.0	0.0	47.6
2014	231.2	0.0	0.0	1.8	88.7	0.0	0.0	0.0	170.0	39.9	0.0	0.0	39.9
2015	233.6	0.0	0.0	4.6	100.2	0.0	0.0	0.0	130.2	32.5	0.0	0.0	32.5
Sub.	1582.2	0.0	0.0	15.0	623.3	0.0	0.0	0.0	130.2	365.8	0.0	0.0	365.8
Rem.	3124.0	0.0	0.0	388.8	1241.7	0.0	0.0	0.0	5.5	184.5	0.0	0.0	184.5
Tot.	**4706.2**	**0.0**	**0.0**	**403.8**	**1865.0**	**0.0**	**0.0**	**0.0**	**5.5**	**550.3**	**0.0**	**0.0**	**550.3**
Disc	1278.3	0.0	0.0	73.4	510.1	0.0	0.0	0.0	131.6	206.8	0.0	0.0	206.8

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write -off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	-0.5	0.0	0.0	0.0	0.0	0.0	26.4	0.0	0.0	0.0	0.0	-0.5
2006	0.0	0.4	0.0	0.0	0.0	0.0	0.0	66.3	0.4	0.0	0.0	0.4	0.0
2007	0.0	14.5	0.0	0.0	0.0	0.0	0.0	65.9	14.4	0.0	0.0	14.4	0.1
2008	0.0	28.2	0.0	0.0	0.0	0.0	0.0	114.5	28.1	0.0	0.0	28.1	0.2
2009	0.0	38.8	0.0	0.0	0.0	0.0	0.0	128.4	38.5	0.0	0.0	38.5	0.3
2010	0.0	27.4	0.0	0.0	0.0	0.0	0.0	89.9	27.0	0.0	0.0	27.0	0.5
2011	0.0	74.8	0.0	0.0	0.0	0.0	0.0	62.9	18.9	0.0	0.0	18.9	55.9
2012	0.0	97.6	0.0	0.0	0.0	0.0	0.0	65.1	19.5	0.0	0.0	19.5	78.1
2013	0.0	99.6	0.0	0.0	0.0	0.0	0.0	77.0	23.1	0.0	0.0	23.1	76.5
2014	0.0	100.8	0.0	0.0	0.0	0.0	0.0	106.4	31.9	0.0	0.0	31.9	68.9
2015	0.0	96.2	0.0	0.0	0.0	0.0	0.0	74.5	22.3	0.0	0.0	22.3	73.9
Sub.	0.0	578.1	0.0	0.0	0.0	0.0	0.0	74.5	224.2	0.0	0.0	224.2	353.9
Rem.	0.0	1309.0	0.0	0.0	0.0	0.0	0.0	5.0	277.6	0.0	0.0	277.6	1031.4
Tot.	**0.0**	**1887.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**5.0**	**501.7**	**0.0**	**0.0**	**501.7**	**1385.3**
Disc	0.0	488.1	0.0	0.0	0.0	0.0	0.0	61.3	166.1	0.0	0.0	166.1	321.9

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest -ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	Net Cash Flow After Income Tax 10% Dcf Cum. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	-0.5	-0.5	0.0	0.0	0.0	-0.5	0.0	0.0	0.0	-8.9	-19.5	-17.8
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-139.5	-159.0	-127.7
2007	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-35.9	-194.8	-153.4
2008	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-127.2	-322.1	-236.3
2009	0.0	0.0	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-121.1	-443.2	-308.0
2010	0.0	0.0	0.5	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.1	84.6	-358.6	-262.4
2011	0.0	0.0	55.9	55.9	12.3	0.0	0.0	55.4	6.9	0.0	19.1	134.2	-224.4	-196.8
2012	0.0	0.0	78.1	78.1	17.3	0.0	0.0	77.6	9.7	0.0	27.0	101.2	-123.3	-151.8
2013	0.0	0.0	76.5	76.5	16.9	0.0	0.0	76.0	9.5	0.0	26.4	76.6	-46.6	-120.8
2014	0.0	0.0	68.9	68.9	15.2	0.0	0.0	68.4	8.5	0.0	23.8	43.4	-3.2	-104.9
2015	0.0	0.0	73.9	73.9	16.3	0.0	0.0	73.4	9.2	0.0	25.5	103.3	100.0	-70.4
Sub.	0.0	0.0	353.9	353.9	78.3	0.1	0.0	350.3	43.8	0.0	122.1	100.0	100.0	-70.4
Rem.	0.0	0.0	1031.4	1031.4	228.2	0.0	0.0	1023.2	127.9	0.0	356.0	816.8	916.8	69.1
Tot.	**0.0**	**0.0**	**1385.3**	**1385.3**	**306.4**	**0.1**	**0.0**	**1373.5**	**171.7**	**0.0**	**478.1**	**916.8**	**916.8**	**69.1**
Disc	0.0	0.0	321.9	321.9	71.3	0.1	0.0	319.0	39.9	0.0	111.1	69.1	69.1	69.1

RESERVE SUMMARY

Product	Units	Remaining Reserves at January 1, 2004				Oil Equivalents			Reserve Life Indic. (yr)		
		Working Interest	Roy/NPI Interest	Total Company	Net	BOE Factor	Company Mstb	% of Total	Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	250195	0	250195	228100	1.000	250195	100	29.0	100.0	15.4
Total Oil Eq.	Mstb	250195	0	250195	228100		250195	100	29.0	0.0	15.4

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values							Net Revenue After Royalties			
		Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4290567	100	1201917	100
Total Oil Eq.	$/BOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4290567	100	1201917	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)			Disc. Rate %	Net Present Value Before Income Tax					Net Present Value After Tax			
				Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
	Initial	Average										
Crown Royalty	0.0000	8.8310	0.0	2435188	2437318	1042363	1394956	5.58	1959201	1042363	916838	3.66
Non-crown Royalty	0.0000	0.0000	5.0	1233790	1235901	704685	531215	2.12	1016549	704685	311864	1.25
Mineral Tax	0.0000	0.0000	8.0	863480	865298	579089	286209	1.14	720988	579089	141899	0.57
NPI Payment	0.0000	0.0000	10.0	693195	694812	514575	180237	0.72	583663	514575	69088	0.28
			12.0	563779	565207	461217	103990	0.42	478467	461217	17250	0.07
			15.0	422565	423747	396796	26951	0.11	362596	396796	-34200	-0.14
			20.0	274381	275246	317993	-42747	-0.17	239291	317993	-78701	-0.31

Project.......1046350
Entity.......Total With Adjustments (Probable Undeveloped)
Run date....Fri May 21 2004 10:43:31
Evaluator...Laustsen, Dana B.

Economic Forecast

Company:	Deer Creek Energy Ltd.	Reserve Class:	PPP
Property:	Corporate	Development Class:	Undeveloped
Description:	Total With Adjustments	Pricing:	Posted (2003-Dec-31) Constant
		Effective Date:	January 01, 2004

PRODUCTION FORECAST

		Heavy Oil Production			
Year	Compny Oil Wells	Compny Daily Stb	Compny Yearly Mstb	Net Yearly Mstb	Price $/Bbl
2004	0	0	0	0	0.00
2005	3	672	245	243	18.81
2006	3	1428	521	516	18.81
2007	24	6212	2267	2245	18.81
2008	45	15662	5717	5659	18.81
2009	70	29501	10768	10660	18.81
2010	87	42395	15474	15319	18.81
2011	87	49938	18227	18045	18.81
2012	87	51450	18779	18591	18.81
2013	87	49832	18189	18007	18.81
2014	102	49984	18244	17062	18.81
2015	106	45830	16728	15369	18.81
Sub.	58	28575	125160	121717	18.81
Rem.	104	39983	277282	242744	18.81
Tot.	**86**	**35567**	**402442**	**364460**	**18.81**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses			Other Expenses			Net Prod'n Revenue
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	MM$	MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	4.6	0.0	4.6	0.0	0.0	0.0	0.0	0.0	4.6	4.9	0.0	4.9	0.0	0.0	0.0	-0.4
2006	9.8	0.0	9.8	0.1	0.0	0.0	0.0	0.1	9.7	9.3	0.0	9.3	0.0	0.0	0.0	0.4
2007	42.6	0.0	42.6	0.4	0.0	0.0	0.0	0.4	42.2	22.2	2.6	24.8	0.0	0.0	0.0	17.5
2008	107.5	0.0	107.5	1.1	0.0	0.0	0.0	1.1	106.5	50.5	6.5	57.0	0.0	0.0	0.0	49.4
2009	202.5	0.0	202.5	2.0	0.0	0.0	0.0	2.0	200.5	74.5	11.1	85.6	0.0	0.0	0.0	114.9
2010	291.1	0.0	291.1	2.9	0.0	0.0	0.0	2.9	288.2	90.0	15.2	105.1	0.0	0.0	0.0	183.0
2011	342.9	0.0	342.9	3.4	0.0	0.0	0.0	3.4	339.4	95.0	16.8	111.7	0.0	0.0	0.0	227.7
2012	353.2	0.0	353.2	3.5	0.0	0.0	0.0	3.5	349.7	92.2	16.7	108.9	0.0	0.0	0.0	240.8
2013	342.1	0.0	342.1	3.4	0.0	0.0	0.0	3.4	338.7	94.3	16.7	111.0	0.0	0.0	0.0	227.7
2014	343.2	0.0	343.2	22.2	0.0	0.0	0.0	22.2	320.9	109.6	18.4	128.0	0.0	0.0	0.0	192.9
2015	314.7	0.0	314.7	25.6	0.0	0.0	0.0	25.6	289.1	111.0	17.9	128.9	0.0	0.0	0.0	160.1
Sub.	2354.3	0.0	2354.3	64.8	0.0	0.0	0.0	64.8	2289.5	753.4	121.9	875.3	0.0	0.0	0.0	1414.1
Rem.	5215.7	0.0	5215.7	649.7	0.0	0.0	0.0	649.7	4566.0	1801.7	288.9	2090.6	0.0	0.0	0.0	2475.4
Tot.	**7569.9**	**0.0**	**7569.9**	**714.4**	**0.0**	**0.0**	**0.0**	**714.4**	**6855.5**	**2555.1**	**410.8**	**2965.9**	**0.0**	**0.0**	**0.0**	**3889.6**
Disc	1961.6	0.0	1961.6	134.8	0.0	0.0	0.0	134.8	1826.8	652.4	104.3	756.7	0.0	0.0	0.0	1070.1

	Other Income				Net Capital Investment				Before Tax Cash Flow				After Tax Cash Flow		
Year	Other MM$	ARTC MM$	Aband. Costs MM$	Oper. Income MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	Income Tax MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	10.6	10.6	-10.6	-10.6	-10.1	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	-0.3	8.4	0.0	0.0	8.4	-8.7	-19.3	-17.7	0.0	-8.7	-19.3	-17.7
2006	0.0	0.0	0.0	0.4	50.4	0.0	87.4	137.8	-137.4	-156.7	-125.9	0.0	-137.4	-156.7	-125.9
2007	0.0	0.1	0.0	17.6	52.5	0.0	71.4	123.9	-106.3	-263.0	-202.1	0.0	-106.4	-263.1	-202.1
2008	0.0	0.3	0.0	49.7	63.0	0.0	109.2	172.2	-122.5	-385.6	-281.9	0.1	-122.6	-385.7	-281.9
2009	0.0	0.5	0.0	115.4	42.0	0.0	142.8	184.8	-69.4	-454.9	-323.0	0.1	-69.5	-455.1	-323.1
2010	0.0	0.5	0.0	183.5	0.0	0.0	126.0	126.0	57.5	-397.4	-292.0	14.9	42.6	-412.5	-300.2
2011	0.0	0.5	0.0	228.2	0.0	0.0	67.2	67.2	161.0	-236.5	-213.2	34.8	126.1	-286.4	-238.4
2012	0.0	0.5	0.0	241.3	0.0	0.0	0.0	0.0	241.3	4.9	-105.9	47.9	193.4	-93.0	-152.4
2013	0.0	0.5	0.0	228.2	48.3	0.0	19.3	67.6	160.6	165.4	-41.0	46.7	113.9	20.9	-106.4
2014	0.0	0.5	0.0	193.4	58.8	0.0	23.5	82.3	111.1	276.5	-0.1	35.2	75.9	96.7	-78.5
2015	0.0	0.5	0.0	160.6	63.0	0.0	25.2	88.2	72.4	349.0	24.1	23.8	48.7	145.4	-62.2
Sub.	0.0	3.9	0.0	1418.1	386.4	0.0	682.7	1069.1	349.0	349.0	24.1	203.6	145.4	145.4	-62.2
Rem.	0.0	9.4	21.5	2463.3	396.9	0.0	158.9	555.8	1907.5	2256.4	346.4	575.1	1332.3	1477.7	163.4
Tot.	**0.0**	**13.3**	**21.5**	**3881.4**	**783.3**	**0.0**	**841.6**	**1624.9**	**2256.4**	**2256.4**	**346.4**	**778.7**	**1477.7**	**1477.7**	**163.4**
Disc	0.0	3.3	2.5	1070.9	284.4	0.0	440.1	724.5	346.4	346.4	346.4	183.0	163.4	163.4	163.4

AFTER TAX ANALYSIS

Year Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2005	4.6	0.0	0.0	0.0	4.9	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2006	9.8	0.0	0.0	0.0	9.3	0.0	0.0	0.0	98.0	0.0	0.0	0.0	0.0
2007	42.6	0.0	0.0	0.3	24.8	0.0	0.0	0.0	169.4	0.0	0.0	0.0	0.0
2008	107.5	0.0	0.0	0.8	57.0	0.0	0.0	0.0	278.6	0.0	0.0	0.0	0.0
2009	202.5	0.0	0.0	1.5	85.6	0.0	0.0	0.0	421.4	64.8	0.0	0.0	64.8
2010	291.1	0.0	0.0	2.4	105.1	0.0	0.0	0.0	482.6	104.9	0.0	0.0	104.9
2011	342.9	0.0	0.0	2.9	111.7	0.0	0.0	0.0	444.9	102.8	0.0	0.0	102.8
2012	353.2	0.0	0.0	3.0	108.9	0.0	0.0	0.0	342.1	85.5	0.0	0.0	85.5
2013	342.1	0.0	0.0	2.9	111.0	0.0	0.0	0.0	275.9	66.6	0.0	0.0	66.6
2014	343.2	0.0	0.0	21.7	128.0	0.0	0.0	0.0	232.9	55.3	0.0	0.0	55.3
2015	314.7	0.0	0.0	25.1	128.9	0.0	0.0	0.0	202.8	47.5	0.0	0.0	47.5
Sub.	2354.3	0.0	0.0	60.8	875.3	0.0	0.0	0.0	202.8	527.4	0.0	0.0	527.4
Rem.	5215.7	0.0	0.0	640.3	2109.6	0.0	0.0	0.0	8.6	307.0	0.0	0.0	307.0
Tot.	**7569.9**	**0.0**	**0.0**	**701.1**	**2984.9**	**0.0**	**0.0**	**0.0**	**8.6**	**834.4**	**0.0**	**0.0**	**834.4**
Disc	1961.6	0.0	0.0	131.5	759.0	0.0	0.0	0.0	163.2	304.6	0.0	0.0	304.6

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write-off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	-0.3	0.0	0.0	0.0	0.0	0.0	26.4	0.0	0.0	0.0	0.0	-0.3
2006	0.0	0.4	0.0	0.0	0.0	0.0	0.0	76.8	0.4	0.0	0.0	0.4	0.0
2007	0.0	17.6	0.0	0.0	0.0	0.0	0.0	128.9	17.5	0.0	0.0	17.5	0.1
2008	0.0	49.7	0.0	0.0	0.0	0.0	0.0	174.5	49.4	0.0	0.0	49.4	0.3
2009	0.0	50.6	0.0	0.0	0.0	0.0	0.0	167.0	50.1	0.0	0.0	50.1	0.5
2010	0.0	78.6	0.0	0.0	0.0	0.0	0.0	116.9	35.1	0.0	0.0	35.1	43.6
2011	0.0	125.4	0.0	0.0	0.0	0.0	0.0	81.8	24.6	0.0	0.0	24.6	100.8
2012	0.0	155.8	0.0	0.0	0.0	0.0	0.0	57.3	17.2	0.0	0.0	17.2	138.6
2013	0.0	161.7	0.0	0.0	0.0	0.0	0.0	88.4	26.5	0.0	0.0	26.5	135.1
2014	0.0	138.1	0.0	0.0	0.0	0.0	0.0	120.7	36.2	0.0	0.0	36.2	101.9
2015	0.0	113.1	0.0	0.0	0.0	0.0	0.0	147.5	44.2	0.0	0.0	44.2	68.9
Sub.	0.0	890.7	0.0	0.0	0.0	0.0	0.0	147.5	301.2	0.0	0.0	301.2	589.5
Rem.	0.0	2158.9	0.0	0.0	0.0	0.0	0.0	8.5	494.2	0.0	0.0	494.2	1664.7
Tot.	**0.0**	**3049.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**8.5**	**795.3**	**0.0**	**0.0**	**795.3**	**2254.2**
Disc	0.0	766.5	0.0	0.0	0.0	0.0	0.0	86.4	236.8	0.0	0.0	236.8	529.6

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest-ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	Net Cash Flow After Income Tax 10% Dcf Cum. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	-0.3	-0.3	0.0	0.0	0.0	-0.3	0.0	0.0	0.0	-8.7	-19.3	-17.7
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-137.4	-156.7	-125.9
2007	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-106.4	-263.1	-202.1
2008	0.0	0.0	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-122.6	-385.7	-281.9
2009	0.0	0.0	0.5	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-69.5	-455.1	-323.1
2010	0.0	0.0	43.6	43.6	9.6	0.0	0.0	43.1	5.3	0.0	14.9	42.6	-412.5	-300.2
2011	0.0	0.0	100.8	100.8	22.3	0.0	0.0	100.3	12.5	0.0	34.8	126.1	-286.4	-238.4
2012	0.0	0.0	138.6	138.6	30.7	0.0	0.0	138.1	17.3	0.0	47.9	193.4	-93.0	-152.4
2013	0.0	0.0	135.1	135.1	29.9	0.0	0.0	134.6	16.8	0.0	46.7	113.9	20.9	-106.4
2014	0.0	0.0	101.9	101.9	22.5	0.0	0.0	101.4	12.7	0.0	35.2	75.9	96.7	-78.5
2015	0.0	0.0	68.9	68.9	15.2	0.0	0.0	68.4	8.5	0.0	23.8	48.7	145.4	-62.2
Sub.	0.0	0.0	589.5	589.5	130.4	0.1	0.0	585.6	73.2	0.0	203.6	145.4	145.4	-62.2
Rem.	0.0	0.0	1664.7	1664.7	368.2	0.0	0.0	1655.3	206.9	0.0	575.1	1332.3	1477.7	163.4
Tot.	**0.0**	**0.0**	**2254.2**	**2254.2**	**498.6**	**0.1**	**0.0**	**2240.9**	**280.1**	**0.0**	**778.7**	**1477.7**	**1477.7**	**163.4**
Disc	0.0	0.0	529.6	529.6	117.2	0.1	0.0	526.4	65.8	0.0	183.0	163.4	163.4	163.4

RESERVE SUMMARY

Product	Units	Remaining Reserves at January 1, 2004: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: BOE Factor	Company Mstb	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	402442	0	402442	364460	1.000	402442	100	31.0	100.0	16.1
Total Oil Eq.	Mstb	402442	0	402442	364460		402442	100	31.0	0.0	16.1

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6855502	100	1826834	100
Total Oil Eq.	$/BOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6855502	100	1826834	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)	Initial	Average
Crown Royalty	0.0000	9.4378
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000
NPI Payment	0.0000	0.0000

Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Net Present Value After Tax: Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
0.0	3889552	3881351	1624921	2256430	5.61	3102622	1624921	1477701	3.67
5.0	1925553	1924828	1033920	890909	2.21	1567631	1033920	533712	1.33
8.0	1337260	1337737	827392	510344	1.27	1101440	827392	274048	0.68
10.0	1070140	1070941	724539	346403	0.86	887948	724539	163409	0.41
12.0	868678	869617	641223	228394	0.57	725864	641223	84641	0.21
15.0	650400	651368	542816	108552	0.27	548848	542816	6032	0.01
20.0	422928	423771	425755	-1984	0.00	362147	425755	-63608	-0.16

Project.......1046350
Entity.......Total With Adjustments (PPP Undeveloped)
Run date....Fri May 21 2004 10:43:31
Evaluator...Laustsen, Dana B.

Economic Forecast

Company:	Deer Creek Energy Ltd.	Resource Class:	Best Estimate
Property:	Joslyn Creek Mining Resources	Development Class:	Total
		Pricing:	Posted (2003-Dec-31) Constant
		Effective Date:	1-Jan-04

PRODUCTION FORECAST

Heavy Oil Production

Year	Company Daily Stb	Company Yearly Mmb	Net Yearly Mmb	Price $/Bbl
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	25200	9	9	18.81
2011	42000	15	15	18.81
2012	42000	15	15	18.81
2013	75600	28	27	18.81
2014	84000	31	30	18.81
2015	84000	31	30	18.81
Sub.	29400	129	127	18.81
Rem.	121209	1106	981	18.81
Tot.	**91433**	**1235**	**1108**	**18.81**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses			Other Expenses			Net Prod'n Revenue
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	MM$	MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	173	0	173	2	0	0	0	2	171	66	32	98	0	0	0	73
2011	288	0	288	3	0	0	0	3	285	109	38	148	0	0	0	138
2012	288	0	288	3	0	0	0	3	285	110	38	148	0	0	0	137
2013	519	0	519	5	0	0	0	5	514	194	69	263	0	0	0	251
2014	577	0	577	6	0	0	0	6	571	197	69	266	0	0	0	305
2015	577	0	577	6	0	0	0	6	571	231	69	300	0	0	0	271
Sub.	2422	0	2422	24	0	0	0	24	2398	907	316	1222	0	0	0	1176
Rem.	20804	0	20804	2358	0	0	0	2358	18446	7116	2223	9339	0	0	0	9108
Tot.	**23227**	**0**	**23227**	**2382**	**0**	**0**	**0**	**2382**	**20844**	**8023**	**2539**	**10561**	**0**	**0**	**0**	**10283**
Disc	3560	0	3560	258	0	0	0	258	3302	1250	407	1657	0	0	0	1645

	Other Income		Aband. Costs	Oper. Income	Net Capital Investment				Before Tax Cash Flow			Income Tax	After Tax Cash Flow		
Year	Other MM$	ARTC MM$	MM$	MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	8	8	-8	-8	-7	0	-8	-8	-7
2007	0	0	0	0	0	0	13	13	-13	-21	-16	0	-13	-21	-16
2008	0	0	0	0	0	0	277	277	-277	-298	-196	0	-277	-298	-196
2009	0	0	0	0	0	0	260	260	-260	-559	-350	0	-260	-559	-350
2010	0	0	0	73	0	0	63	63	10	-548	-345	0	10	-548	-345
2011	0	0	0	138	0	0	277	277	-139	-688	-413	0	-139	-688	-413
2012	0	0	0	137	0	0	260	260	-123	-811	-468	0	-123	-811	-468
2013	0	0	0	251	0	0	71	71	180	-631	-395	0	180	-631	-395
2014	0	0	0	305	31	0	277	308	-3	-634	-396	0	-3	-634	-396
2015	0	0	0	271	31	0	260	291	-20	-654	-403	0	-20	-654	-403
Sub.	0	0	0	1176	61	0	1768	1830	-654	-654	-403	0	-654	-654	-403
Rem.	0	0	0	9108	1009	0	59	1068	8040	7386	618	2570	5470	4816	321
Tot.	**0**	**0**	**0**	**10283**	**1070**	**0**	**1827**	**2897**	**7386**	**7386**	**618**	**2570**	**4816**	**4816**	**321**
Disc	0	0	0	1645	155	0	871	1027	618	618	618	296	321	321	321

AFTER TAX ANALYSIS

Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	8	0	0	0	0
2007	0	0	0	0	0	0	0	0	21	0	0	0	0
2008	0	0	0	0	0	0	0	0	298	0	0	0	0
2009	0	0	0	0	0	0	0	0	559	0	0	0	0
2010	173	0	0	2	98	0	0	0	622	73	0	0	73
2011	288	0	0	3	148	0	0	0	826	138	0	0	138
2012	288	0	0	3	148	0	0	0	948	137	0	0	137
2013	519	0	0	5	263	0	0	0	882	251	0	0	251
2014	577	0	0	6	266	0	0	0	908	296	0	0	296
2015	577	0	0	6	300	0	0	0	873	255	0	0	255
Sub.	2422	0	0	24	1222	0	0	0	873	1151	0	0	1151
Rem.	20804	0	0	2358	9339	0	0	0	0	676	0	0	676
Tot.	**23227**	**0**	**0**	**2382**	**10561**	**0**	**0**	**0**	**0**	**1827**	**0**	**0**	**1827**
Disc	3560	0	0	258	1657	0	0	0	271	661	0	0	661

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write-off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	9	0	0	0	0	0	31	9	0	0	9	0
2015	0	16	0	0	0	0	0	52	16	0	0	16	0
Sub.	0	25	0	0	0	0	0	52	25	0	0	25	0
Rem.	0	8431	0	0	0	0	0	53	1008	0	0	1008	7423
Tot.	**0**	**8456**	**0**	**0**	**0**	**0**	**0**	**53**	**1033**	**0**	**0**	**1033**	**7423**
Disc	0	984	0	0	0	0	0	40	127	0	0	127	856

Year	Allowable Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest-ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	10% Dcf Cum. MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	-8	-8	-7
2007	0	0	0	0	0	0	0	0	0	0	0	-13	-21	-16
2008	0	0	0	0	0	0	0	0	0	0	0	-277	-298	-196
2009	0	0	0	0	0	0	0	0	0	0	0	-260	-559	-350
2010	0	0	0	0	0	0	0	0	0	0	0	10	-548	-345
2011	0	0	0	0	0	0	0	0	0	0	0	-139	-688	-413
2012	0	0	0	0	0	0	0	0	0	0	0	-123	-811	-468
2013	0	0	0	0	0	0	0	0	0	0	0	180	-631	-395
2014	0	0	0	0	0	0	0	0	0	0	0	-3	-634	-396
2015	0	0	0	0	0	0	0	0	0	0	0	-20	-654	-403
Sub.	0	0	0	0	0	0	0	0	0	0	0	-654	-654	-403
Rem.	0	0	7423	7423	1642	0	0	7423	928	0	2570	5470	4816	321
Tot.	**0**	**0**	**7423**	**7423**	**1642**	**0**	**0**	**7423**	**928**	**0**	**2570**	**4816**	**4816**	**321**
Disc	0	0	856	856	189	0	0	856	107	0	296	321	321	321

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RESOURCE SUMMARY

		Remaining Resources at January 1, 2004				Oil Equivalents			Resource Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	BOE Factor	Company Mstb	% of Total	Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	1234800	0	1234800	1108151	1	1234800	100	37	100	22.7
Total Oil Eq.	Mstb	1234800	0	1234800	1108151		1234800	100	37	0	22.7

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0	0	0	0	0	0	0	20844320	100	3301641	100
Total Oil Eq.	$/BOE	0	0	0	0	0	0	0	20844320	100	3301641	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)				Net Present Value Before Income Tax					Net Present Value After Tax			
			Disc. Rate	Prod'n Revenue	Operating Income	Capital Invest.	Cash Flow		Operating Income	Capital Invest.	Cash Flow	
	Initial	Average	%	M$	M$	M$	M$	$/BOE	M$	M$	M$	$/BOE
Crown Royalty	0	10.2567	0	10283212	10283212	2897034	7386178	5.98	7713379	2897034	4816345	3.9
Non-crown Royalty	0	0	5	3763528	3763528	1620999	2142530	1.74	2951082	1620999	1330083	1.08
Mineral Tax	0	0	8	2248364	2248364	1218970	1029394	0.83	1811391	1218970	592420	0.48
NPI Payment	0	0	10	1644651	1644651	1026739	617911	0.5	1348161	1026739	321422	0.26
			12	1229025	1229025	874976	354049	0.29	1024136	874976	149160	0.12
			15	821870	821870	700677	121193	0.1	700514	700677	-163	0
			20	452866	452866	501939	-49073	-0.04	398553	501939	-103385	-0.08

Project.......1046350

Entity.......Joslyn Creek Mining Resources (Best Estimate)

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Evaluator...Laustsen, Dana B.

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SECURITIES REPORTING DISCUSSION

The Canadian Securities Administrators (CSA) have set out disclosure standards for Canadian publicly traded oil and gas companies in National Instrument 51-101 (NI 51-101).

This section presents reserves data in a format that follows CSA Form 51-101F1 and the sample tables contained in Appendix 2 to the NI 51-101 Companion Policy (51-101CP).

PART 1 DATE OF STATEMENT

Item 1.1 Relevant Dates

1. Effective Date:
   The effective date of the reserves estimates and revenue projections in this report is January 1, 2004.

2. Data Date:
   Estimates of reserves and projections of production were generally prepared using general well information and production data available in the public domain to approximately December 31, 2004. In certain instances, the Company provided production and well information up to January 31, 2004. The Company has provided GLJ with a representation letter confirming that complete and correct information has been provided to GLJ.

3. Preparation Date:
   The preparation date of this report is March 16, 2004. As of the preparation date, GLJ was not aware of any new information (other than commodity pricing assumptions which may differ from those used in this analysis) which could materially impact this evaluation.

PART 2 DISCLOSURE OF RESERVES DATA

Item 2.1 Reserves Data (Constant Prices and Costs)

1. Breakdown of Reserves (Constant Case)

There are no Company interest proved reserves to report, however data on probable and possible reserves are provided.
Refer to Table CP-1

2. Net Present Value of Future Net Revenue (Constant Case)
Refer to Table CP-1

3. Additional Information Concerning Future Net Revenue (Constant Case)
   (a) Undiscounted Revenue and Costs
   Refer to Table CP-2
   (b) Discounted Future Net Revenue by Production Group
   Refer to Table CP-3

Item 2.2 Reserves Data (Forecast Prices and Costs)

1. Breakdown of Reserves (Forecast Case)
Refer to Table FP-1

2. Net Present Value of Future Net Revenue (Forecast Case)
Refer to Table FP-1

3. Additional Information Concerning Future Net Revenue (Forecast Case)
   (a) Undiscounted Revenue and Costs
   Refer to Table FP-2
   (b) Discounted Future Net Revenue by Production Group
   Refer to Table FP-3

PART 3 PRICING ASSUMPTIONS

Item 3.1 Constant Prices Used in Estimates

The reference benchmark prices (reflecting the posted prices corresponding to the last day of the Company's most recent financial year) used in the Constant price analysis, are provided in Table CP-4.

Item 3.2 Forecast Prices Used in Estimates

The forecast reference prices used in preparing the Company's reserves data are provided in Table FP-4.

This price forecast is GLJ's standard price forecast effective April 1, 2004.

PART 4 RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 Reserves Reconciliation

Table FP-5 provides a reconciliation of the Company's net reserves based on forecast prices and costs between this analysis and the Company's prior year-end evaluation.

Item 4.2 Future Net Revenue Reconciliation

The Company has no proved reserves to report.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

No proved undeveloped reserves are reported. Probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The significant majority of the probable undeveloped reserves are scheduled to be developed within the next seven years of the effective date.

Item 5.2 Significant Factors or Uncertainties

The development forecasts herein are predicated on the Company securing financing for the project.

Item 5.3 Future Development Costs

Tables CP-6 and FP-6 summarize capital development costs related to the recovery of the Company's reserves.

PART 6 OTHER OIL AND GAS INFORMATION

Item 6.3 Forward Contracts

Hedging Activity – There are no forward contracts to report.

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

The following aspects of the Company's future abandonment and reclamation costs have been included/excluded in the economic forecasts.

Included:

- Well Abandonment Costs:
  - future reserves wells

Excluded:
- Pipelines
- Production Facilities
- Site Reclamation

Total abandonment costs are included in the reserves data summarized in Tables CP-7 and FP-7 for the constant and forecast price cases, respectively.

Item 6.5 Tax Horizon

Based on after tax economic forecasts prepared by GLJ, which exclude certain items impacting income taxes payable (e.g. exploration and seismic, and land or property acquisition costs), income taxes are payable by the Company beginning in 2011).

Item 6.8 Production Estimates

There is no first year production to report.

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 May 18, 2004

ORIGINALLY SIGNED BY

Dana B. Laustsen, P. Eng.

TABLE CP-1
Summary of Reserves and Values

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total With Adjustments**

Pricing: **Posted (2003-Dec-31) Constant**
Effective Date: **January 01, 2004**

	Probable Undeveloped	PPP Undeveloped
MARKETABLE RESERVES		
Heavy Oil - MMSTB		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
Oil Equivalent - MMBOE		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
BEFORE TAX PRESENT VALUE - $M		
0.0%	1394956	2256430
5.0%	531215	890909
8.0%	286209	510345
10.0%	180237	346402
12.0%	103990	228394
15.0%	26951	108552
20.0%	-42747	-1984
AFTER TAX PRESENT VALUE - $M		
0.0%	916838	1477701
5.0%	311864	533712
8.0%	141899	274048
10.0%	69088	163409
12.0%	17250	84641
15.0%	-34200	6032
20.0%	-78702	-63608

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

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Run date Fri May 21 2004 10:43:31

p:/s1046350/rems/econ/Posted_2003-Dec-31_Constant/_Corporate_Total_With_Adjustments_RC00_psum.htm

Table CP-2

Total Future Net Revenue (Undiscounted)

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total With Adjustments**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **Posted (2003-Dec-31) Co**
Effective Date: **January 01, 2004**

	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Capital Development Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)
Probable Undeveloped	4706170	403813	1855379	1042363	9660	1394956
PPP Undeveloped	7569939	701135	2965949	1624921	21504	2256430

p:/s1046350/rems/econ/Posted_2003-Dec-31_Constant/_Corporate_Total_With_Adjustments_RC00_cs3.htm

Table CP-3

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **Posted (2003-Dec-31) Co**
Effective Date: **January 01, 2004**

	Reserves										Net
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent		
	W.I. Mbbl	Net Mbbl	W.I. Mbbl	Net Mbbl	W.I. Mmcf	Net Mmcf	W.I. Mbbl	Net Mbbl	W.I. Mbbl	Net Mbbl	0% M$
Probable Undeveloped											
Heavy Oil Properties	0	0	250195	228100	0	0	0	0	250195	228100	1383165
ARTC	0	0	0	0	0	0	0	0	0	0	11790
Probable Undeveloped	0	0	250195	228100	0	0	0	0	250195	228100	1394956
PPP Undeveloped											
Heavy Oil Properties	0	0	402442	364460	0	0	0	0	402442	364460	2243127
ARTC	0	0	0	0	0	0	0	0	0	0	13303
PPP Undeveloped	0	0	402442	364460	0	0	0	0	402442	364460	2256430

BOE Factors:								
	OIL	1.00000	RES GAS	6.00000	PROPANE	1.00000	ETHANE	1.00000
	COND	1.00000	SLN GAS	6.00000	BUTANE	1.00000	SULPHUR	0.00000

p:/s1046350/rems/econ/Posted_2003-Dec-31_Constant/_Corporate_Table_CP-3_RC00_cs1bt.htm

TABLE CP-4
DECEMBER 31, 2003 CONSTANT PRICES

Crude Oil and Natural Gas Prices

Year	Inflation %	Exchange Rate $US/$Cdn	West Texas Intermediate Crude Oil at Cushing Oklahoma Then Current $US/bbl	Brent Blend Crude Oil FOB North Sea Then Current $US/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current $Cdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current $Cdn/bbl	Alberta Natural Gas Liquids (Then Current Dollars) Spec Ethane $Cdn/bbl	Edmonton Propane $Cdn/bbl	Edmonton Butane $Cdn/bbl
1993	1.8	0.7750	18.46	17.03	21.94	16.73	13.26	17.59	n/a	14.10	13.64
1994	0.2	0.7300	17.18	15.82	22.22	18.47	15.02	19.30	n/a	12.53	13.45
1995	2.2	0.7290	18.39	17.04	24.23	20.80	17.28	21.69	n/a	13.90	13.79
1996	1.6	0.7334	21.99	20.43	29.39	25.13	20.06	26.10	n/a	22.31	17.15
1997	1.6	0.7224	20.61	19.18	27.85	21.17	14.41	23.72	n/a	18.62	18.73
1998	0.9	0.6723	14.42	12.83	20.36	14.64	9.45	16.95	n/a	11.15	12.44
1999	1.7	0.6750	19.29	17.81	27.69	23.84	19.67	25.42	n/a	15.89	18.70
2000	2.7	0.6740	30.22	28.35	44.56	35.25	27.34	39.91	n/a	32.18	35.60
2001	2.6	0.6448	25.97	24.37	39.40	27.70	16.94	31.56	n/a	31.85	31.17
2002	2.2	0.6376	26.08	24.99	40.33	31.83	26.57	35.48	n/a	21.39	27.08
2003 (e)	2.8	0.7213	30.96	29.00	43.51	32.01	26.01	37.26	n/a	32.01	34.01
2004	**0.0**	**0.7738**	**32.52**	**31.02**	**40.81**	**29.81**	**23.31**	**34.81**	**19.50**	**29.81**	**31.81**

Constant Thereafter

Natural Gas and Sulphur

Year	US Gulf Coast Gas Price @ Henry Hub Then Current $US/mmbtu	Midwest Price @ Chicago Then Current $US/mmbtu	AECO-C Spot Then Current $Cdn/mmbtu	Alberta Plant Gate: Spot Then Current $/mmbtu	Alberta Plant Gate: ARP $/mmbtu	Alberta Plant Gate: Aggregator $/mmbtu	Alberta Plant Gate: Alliance $/mmbtu	Saskatchewan Plant Gate: SaskEnergy $/mmbtu	Saskatchewan Plant Gate: Spot $/mmbtu	Sumas Spot $US/mmbtu	British CanWest Plant Gate $/mmbtu
1993	2.11	2.31	2.26	2.16	1.71	n/a	n/a	1.48	2.07	1.89	1.73
1994	1.94	2.11	1.98	1.86	1.81	n/a	n/a	1.88	1.87	1.59	1.81
1995	1.70	1.69	1.15	1.02	1.31	n/a	n/a	1.35	0.98	1.03	1.29
1996	2.52	2.73	1.39	1.26	1.63	n/a	n/a	1.52	1.28	1.32	1.50
1997	2.47	2.75	1.84	1.69	1.96	n/a	n/a	1.84	1.74	1.70	1.80
1998	2.16	2.20	2.03	1.88	1.94	n/a	n/a	2.05	2.13	1.60	1.94
1999	2.32	2.34	2.92	2.75	2.48	n/a	n/a	2.83	2.97	2.15	2.51
2000	4.33	4.38	5.08	4.92	4.50	4.60	n/a	4.79	5.16	4.17	5.27
2001	4.05	4.17	6.21	6.07	5.41	5.30	5.61	5.71	6.20	4.56	6.76
2002	3.36	3.30	4.04	3.88	3.88	3.83	3.82	4.04	4.08	2.68	3.64
2003 (e)	5.43	5.46	6.66	6.49	6.33	5.85	6.83	6.60	6.68	4.66	5.69
2004	**5.77**	**5.86**	**6.09**	**5.83**	**5.73**	**5.43**	**5.83**	**5.88**	**5.98**	**5.49**	**5.43**

Constant Thereafter

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering and processing charges are deducted.
Spot refers to weighted average one month price.

Note: These prices are actual posted prices at the referenced date; other reference prices are derived based on estimated price offsets.

TABLE CP-5

RESERVES RECONCILIATION

The reserves reconciliation has only been prepared for the forecast price analysis. Refer to Table

Table CP-6

Company Annual Capital Expenditures (MM$)

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total With Adjustments**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **Posted (2003-Dec-31) Co**
Effective Date: **January 01, 2004**

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Probable Undeveloped	11	8	140	50	155	185	25	0	29	44	74	0
PPP Undeveloped	11	8	138	124	172	185	126	67	0	68	82	88

p:/s1046350/rems/econ/Posted_2003-Dec-31_Constant/_Corporate_Total_Joslyn_Creek_RC00_cs4.htm

Table CP-7

Company Annual Abandonment Costs (M$)

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **Posted (2003-Dec-31) Co**
Effective Date: **January 01, 2004**

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Probable Undeveloped												
Joslyn SAGD property	0	0	0	0	0	0	0	0	0	0	0	0
PPP Undeveloped												
Joslyn SAGD property	0	0	0	0	0	0	0	0	0	0	0	0

p:/s1046350/rems/econ/Posted_2003-Dec-31_Constant/_Corporate_Total_Joslyn_Creek_RC00_cs5.htm

Table CP-8
Summary of Oil Resources and Net Present Values of Future Net Revenue from Mining Activity

Company: **Deer Creek Energy Ltd.** Pricing: **Posted (2003-Dec-31) Constant**

Property: **Joslyn Creek Mining Resources** Effective Date: **1-Jan-04**

	Best Estimate
MARKETABLE RESERVES	
Heavy Oil - MMSTB	
Total Company Interest	1235
Working Interest	1235
Net After Royalty	1107
Oil Equivalent - MMBOE	
Total Company Interest	1235
Working Interest	1235
Net After Royalty	1107
BEFORE TAX PRESENT VALUE - $M	
0.00%	7386178
5.00%	2142530
8.00%	1029394
10.00%	617911
12.00%	354049
15.00%	121193
20.00%	-49073
AFTER TAX PRESENT VALUE - $M	
0.00%	4816345
5.00%	1330083
8.00%	592420
10.00%	321422
12.00%	149160
15.00%	-163
20.00%	-103385

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

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Table CP-8.xls

p:\s1046350\rems\econ\Posted (2003-12-31 Constant) \Joslyn_Creek_Mining_Resources_RC38_psum.htm

TABLE FP-1
Summary of Reserves and Values

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total With Adjustments**

Pricing: **GLJ (2004-04) Full Year**
Effective Date: **January 01, 2004**

	Probable Undeveloped	PPP Undeveloped
MARKETABLE RESERVES		
Heavy Oil - MMSTB		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
Oil Equivalent - MMBOE		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
BEFORE TAX PRESENT VALUE - $M		
0.0%	1742695	2871677
5.0%	626186	1056871
8.0%	322548	575921
10.0%	194669	375113
12.0%	104608	234091
15.0%	16050	95200
20.0%	-60419	-26602
AFTER TAX PRESENT VALUE - $M		
0.0%	1143699	1878290
5.0%	368176	634331
8.0%	159059	308446
10.0%	71790	173764
12.0%	10968	80182
15.0%	-47749	-10379
20.0%	-96022	-86447

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

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p:/s1046350/rems/econ/GLJ_2004-04_Full_Year/_Corporate_Total_With_Adjustments_RC00_psum.htm

Table FP-2

Total Future Net Revenue (Undiscounted)

Company:	**Deer Creek Energy Ltd.**	Reserve Class:	**Various**
Property:	**Corporate**	Development Class:	**Classifications**
Description:	***Total With Adjustments***	*Pricing:*	***GLJ (2004-04) Full Year***
		Effective Date:	**January 01, 2004**

	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Capital Development Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)
Probable Undeveloped	5416347	508887	1967813	1183621	13330	1742695
PPP Undeveloped	8882234	897008	3195192	1887587	30770	2871677

p:/s1046350/rems/econ/GLJ_2004-04_Full_Year/_Corporate_Total_With_Adjustments_RC00_cs3.htm

Table FP-3

Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2004-04) Full Year**
Effective Date: **January 01, 2004**

	Reserves										Net
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent		
	W.I. Mbbl	Net Mbbl	W.I. Mbbl	Net Mbbl	W.I. Mmcf	Net Mmcf	W.I. Mbbl	Net Mbbl	W.I. Mbbl	Net Mbbl	0% M$
Probable Undeveloped											
Heavy Oil Properties	0	0	250195	228258	0	0	0	0	250195	228258	1730763
ARTC	0	0	0	0	0	0	0	0	0	0	11931
Probable Undeveloped	0	0	250195	228258	0	0	0	0	250195	228258	1742695
PPP Undeveloped											
Heavy Oil Properties	0	0	402442	364296	0	0	0	0	402442	364296	2858366
ARTC	0	0	0	0	0	0	0	0	0	0	13311
PPP Undeveloped	0	0	402442	364296	0	0	0	0	402442	364296	2871677

BOE Factors:								
	OIL	1.00000	RES GAS	6.00000	PROPANE	1.00000	ETHANE	1.00000
	COND	1.00000	SLN GAS	6.00000	BUTANE	1.00000	SULPHUR	0.00000

p:/s1046350/rems/econ/GLJ_2004-04_Full_Year/_Corporate_Table_FP-3_RC00_cs1bt.htm

Table FP-4
FORECAST PRICES USED IN PREPARING RESERVES DATA

Gilbert Laustsen Jung Associates Ltd.
Crude Oil and Natural Gas Liquids
Price Forecast
Effective April 1, 2004

Year	Inflation %	Bank of Canada Average Noon Exchange Rate $US/$Cdn	West Texas Intermediate Crude Oil at Cushing Oklahoma Constant 2004 $ $US/bbl	West Texas Intermediate Crude Oil at Cushing Oklahoma Then Current $US/bbl	Brent Blend Crude Oil FOB North Sea Constant 2004 $ $US/bbl	Brent Blend Crude Oil FOB North Sea Then Current $US/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Constant 2004 $ $Cdn/bbl	Light, Sweet Crude Oil (40 API, 0.3%S) at Edmonton Then Current $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Constant 2004 $ $Cdn/bbl	Bow River Crude Oil Stream Quality at Hardisty Then Current $Cdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Constant 2004 $ $Cdn/bbl	Heavy Crude Oil Proxy (12 API) at Hardisty Then Current $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Constant 2004 $ $Cdn/bbl	Medium Crude Oil (29 API, 2.0%S) at Cromer Then Current $Cdn/bbl	Spec Ethane $Cdn/bbl
1993	1.8	0.775	22.56	18.46	20.81	17.03	26.81	21.94	20.44	16.73	16.20	13.26	21.49	17.59	n/a
1994	0.2	0.732	20.62	17.18	18.99	15.82	26.67	22.22	22.17	18.47	18.03	15.02	23.17	19.30	n/a
1995	2.2	0.729	22.03	18.39	20.41	17.04	29.03	24.23	24.92	20.80	20.70	17.28	25.98	21.69	n/a
1996	1.6	0.733	25.78	21.99	23.95	20.43	34.46	29.39	29.47	25.13	23.52	20.06	30.60	26.10	n/a
1997	1.6	0.722	23.79	20.61	22.14	19.18	32.14	27.85	24.43	21.17	16.63	14.41	27.37	23.72	n/a
1998	0.9	0.675	16.38	14.42	14.57	12.83	23.13	20.36	16.63	14.64	10.73	9.45	19.25	16.95	n/a
1999	1.7	0.673	21.72	19.29	20.05	17.81	31.17	27.69	26.84	23.84	22.14	19.67	28.62	25.42	n/a
2000	2.7	0.673	33.45	30.22	31.38	28.35	49.33	44.56	39.02	35.25	30.26	27.34	44.18	39.91	n/a
2001	2.6	0.646	27.99	25.97	26.27	24.37	42.47	39.40	29.86	27.70	18.26	16.94	34.02	31.56	n/a
2002	2.2	0.637	27.40	26.08	26.25	24.99	42.37	40.33	33.44	31.83	27.91	26.57	37.27	35.48	n/a
2003	2.8	0.721	31.93	31.07	29.74	28.93	44.88	43.66	33.01	32.11	26.99	26.26	38.60	37.55	n/a
2004 Q1 (e)	1.5	0.757	34.50	34.50	33.00	33.00	44.50	44.50	34.25	34.25	28.00	28.00	40.50	40.50	n/a
2004 Q2	1.5	0.750	36.00	36.00	34.50	34.50	47.25	47.25	37.75	37.75	31.75	31.75	43.75	43.75	22.00
2004 Q3	1.5	0.750	34.00	34.00	32.50	32.50	44.50	44.50	35.25	35.25	29.50	29.50	41.00	41.00	22.25
2004 Q4	1.5	0.750	32.75	32.75	31.25	31.25	43.00	43.00	32.50	32.50	26.25	26.25	39.00	39.00	23.25
2004 Full Yea	1.5	0.750	34.25	34.25	32.75	32.75	44.75	44.75	35.00	35.00	29.00	29.00	41.00	41.00	22.50
2004 Q2-Q4	0.0	0.750	34.25	34.25	32.75	32.75	44.75	44.75	35.00	35.00	29.00	29.00	41.00	41.00	22.50
2005	1.5	0.750	28.50	29.00	27.00	27.50	37.25	37.75	29.75	30.25	24.75	25.00	33.25	33.75	18.50
2006	1.5	0.750	26.25	27.00	24.75	25.50	34.25	35.25	28.00	28.75	23.00	23.75	30.25	31.25	17.25
2007	1.5	0.750	24.00	25.00	22.50	23.50	31.00	32.50	24.75	26.00	20.00	21.00	27.25	28.50	16.50
2008	1.5	0.750	23.50	25.00	22.25	23.50	30.50	32.50	24.50	26.00	19.75	21.00	26.75	28.50	16.50
2009	1.5	0.750	23.25	25.00	21.75	23.50	30.25	32.50	24.25	26.00	19.50	21.00	26.50	28.50	16.50
2010	1.5	0.750	23.25	25.50	22.00	24.00	30.25	33.00	24.25	26.50	19.75	21.50	26.50	29.00	17.00
2011	1.5	0.750	23.25	25.75	21.75	24.25	30.25	33.50	24.25	27.00	19.75	22.00	26.50	29.50	17.25
2012	1.5	0.750	23.25	26.25	22.00	24.75	30.25	34.00	24.50	27.50	20.00	22.50	26.75	30.00	17.50
2013	1.5	0.750	23.25	26.50	21.75	25.00	30.25	34.50	24.50	28.00	20.00	23.00	26.75	30.50	18.00
2014	1.5	0.750	23.25	27.00	22.00	25.50	30.25	35.00	24.50	28.50	20.25	23.50	26.75	31.00	18.00
2015+	1.5	0.750	23.25	+1.5%/yr	22.00	+1.5%/yr	30.25	+1.5%/yr	24.50	+1.5%/yr	20.25	+1.5%/yr	26.75	+1.5%/yr	

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Table FP-4 (continued)
FORECAST PRICES USED IN PREPARING RESERVES DATA

Gilbert Laustsen Jung Associates Ltd.
Natural Gas and Sulphur
Price Forecast
Effective April 1, 2004

	US Gulf Coast Gas Price @ Henry Hub		Midwest Price @ Chicago	AECO-C Spot	Alberta Plant Gate					Saskatchewan Plant Gate			British
					Spot								
	Constant	Then	Then	Then	Constant	Then							CanWest
	2004 $	Current	Current	Current	2004 $	Current	ARP	Aggregator	Alliance	SaskEnergy	Spot	Sumas Spot	Plant Gate
Year	$US/mmbtu	$US/mmbtu	$US/mmbtu	$Cdn/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$/mmbtu	$US/mmbtu	$/mmbtu
1993	2.58	2.11	2.31	2.26	2.64	2.16	1.71	n/a	n/a	1.48	2.07	1.89	1.73
1994	2.33	1.94	2.11	1.98	2.23	1.86	1.81	n/a	n/a	1.88	1.87	1.59	1.81
1995	2.04	1.70	1.69	1.15	1.22	1.02	1.31	n/a	n/a	1.35	0.98	1.03	1.29
1996	2.95	2.52	2.73	1.39	1.48	1.26	1.63	n/a	n/a	1.52	1.28	1.32	1.50
1997	2.85	2.47	2.75	1.84	1.95	1.69	1.96	n/a	n/a	1.84	1.74	1.70	1.80
1998	2.45	2.16	2.20	2.03	2.14	1.88	1.94	n/a	n/a	2.05	2.13	1.60	1.94
1999	2.61	2.32	2.34	2.92	3.10	2.75	2.48	n/a	n/a	2.83	2.97	2.15	2.51
2000	4.79	4.33	4.38	5.08	5.45	4.92	4.50	4.60	n/a	4.79	5.16	4.17	5.27
2001	4.37	4.05	4.17	6.21	6.54	6.07	5.41	5.30	5.61	5.71	6.20	4.56	6.76
2002	3.53	3.36	3.30	4.04	4.08	3.88	3.88	3.83	3.82	4.04	4.08	2.68	3.64
2003	5.65	5.50	5.60	6.66	6.67	6.49	6.13	5.89	6.69	6.40	6.68	4.66	5.71
2004 Q1 (e)	5.70	5.70	5.85	6.55	6.30	6.30	6.20	5.90	6.30	6.35	6.45	5.10	5.55
2004 Q2	5.60	5.60	5.65	6.55	6.30	6.30	6.20	5.90	6.15	6.35	6.45	4.95	5.60
2004 Q3	5.70	5.70	5.75	6.65	6.40	6.40	6.30	6.00	6.20	6.45	6.55	5.05	5.65
2004 Q4	5.85	5.85	6.00	6.90	6.65	6.65	6.55	6.20	6.55	6.70	6.80	5.35	5.85
2004 Full Year	5.70	5.70	5.80	6.65	6.40	6.40	6.30	6.00	6.30	6.45	6.55	5.10	5.65
2004 Q2-Q4	5.70	5.70	5.80	6.70	6.45	6.45	6.35	6.05	6.30	6.50	6.60	5.10	5.70
2005	4.75	4.80	5.00	5.55	5.20	5.30	5.25	5.15	5.30	5.40	5.45	4.30	5.15
2006	4.35	4.50	4.75	5.20	4.80	4.95	4.95	4.95	4.95	5.10	5.10	4.05	4.95
2007	4.15	4.35	4.60	5.00	4.55	4.75	4.75	4.75	4.75	4.90	4.90	3.90	4.75
2008	4.10	4.35	4.60	5.00	4.50	4.75	4.75	4.75	4.75	4.90	4.90	3.90	4.75
2009	4.05	4.35	4.60	5.00	4.45	4.75	4.75	4.75	4.75	4.90	4.90	3.90	4.75
2010	4.05	4.40	4.65	5.10	4.45	4.85	4.85	4.85	4.85	5.00	5.00	3.95	4.85
2011	4.05	4.50	4.75	5.20	4.45	4.95	4.95	4.95	4.95	5.10	5.10	4.05	4.95
2012	4.05	4.55	4.80	5.25	4.45	5.05	5.05	5.05	5.05	5.20	5.15	4.10	5.05
2013	4.05	4.60	4.90	5.35	4.50	5.15	5.15	5.15	5.15	5.30	5.25	4.20	5.15
2014	4.05	4.70	4.95	5.45	4.50	5.20	5.20	5.20	5.20	5.35	5.35	4.25	5.20
2015+	4.05	+1.5%/yr	+1.5%/yr	+1.5%/yr	4.50	+1.5%/yr				Escalate at 1.5 % per year			

Unless otherwise stated, the gas price reference point is the receipt point on the applicable provincial gas transmission system known as the plant gate.
The plant gate price represents the price before raw gas gathering and processing charges are deducted.
Spot refers to weighted average one month price.

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TABLE FP-5
RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE

FORECAST PRICES AND COSTS

	Light and Medium Oil			Heavy Oil			Associatec
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)
December 31, 2002	0	0	0	0	0	0	0
Extensions	0	0	0	0	228	228	0
Improved Recovery	0	0	0	0	0	0	0
Technical Revisions	0	0	0	0	0	0	0
Discoveries	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0
December 31, 2003	0	0	0	0	228	228	0

Table FP-6

Company Annual Capital Expenditures (MM$)

Company:	Deer Creek Energy Ltd.	Reserve Class:	Various
Property:	Corporate	Development Class:	Classifications
Description:	Total With Adjustments	Pricing:	GLJ (2004-04) Full Year
		Effective Date:	January 01, 2004

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Probable Undeveloped	11	9	144	53	165	199	28	0	33	50	85	0
PPP Undeveloped	11	9	142	130	183	199	138	75	0	77	96	104

p:/s1046350/rems/econ/GLJ_2004-04_Full_Year/_Corporate_Total_Joslyn_Creek_RC00_cs4.htm

Table FP-7

Company Annual Abandonment Costs (M$)

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total Joslyn Creek**

Reserve Class: **Various**
Development Class: **Classifications**
Pricing: **GLJ (2004-04) Full Year**
Effective Date: **January 01, 2004**

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Probable Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0
PPP Undeveloped	0	0	0	0	0	0	0	0	0	0	0	0

p:/s1046350/rems/econ/GLJ_2004-04_Full_Year/_Corporate_Total_Joslyn_Creek_RC00_cs5.htm

Table FP-8
Summary of Oil Resources and Net Present Values of Future Net Revenue from Mining Activity

Company:	**Deer Creek Energy Ltd.**	Pricing:	**GLJ (2004-04) Full Year**
Property:	**Joslyn Creek Mining Resources**	Effective Date:	**1-Jan-04**

		Best Estimate
MARKETABLE RESERVES		
	Heavy Oil - MMSTB	
	Total Company Interest	1235
	Working Interest	1235
	Net After Royalty	1120
	Oil Equivalent - MMBOE	
	Total Company Interest	1235
	Working Interest	1235
	Net After Royalty	1120
BEFORE TAX PRESENT VALUE - $M		
	0.00%	10164436
	5.00%	2612470
	8.00%	1128010
	10.00%	607279
	12.00%	287998
	15.00%	23167
	20.00%	-147107
AFTER TAX PRESENT VALUE - $M		
	0.00%	6623946
	5.00%	1598145
	8.00%	614536
	10.00%	272556
	12.00%	65610
	15.00%	-101233
	20.00%	-198017

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

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Table FP-8.xls

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APPENDIX I

CERTIFICATES OF QUALIFICATION

Dana B. Laustsen
James H. Willmon
John W. Tuck
Kevin J. Trickett

CERTIFICATION OF QUALIFICATION

I, Dana B. Laustsen, Professional Engineer, 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am a principal officer of Gilbert Laustsen Jung Associates Ltd., which company did prepare a detailed analysis of Canadian oil and gas properties of Deer Creek Energy Ltd.. The effective date of this evaluation is January 1, 2004.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of Deer Creek Energy Ltd. or its affiliated companies.

3. That I attended the University of Calgary and that I graduated with a Bachelor of Science Degree in Mechanical Engineering in 1977; that I am a Registered Professional Engineer in the Province of Alberta; and, that I have in excess of twenty-six years experience in engineering studies relating to Western Canadian oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of Deer Creek Energy Ltd., and the appropriate provincial regulatory authorities.

ORIGINALLY SIGNED BY

Dana B. Laustsen, P. Eng.

CERTIFICATION OF QUALIFICATION

I, James H. Willmon, Professional Engineer, 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of Gilbert Laustsen Jung Associates Ltd., which company did prepare a detailed analysis of Canadian oil and gas properties of Deer Creek Energy Ltd.. The effective date of this evaluation is January 1, 2004.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of Deer Creek Energy Ltd. or its affiliated companies.

3. That I attended the University of Calgary and that I graduated with a Bachelor of Science Degree in Mechanical Engineering in 1978; that I am a Registered Professional Engineer in the Province of Alberta; and, that I have in excess of twenty-five years experience in engineering studies relating to Western Canadian oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of Deer Creek Energy Ltd., and the appropriate provincial regulatory authorities.

ORIGINALLY SIGNED BY

James H. Willmon, P. Eng.

CERTIFICATION OF QUALIFICATION

I, John W. Tuck, Professional Engineer, 4100, 400 - 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am an employee of Gilbert Laustsen Jung Associates Ltd., which company did prepare a detailed analysis of Canadian oil and gas properties of Deer Creek Energy Ltd.. The effective date of this evaluation is January 1, 2004.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of Deer Creek Energy Ltd. or its affiliated companies.

3. That I attended the University of Saskatchewan and that I graduated with a Bachelor of Science Degree in Mechanical Engineering in 1980; that I am a Registered Professional Engineer in the Province of Alberta; and, that I have in excess of twenty-three years experience in engineering studies relating to Western Canadian oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of Deer Creek Energy Ltd., and the appropriate provincial regulatory authorities.

ORIGINALLY SIGNED BY

John W. Tuck, P. Eng.

CERTIFICATION OF QUALIFICATION

I, Kevin J. Trickett, Professional Geologist, c/o 4100, 400 – 3rd Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I have been retained by Gilbert Laustsen Jung Associates Ltd., which company did prepare a detailed analysis of Canadian oil and gas properties of Deer Creek Energy Ltd.. The effective date of this evaluation is January 1, 2004.

2. That I do not have, nor do I expect to receive any direct or indirect interest in the securities of Deer Creek Energy Ltd. or its affiliated companies.

3. That I attended the University of Western Ontario and that I graduated in 1981 with a Bachelor of Science Degree (Honors) in Geology; that I am a Registered Professional Geologist in the Province of Alberta; and, that I have in excess of nineteen years experience in geological and engineering studies relating to Western Canadian oil and gas fields.

4. That a personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information and records, the files of Deer Creek Energy Ltd., and the appropriate provincial regulatory authorities.

ORIGINALLY SIGNED BY

Kevin J. Trickett, P. Geol.

APPENDIX II - AFTER TAX ECONOMIC FORECASTS

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AFTER TAX RESERVES

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Summary of Reserves and Values

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total With Adjustments**

Pricing: **GLJ (2004-04) Full Year**
Effective Date: **January 01, 2004**

	Probable Undeveloped	PPP Undeveloped
MARKETABLE RESERVES		
Heavy Oil - MMSTB		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
Oil Equivalent - MMBOE		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
BEFORE TAX PRESENT VALUE - $M		
0.0%	1742695	2871677
5.0%	626186	1056871
8.0%	322548	575921
10.0%	194669	375113
12.0%	104608	234091
15.0%	16050	95200
20.0%	-60419	-26602
AFTER TAX PRESENT VALUE - $M		
0.0%	1143699	1878290
5.0%	368176	634331
8.0%	159059	308446
10.0%	71790	173764
12.0%	10968	80182
15.0%	-47749	-10379
20.0%	-96022	-86447

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Reserve Class:	**Probable**
Property:	**Corporate**	Development Class:	**Undeveloped**
Description:	**Total With Adjustments**	Pricing:	**GLJ (2004-04) Full Year**
		Effective Date:	**January 01, 2004**

PRODUCTION FORECAST

		Heavy Oil Production			
Year	Compny Oil Wells	Compny Daily Stb	Compny Yearly Mstb	Net Yearly Mstb	Price $/Bbl
2004	0	0	0	0	0.00
2005	3	638	233	231	20.50
2006	3	1428	521	516	19.25
2007	19	5250	1916	1897	16.50
2008	19	9345	3411	3377	16.50
2009	45	17052	6224	6162	16.50
2010	61	26943	9834	9736	17.00
2011	61	34251	12502	12377	17.50
2012	61	34476	12584	12458	18.00
2013	66	33369	12180	12058	18.50
2014	79	33676	12292	12169	19.00
2015	84	34020	12417	12293	19.50
Sub.	42	19204	84114	83272	18.06
Rem.	62	26766	166082	144986	23.47
Tot.	**54**	**23637**	**250195**	**228258**	**21.65**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total	Net	Operating Expenses			Other Expenses			Net
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	Royalty After Process. MM$	Revenue After Royalty MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	Prod'n Revenue MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	4.8	0.0	4.8	0.0	0.0	0.0	0.0	0.0	4.7	4.8	0.0	4.8	0.0	0.0	0.0	0.0
2006	10.0	0.0	10.0	0.1	0.0	0.0	0.0	0.1	9.9	9.1	0.0	9.1	0.0	0.0	0.0	0.8
2007	31.6	0.0	31.6	0.3	0.0	0.0	0.0	0.3	31.3	17.5	2.2	19.7	0.0	0.0	0.0	11.6
2008	56.3	0.0	56.3	0.6	0.0	0.0	0.0	0.6	55.7	29.3	3.9	33.2	0.0	0.0	0.0	22.5
2009	102.7	0.0	102.7	1.0	0.0	0.0	0.0	1.0	101.7	42.0	6.7	48.7	0.0	0.0	0.0	53.0
2010	167.2	0.0	167.2	1.7	0.0	0.0	0.0	1.7	165.5	56.3	11.2	67.4	0.0	0.0	0.0	98.1
2011	218.8	0.0	218.8	2.2	0.0	0.0	0.0	2.2	216.6	61.4	13.2	74.6	0.0	0.0	0.0	142.0
2012	226.5	0.0	226.5	2.3	0.0	0.0	0.0	2.3	224.2	60.4	13.0	73.5	0.0	0.0	0.0	150.8
2013	225.3	0.0	225.3	2.3	0.0	0.0	0.0	2.3	223.1	64.2	13.4	77.5	0.0	0.0	0.0	145.5
2014	233.5	0.0	233.5	2.3	0.0	0.0	0.0	2.3	231.2	72.2	14.6	86.7	0.0	0.0	0.0	144.5
2015	242.1	0.0	242.1	2.4	0.0	0.0	0.0	2.4	239.7	82.9	16.2	99.1	0.0	0.0	0.0	140.6
Sub.	1518.9	0.0	1518.9	15.2	0.0	0.0	0.0	15.2	1503.7	500.0	94.4	594.3	0.0	0.0	0.0	909.4
Rem.	3897.5	0.0	3897.5	505.6	0.0	0.0	0.0	505.6	3391.8	1146.3	227.1	1373.5	0.0	0.0	0.0	2018.4
Tot.	**5416.3**	**0.0**	**5416.3**	**520.8**	**0.0**	**0.0**	**0.0**	**520.8**	**4895.5**	**1646.3**	**321.5**	**1967.8**	**0.0**	**0.0**	**0.0**	**2927.7**
Disc	1353.7	0.0	1353.7	85.8	0.0	0.0	0.0	85.8	1267.9	430.8	81.7	512.5	0.0	0.0	0.0	755.4

	Other Income				Net Capital Investment				Before Tax Cash Flow				After Tax Cash Flow		
Year	Other MM$	ARTC MM$	Aband. Costs MM$	Oper. Income MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	Income Tax MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	10.6	10.6	-10.6	-10.6	-10.1	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	0.0	8.5	0.0	0.0	8.5	-8.5	-19.1	-17.5	0.0	-8.5	-19.1	-17.5
2006	0.0	0.0	0.0	0.9	41.1	0.0	103.0	144.1	-143.2	-162.4	-130.4	0.0	-143.2	-162.4	-130.4
2007	0.0	0.1	0.0	11.6	0.0	0.0	52.7	52.7	-41.1	-203.4	-159.8	0.0	-41.1	-203.5	-159.8
2008	0.0	0.1	0.0	22.7	66.9	0.0	98.1	164.9	-142.3	-345.7	-252.4	0.0	-142.3	-345.8	-252.5
2009	0.0	0.3	0.0	53.3	45.2	0.0	153.8	199.1	-145.8	-491.5	-338.8	0.1	-145.9	-491.6	-338.8
2010	0.0	0.4	0.0	98.5	0.0	0.0	27.6	27.6	70.9	-420.6	-300.6	0.1	70.8	-420.8	-300.7
2011	0.0	0.5	0.0	142.5	0.0	0.0	0.0	0.0	142.5	-278.1	-230.9	10.0	132.5	-288.3	-235.9
2012	0.0	0.5	0.0	151.3	23.7	0.0	9.5	33.1	118.1	-160.0	-178.3	20.4	97.8	-190.5	-192.4
2013	0.0	0.5	0.0	146.0	36.0	0.0	14.4	50.4	95.6	-64.4	-139.7	22.1	73.5	-117.1	-162.7
2014	0.0	0.5	0.0	145.0	60.9	0.0	24.4	85.3	59.7	-4.7	-117.7	21.3	38.4	-78.7	-148.6
2015	0.0	0.5	0.0	141.1	0.0	0.0	0.0	0.0	141.1	136.4	-70.6	26.7	114.3	35.6	-110.4
Sub.	0.0	3.4	0.0	912.8	282.3	0.0	494.1	776.4	136.4	136.4	-70.6	100.7	35.6	35.6	-110.4
Rem.	0.0	8.5	13.3	2013.5	290.7	0.0	116.5	407.2	1606.3	1742.7	194.7	498.3	1108.1	1143.7	71.8
Tot.	**0.0**	**11.9**	**13.3**	**2926.3**	**573.0**	**0.0**	**610.6**	**1183.6**	**1742.7**	**1742.7**	**194.7**	**599.0**	**1143.7**	**1143.7**	**71.8**
Disc	0.0	2.9	1.8	756.5	219.3	0.0	342.5	561.8	194.7	194.7	194.7	122.9	71.8	71.8	71.8

AFTER TAX ANALYSIS

Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2005	4.8	0.0	0.0	0.0	4.8	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2006	10.0	0.0	0.0	0.0	9.1	0.0	0.0	0.0	113.6	0.0	0.0	0.0	0.0
2007	31.6	0.0	0.0	0.2	19.7	0.0	0.0	0.0	166.3	0.0	0.0	0.0	0.0
2008	56.3	0.0	0.0	0.4	33.2	0.0	0.0	0.0	264.4	0.0	0.0	0.0	0.0
2009	102.7	0.0	0.0	0.8	48.7	0.0	0.0	0.0	418.2	9.5	0.0	0.0	9.5
2010	167.2	0.0	0.0	1.3	67.4	0.0	0.0	0.0	436.2	67.7	0.0	0.0	67.7
2011	218.8	0.0	0.0	1.7	74.6	0.0	0.0	0.0	368.6	92.1	0.0	0.0	92.1
2012	226.5	0.0	0.0	1.8	73.5	0.0	0.0	0.0	285.9	70.3	0.0	0.0	70.3
2013	225.3	0.0	0.0	1.8	77.5	0.0	0.0	0.0	230.0	55.7	0.0	0.0	55.7
2014	233.5	0.0	0.0	1.8	86.7	0.0	0.0	0.0	198.7	46.6	0.0	0.0	46.6
2015	242.1	0.0	0.0	1.9	99.1	0.0	0.0	0.0	152.1	38.0	0.0	0.0	38.0
Sub.	1518.9	0.0	0.0	11.7	594.3	0.0	0.0	0.0	152.1	380.0	0.0	0.0	380.0
Rem.	3897.5	0.0	0.0	497.1	1386.8	0.0	0.0	0.0	7.0	225.3	0.0	0.0	225.3
Tot.	**5416.3**	**0.0**	**0.0**	**508.8**	**1981.1**	**0.0**	**0.0**	**0.0**	**7.0**	**605.3**	**0.0**	**0.0**	**605.3**
Disc	1353.7	0.0	0.0	82.9	514.3	0.0	0.0	0.0	146.0	216.3	0.0	0.0	216.3

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write -off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.5	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.9	0.1	0.0	0.0	0.0	0.0	67.6	0.8	0.0	0.0	0.8	0.0
2007	0.0	11.6	0.0	0.0	0.0	0.0	0.0	66.8	11.6	0.0	0.0	11.6	0.1
2008	0.0	22.7	0.0	0.0	0.0	0.0	0.0	122.1	22.5	0.0	0.0	22.5	0.1
2009	0.0	43.7	0.0	0.0	0.0	0.0	0.0	144.8	43.5	0.0	0.0	43.5	0.3
2010	0.0	30.8	0.0	0.0	0.0	0.0	0.0	101.4	30.4	0.0	0.0	30.4	0.4
2011	0.0	50.3	0.0	0.0	0.0	0.0	0.0	71.0	21.3	0.0	0.0	21.3	29.0
2012	0.0	81.0	0.0	0.0	0.0	0.0	0.0	73.3	22.0	0.0	0.0	22.0	59.0
2013	0.0	90.3	0.0	0.0	0.0	0.0	0.0	87.4	26.2	0.0	0.0	26.2	64.1
2014	0.0	98.4	0.0	0.0	0.0	0.0	0.0	122.1	36.6	0.0	0.0	36.6	61.7
2015	0.0	103.0	0.0	0.0	0.0	0.0	0.0	85.5	25.6	0.0	0.0	25.6	77.4
Sub.	0.0	532.8	0.1	0.0	0.0	0.0	0.0	85.5	240.5	0.0	0.0	240.5	292.2
Rem.	0.0	1788.3	0.0	0.0	0.0	0.0	0.0	6.5	346.0	0.0	0.0	346.0	1442.3
Tot.	**0.0**	**2321.1**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**6.5**	**586.5**	**0.0**	**0.0**	**586.5**	**1734.5**
Disc	0.0	540.2	0.1	0.0	0.0	0.0	0.0	69.1	184.2	0.0	0.0	184.2	356.0

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest -ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	Net Cash Flow After Income Tax 10% Dcf Cum. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-8.5	-19.1	-17.5
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-143.2	-162.4	-130.4
2007	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-41.1	-203.5	-159.8
2008	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-142.3	-345.8	-252.5
2009	0.0	0.0	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-145.9	-491.6	-338.8
2010	0.0	0.0	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.1	70.8	-420.8	-300.7
2011	0.0	0.0	29.0	29.0	6.4	0.0	0.0	28.5	3.6	0.0	10.0	132.5	-288.3	-235.9
2012	0.0	0.0	59.0	59.0	13.0	0.0	0.0	58.5	7.3	0.0	20.4	97.8	-190.5	-192.4
2013	0.0	0.0	64.1	64.1	14.2	0.0	0.0	63.6	8.0	0.0	22.1	73.5	-117.1	-162.7
2014	0.0	0.0	61.7	61.7	13.7	0.0	0.0	61.2	7.7	0.0	21.3	38.4	-78.7	-148.6
2015	0.0	0.0	77.4	77.4	17.1	0.0	0.0	76.9	9.6	0.0	26.7	114.3	35.6	-110.4
Sub.	0.0	0.0	292.2	292.2	64.6	0.1	0.0	288.8	36.1	0.0	100.7	35.6	35.6	-110.4
Rem.	0.0	0.0	1442.3	1442.3	319.0	0.0	0.0	1433.8	179.2	0.0	498.3	1108.1	1143.7	71.8
Tot.	**0.0**	**0.0**	**1734.5**	**1734.5**	**383.7**	**0.1**	**0.0**	**1722.6**	**215.3**	**0.0**	**599.0**	**1143.7**	**1143.7**	**71.8**
Disc	0.0	0.0	356.0	356.0	78.7	0.1	0.0	353.1	44.1	0.0	122.9	71.8	71.8	71.8

RESERVE SUMMARY

Product	Units	Remaining Reserves at January 1, 2004: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: BOE Factor	Company Mstb	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	250195	0	250195	228258	1.000	250195	100	29.0	100.0	15.4
Total Oil Eq.	Mstb	250195	0	250195	228258		250195	100	29.0	0.0	15.4

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4895528	100	1267851	100
Total Oil Eq.	$/BOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4895528	100	1267851	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)	Initial	Average
Crown Royalty	0.0000	9.6157
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000
NPI Payment	0.0000	0.0000

Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Net Present Value After Tax: Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
0.0	2927715	2926316	1183621	1742695	6.97	2327320	1183621	1143699	4.57
5.0	1407668	1408549	782363	626186	2.50	1150539	782363	368176	1.47
8.0	957518	958639	636091	322548	1.29	795150	636091	159059	0.64
10.0	755365	756491	561823	194669	0.78	633613	561823	71790	0.29
12.0	604449	605525	500917	104608	0.42	511885	500917	10968	0.04
15.0	443181	444139	428089	16050	0.06	380340	428089	-47749	-0.19
20.0	279009	279756	340175	-60419	-0.24	244153	340175	-96022	-0.38

Project.......1046350
Entity.......Total With Adjustments (Probable Undeveloped)
Run date....Fri May 21 2004 10:42:50
Evaluator...Laustsen, Dana B.

Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Reserve Class:	**PPP**
Property:	**Corporate**	Development Class:	**Undeveloped**
Description:	**Total With Adjustments**	Pricing:	**GLJ (2004-04) Full Year**
		Effective Date:	**January 01, 2004**

PRODUCTION FORECAST

		Heavy Oil Production			
Year	Compny Oil Wells	Compny Daily Stb	Compny Yearly Mstb	Net Yearly Mstb	Price $/Bbl
2004	0	0	0	0	0.00
2005	3	672	245	243	20.50
2006	3	1428	521	516	19.25
2007	24	6212	2267	2245	16.50
2008	45	15662	5717	5659	16.50
2009	70	29501	10768	10660	16.50
2010	87	42395	15474	15319	17.00
2011	87	49938	18227	18045	17.50
2012	87	51450	18779	18591	18.00
2013	87	49832	18189	18007	18.50
2014	102	49984	18244	18062	19.00
2015	106	45830	16728	16561	19.50
Sub.	58	28575	125160	123908	18.01
Rem.	104	39983	277282	240388	23.90
Tot.	**86**	**35567**	**402442**	**364296**	**22.07**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance				Operating Expenses			Other Expenses			
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	Total Royalty After Process. MM$	Net Revenue After Royalty MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	Net Prod'n Revenue MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	5.0	0.0	5.0	0.1	0.0	0.0	0.0	0.1	5.0	4.8	0.0	4.8	0.0	0.0	0.0	0.1
2006	10.0	0.0	10.0	0.1	0.0	0.0	0.0	0.1	9.9	9.1	0.0	9.1	0.0	0.0	0.0	0.8
2007	37.4	0.0	37.4	0.4	0.0	0.0	0.0	0.4	37.0	20.1	2.7	22.8	0.0	0.0	0.0	14.2
2008	94.3	0.0	94.3	0.9	0.0	0.0	0.0	0.9	93.4	45.4	6.9	52.3	0.0	0.0	0.0	41.1
2009	177.7	0.0	177.7	1.8	0.0	0.0	0.0	1.8	175.9	66.2	11.9	78.1	0.0	0.0	0.0	97.8
2010	263.1	0.0	263.1	2.6	0.0	0.0	0.0	2.6	260.4	79.8	16.6	96.4	0.0	0.0	0.0	164.1
2011	319.0	0.0	319.0	3.2	0.0	0.0	0.0	3.2	315.8	85.7	18.6	104.3	0.0	0.0	0.0	211.4
2012	338.0	0.0	338.0	3.4	0.0	0.0	0.0	3.4	334.6	84.9	18.8	103.7	0.0	0.0	0.0	230.9
2013	336.5	0.0	336.5	3.4	0.0	0.0	0.0	3.4	333.1	88.4	19.1	107.5	0.0	0.0	0.0	225.6
2014	346.6	0.0	346.6	3.5	0.0	0.0	0.0	3.5	343.2	103.7	21.4	125.1	0.0	0.0	0.0	218.1
2015	326.2	0.0	326.2	3.3	0.0	0.0	0.0	3.3	322.9	106.7	21.1	127.7	0.0	0.0	0.0	195.2
Sub.	2253.9	0.0	2253.9	22.5	0.0	0.0	0.0	22.5	2231.3	694.8	137.2	832.0	0.0	0.0	0.0	1399.4
Rem.	6628.4	0.0	6628.4	887.8	0.0	0.0	0.0	887.8	5740.6	1977.3	385.9	2363.2	0.0	0.0	0.0	3377.4
Tot.	**8882.2**	**0.0**	**8882.2**	**910.3**	**0.0**	**0.0**	**0.0**	**910.3**	**7971.9**	**2672.1**	**523.1**	**3195.2**	**0.0**	**0.0**	**0.0**	**4776.7**
Disc	2092.2	0.0	2092.2	149.8	0.0	0.0	0.0	149.8	1942.4	641.6	125.2	766.7	0.0	0.0	0.0	1175.7

	Other Income				Net Capital Investment				Before Tax Cash Flow				After Tax Cash Flow		
Year	Other MM$	ARTC MM$	Aband. Costs MM$	Oper. Income MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	Income Tax MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	10.6	10.6	-10.6	-10.6	-10.1	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	0.1	8.5	0.0	0.0	8.5	-8.4	-19.0	-17.4	0.0	-8.4	-19.0	-17.4
2006	0.0	0.0	0.0	0.9	51.9	0.0	90.0	141.9	-141.1	-160.0	-128.5	0.0	-141.1	-160.0	-128.5
2007	0.0	0.1	0.0	14.3	54.9	0.0	74.7	129.6	-115.3	-275.3	-211.1	0.0	-115.3	-275.3	-211.1
2008	0.0	0.2	0.0	41.3	66.9	0.0	115.9	182.8	-141.5	-416.8	-303.2	0.1	-141.5	-416.9	-303.3
2009	0.0	0.4	0.0	98.2	45.2	0.0	153.8	199.1	-100.9	-517.7	-363.0	0.1	-101.0	-517.8	-363.1
2010	0.0	0.5	0.0	164.6	0.0	0.0	137.8	137.8	26.8	-490.9	-348.5	2.2	24.6	-493.3	-349.8
2011	0.0	0.5	0.0	211.9	0.0	0.0	74.6	74.6	137.4	-353.5	-281.3	23.8	113.6	-379.7	-294.3
2012	0.0	0.5	0.0	231.4	0.0	0.0	0.0	0.0	231.4	-122.1	-178.4	40.2	191.3	-188.5	-209.2
2013	0.0	0.5	0.0	226.1	55.2	0.0	22.1	77.3	148.8	26.7	-118.2	41.9	106.8	-81.6	-166.0
2014	0.0	0.5	0.0	218.6	68.2	0.0	27.3	95.5	123.0	149.7	-73.0	39.7	83.3	1.7	-135.4
2015	0.0	0.5	0.0	195.7	74.2	0.0	29.7	103.9	91.8	241.5	-42.3	31.3	60.5	62.2	-115.2
Sub.	0.0	3.8	0.0	1403.2	425.1	0.0	736.5	1161.7	241.5	241.5	-42.3	179.3	62.2	62.2	-115.2
Rem.	0.0	9.5	30.8	3356.1	518.4	0.0	207.6	725.9	2630.2	2871.7	375.1	814.1	1816.1	1878.3	173.8
Tot.	**0.0**	**13.3**	**30.8**	**4759.3**	**943.5**	**0.0**	**944.1**	**1887.6**	**2871.7**	**2871.7**	**375.1**	**993.4**	**1878.3**	**1878.3**	**173.8**
Disc	0.0	3.2	3.3	1175.5	322.7	0.0	477.7	800.4	375.1	375.1	375.1	201.3	173.8	173.8	173.8

AFTER TAX ANALYSIS

Year Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2005	5.0	0.0	0.0	0.0	4.8	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2006	10.0	0.0	0.0	0.0	9.1	0.0	0.0	0.0	100.6	0.0	0.0	0.0	0.0
2007	37.4	0.0	0.0	0.3	22.8	0.0	0.0	0.0	175.3	0.0	0.0	0.0	0.0
2008	94.3	0.0	0.0	0.7	52.3	0.0	0.0	0.0	291.2	0.0	0.0	0.0	0.0
2009	177.7	0.0	0.0	1.3	78.1	0.0	0.0	0.0	445.0	41.0	0.0	0.0	41.0
2010	263.1	0.0	0.0	2.1	96.4	0.0	0.0	0.0	541.8	118.2	0.0	0.0	118.2
2011	319.0	0.0	0.0	2.7	104.3	0.0	0.0	0.0	498.2	115.2	0.0	0.0	115.2
2012	338.0	0.0	0.0	2.9	103.7	0.0	0.0	0.0	383.0	95.7	0.0	0.0	95.7
2013	336.5	0.0	0.0	2.9	107.5	0.0	0.0	0.0	309.3	74.6	0.0	0.0	74.6
2014	346.6	0.0	0.0	3.0	125.1	0.0	0.0	0.0	262.1	62.1	0.0	0.0	62.1
2015	326.2	0.0	0.0	2.8	127.7	0.0	0.0	0.0	229.7	53.7	0.0	0.0	53.7
Sub.	2253.9	0.0	0.0	18.7	832.0	0.0	0.0	0.0	229.7	560.6	0.0	0.0	560.6
Rem.	6628.4	0.0	0.0	878.3	2390.1	0.0	0.0	0.0	11.4	375.0	0.0	0.0	375.0
Tot.	**8882.2**	**0.0**	**0.0**	**897.0**	**3222.0**	**0.0**	**0.0**	**0.0**	**11.4**	**935.5**	**0.0**	**0.0**	**935.5**
Disc	2092.2	0.0	0.0	146.6	769.9	0.0	0.0	0.0	180.3	327.2	0.0	0.0	327.2

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write -off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.2	0.0	0.0	0.0	0.0	0.0	26.5	0.1	0.0	0.0	0.1	0.0
2006	0.0	0.9	0.1	0.0	0.0	0.0	0.0	78.3	0.8	0.0	0.0	0.8	0.0
2007	0.0	14.3	0.0	0.0	0.0	0.0	0.0	132.4	14.2	0.0	0.0	14.2	0.1
2008	0.0	41.3	0.0	0.0	0.0	0.0	0.0	185.1	41.1	0.0	0.0	41.1	0.2
2009	0.0	57.2	0.0	0.0	0.0	0.0	0.0	189.2	56.8	0.0	0.0	56.8	0.4
2010	0.0	46.3	0.0	0.0	0.0	0.0	0.0	132.5	39.7	0.0	0.0	39.7	6.6
2011	0.0	96.7	0.0	0.0	0.0	0.0	0.0	92.7	27.8	0.0	0.0	27.8	68.9
2012	0.0	135.7	0.0	0.0	0.0	0.0	0.0	64.9	19.5	0.0	0.0	19.5	116.2
2013	0.0	151.6	0.0	0.0	0.0	0.0	0.0	100.7	30.2	0.0	0.0	30.2	121.4
2014	0.0	156.5	0.0	0.0	0.0	0.0	0.0	138.7	41.6	0.0	0.0	41.6	114.9
2015	0.0	142.0	0.0	0.0	0.0	0.0	0.0	171.3	51.4	0.0	0.0	51.4	90.6
Sub.	0.0	842.7	0.1	0.0	0.0	0.0	0.0	171.3	323.2	0.0	0.0	323.2	519.3
Rem.	0.0	2985.1	0.0	0.0	0.0	0.0	0.0	11.5	630.2	0.0	0.0	630.2	2354.9
Tot.	**0.0**	**3827.7**	**0.1**	**0.0**	**0.0**	**0.0**	**0.0**	**11.5**	**953.4**	**0.0**	**0.0**	**953.4**	**2874.2**
Disc	0.0	848.5	0.1	0.0	0.0	0.0	0.0	98.5	265.7	0.0	0.0	265.7	582.7

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest -ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	10% Dcf Cum. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-8.4	-19.0	-17.4
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-141.1	-160.0	-128.5
2007	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-115.3	-275.3	-211.1
2008	0.0	0.0	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-141.5	-416.9	-303.3
2009	0.0	0.0	0.4	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-101.0	-517.8	-363.1
2010	0.0	0.0	6.6	6.6	1.5	0.0	0.0	6.1	0.8	0.0	2.2	24.6	-493.3	-349.8
2011	0.0	0.0	68.9	68.9	15.2	0.0	0.0	68.4	8.6	0.0	23.8	113.6	-379.7	-294.3
2012	0.0	0.0	116.2	116.2	25.7	0.0	0.0	115.7	14.5	0.0	40.2	191.3	-188.5	-209.2
2013	0.0	0.0	121.4	121.4	26.8	0.0	0.0	120.9	15.1	0.0	41.9	106.8	-81.6	-166.0
2014	0.0	0.0	114.9	114.9	25.4	0.0	0.0	114.4	14.3	0.0	39.7	83.3	1.7	-135.4
2015	0.0	0.0	90.6	90.6	20.0	0.0	0.0	90.1	11.3	0.0	31.3	60.5	62.2	-115.2
Sub.	0.0	0.0	519.3	519.3	114.9	0.1	0.1	515.5	64.4	0.0	179.3	62.2	62.2	-115.2
Rem.	0.0	0.0	2354.9	2354.9	520.9	0.0	0.0	2345.4	293.2	0.0	814.1	1816.1	1878.3	173.8
Tot.	**0.0**	**0.0**	**2874.2**	**2874.2**	**635.8**	**0.1**	**0.1**	**2860.9**	**357.6**	**0.0**	**993.4**	**1878.3**	**1878.3**	**173.8**
Disc	0.0	0.0	582.7	582.7	128.9	0.1	0.1	579.6	72.4	0.0	201.3	173.8	173.8	173.8

RESERVE SUMMARY

Product	Units	Remaining Reserves at January 1, 2004: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: BOE Factor	Company Mstb	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	402442	0	402442	364296	1.000	402442	100	31.0	100.0	16.1
Total Oil Eq.	Mstb	402442	0	402442	364296		402442	100	31.0	0.0	16.1

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7971916	100	1942376	100
Total Oil Eq.	$/BOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7971916	100	1942376	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)	Initial	Average	Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Net Present Value After Tax: Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
Crown Royalty	0.0000	10.2488	0.0	4776723	4759265	1887587	2871677	7.14	3765878	1887587	1878290	4.67
Non-crown Royalty	0.0000	0.0000	5.0	2227183	2223694	1166823	1056871	2.63	1801154	1166823	634331	1.58
Mineral Tax	0.0000	0.0000	8.0	1497929	1496975	921053	575921	1.43	1229499	921053	308446	0.77
NPI Payment	0.0000	0.0000	10.0	1175656	1175507	800394	375113	0.93	974158	800394	173764	0.43
			12.0	937475	937767	703677	234091	0.58	783859	703677	80182	0.20
			15.0	685402	685990	590789	95200	0.24	580410	590789	-10379	-0.03
			20.0	431392	432057	458660	-26602	-0.07	372212	458660	-86447	-0.21

Project.......1046350
Entity.......Total With Adjustments (PPP Undeveloped)
Run date....Fri May 21 2004 10:42:51
Evaluator...Laustsen, Dana B.

Summary of Reserves and Values

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total With Adjustments**

Pricing: **Posted (2003-Dec-31) Constant**
Effective Date: **January 01, 2004**

	Probable Undeveloped	PPP Undeveloped
MARKETABLE RESERVES		
Heavy Oil - MMSTB		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
Oil Equivalent - MMBOE		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	228	364
BEFORE TAX PRESENT VALUE - $M		
0.0%	1394956	2256430
5.0%	531215	890909
8.0%	286209	510345
10.0%	180237	346402
12.0%	103990	228394
15.0%	26951	108552
20.0%	-42747	-1984
AFTER TAX PRESENT VALUE - $M		
0.0%	916838	1477701
5.0%	311864	533712
8.0%	141899	274048
10.0%	69088	163409
12.0%	17250	84641
15.0%	-34200	6032
20.0%	-78702	-63608

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

Project 1046350
Run date Fri May 21 2004 10:43:31

Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Reserve Class:	**Probable**
Property:	**Corporate**	Development Class:	**Undeveloped**
Description:	**Total With Adjustments**	Pricing:	**Posted (2003-Dec-31) Constant**
		Effective Date:	**January 01, 2004**

PRODUCTION FORECAST

Year	Compny Oil Wells	Heavy Oil Production: Compny Daily Stb	Compny Yearly Mstb	Net Yearly Mstb	Price $/Bbl
2004	0	0	0	0	0.00
2005	3	638	233	231	18.81
2006	3	1428	521	516	18.81
2007	19	5250	1916	1897	18.81
2008	19	9345	3411	3377	18.81
2009	45	17052	6224	6162	18.81
2010	61	26943	9834	9736	18.81
2011	61	34251	12502	12377	18.81
2012	61	34476	12584	12458	18.81
2013	66	33369	12180	12058	18.81
2014	79	33676	12292	12169	18.81
2015	84	34020	12417	12148	18.81
Sub.	42	19204	84114	83127	18.81
Rem.	62	26766	166082	144973	18.81
Tot.	**54**	**23637**	**250195**	**228100**	**18.81**

REVENUE AND EXPENSE FORECAST

Year	Revenue Before Burdens: Working Interest MM$	Royalty Interest MM$	Company Total MM$	Royalty Burdens Pre-Processing: Crown MM$	Other MM$	Gas Processing Allowance: Crown MM$	Other MM$	Total Royalty After Process. MM$	Net Revenue After Royalty MM$	Operating Expenses: Fixed MM$	Variable MM$	Total MM$	Other Expenses: Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	Net Prod'n Revenue MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	4.4	0.0	4.4	0.0	0.0	0.0	0.0	0.0	4.3	4.8	0.0	4.8	0.0	0.0	0.0	-0.5
2006	9.8	0.0	9.8	0.1	0.0	0.0	0.0	0.1	9.7	9.3	0.0	9.3	0.0	0.0	0.0	0.4
2007	36.0	0.0	36.0	0.4	0.0	0.0	0.0	0.4	35.7	19.1	2.1	21.2	0.0	0.0	0.0	14.4
2008	64.2	0.0	64.2	0.6	0.0	0.0	0.0	0.6	63.5	31.8	3.6	35.5	0.0	0.0	0.0	28.1
2009	117.1	0.0	117.1	1.2	0.0	0.0	0.0	1.2	115.9	46.2	6.2	52.4	0.0	0.0	0.0	63.5
2010	185.0	0.0	185.0	1.8	0.0	0.0	0.0	1.8	183.1	63.5	10.2	73.7	0.0	0.0	0.0	109.4
2011	235.2	0.0	235.2	2.4	0.0	0.0	0.0	2.4	232.8	68.1	11.9	80.0	0.0	0.0	0.0	152.8
2012	236.7	0.0	236.7	2.4	0.0	0.0	0.0	2.4	234.3	65.7	11.6	77.3	0.0	0.0	0.0	157.1
2013	229.1	0.0	229.1	2.3	0.0	0.0	0.0	2.3	226.8	68.4	11.7	80.1	0.0	0.0	0.0	146.7
2014	231.2	0.0	231.2	2.3	0.0	0.0	0.0	2.3	228.9	76.2	12.5	88.7	0.0	0.0	0.0	140.2
2015	233.6	0.0	233.6	5.1	0.0	0.0	0.0	5.1	228.5	86.4	13.8	100.2	0.0	0.0	0.0	128.3
Sub.	1582.2	0.0	1582.2	18.5	0.0	0.0	0.0	18.5	1563.6	539.6	83.7	623.3	0.0	0.0	0.0	940.3
Rem.	3124.0	0.0	3124.0	397.1	0.0	0.0	0.0	397.1	2726.9	1059.9	172.1	1232.0	0.0	0.0	0.0	1494.9
Tot.	**4706.2**	**0.0**	**4706.2**	**415.6**	**0.0**	**0.0**	**0.0**	**415.6**	**4290.6**	**1599.6**	**255.8**	**1855.4**	**0.0**	**0.0**	**0.0**	**2435.2**
Disc	1278.3	0.0	1278.3	76.4	0.0	0.0	0.0	76.4	1201.9	440.3	68.4	508.7	0.0	0.0	0.0	693.2

Year	Other Income: Other MM$	ARTC MM$	Aband. Costs MM$	Oper. Income MM$	Net Capital Investment: Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Before Tax Cash Flow: Annual MM$	Cum. MM$	10% Dcf MM$	Income Tax MM$	After Tax Cash Flow: Annual MM$	Cum. MM$	10% Dcf MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	10.6	10.6	-10.6	-10.6	-10.1	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	-0.5	8.4	0.0	0.0	8.4	-8.9	-19.5	-17.8	0.0	-8.9	-19.5	-17.8
2006	0.0	0.0	0.0	0.4	39.9	0.0	100.0	139.9	-139.5	-158.9	-127.7	0.0	-139.5	-159.0	-127.7
2007	0.0	0.1	0.0	14.5	0.0	0.0	50.4	50.4	-35.9	-194.8	-153.4	0.0	-35.9	-194.8	-153.4
2008	0.0	0.2	0.0	28.2	63.0	0.0	92.4	155.4	-127.2	-322.0	-236.2	0.0	-127.2	-322.1	-236.3
2009	0.0	0.3	0.0	63.8	42.0	0.0	142.8	184.8	-121.0	-443.0	-307.9	0.1	-121.1	-443.2	-308.0
2010	0.0	0.5	0.0	109.9	0.0	0.0	25.2	25.2	84.7	-358.4	-262.3	0.1	84.6	-358.6	-262.4
2011	0.0	0.5	0.0	153.3	0.0	0.0	0.0	0.0	153.3	-205.1	-187.3	19.1	134.2	-224.4	-196.8
2012	0.0	0.5	0.0	157.6	21.0	0.0	8.4	29.4	128.2	-76.9	-130.3	27.0	101.2	-123.3	-151.8
2013	0.0	0.5	0.0	147.2	31.5	0.0	12.6	44.1	103.1	26.2	-88.6	26.4	76.6	-46.6	-120.8
2014	0.0	0.5	0.0	140.7	52.5	0.0	21.0	73.5	67.2	93.3	-63.9	23.8	43.4	-3.2	-104.9
2015	0.0	0.5	0.0	128.8	0.0	0.0	0.0	0.0	128.8	222.1	-20.9	25.5	103.3	100.0	-70.4
Sub.	0.0	3.5	0.0	943.8	258.3	0.0	463.4	721.7	222.1	222.1	-20.9	122.1	100.0	100.0	-70.4
Rem.	0.0	8.2	9.7	1493.5	228.9	0.0	91.7	320.6	1172.9	1395.0	180.2	356.0	816.8	916.8	69.1
Tot.	**0.0**	**11.8**	**9.7**	**2437.3**	**487.2**	**0.0**	**555.2**	**1042.4**	**1395.0**	**1395.0**	**180.2**	**478.1**	**916.8**	**916.8**	**69.1**
Disc	0.0	3.0	1.3	694.8	195.1	0.0	319.5	514.6	180.2	180.2	180.2	111.1	69.1	69.1	69.1

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AFTER TAX ANALYSIS

Year Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2005	4.4	0.0	0.0	0.0	4.8	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2006	9.8	0.0	0.0	0.0	9.3	0.0	0.0	0.0	110.6	0.0	0.0	0.0	0.0
2007	36.0	0.0	0.0	0.3	21.2	0.0	0.0	0.0	161.0	0.0	0.0	0.0	0.0
2008	64.2	0.0	0.0	0.5	35.5	0.0	0.0	0.0	253.4	0.0	0.0	0.0	0.0
2009	117.1	0.0	0.0	0.9	52.4	0.0	0.0	0.0	396.2	25.0	0.0	0.0	25.0
2010	185.0	0.0	0.0	1.4	73.7	0.0	0.0	0.0	396.4	82.5	0.0	0.0	82.5
2011	235.2	0.0	0.0	1.9	80.0	0.0	0.0	0.0	314.0	78.5	0.0	0.0	78.5
2012	236.7	0.0	0.0	1.9	77.3	0.0	0.0	0.0	243.9	59.9	0.0	0.0	59.9
2013	229.1	0.0	0.0	1.8	80.1	0.0	0.0	0.0	196.6	47.6	0.0	0.0	47.6
2014	231.2	0.0	0.0	1.8	88.7	0.0	0.0	0.0	170.0	39.9	0.0	0.0	39.9
2015	233.6	0.0	0.0	4.6	100.2	0.0	0.0	0.0	130.2	32.5	0.0	0.0	32.5
Sub.	1582.2	0.0	0.0	15.0	623.3	0.0	0.0	0.0	130.2	365.8	0.0	0.0	365.8
Rem.	3124.0	0.0	0.0	388.8	1241.7	0.0	0.0	0.0	5.5	184.5	0.0	0.0	184.5
Tot.	**4706.2**	**0.0**	**0.0**	**403.8**	**1865.0**	**0.0**	**0.0**	**0.0**	**5.5**	**550.3**	**0.0**	**0.0**	**550.3**
Disc	1278.3	0.0	0.0	73.4	510.1	0.0	0.0	0.0	131.6	206.8	0.0	0.0	206.8

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write -off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	-0.5	0.0	0.0	0.0	0.0	0.0	26.4	0.0	0.0	0.0	0.0	-0.5
2006	0.0	0.4	0.0	0.0	0.0	0.0	0.0	66.3	0.4	0.0	0.0	0.4	0.0
2007	0.0	14.5	0.0	0.0	0.0	0.0	0.0	65.9	14.4	0.0	0.0	14.4	0.1
2008	0.0	28.2	0.0	0.0	0.0	0.0	0.0	114.5	28.1	0.0	0.0	28.1	0.2
2009	0.0	38.8	0.0	0.0	0.0	0.0	0.0	128.4	38.5	0.0	0.0	38.5	0.3
2010	0.0	27.4	0.0	0.0	0.0	0.0	0.0	89.9	27.0	0.0	0.0	27.0	0.5
2011	0.0	74.8	0.0	0.0	0.0	0.0	0.0	62.9	18.9	0.0	0.0	18.9	55.9
2012	0.0	97.6	0.0	0.0	0.0	0.0	0.0	65.1	19.5	0.0	0.0	19.5	78.1
2013	0.0	99.6	0.0	0.0	0.0	0.0	0.0	77.0	23.1	0.0	0.0	23.1	76.5
2014	0.0	100.8	0.0	0.0	0.0	0.0	0.0	106.4	31.9	0.0	0.0	31.9	68.9
2015	0.0	96.2	0.0	0.0	0.0	0.0	0.0	74.5	22.3	0.0	0.0	22.3	73.9
Sub.	0.0	578.1	0.0	0.0	0.0	0.0	0.0	74.5	224.2	0.0	0.0	224.2	353.9
Rem.	0.0	1309.0	0.0	0.0	0.0	0.0	0.0	5.0	277.6	0.0	0.0	277.6	1031.4
Tot.	**0.0**	**1887.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**5.0**	**501.7**	**0.0**	**0.0**	**501.7**	**1385.3**
Disc	0.0	488.1	0.0	0.0	0.0	0.0	0.0	61.3	166.1	0.0	0.0	166.1	321.9

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest -ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	Net Cash Flow After Income Tax 10% Dcf Cum. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	-0.5	-0.5	0.0	0.0	0.0	-0.5	0.0	0.0	0.0	-8.9	-19.5	-17.8
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-139.5	-159.0	-127.7
2007	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-35.9	-194.8	-153.4
2008	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-127.2	-322.1	-236.3
2009	0.0	0.0	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-121.1	-443.2	-308.0
2010	0.0	0.0	0.5	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.1	84.6	-358.6	-262.4
2011	0.0	0.0	55.9	55.9	12.3	0.0	0.0	55.4	6.9	0.0	19.1	134.2	-224.4	-196.8
2012	0.0	0.0	78.1	78.1	17.3	0.0	0.0	77.6	9.7	0.0	27.0	101.2	-123.3	-151.8
2013	0.0	0.0	76.5	76.5	16.9	0.0	0.0	76.0	9.5	0.0	26.4	76.6	-46.6	-120.8
2014	0.0	0.0	68.9	68.9	15.2	0.0	0.0	68.4	8.5	0.0	23.8	43.4	-3.2	-104.9
2015	0.0	0.0	73.9	73.9	16.3	0.0	0.0	73.4	9.2	0.0	25.5	103.3	100.0	-70.4
Sub.	0.0	0.0	353.9	353.9	78.3	0.1	0.0	350.3	43.8	0.0	122.1	100.0	100.0	-70.4
Rem.	0.0	0.0	1031.4	1031.4	228.2	0.0	0.0	1023.2	127.9	0.0	356.0	816.8	916.8	69.1
Tot.	**0.0**	**0.0**	**1385.3**	**1385.3**	**306.4**	**0.1**	**0.0**	**1373.5**	**171.7**	**0.0**	**478.1**	**916.8**	**916.8**	**69.1**
Disc	0.0	0.0	321.9	321.9	71.3	0.1	0.0	319.0	39.9	0.0	111.1	69.1	69.1	69.1

RESERVE SUMMARY

Product	Units	Remaining Reserves at January 1, 2004: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: BOE Factor	Company Mstb	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	250195	0	250195	228100	1.000	250195	100	29.0	100.0	15.4
Total Oil Eq.	Mstb	250195	0	250195	228100		250195	100	29.0	0.0	15.4

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4290567	100	1201917	100
Total Oil Eq.	$/BOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4290567	100	1201917	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)	Initial	Average
Crown Royalty	0.0000	8.8310
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000
NPI Payment	0.0000	0.0000

Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Net Present Value After Tax: Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
0.0	2435188	2437318	1042363	1394956	5.58	1959201	1042363	916838	3.66
5.0	1233790	1235901	704685	531215	2.12	1016549	704685	311864	1.25
8.0	863480	865298	579089	286209	1.14	720988	579089	141899	0.57
10.0	693195	694812	514575	180237	0.72	583663	514575	69088	0.28
12.0	563779	565207	461217	103990	0.42	478467	461217	17250	0.07
15.0	422565	423747	396796	26951	0.11	362596	396796	-34200	-0.14
20.0	274381	275246	317993	-42747	-0.17	239291	317993	-78701	-0.31

Project.......1046350
Entity.......Total With Adjustments (Probable Undeveloped)
Run date....Fri May 21 2004 10:43:31
Evaluator...Laustsen, Dana B.

Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Reserve Class:	**PPP**
Property:	**Corporate**	Development Class:	**Undeveloped**
Description:	**Total With Adjustments**	Pricing:	**Posted (2003-Dec-31) Constant**
		Effective Date:	**January 01, 2004**

PRODUCTION FORECAST

		Heavy Oil Production			
Year	Compny Oil Wells	Compny Daily Stb	Compny Yearly Mstb	Net Yearly Mstb	Price $/Bbl
2004	0	0	0	0	0.00
2005	3	672	245	243	18.81
2006	3	1428	521	516	18.81
2007	24	6212	2267	2245	18.81
2008	45	15662	5717	5659	18.81
2009	70	29501	10768	10660	18.81
2010	87	42395	15474	15319	18.81
2011	87	49938	18227	18045	18.81
2012	87	51450	18779	18591	18.81
2013	87	49832	18189	18007	18.81
2014	102	49984	18244	17062	18.81
2015	106	45830	16728	15369	18.81
Sub.	58	28575	125160	121717	18.81
Rem.	104	39983	277282	242744	18.81
Tot.	**86**	**35567**	**402442**	**364460**	**18.81**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty	Net Revenue	Operating Expenses			Other Expenses			Net Prod'n Revenue
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	After Process. MM$	After Royalty MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	4.6	0.0	4.6	0.0	0.0	0.0	0.0	0.0	4.6	4.9	0.0	4.9	0.0	0.0	0.0	-0.4
2006	9.8	0.0	9.8	0.1	0.0	0.0	0.0	0.1	9.7	9.3	0.0	9.3	0.0	0.0	0.0	0.4
2007	42.6	0.0	42.6	0.4	0.0	0.0	0.0	0.4	42.2	22.2	2.6	24.8	0.0	0.0	0.0	17.5
2008	107.5	0.0	107.5	1.1	0.0	0.0	0.0	1.1	106.5	50.5	6.5	57.0	0.0	0.0	0.0	49.4
2009	202.5	0.0	202.5	2.0	0.0	0.0	0.0	2.0	200.5	74.5	11.1	85.6	0.0	0.0	0.0	114.9
2010	291.1	0.0	291.1	2.9	0.0	0.0	0.0	2.9	288.2	90.0	15.2	105.1	0.0	0.0	0.0	183.0
2011	342.9	0.0	342.9	3.4	0.0	0.0	0.0	3.4	339.4	95.0	16.8	111.7	0.0	0.0	0.0	227.7
2012	353.2	0.0	353.2	3.5	0.0	0.0	0.0	3.5	349.7	92.2	16.7	108.9	0.0	0.0	0.0	240.8
2013	342.1	0.0	342.1	3.4	0.0	0.0	0.0	3.4	338.7	94.3	16.7	111.0	0.0	0.0	0.0	227.7
2014	343.2	0.0	343.2	22.2	0.0	0.0	0.0	22.2	320.9	109.6	18.4	128.0	0.0	0.0	0.0	192.9
2015	314.7	0.0	314.7	25.6	0.0	0.0	0.0	25.6	289.1	111.0	17.9	128.9	0.0	0.0	0.0	160.1
Sub.	2354.3	0.0	2354.3	64.8	0.0	0.0	0.0	64.8	2289.5	753.4	121.9	875.3	0.0	0.0	0.0	1414.1
Rem.	5215.7	0.0	5215.7	649.7	0.0	0.0	0.0	649.7	4566.0	1801.7	288.9	2090.6	0.0	0.0	0.0	2475.4
Tot.	**7569.9**	**0.0**	**7569.9**	**714.4**	**0.0**	**0.0**	**0.0**	**714.4**	**6855.5**	**2555.1**	**410.8**	**2965.9**	**0.0**	**0.0**	**0.0**	**3889.6**
Disc	1961.6	0.0	1961.6	134.8	0.0	0.0	0.0	134.8	1826.8	652.4	104.3	756.7	0.0	0.0	0.0	1070.1

	Other Income				Net Capital Investment				Before Tax Cash Flow				After Tax Cash Flow		
Year	Other MM$	ARTC MM$	Aband. Costs MM$	Oper. Income MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	Income Tax MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	10.6	10.6	-10.6	-10.6	-10.1	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	-0.3	8.4	0.0	0.0	8.4	-8.7	-19.3	-17.7	0.0	-8.7	-19.3	-17.7
2006	0.0	0.0	0.0	0.4	50.4	0.0	87.4	137.8	-137.4	-156.7	-125.9	0.0	-137.4	-156.7	-125.9
2007	0.0	0.1	0.0	17.6	52.5	0.0	71.4	123.9	-106.3	-263.0	-202.1	0.0	-106.4	-263.1	-202.1
2008	0.0	0.3	0.0	49.7	63.0	0.0	109.2	172.2	-122.5	-385.6	-281.9	0.1	-122.6	-385.7	-281.9
2009	0.0	0.5	0.0	115.4	42.0	0.0	142.8	184.8	-69.4	-454.9	-323.0	0.1	-69.5	-455.1	-323.1
2010	0.0	0.5	0.0	183.5	0.0	0.0	126.0	126.0	57.5	-397.4	-292.0	14.9	42.6	-412.5	-300.2
2011	0.0	0.5	0.0	228.2	0.0	0.0	67.2	67.2	161.0	-236.5	-213.2	34.8	126.1	-286.4	-238.4
2012	0.0	0.5	0.0	241.3	0.0	0.0	0.0	0.0	241.3	4.9	-105.9	47.9	193.4	-93.0	-152.4
2013	0.0	0.5	0.0	228.2	48.3	0.0	19.3	67.6	160.6	165.4	-41.0	46.7	113.9	20.9	-106.4
2014	0.0	0.5	0.0	193.4	58.8	0.0	23.5	82.3	111.1	276.5	-0.1	35.2	75.9	96.7	-78.5
2015	0.0	0.5	0.0	160.6	63.0	0.0	25.2	88.2	72.4	349.0	24.1	23.8	48.7	145.4	-62.2
Sub.	0.0	3.9	0.0	1418.1	386.4	0.0	682.7	1069.1	349.0	349.0	24.1	203.6	145.4	145.4	-62.2
Rem.	0.0	9.4	21.5	2463.3	396.9	0.0	158.9	555.8	1907.5	2256.4	346.4	575.1	1332.3	1477.7	163.4
Tot.	**0.0**	**13.3**	**21.5**	**3881.4**	**783.3**	**0.0**	**841.6**	**1624.9**	**2256.4**	**2256.4**	**346.4**	**778.7**	**1477.7**	**1477.7**	**163.4**
Disc	0.0	3.3	2.5	1070.9	284.4	0.0	440.1	724.5	346.4	346.4	346.4	183.0	163.4	163.4	163.4

AFTER TAX ANALYSIS

Year Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2005	4.6	0.0	0.0	0.0	4.9	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2006	9.8	0.0	0.0	0.0	9.3	0.0	0.0	0.0	98.0	0.0	0.0	0.0	0.0
2007	42.6	0.0	0.0	0.3	24.8	0.0	0.0	0.0	169.4	0.0	0.0	0.0	0.0
2008	107.5	0.0	0.0	0.8	57.0	0.0	0.0	0.0	278.6	0.0	0.0	0.0	0.0
2009	202.5	0.0	0.0	1.5	85.6	0.0	0.0	0.0	421.4	64.8	0.0	0.0	64.8
2010	291.1	0.0	0.0	2.4	105.1	0.0	0.0	0.0	482.6	104.9	0.0	0.0	104.9
2011	342.9	0.0	0.0	2.9	111.7	0.0	0.0	0.0	444.9	102.8	0.0	0.0	102.8
2012	353.2	0.0	0.0	3.0	108.9	0.0	0.0	0.0	342.1	85.5	0.0	0.0	85.5
2013	342.1	0.0	0.0	2.9	111.0	0.0	0.0	0.0	275.9	66.6	0.0	0.0	66.6
2014	343.2	0.0	0.0	21.7	128.0	0.0	0.0	0.0	232.9	55.3	0.0	0.0	55.3
2015	314.7	0.0	0.0	25.1	128.9	0.0	0.0	0.0	202.8	47.5	0.0	0.0	47.5
Sub.	2354.3	0.0	0.0	60.8	875.3	0.0	0.0	0.0	202.8	527.4	0.0	0.0	527.4
Rem.	5215.7	0.0	0.0	640.3	2109.6	0.0	0.0	0.0	8.6	307.0	0.0	0.0	307.0
Tot.	**7569.9**	**0.0**	**0.0**	**701.1**	**2984.9**	**0.0**	**0.0**	**0.0**	**8.6**	**834.4**	**0.0**	**0.0**	**834.4**
Disc	1961.6	0.0	0.0	131.5	759.0	0.0	0.0	0.0	163.2	304.6	0.0	0.0	304.6

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write -off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	-0.3	0.0	0.0	0.0	0.0	0.0	26.4	0.0	0.0	0.0	0.0	-0.3
2006	0.0	0.4	0.0	0.0	0.0	0.0	0.0	76.8	0.4	0.0	0.0	0.4	0.0
2007	0.0	17.6	0.0	0.0	0.0	0.0	0.0	128.9	17.5	0.0	0.0	17.5	0.1
2008	0.0	49.7	0.0	0.0	0.0	0.0	0.0	174.5	49.4	0.0	0.0	49.4	0.3
2009	0.0	50.6	0.0	0.0	0.0	0.0	0.0	167.0	50.1	0.0	0.0	50.1	0.5
2010	0.0	78.6	0.0	0.0	0.0	0.0	0.0	116.9	35.1	0.0	0.0	35.1	43.6
2011	0.0	125.4	0.0	0.0	0.0	0.0	0.0	81.8	24.6	0.0	0.0	24.6	100.8
2012	0.0	155.8	0.0	0.0	0.0	0.0	0.0	57.3	17.2	0.0	0.0	17.2	138.6
2013	0.0	161.7	0.0	0.0	0.0	0.0	0.0	88.4	26.5	0.0	0.0	26.5	135.1
2014	0.0	138.1	0.0	0.0	0.0	0.0	0.0	120.7	36.2	0.0	0.0	36.2	101.9
2015	0.0	113.1	0.0	0.0	0.0	0.0	0.0	147.5	44.2	0.0	0.0	44.2	68.9
Sub.	0.0	890.7	0.0	0.0	0.0	0.0	0.0	147.5	301.2	0.0	0.0	301.2	589.5
Rem.	0.0	2158.9	0.0	0.0	0.0	0.0	0.0	8.5	494.2	0.0	0.0	494.2	1664.7
Tot.	**0.0**	**3049.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**8.5**	**795.3**	**0.0**	**0.0**	**795.3**	**2254.2**
Disc	0.0	766.5	0.0	0.0	0.0	0.0	0.0	86.4	236.8	0.0	0.0	236.8	529.6

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest -ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	Net Cash Flow After Income Tax 10% Dcf Cum. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	-0.3	-0.3	0.0	0.0	0.0	-0.3	0.0	0.0	0.0	-8.7	-19.3	-17.7
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-137.4	-156.7	-125.9
2007	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-106.4	-263.1	-202.1
2008	0.0	0.0	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-122.6	-385.7	-281.9
2009	0.0	0.0	0.5	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-69.5	-455.1	-323.1
2010	0.0	0.0	43.6	43.6	9.6	0.0	0.0	43.1	5.3	0.0	14.9	42.6	-412.5	-300.2
2011	0.0	0.0	100.8	100.8	22.3	0.0	0.0	100.3	12.5	0.0	34.8	126.1	-286.4	-238.4
2012	0.0	0.0	138.6	138.6	30.7	0.0	0.0	138.1	17.3	0.0	47.9	193.4	-93.0	-152.4
2013	0.0	0.0	135.1	135.1	29.9	0.0	0.0	134.6	16.8	0.0	46.7	113.9	20.9	-106.4
2014	0.0	0.0	101.9	101.9	22.5	0.0	0.0	101.4	12.7	0.0	35.2	75.9	96.7	-78.5
2015	0.0	0.0	68.9	68.9	15.2	0.0	0.0	68.4	8.5	0.0	23.8	48.7	145.4	-62.2
Sub.	0.0	0.0	589.5	589.5	130.4	0.1	0.0	585.6	73.2	0.0	203.6	145.4	145.4	-62.2
Rem.	0.0	0.0	1664.7	1664.7	368.2	0.0	0.0	1655.3	206.9	0.0	575.1	1332.3	1477.7	163.4
Tot.	**0.0**	**0.0**	**2254.2**	**2254.2**	**498.6**	**0.1**	**0.0**	**2240.9**	**280.1**	**0.0**	**778.7**	**1477.7**	**1477.7**	**163.4**
Disc	0.0	0.0	529.6	529.6	117.2	0.1	0.0	526.4	65.8	0.0	183.0	163.4	163.4	163.4

RESERVE SUMMARY

Product	Units	Remaining Reserves at January 1, 2004 Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents BOE Factor	Company Mstb	% of Total	Reserve Life Indic. (yr) Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	402442	0	402442	364460	1.000	402442	100	31.0	100.0	16.1
Total Oil Eq.	Mstb	402442	0	402442	364460		402442	100	31.0	0.0	16.1

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6855502	100	1826834	100
Total Oil Eq.	$/BOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6855502	100	1826834	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)	Initial	Average
Crown Royalty	0.0000	9.4378
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000
NPI Payment	0.0000	0.0000

Disc. Rate %	Net Present Value Before Income Tax Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Net Present Value After Tax Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
0.0	3889552	3881351	1624921	2256430	5.61	3102622	1624921	1477701	3.67
5.0	1925553	1924828	1033920	890909	2.21	1567631	1033920	533712	1.33
8.0	1337260	1337737	827392	510344	1.27	1101440	827392	274048	0.68
10.0	1070140	1070941	724539	346403	0.86	887948	724539	163409	0.41
12.0	868678	869617	641223	228394	0.57	725864	641223	84641	0.21
15.0	650400	651368	542816	108552	0.27	548848	542816	6032	0.01
20.0	422928	423771	425755	-1984	0.00	362147	425755	-63608	-0.16

Project.......1046350
Entity.......Total With Adjustments (PPP Undeveloped)
Run date....Fri May 21 2004 10:43:31
Evaluator...Laustsen, Dana B.

AFTER TAX RESOURCES

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Summary of Resources and Values

Company: **Deer Creek Energy Ltd.** Pricing: **GLJ (2004-04) Full Year**

Property: **Joslyn Creek Mining Resources** Effective Date: **January 1, 2004**

	Best Estimate
MARKETABLE REOURCES	
Heavy Oil - MMSTB	
Total Company Interest	1235
Working Interest	1235
Net After Royalty	1120
Oil Equivalent - MMBOE	
Total Company Interest	1235
Working Interest	1235
Net After Royalty	1120
BEFORE TAX PRESENT VALUE - $M	
0.00%	10164436
5.00%	2612470
8.00%	1128010
10.00%	607279
12.00%	287998
15.00%	23167
20.00%	-147107
AFTER TAX PRESENT VALUE - $M	
0.00%	6623946
5.00%	1598145
8.00%	614536
10.00%	272556
12.00%	65610
15.00%	-101233
20.00%	-198017

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

Project 1046350

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Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Resource Class:	**Best Estimate**
Property:	**Joslyn Creek Mining Resources**	Development Class:	**Total**
		Pricing:	**GLJ (2004-04) Full Year**
		Effective Date:	**1-Jan-04**

PRODUCTION FORECAST

Heavy Oil Production

Year	Compny Daily Stb	Compny Yearly Mmb	Net Yearly Mmb	Price $/Bbl
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	25200	9	9	17
2011	42000	15	15	17.5
2012	42000	15	15	18
2013	75600	28	27	18.5
2014	84000	31	30	19
2015	84000	31	30	19.5
Sub.	29400	129	127	18.57
Rem.	121209	1106	992	26.73
Tot.	**91433**	**1235**	**1120**	**25.88**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses			Other Expenses			Net Prod'n Revenue
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	MM$	MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	156	0	156	2	0	0	0	2	155	71	38	108	0	0	0	46
2011	268	0	268	3	0	0	0	3	266	119	46	165	0	0	0	101
2012	276	0	276	3	0	0	0	3	273	122	46	168	0	0	0	105
2013	510	0	510	5	0	0	0	5	505	218	84	303	0	0	0	203
2014	583	0	583	6	0	0	0	6	577	223	86	308	0	0	0	268
2015	598	0	598	6	0	0	0	6	592	270	87	357	0	0	0	235
Sub.	2391	0	2391	24	0	0	0	24	2368	1022	387	1409	0	0	0	959
Rem.	29567	0	29567	3213	0	0	0	3213	26354	9964	3398	13362	0	0	0	12993
Tot.	**31959**	**0**	**31959**	**3237**	**0**	**0**	**0**	**3237**	**28722**	**10986**	**3785**	**14771**	**0**	**0**	**0**	**13951**
Disc	4271	.0	4271	283	0	0	0	283	3988	1571	556	2127	0	0	0	1861

Year	Other Income: Other MM$	Other Income: ARTC MM$	Aband. Costs MM$	Oper. Income MM$	Net Capital Investment: Dev. MM$	Net Capital Investment: Plant MM$	Net Capital Investment: Tang. MM$	Net Capital Investment: Total MM$	Before Tax Cash Flow: Annual MM$	Before Tax Cash Flow: Cum. MM$	Before Tax Cash Flow: 10% Dcf MM$	Income Tax MM$	After Tax Cash Flow: Annual MM$	After Tax Cash Flow: Cum. MM$	After Tax Cash Flow: 10% Dcf MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	9	9	-9	-9	-7	0	-9	-9	-7
2007	0	0	0	0	0	0	14	14	-14	-23	-17	0	-14	-23	-17
2008	0	0	0	0	0	0	315	315	-315	-338	-223	0	-315	-338	-223
2009	0	0	0	0	0	0	300	300	-300	-639	-400	0	-300	-639	-400
2010	0	0	0	46	0	0	74	74	-27	-666	-415	0	-27	-666	-415
2011	0	0	0	101	0	0	330	330	-229	-895	-527	0	-229	-895	-527
2012	0	0	0	105	0	0	314	314	-209	-1104	-620	0	-209	-1104	-620
2013	0	0	0	203	0	0	87	87	115	-989	-573	0	115	-989	-573
2014	0	0	0	268	38	0	345	383	-114	-1103	-615	0	-114	-1103	-615
2015	0	0	0	235	39	0	329	367	-132	-1235	-660	0	-132	-1235	-660
Sub.	0	0	0	959	77	0	2117	2194	-1235	-1235	-660	0	-1235	-1235	-660
Rem.	0	0	0	12993	1518	0	75	1593	11399	10164	607	3540	7859	6624	273
Tot.	**0**	**0**	**0**	**13951**	**1595**	**0**	**2192**	**3787**	**10164**	**10164**	**607**	**3540**	**6624**	**6624**	**273**
Disc	0	0	0	1861	218	0	1036	1254	607	607	607	335	273	273	273

AFTER TAX ANALYSIS

Year Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation: Balance MM$	Field Depreciation: Annual MM$	Gather System Depreciation: Balance MM$	Gather System Depreciation: Annual MM$	Total Annual Depr. MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	9	0	0	0	0
2007	0	0	0	0	0	0	0	0	23	0	0	0	0
2008	0	0	0	0	0	0	0	0	338	0	0	0	0
2009	0	0	0	0	0	0	0	0	639	0	0	0	0
2010	156	0	0	2	108	0	0	0	713	46	0	0	46
2011	268	0	0	3	165	0	0	0	996	101	0	0	101
2012	276	0	0	3	168	0	0	0	1209	105	0	0	105
2013	510	0	0	5	303	0	0	0	1192	203	0	0	203
2014	583	0	0	6	308	0	0	0	1333	257	0	0	257
2015	598	0	0	6	357	0	0	0	1405	216	0	0	216
Sub.	2391	0	0	24	1409	0	0	0	1405	928	0	0	928
Rem.	29567	0	0	3213	13362	0	0	0	0	1265	0	0	1265
Tot.	**31959**	**0**	**0**	**3237**	**14771**	**0**	**0**	**0**	**0**	**2192**	**0**	**0**	**2192**
Disc	4271	0	0	283	2127	0	0	0	385	716	0	0	716

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write -off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	11	0	0	0	0	0	38	11	0	0	11	0
2015	0	20	0	0	0	0	0	65	20	0	0	20	0
Sub.	0	31	0	0	0	0	0	65	31	0	0	31	0
Rem.	0	11728	0	0	0	0	0	89	1501	0	0	1501	10227
Tot.	**0**	**11759**	**0**	**0**	**0**	**0**	**0**	**89**	**1532**	**0**	**0**	**1532**	**10227**
Disc	0	1145	0	0	0	0	0	57	178	0	0	178	967

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest -ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	Net Cash Flow After Income Tax 10% Dcf Cum. MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	-9	-9	-7
2007	0	0	0	0	0	0	0	0	0	0	0	-14	-23	-17
2008	0	0	0	0	0	0	0	0	0	0	0	-315	-338	-223
2009	0	0	0	0	0	0	0	0	0	0	0	-300	-639	-400
2010	0	0	0	0	0	0	0	0	0	0	0	-27	-666	-415
2011	0	0	0	0	0	0	0	0	0	0	0	-229	-895	-527
2012	0	0	0	0	0	0	0	0	0	0	0	-209	-1104	-620
2013	0	0	0	0	0	0	0	0	0	0	0	115	-989	-573
2014	0	0	0	0	0	0	0	0	0	0	0	-114	-1103	-615
2015	0	0	0	0	0	0	0	0	0	0	0	-132	-1235	-660
Sub.	0	0	0	0	0	0	0	0	0	0	0	-1235	-1235	-660
Rem.	0	0	10227	10227	2262	0	0	10227	1278	0	3540	7859	6624	273
Tot.	**0**	**0**	**10227**	**10227**	**2262**	**0**	**0**	**10227**	**1278**	**0**	**3540**	**6624**	**6624**	**273**
Disc	0	0	967	967	214	0	0	967	121	0	335	273	273	273

RESOURCE SUMMARY

		Remaining Resources at January 1, 2004				Oil Equivalents			Resource Life Indic. (yr)		
Product	Units	Working Interest	Roy/NPI Interest	Total Company	Net	BOE Factor	Company Mstb	% of Total	Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	1234800	0	1234800	1119936	1	1234800	100	37	100	22.7
Total Oil Eq.	Mstb	1234800	0	1234800	1119936		1234800	100	37	0	22.7

PRODUCT REVENUE AND EXPENSES

		Average First Year Unit Values							Net Revenue After Royalties			
Product	Units	Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0	0	0	0	0	0	0	28721748	100	3988123	100
Total Oil Eq.	$/BOE	0	0	0	0	0	0	0	28721748	100	3988123	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)

	Initial	Average
Crown Royalty	0	10.1291
Non-crown Royalty	0	0
Mineral Tax	0	0
NPI Payment	0	0

	Net Present Value Before Income Tax					Net Present Value After Tax			
Disc. Rate %	Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
0	13951221	13951221	3786788	10164434	8.23	10410734	3786788	6623946	5.36
5	4642361	4642361	2029892	2612469	2.12	3628037	2029892	1598145	1.29
8	2629097	2629097	1501086	1128010	0.91	2115622	1501086	614536	0.5
10	1860941	1860941	1253662	607278	0.49	1526218	1253662	272556	0.22
12	1349005	1349005	1061007	287998	0.23	1126617	1061007	65610	0.05
15	865932	865932	842765	23167	0.02	741532	842765	-101233	-0.08
20	450801	450801	597908	-147107	-0.12	399891	597908	-198017	-0.16

Project.......1046350

Entity.......Joslyn Creek Mining Resources (Best Estimate)

Run date....Thu May 13 2004 08:47:46

Evaluator...Laustsen, Dana B.

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Summary of Resources and Values

Company: **Deer Creek Energy Ltd.** Pricing: **Posted (2003-Dec-31) Constant**

Property: **Joslyn Creek Mining Resources** Effective Date: **January 1, 2004**

	Best Estimate
MARKETABLE RESOURCES	
Heavy Oil - MMSTB	
Total Company Interest	1235
Working Interest	1235
Net After Royalty	1107
Oil Equivalent - MMBOE	
Total Company Interest	1235
Working Interest	1235
Net After Royalty	1107
BEFORE TAX PRESENT VALUE - $M	
0.00%	7386178
5.00%	2142530
8.00%	1029394
10.00%	617911
12.00%	354049
15.00%	121193
20.00%	-49073
AFTER TAX PRESENT VALUE - $M	
0.00%	4816345
5.00%	1330083
8.00%	592420
10.00%	321422
12.00%	149160
15.00%	-163
20.00%	-103385

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

Project 1046350

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Economic Forecast

Company:	Deer Creek Energy Ltd.	Resource Class:	Best Estimate
Property:	Joslyn Creek Mining Resources	Development Class:	Total
		Pricing:	Posted (2003-Dec-31) Constant
		Effective Date:	1-Jan-04

PRODUCTION FORECAST

Heavy Oil Production

Year	Compny Daily Stb	Compny Yearly Mmb	Net Yearly Mmb	Price $/Bbl
2004	0	0	0	0
2005	0	0	0	0
2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	25200	9	9	18.81
2011	42000	15	15	18.81
2012	42000	15	15	18.81
2013	75600	28	27	18.81
2014	84000	31	30	18.81
2015	84000	31	30	18.81
Sub.	29400	129	127	18.81
Rem.	121209	1106	981	18.81
Tot.	**91433**	**1235**	**1108**	**18.81**

REVENUE AND EXPENSE FORECAST

Year	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses			Other Expenses			Net Prod'n Revenue
	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	MM$	MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	173	0	173	2	0	0	0	2	171	66	32	98	0	0	0	73
2011	288	0	288	3	0	0	0	3	285	109	38	148	0	0	0	138
2012	288	0	288	3	0	0	0	3	285	110	38	148	0	0	0	137
2013	519	0	519	5	0	0	0	5	514	194	69	263	0	0	0	251
2014	577	0	577	6	0	0	0	6	571	197	69	266	0	0	0	305
2015	577	0	577	6	0	0	0	6	571	231	69	300	0	0	0	271
Sub.	2422	0	2422	24	0	0	0	24	2398	907	316	1222	0	0	0	1176
Rem.	20804	0	20804	2358	0	0	0	2358	18446	7116	2223	9339	0	0	0	9108
Tot.	**23227**	**0**	**23227**	**2382**	**0**	**0**	**0**	**2382**	**20844**	**8023**	**2539**	**10561**	**0**	**0**	**0**	**10283**
Disc	3560	0	3560	258	0	0	0	258	3302	1250	407	1657	0	0	0	1645

Year	Other Income		Aband. Costs	Oper. Income	Net Capital Investment				Before Tax Cash Flow			Income Tax	After Tax Cash Flow		
	Other MM$	ARTC MM$	MM$	MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	8	8	-8	-8	-7	0	-8	-8	-7
2007	0	0	0	0	0	0	13	13	-13	-21	-16	0	-13	-21	-16
2008	0	0	0	0	0	0	277	277	-277	-298	-196	0	-277	-298	-196
2009	0	0	0	0	0	0	260	260	-260	-559	-350	0	-260	-559	-350
2010	0	0	0	73	0	0	63	63	10	-548	-345	0	10	-548	-345
2011	0	0	0	138	0	0	277	277	-139	-688	-413	0	-139	-688	-413
2012	0	0	0	137	0	0	260	260	-123	-811	-468	0	-123	-811	-468
2013	0	0	0	251	0	0	71	71	180	-631	-395	0	180	-631	-395
2014	0	0	0	305	31	0	277	308	-3	-634	-396	0	-3	-634	-396
2015	0	0	0	271	31	0	260	291	-20	-654	-403	0	-20	-654	-403
Sub.	0	0	0	1176	61	0	1768	1830	-654	-654	-403	0	-654	-654	-403
Rem.	0	0	0	9108	1009	0	59	1068	8040	7386	618	2570	5470	4816	321
Tot.	**0**	**0**	**0**	**10283**	**1070**	**0**	**1827**	**2897**	**7386**	**7386**	**618**	**2570**	**4816**	**4816**	**321**
Disc	0	0	0	1645	155	0	871	1027	618	618	618	296	321	321	321

AFTER TAX ANALYSIS

Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	8	0	0	0	0
2007	0	0	0	0	0	0	0	0	21	0	0	0	0
2008	0	0	0	0	0	0	0	0	298	0	0	0	0
2009	0	0	0	0	0	0	0	0	559	0	0	0	0
2010	173	0	0	2	98	0	0	0	622	73	0	0	73
2011	288	0	0	3	148	0	0	0	826	138	0	0	138
2012	288	0	0	3	148	0	0	0	948	137	0	0	137
2013	519	0	0	5	263	0	0	0	882	251	0	0	251
2014	577	0	0	6	266	0	0	0	908	296	0	0	296
2015	577	0	0	6	300	0	0	0	873	255	0	0	255
Sub.	2422	0	0	24	1222	0	0	0	873	1151	0	0	1151
Rem.	20804	0	0	2358	9339	0	0	0	0	676	0	0	676
Tot.	23227	0	0	2382	10561	0	0	0	0	1827	0	0	1827
Disc	3560	0	0	258	1657	0	0	0	271	661	0	0	661

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write-off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	9	0	0	0	0	0	31	9	0	0	9	0
2015	0	16	0	0	0	0	0	52	16	0	0	16	0
Sub.	0	25	0	0	0	0	0	52	25	0	0	25	0
Rem.	0	8431	0	0	0	0	0	53	1008	0	0	1008	7423
Tot.	0	8456	0	0	0	0	0	53	1033	0	0	1033	7423
Disc	0	984	0	0	0	0	0	40	127	0	0	127	856

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest-ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	10% Dcf Cum. MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	-8	-8	-7
2007	0	0	0	0	0	0	0	0	0	0	0	-13	-21	-16
2008	0	0	0	0	0	0	0	0	0	0	0	-277	-298	-196
2009	0	0	0	0	0	0	0	0	0	0	0	-260	-559	-350
2010	0	0	0	0	0	0	0	0	0	0	0	10	-548	-345
2011	0	0	0	0	0	0	0	0	0	0	0	-139	-688	-413
2012	0	0	0	0	0	0	0	0	0	0	0	-123	-811	-468
2013	0	0	0	0	0	0	0	0	0	0	0	180	-631	-395
2014	0	0	0	0	0	0	0	0	0	0	0	-3	-634	-396
2015	0	0	0	0	0	0	0	0	0	0	0	-20	-654	-403
Sub.	0	0	0	0	0	0	0	0	0	0	0	-654	-654	-403
Rem.	0	0	7423	7423	1642	0	0	7423	928	0	2570	5470	4816	321
Tot.	0	0	7423	7423	1642	0	0	7423	928	0	2570	4816	4816	321
Disc	0	0	856	856	189	0	0	856	107	0	296	321	321	321

RESOURCE SUMMARY

Product	Units	Remaining Resources at January 1, 2004: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: BOE Factor	Company Mstb	% of Total	Resource Life Indic. (yr): Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	1234800	0	1234800	1108151	1	1234800	100	37	100	22.7
Total Oil Eq.	Mstb	1234800	0	1234800	1108151		1234800	100	37	0	22.7

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0	0	0	0	0	0	0	20844320	100	3301641	100
Total Oil Eq.	$/BOE	0	0	0	0	0	0	0	20844320	100	3301641	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)	Initial	Average
Crown Royalty	0	10.2567
Non-crown Royalty	0	0
Mineral Tax	0	0
NPI Payment	0	0

Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Net Present Value After Tax: Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
0	10283212	10283212	2897034	7386178	5.98	7713379	2897034	4816345	3.9
5	3763528	3763528	1620999	2142530	1.74	2951082	1620999	1330083	1.08
8	2248364	2248364	1218970	1029394	0.83	1811391	1218970	592420	0.48
10	1644651	1644651	1026739	617911	0.5	1348161	1026739	321422	0.26
12	1229025	1229025	874976	354049	0.29	1024136	874976	149160	0.12
15	821870	821870	700677	121193	0.1	700514	700677	-163	0
20	452866	452866	501939	-49073	-0.04	398553	501939	-103385	-0.08

Project.......1046350

Entity......Joslyn Creek Mining Resources (Best Estimate)

rc38_pri.xls

Evaluator...Laustsen, Dana B.

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Gilbert Laustsen Jung
Associates Ltd. Petroleum Consultants
4100,400 - 3rd Avenue S.W.,Calgary,Alberta,Canada T2P 4H2 (403) 266-9500 Fax (403) 262-1855

June 10, 2004

Project 1046350

Mr. Gary Purcell
Deer Creek Energy Ltd.
2600, 205 – 5th Avenue S.W.
Calgary, Alberta
T2P 2V7

Dear Sir:

Re: Deer Creek Energy Ltd.
Corporate Evaluation
Pricing Sensitivity
Effective January 1, 2004

At the request of Deer Creek Energy Ltd., Gilbert Laustsen Jung Associates Ltd. has prepared pricing sensitivities based on the Deer Creek Summary report with a preparation date of March 16, 2004 and an effective date of January 1, 2004. Sensitivities were performed for the RBC (June 2004) price forecast, as presented in Table 1. The results of the evaluation are contained in the attached report.

It is trusted that this evaluation meets your current requirements. Should you have any questions regarding this analysis, please contact the undersigned.

Yours very truly,

GILBERT LAUSTSEN JUNG ASSOCIATES LTD.

ORIGINALLY SIGNED BY

Dana B. Laustsen, P. Eng.
Executive Vice-President

DBL/jem
Attachments

Table 1
RBC Price Forecast

Summary	2004	2005	Long Term
WTI (US$/bbl)	$36.00	$34.00	$25.00 (escalated at 2% from 2004)
Cdn/US FX Rate	0.75	0.75	0.75
NYMEX (US$/Mcf)	$5.75	$5.35	$4.00 (escalated at 2% from 2004)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
WTI (US$/bbl)	$36.00	$34.00	$26.01	$26.53	$27.06	$27.60	$28.15	$28.72	$29.29	$29.88	$30.47	$31.08	$31.71	$32.34	$32.99	$33.65
Cdn/US FX Rate	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
NYMEX (US$/Mcf)	$5.75	$5.35	$4.16	$4.24	$4.33	$4.42	$4.50	$4.59	$4.69	$4.78	$4.88	$4.97	$5.07	$5.17	$5.28	$5.38
AECO (C$/Mcf)	$6.58	$6.05	$4.48	$4.59	$4.71	$4.82	$4.94	$5.06	$5.18	$5.30	$5.43	$5.56	$5.69	$5.82	$5.96	$6.10

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
WTI (US$/bbl)	37.892	38.649	39.4225	40.2109	41.015	41.835	42.672	43.526	44.396	45.284	46.19	47.114	48.056	49.017	49.997	50.997
Cdn/US FX Rate	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
NYMEX (US$/Mcf)	6.0627	6.1839	6.3076	6.43375	6.5624	6.6937	6.8275	6.9641	7.1034	7.2454	7.3904	7.5382	7.6889	7.8427	7.9996	8.1595
AECO (C$/Mcf)	6.9927	7.1528	7.31603	7.48255	7.6524	7.8256	8.0024	8.1826	8.3665	8.554	8.7453	8.9404	9.1394	9.3424	9.5494	9.7606

Summary of Reserves and Values

Company: **Deer Creek Energy Ltd.**
Property: **Corporate**
Description: **Total With Adjustments**

Pricing: **RBC (June 2004) Forecast**
Effective Date: **January 01, 2004**

	Probable Undeveloped	PPP Undeveloped
MARKETABLE RESERVES		
Heavy Oil - MMSTB		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	220	351
Oil Equivalent - MMBOE		
Total Company Interest	250	402
Working Interest	250	402
Net After Royalty	220	351
BEFORE TAX PRESENT VALUE - $MM		
0.0%	2,851.7	4,698.1
5.0%	1,141.9	1,873.4
8.5%	610.6	1,021.8
10.0%	465.1	791.3
12.0%	319.7	562.3
15.0%	172.9	332.0
20.0%	38.2	120.5
AFTER TAX PRESENT VALUE - $MM		
0.0%	1,868.9	3,072.5
5.0%	709.0	1,171.4
8.5%	350.9	603.0
10.0%	253.4	450.2
12.0%	156.5	299.3
15.0%	59.7	149.1
20.0%	-26.9	14.2

Oil Equivalent Factors:

Heavy Oil - 1.0 bbl/boe

Project 1046350
Run date Thu Jun 10 2004 11:44:44

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Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Reserve Class:	**Probable**
Property:	**Corporate**	Development Class:	**Undeveloped**
Description:	**Total With Adjustments**	Pricing:	**RBC (June 2004) Forecast**
		Effective Date:	**January 01, 2004**

PRODUCTION FORECAST

	Heavy Oil Production				
Year	Compny Oil Wells	Compny Daily Stb	Compny Yearly Mstb	Net Yearly Mstb	Price $/Bbl
2004	0	0	0	0	0.00
2005	3	638	233	231	27.28
2006	3	1428	521	516	17.88
2007	19	5250	1916	1897	18.57
2008	19	9345	3411	3377	19.28
2009	45	17052	6224	6162	20.00
2010	61	26943	9834	9736	20.73
2011	61	34251	12502	12377	21.49
2012	61	34476	12584	12458	22.25
2013	66	33369	12180	12058	23.04
2014	79	33676	12292	11175	23.83
2015	84	34020	12417	10329	24.64
Sub.	42	19204	84114	80315	22.27
Rem.	62	26766	166082	139566	30.61
Tot.	**54**	**23637**	**250195**	**219880**	**27.81**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses			Other Expenses			Net Prod'n Revenue
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	MM$	MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	6.4	0.0	6.4	0.1	0.0	0.0	0.0	0.1	6.3	4.9	0.0	4.9	0.0	0.0	0.0	1.4
2006	9.3	0.0	9.3	0.1	0.0	0.0	0.0	0.1	9.2	8.7	0.0	8.7	0.0	0.0	0.0	0.5
2007	35.6	0.0	35.6	0.4	0.0	0.0	0.0	0.4	35.2	16.7	2.2	18.9	0.0	0.0	0.0	16.3
2008	65.8	0.0	65.8	0.7	0.0	0.0	0.0	0.7	65.1	28.3	3.9	32.2	0.0	0.0	0.0	32.9
2009	124.5	0.0	124.5	1.2	0.0	0.0	0.0	1.2	123.2	40.9	6.7	47.6	0.0	0.0	0.0	75.7
2010	203.9	0.0	203.9	2.0	0.0	0.0	0.0	2.0	201.8	54.9	11.2	66.0	0.0	0.0	0.0	135.8
2011	268.7	0.0	268.7	2.7	0.0	0.0	0.0	2.7	266.0	59.9	13.2	73.1	0.0	0.0	0.0	192.9
2012	280.0	0.0	280.0	2.8	0.0	0.0	0.0	2.8	277.2	59.9	13.0	73.0	0.0	0.0	0.0	204.2
2013	280.6	0.0	280.6	2.8	0.0	0.0	0.0	2.8	277.8	63.7	13.4	77.0	0.0	0.0	0.0	200.8
2014	292.9	0.0	292.9	26.6	0.0	0.0	0.0	26.6	266.3	72.7	14.6	87.3	0.0	0.0	0.0	179.0
2015	306.0	0.0	306.0	51.5	0.0	0.0	0.0	51.5	254.5	83.9	16.2	100.1	0.0	0.0	0.0	154.4
Sub.	1873.5	0.0	1873.5	90.8	0.0	0.0	0.0	90.8	1782.7	494.5	94.4	588.9	0.0	0.0	0.0	1193.8
Rem.	5083.8	0.0	5083.8	817.7	0.0	0.0	0.0	817.7	4266.1	1196.3	227.1	1423.4	0.0	0.0	0.0	2842.7
Tot.	**6957.3**	**0.0**	**6957.3**	**908.5**	**0.0**	**0.0**	**0.0**	**908.5**	**6048.8**	**1690.8**	**321.5**	**2012.3**	**0.0**	**0.0**	**0.0**	**4036.5**
Disc	1710.8	0.0	1710.8	168.9	0.0	0.0	0.0	168.9	1542.0	434.6	81.7	516.3	0.0	0.0	0.0	1025.7

	Other Income		Aband. Costs	Oper. Income	Net Capital Investment				Before Tax Cash Flow			Income Tax	After Tax Cash Flow		
Year	Other MM$	ARTC MM$	MM$	MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	10.6	10.6	-10.6	-10.6	-10.1	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	1.4	8.5	0.0	0.0	8.5	-7.1	-17.7	-16.3	0.0	-7.1	-17.7	-16.3
2006	0.0	0.0	0.0	0.5	41.1	0.0	103.0	144.1	-143.5	-161.3	-129.4	0.0	-143.6	-161.3	-129.4
2007	0.0	0.1	0.0	16.4	0.0	0.0	52.7	52.7	-36.3	-197.6	-155.4	0.0	-36.4	-197.6	-155.4
2008	0.0	0.2	0.0	33.1	66.9	0.0	98.1	164.9	-131.8	-329.4	-241.3	0.0	-131.9	-329.5	-241.3
2009	0.0	0.3	0.0	76.0	45.2	0.0	153.8	199.1	-123.1	-452.6	-314.2	0.1	-123.2	-452.7	-314.3
2010	0.0	0.5	0.0	136.3	0.0	0.0	27.6	27.6	108.7	-343.9	-255.7	3.6	105.1	-347.6	-257.7
2011	0.0	0.5	0.0	193.4	0.0	0.0	0.0	0.0	193.4	-150.5	-161.1	33.5	159.9	-187.7	-179.4
2012	0.0	0.5	0.0	204.7	23.7	0.0	9.5	33.1	171.6	21.1	-84.7	43.2	128.3	-59.3	-122.4
2013	0.0	0.5	0.0	201.3	36.0	0.0	14.4	50.4	150.9	171.9	-23.7	44.5	106.3	47.0	-79.4
2014	0.0	0.5	0.0	179.5	60.9	0.0	24.4	85.3	94.2	266.2	10.9	35.7	58.5	105.5	-57.8
2015	0.0	0.5	0.0	154.9	0.0	0.0	0.0	0.0	154.9	421.0	62.6	33.3	121.5	227.1	-17.2
Sub.	0.0	3.6	0.0	1197.4	282.3	0.0	494.1	776.4	421.0	421.0	62.6	193.9	227.1	227.1	-17.2
Rem.	0.0	8.5	13.3	2837.8	290.7	0.0	116.5	407.2	2430.6	2851.7	465.1	788.9	1641.8	1868.9	253.4
Tot.	**0.0**	**12.1**	**13.3**	**4035.3**	**573.0**	**0.0**	**610.6**	**1183.6**	**2851.7**	**2851.7**	**465.1**	**982.8**	**1868.9**	**1868.9**	**253.4**
Disc	0.0	3.0	1.8	1026.9	219.3	0.0	342.5	561.8	465.1	465.1	465.1	211.7	253.4	253.4	253.4

AFTER TAX ANALYSIS

Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2005	6.4	0.0	0.0	0.0	4.9	0.0	0.0	0.0	10.6	0.0	0.0	0.0	0.0
2006	9.3	0.0	0.0	0.0	8.7	0.0	0.0	0.0	113.6	0.0	0.0	0.0	0.0
2007	35.6	0.0	0.0	0.3	18.9	0.0	0.0	0.0	166.3	0.0	0.0	0.0	0.0
2008	65.8	0.0	0.0	0.5	32.2	0.0	0.0	0.0	264.4	0.0	0.0	0.0	0.0
2009	124.5	0.0	0.0	0.9	47.6	0.0	0.0	0.0	418.2	37.0	0.0	0.0	37.0
2010	203.9	0.0	0.0	1.5	66.0	0.0	0.0	0.0	408.8	98.7	0.0	0.0	98.7
2011	268.7	0.0	0.0	2.2	73.1	0.0	0.0	0.0	310.0	77.5	0.0	0.0	77.5
2012	280.0	0.0	0.0	2.3	73.0	0.0	0.0	0.0	242.0	59.3	0.0	0.0	59.3
2013	280.6	0.0	0.0	2.3	77.0	0.0	0.0	0.0	197.1	47.5	0.0	0.0	47.5
2014	292.9	0.0	0.0	26.1	87.3	0.0	0.0	0.0	174.0	40.5	0.0	0.0	40.5
2015	306.0	0.0	0.0	51.0	100.1	0.0	0.0	0.0	133.6	33.4	0.0	0.0	33.4
Sub.	1873.5	0.0	0.0	87.2	588.9	0.0	0.0	0.0	133.6	393.9	0.0	0.0	393.9
Rem.	5083.8	0.0	0.0	809.2	1436.8	0.0	0.0	0.0	6.9	211.5	0.0	0.0	211.5
Tot.	**6957.3**	**0.0**	**0.0**	**896.3**	**2025.6**	**0.0**	**0.0**	**0.0**	**6.9**	**605.4**	**0.0**	**0.0**	**605.4**
Disc	1710.8	0.0	0.0	165.8	518.1	0.0	0.0	0.0	136.5	226.8	0.0	0.0	226.8

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write -off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	1.4	0.2	0.0	0.0	0.0	0.0	26.5	1.2	0.0	0.0	1.2	0.0
2006	0.0	0.6	0.1	0.0	0.0	0.0	0.0	66.4	0.5	0.0	0.0	0.5	0.0
2007	0.0	16.4	0.0	0.0	0.0	0.0	0.0	65.9	16.3	0.0	0.0	16.3	0.1
2008	0.0	33.1	0.0	0.0	0.0	0.0	0.0	116.5	32.9	0.0	0.0	32.9	0.2
2009	0.0	39.0	0.0	0.0	0.0	0.0	0.0	128.8	38.6	0.0	0.0	38.6	0.3
2010	0.0	37.5	0.0	0.0	0.0	0.0	0.0	90.2	27.1	0.0	0.0	27.1	10.5
2011	0.0	115.9	0.0	0.0	0.0	0.0	0.0	63.1	18.9	0.0	0.0	18.9	96.9
2012	0.0	145.4	0.0	0.0	0.0	0.0	0.0	67.8	20.4	0.0	0.0	20.4	125.0
2013	0.0	153.8	0.0	0.0	0.0	0.0	0.0	83.5	25.1	0.0	0.0	25.1	128.8
2014	0.0	139.1	0.0	0.0	0.0	0.0	0.0	119.4	35.8	0.0	0.0	35.8	103.3
2015	0.0	121.5	0.0	0.0	0.0	0.0	0.0	83.6	25.1	0.0	0.0	25.1	96.4
Sub.	0.0	803.6	0.3	0.0	0.0	0.0	0.0	83.6	241.8	0.0	0.0	241.8	561.5
Rem.	0.0	2626.3	0.0	0.0	0.0	0.0	0.0	6.5	344.6	0.0	0.0	344.6	2281.7
Tot.	**0.0**	**3429.9**	**0.3**	**0.0**	**0.0**	**0.0**	**0.0**	**6.5**	**586.5**	**0.0**	**0.0**	**586.5**	**2843.2**
Disc	0.0	800.1	0.2	0.0	0.0	0.0	0.0	66.3	187.3	0.0	0.0	187.3	612.6

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest -ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Cum. MM$	10% Dcf Cum. MM$
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-10.6	-10.6	-10.1
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-7.1	-17.7	-16.3
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-143.6	-161.3	-129.4
2007	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-36.4	-197.6	-155.4
2008	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-131.9	-329.5	-241.3
2009	0.0	0.0	0.3	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.1	-123.2	-452.7	-314.3
2010	0.0	0.0	10.5	10.5	2.3	0.0	0.0	10.0	1.2	0.0	3.6	105.1	-347.6	-257.7
2011	0.0	0.0	96.9	96.9	21.4	0.0	0.0	96.4	12.1	0.0	33.5	159.9	-187.7	-179.4
2012	0.0	0.0	125.0	125.0	27.7	0.0	0.0	124.5	15.6	0.0	43.2	128.3	-59.3	-122.4
2013	0.0	0.0	128.8	128.8	28.5	0.0	0.0	128.3	16.0	0.0	44.5	106.3	47.0	-79.4
2014	0.0	0.0	103.3	103.3	22.8	0.0	0.0	102.8	12.8	0.0	35.7	58.5	105.5	-57.8
2015	0.0	0.0	96.4	96.4	21.3	0.0	0.0	95.9	12.0	0.0	33.3	121.5	227.1	-17.2
Sub.	0.0	0.0	561.5	561.5	124.2	0.1	0.1	557.9	69.7	0.0	193.9	227.1	227.1	-17.2
Rem.	0.0	0.0	2281.7	2281.7	504.7	0.0	0.0	2273.2	284.1	0.0	788.9	1641.8	1868.9	253.4
Tot.	**0.0**	**0.0**	**2843.2**	**2843.2**	**628.9**	**0.1**	**0.1**	**2831.1**	**353.9**	**0.0**	**982.8**	**1868.9**	**1868.9**	**253.4**
Disc	0.0	0.0	612.6	612.6	135.5	0.1	0.1	609.6	76.2	0.0	211.7	253.4	253.4	253.4

RESERVE SUMMARY

Product	Units	Remaining Reserves at January 1, 2004: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: BOE Factor	Company Mstb	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	250195	0	250195	219880	1.000	250195	100	29.0	100.0	15.4
Total Oil Eq.	Mstb	250195	0	250195	219880		250195	100	29.0	0.0	15.4

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6048796	100	1541961	100
Total Oil Eq.	$/BOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6048796	100	1541961	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)	Initial	Average
Crown Royalty	0.0000	13.0579
Non-crown Royalty	0.0000	0.0000
Mineral Tax	0.0000	0.0000
NPI Payment	0.0000	0.0000

Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Net Present Value After Tax: Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
0.0	4036505	4035279	1183621	2851657	11.40	3052487	1183621	1868865	7.47
5.0	1923214	1924226	782363	1141863	4.56	1491329	782363	708967	2.83
8.5	1225447	1226686	616062	610624	2.44	966941	616062	350879	1.40
10.0	1025665	1026892	561823	465069	1.86	815189	561823	253366	1.01
12.0	819451	820618	500917	319702	1.28	657432	500917	156516	0.63
15.0	599939	600976	428089	172887	0.69	487801	428089	59712	0.24
20.0	377558	378369	340175	38194	0.15	313257	340175	-26918	-0.11

Project.......1046350
Entity.......Total With Adjustments (Probable Undeveloped)
Run date....Thu Jun 10 2004 11:44:44
Evaluator...Laustsen, Dana B.

Economic Forecast

Company:	**Deer Creek Energy Ltd.**	Reserve Class:	**PPP**
Property:	**Corporate**	Development Class:	**Undeveloped**
Description:	**Total With Adjustments**	Pricing:	**RBC (June 2004) Forecast**
		Effective Date:	**January 01, 2004**

PRODUCTION FORECAST

		Heavy Oil Production			
Year	Compny Oil Wells	Compny Daily Stb	Compny Yearly Mstb	Net Yearly Mstb	Price $/Bbl
2004	0	0	0	0	0.00
2005	3	672	245	243	27.28
2006	3	1428	521	516	17.88
2007	24	6212	2267	2245	18.57
2008	45	15662	5717	5659	19.28
2009	70	29501	10768	10660	20.00
2010	87	42395	15474	15319	20.73
2011	87	49938	18227	18045	21.49
2012	87	51450	18779	18591	22.25
2013	87	49832	18189	16057	23.04
2014	102	49984	18244	15961	23.83
2015	106	45830	16728	14861	24.64
Sub.	58	28575	125160	118158	22.21
Rem.	104	39983	277282	233342	31.16
Tot.	**86**	**35567**	**402442**	**351500**	**28.38**

REVENUE AND EXPENSE FORECAST

	Revenue Before Burdens			Royalty Burdens Pre-Processing		Gas Processing Allowance		Total Royalty After Process.	Net Revenue After Royalty	Operating Expenses			Other Expenses			Net Prod'n Revenue
Year	Working Interest MM$	Royalty Interest MM$	Company Total MM$	Crown MM$	Other MM$	Crown MM$	Other MM$	MM$	MM$	Fixed MM$	Variable MM$	Total MM$	Mineral Tax MM$	Capital Tax MM$	NPI Payment MM$	MM$
2004	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	7	0	7	0	0	0	0	0	7	5	0	5	0	0	0	2
2006	9	0	9	0	0	0	0	0	9	9	0	9	0	0	0	1
2007	42	0	42	0	0	0	0	0	42	19	3	22	0	0	0	20
2008	110	0	110	1	0	0	0	1	109	44	7	50	0	0	0	59
2009	215	0	215	2	0	0	0	2	213	64	12	76	0	0	0	137
2010	321	0	321	3	0	0	0	3	318	78	17	94	0	0	0	223
2011	392	0	392	4	0	0	0	4	388	84	19	102	0	0	0	286
2012	418	0	418	4	0	0	0	4	414	84	19	103	0	0	0	311
2013	419	0	419	49	0	0	0	49	370	88	19	107	0	0	0	263
2014	435	0	435	54	0	0	0	54	380	105	21	126	0	0	0	254
2015	412	0	412	46	0	0	0	46	366	108	21	129	0	0	0	237
Sub.	2780	0	2780	165	0	0	0	165	2615	686	137	824	0	0	0	1792
Rem.	8639	0	8639	1372	0	0	0	1372	7267	2070	386	2456	0	0	0	4811
Tot.	**11419**	**0**	**11419**	**1537**	**0**	**0**	**0**	**1537**	**9882**	**2756**	**523**	**3279**	**0**	**0**	**0**	**6603**
Disc	2647	0	2647	282	0	0	0	282	2366	649	125	774	0	0	0	1592

	Other Income		Aband. Costs	Oper. Income	Net Capital Investment				Before Tax Cash Flow			Income Tax	After Tax Cash Flow		
Year	Other MM$	ARTC MM$	MM$	MM$	Dev. MM$	Plant MM$	Tang. MM$	Total MM$	Annual MM$	Cum. MM$	10% Dcf MM$	MM$	Annual MM$	Cum. MM$	10% Dcf MM$
2004	0	0	0	0	0	0	11	11	-11	-11	-10	0	-11	-11	-10
2005	0	0	0	2	9	0	0	9	-7	-17	-16	0	-7	-17	-16
2006	0	0	0	1	52	0	90	142	-141	-159	-127	0	-141	-159	-127
2007	0	0	0	20	55	0	75	130	-110	-269	-206	0	-110	-269	-206
2008	0	0	0	59	67	0	116	183	-124	-392	-287	0	-124	-392	-287
2009	0	1	0	138	45	0	154	199	-62	-454	-323	0	-62	-454	-323
2010	0	1	0	224	0	0	138	138	86	-368	-277	28	57	-397	-292
2011	0	1	0	286	0	0	75	75	211	-157	-173	54	158	-239	-215
2012	0	1	0	311	0	0	0	0	311	155	-35	71	240	1	-108
2013	0	1	0	264	55	0	22	77	186	341	40	57	129	130	-56
2014	0	1	0	255	68	0	27	96	159	500	99	54	105	236	-17
2015	0	1	0	238	74	0	30	104	134	634	144	47	87	323	12
Sub.	0	4	0	1796	425	0	737	1162	634	634	144	311	323	323	12
Rem.	0	10	31	4790	518	0	208	726	4064	4698	791	1314	2750	3072	450
Tot.	**0**	**13**	**31**	**6586**	**943**	**0**	**944**	**1888**	**4698**	**4698**	**791**	**1626**	**3072**	**3072**	**450**
Disc	0	3	3	1592	323	0	478	800	791	791	791	341	450	450	450

AFTER TAX ANALYSIS

Year Year	Total Field Revenue MM$	Gather System Revenue MM$	Other Resource Revenue MM$	Prod'n Royalty Deduct. MM$	Field Oper. Expense MM$	Gather System Oper. Expense MM$	Field Process Fee MM$	Over-head MM$	Field Depreciation Balance MM$	Field Depreciation Annual MM$	Gather System Depreciation Balance MM$	Gather System Depreciation Annual MM$	Total Annual Depr. MM$
2004	0	0	0	0	0	0	0	0	11	0	0	0	0
2005	7	0	0	0	5	0	0	0	11	0	0	0	0
2006	9	0	0	0	9	0	0	0	101	0	0	0	0
2007	42	0	0	0	22	0	0	0	175	0	0	0	0
2008	110	0	0	1	50	0	0	0	291	5	0	0	5
2009	215	0	0	2	76	0	0	0	440	86	0	0	86
2010	321	0	0	3	94	0	0	0	492	106	0	0	106
2011	392	0	0	3	102	0	0	0	461	106	0	0	106
2012	418	0	0	4	103	0	0	0	355	89	0	0	89
2013	419	0	0	49	107	0	0	0	288	69	0	0	69
2014	435	0	0	54	126	0	0	0	246	58	0	0	58
2015	412	0	0	46	129	0	0	0	218	51	0	0	51
Sub.	2780	0	0	161	824	0	0	0	218	569	0	0	569
Rem.	8639	0	0	1363	2483	0	0	0	11	366	0	0	366
Tot.	**11419**	**0**	**0**	**1524**	**3306**	**0**	**0**	**0**	**11**	**936**	**0**	**0**	**936**
Disc	2647	0	0	278	777	0	0	0	172	336	0	0	336

Year	Non-Resource Allow. Revenue MM$	Income for Resource Allow. MM$	Resource Allow. MM$	Allowed Royalty Deduct. MM$	Non-Cash Write -off MM$	COGPE Balance MM$	COGPE Wrtoff MM$	CDE Balance MM$	CDE Wrtoff MM$	CEE Balance MM$	CEE Wrtoff MM$	Total CDE,CEE & COGPE Wrtoff MM$	Net Income for Depl. MM$
2004	0	0	0	0	0	0	0	18	0	0	0	0	0
2005	0	2	0	0	0	0	0	27	1	0	0	1	0
2006	0	1	0	0	0	0	0	77	1	0	0	1	0
2007	0	20	0	0	0	0	0	131	20	0	0	20	0
2008	0	54	0	0	0	0	0	178	54	0	0	54	0
2009	0	52	0	0	0	0	0	170	51	0	0	51	1
2010	0	118	0	0	0	0	0	119	36	0	0	36	82
2011	0	180	0	0	0	0	0	83	25	0	0	25	155
2012	0	222	0	0	0	0	0	58	18	0	0	18	205
2013	0	194	0	0	0	0	0	96	29	0	0	29	166
2014	0	197	0	0	0	0	0	136	41	0	0	41	156
2015	0	187	0	0	0	0	0	169	51	0	0	51	136
Sub.	0	1226	0	0	0	0	0	169	325	0	0	325	901
Rem.	0	4428	0	0	0	0	0	11	629	0	0	629	3799
Tot.	**0**	**5654**	**0**	**0**	**0**	**0**	**0**	**11**	**953**	**0**	**0**	**953**	**4700**
Disc	0	1256	0	0	0	0	0	95	269	0	0	269	986

Year	Allow-able Earned Depl. MM$	Non-Depl. Other Income MM$	Net Resource Profit MM$	Federal Taxable Income MM$	Federal Income Tax MM$	Taxable Crown Payments MM$	Non-Deduct. Resource Allow. MM$	Provincial Taxable Income MM$	Provincial Income Tax MM$	Invest -ment Credit MM$	Total Income Tax MM$	Net Cash Flow After Income Tax Annual MM$	Net Cash Flow After Income Tax Cum. MM$	Net Cash Flow After Income Tax 10% Dcf Cum. MM$
2004	0	0	0	0	0	0	0	0	0	0	0	-11	-11	-10
2005	0	0	0	0	0	0	0	0	0	0	0	-7	-17	-16
2006	0	0	0	0	0	0	0	0	0	0	0	-141	-159	-127
2007	0	0	0	0	0	0	0	0	0	0	0	-110	-269	-206
2008	0	0	0	0	0	0	0	0	0	0	0	-124	-392	-287
2009	0	0	1	1	0	0	0	0	0	0	0	-62	-454	-323
2010	0	0	82	82	18	0	0	82	10	0	28	57	-397	-292
2011	0	0	155	155	34	0	0	155	19	0	54	158	-239	-215
2012	0	0	205	205	45	0	0	204	26	0	71	240	1	-108
2013	0	0	166	166	37	0	0	165	21	0	57	129	130	-56
2014	0	0	156	156	35	0	0	156	19	0	54	105	236	-17
2015	0	0	136	136	30	0	0	136	17	0	47	87	323	12
Sub.	0	0	901	901	199	0	0	897	112	0	311	323	323	12
Rem.	0	0	3799	3799	840	0	0	3790	474	0	1314	2750	3072	450
Tot.	**0**	**0**	**4700**	**4700**	**1040**	**0**	**0**	**4687**	**586**	**0**	**1626**	**3072**	**3072**	**450**
Disc	0	0	986	986	218	0	0	983	123	0	341	450	450	450

RESERVE SUMMARY

Product	Units	Remaining Reserves at January 1, 2004: Working Interest	Roy/NPI Interest	Total Company	Net	Oil Equivalents: BOE Factor	Company Mstb	% of Total	Reserve Life Indic. (yr): Reserve Life	Life Index	Half Life
Heavy Oil	Mstb	402442	0	402442	351500	1.000	402442	100	31.0	100.0	16.1
Total Oil Eq.	Mstb	402442	0	402442	351500		402442	100	31.0	0.0	16.1

PRODUCT REVENUE AND EXPENSES

Product	Units	Average First Year Unit Values: Base Price	Price Adjust.	Wellhead Price	Net Burdens	Operating Expenses	Other Expenses	Prod'n Revenue	Net Revenue After Royalties: Undisc M$	% of Total	10% Disc M$	% of Total
Heavy Oil	$/Stb	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9882456	100	2365529	100
Total Oil Eq.	$/BOE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9882456	100	2365529	100

REVENUE BURDENS AND NET PRESENT VALUE SUMMARY

Revenue Burdens (%)	Initial	Average	Disc. Rate %	Net Present Value Before Income Tax: Prod'n Revenue M$	Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE	Net Present Value After Tax: Operating Income M$	Capital Invest. M$	Cash Flow M$	Cash Flow $/BOE
Crown Royalty	0.0000	13.4596	0.0	6603027	6585678	1887587	4698091	11.67	4960086	1887587	3072499	7.63
Non-crown Royalty	0.0000	0.0000	5.0	3043581	3040178	1166823	1873355	4.65	2338214	1166823	1171391	2.91
Mineral Tax	0.0000	0.0000	8.5	1910651	1910018	888227	1021791	2.54	1491272	888227	603045	1.50
NPI Payment	0.0000	0.0000	10.0	1591749	1591670	800394	791276	1.97	1250640	800394	450246	1.12
			12.0	1265602	1265958	703677	562281	1.40	1002995	703677	299318	0.74
			15.0	922140	922784	590789	331995	0.82	739866	590789	149077	0.37
			20.0	578420	579132	458660	120472	0.30	472845	458660	14186	0.04

Project.......1046350
Entity.......Total With Adjustments (PPP Undeveloped)
Run date....Thu Jun 10'2004 11:44:44
Evaluator...Laustsen, Dana B.

LEASE 24/PERMIT 70 GEOLOGICAL MODELING AND EVALUATION OF BITUMEN POTENTIAL

Submitted to:
DEER CREEK ENERGY LIMITED

December 2, 2003
(Updated April 30, 2004)

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NORWEST
CORPORATION

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1 SUMMARY

Deer Creek Energy Limited (Deer Creek) retained Norwest Corporation (Norwest) in June of 2003 to develop a geologic model of the oil sand resources underlying Oil Sands Lease No. 24 and Oil Sands Permit No. 70.

Lease 24/Permit 70 lies along and west of the Athabasca River, approximately 70 km north of Fort McMurray in northeast Alberta. Lease 24 includes approximately 78 sections (19,976 hectares) in Townships 94 to 96, Ranges 10 to 12 W4, Permit 70 includes 6 sections (1,536 hectares) in Townships 95 and 96, Range 13 W4. (Figure 1).

Bitumen resources within this area are contained within the Lower Cretaceous McMurray Formation and may be suitable for extraction by either surface mining or SAGD methods. The geologic model was developed to support engineering evaluations of the potential to recover bitumen resources through either surface mining or SAGD processes. Two 3-D geological "gridded-seam grade" models were constructed using data from 425 drill holes completed up to and including 2003. One model was constructed using surface mining criteria and the other model was constructed using SAGD criteria.

The surface mineable and SAGD areas within Oil Sands Lease No. 24 and Oil Sands Permit No. 70 are outlined on the Resource Map in Appendix A.

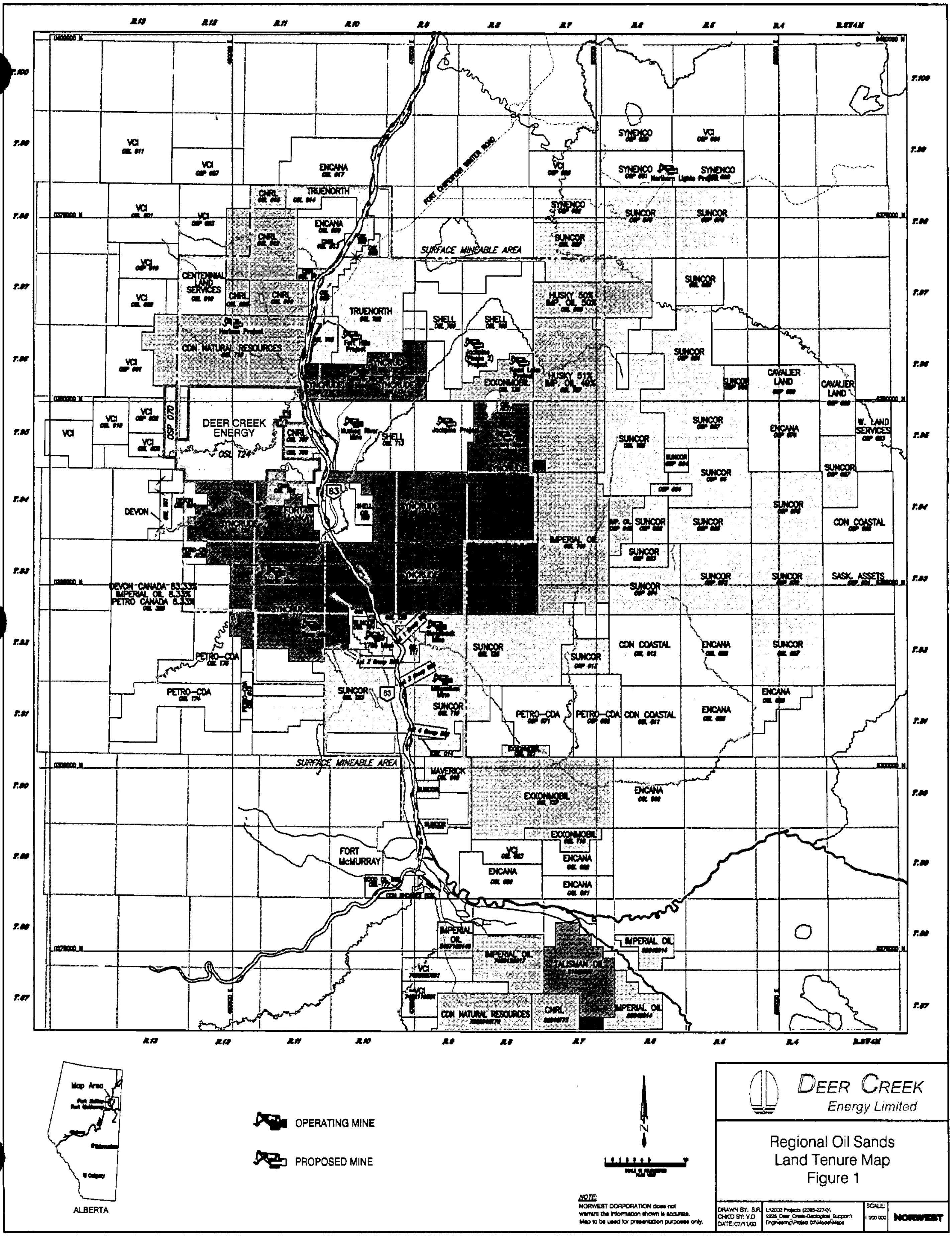
The geologic model constructed using first level surface mining criteria, including minimum ore grade of 7% bitumen by weight and minimum ore thickness of 3 metres, provided an estimate of 8.0 million barrels of in-place bitumen. Application of additional industry-accepted constraints, including consideration of TV:BIP, deposit continuity and mining offsets of 100m from the edge of the Athabasca River and other deeply incised waterways, resulted in an estimate of 3.0 billion barrels of in-place bitumen suitable for evaluation for recovery using surface mining methods.

The model constructed using SAGD criteria provided by Deer Creek indicated that 1.1 to 2.1 billion barrels of bitumen in-place were suitable for evaluation for recovery using in-situ processes. 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 of 15% non-pay material in the SAGD zone.

Additional data will be required to advance the evaluation of the resource potential of Lease 24 and Permit 70. For the surface mineable areas, more resource, fines, and overburden data are necessary. For the purposes of this report, the SAGD area has been defined in areas that do not appear to be attractive as mining targets. At this time the boundary between mineable and SAGD areas is a first-pass and requires more analysis to provide strategic direction with respect to an optimal development approach.

SAGD areas A, B and C have been drilled to a degree of density that provides reasonable confidence in the resource estimate. Further drilling in these areas followed by detailed analysis of the SAGD potential is recommended. Area E has a drilling density of less than 1 hole per section, and although present drilling indicates the potential for significant in-place resources, additional drilling will be required to establish this area as a valid primary target.

This report includes recommendations for essential field testing including additional core drilling and gathering of fines data. A cost comparison study evaluating the SAGD production method verses surface mining is also recommended to address all areas where either method may be applied. Dilution, mining losses, and recovery factors are not considered in any estimates provided in this report.



SURFACE MINEABLE AREA
FORT CHIPEWYAN WINTER ROAD
DEER CREEK ENERGY
OSL 724
SYNCRUDE
SUNCOR
SYNENCO
VCI
ENCANA
TRUENORTH
CNRL
CENTENNIAL LAND SERVICES
CDN NATURAL RESOURCES
Horizon Project
SHELL
HUSKY 50% IMP. OIL 50%
HUSKY 51% IMP. OIL 49%
EXXONMOBIL
CAVALIER LAND
W. LAND SERVICES
DEVON
DEVON CANADA 83.33% IMPERIAL OIL 8.33% PETRO CANADA 8.33%
IMPERIAL OIL
CDN COASTAL
SASK. ASSETS
PETRO-CDA
MAVERICK
FORT McMURRAY
TALISMAN OIL
Northern Lights Project
Jackpine Project
Muskeg River Mine
Fort Hills Project
FORT MacKAY
OPERATING MINE
PROPOSED MINE
ALBERTA
Map Area
DEER CREEK Energy Limited
Regional Oil Sands Land Tenure Map
Figure 1
NOTE:
NORWEST CORPORATION does not warrant the information shown is accurate. Map to be used for presentation purposes only.
DRAWN BY: S.R.
CHK'D BY: V.O.
DATE: 07/11/03
SCALE:
1:200 000
NORWEST

2 SOURCES OF DATA

Deer Creek Energy was the main source of information used in the Norwest work. They provided geologic facies, core analysis data, and geophysical logs. Additional geophysical logs and core analysis data for drill holes around the perimeter of Lease 24 were obtained through a public well data service. The conceptual stratigraphic model established by Deer Creek provided an important component for the modeling process.

The total number of drill holes used in the geologic modeling effort is 425. These data are suitable for either surface mining or SAGD evaluations. The locations of the drill holes are shown on the Resource Map in Appendix A. Drill hole information used in Norwest's assessment comprised:

- Geologic facies and stratigraphic data;
- Dean Stark analyses that provide reliable ore grade data; and
- Good quality geophysical logs

In order to assist Deer Creek in their subsequent evaluation of Lease 24 and Permit 70 with respect to both surface mining and SAGD potential, Norwest undertook the task of identifying ore zones to be used in the model building process. Four distinct ore zones were defined and correlated over the entire lease area. Norwest met with Deer Creek representatives to confirm the ore zone picks and correlations.

Drill hole collar elevations were checked by comparison with digital topography obtained from Altalis Ltd. Individual survey values were found to vary by as much as 6m to 9m from topography. In most cases, however, the survey values were within 1m to 2m of the topographic values. For the purpose of modeling the ground surface between drill holes, the collar elevations were adjusted to match the topographic elevations at each site.

3 BITUMEN RESOURCE ESTIMATION

Bitumen resource estimation was based on two geological models constructed for the study area. One model was built using the mining criteria described in Section 3.1 and another model was built using the SAGD criteria described in Section 3.2. Norwest reviewed each of the 425 drill holes that formed the framework for the models, correlating the ore zones identified in each. Where ore grade data were absent such as in lost core intervals, grades were estimated using the geophysical logs. Ore grade data were depth-adjusted where necessary to facilitate accurate correlation between core analyses and geophysical logs.

Four ore zones were defined for the purposes of geological modeling:

- Kml Lower Ore: Lower McMurray fluvial sands
- Kml Upper Ore: Lower McMurray fluvial sands
- Kmm Lower Ore: Middle McMurray Estuarine sands
- Kmm Upper Ore Middle McMurray Estuarine sands

These ore zones are contained within the Lower Cretaceous McMurray Formation. Isopach maps of all the geologic units as well as maps of TV:BIP, bitumen-in-place and resource distribution were prepared and provided to Deer Creek. Key maps, as listed below, are included in Appendix A of this report:

- Resource Map
- Quaternary Isopach
- Km Isopach
- Devonian Structure
- Average Mineable Grade
- Average SAGD Grade
- TV:BIP
- Bitumen-in-Place (Mineable)
- Bitumen-in-Place (SAGD; 15m minimum zone thickness)

A "gridded seam" modeling approach was used for both resource models. The ore zones were subdivided into variable-thickness layers, constructed such that no single layer exceeded 1m thickness. This assisted in preserving vertical grade resolution within each ore zone and allowed for ore/waste discrimination at 1m resolution for the SAGD Model. Ore grade was interpolated within each layer, between drill holes, using an inverse-distance relationship.

Horizontal block size within both models was set at 100m by 100m, resulting in a total of approximately 1.3 million variable-height blocks, each populated with a bitumen grade determined from the gridded seam interpolation operation. Within the resulting surface mineable model, ore/waste discrimination was followed by TV:BIP and strip ratio calculations. Within the resulting SAGD model, ore/waste discrimination was followed by continuous SAGD zone thickness calculations and pay/non-pay ratio calculations.

The term "TV:BIP" describes the ratio of total volume to the volume of contained bitumen. It is calculated by dividing the total of the ore-plus-waste volume by the volume of contained bitumen. Strip ratio, on the other hand, provides a measure of the relationship between waste and ore volumes and does not reflect the ore grade. It is calculated by dividing the waste volume by the ore volume.

3.1 RESOURCES SUITABLE FOR EVALUATION AS MINEABLE RESERVES

Resources in the mining model were estimated using a minimum grade for ore of 7% and a minimum ore or waste unit thickness of 3m.

The estimation of in-place resources suitable for evaluation as surface mineable reserves proceeded through four steps. Each of these progressively imposed more limiting constraints. The criteria that were generally applied in each step are described as follows:

Step 1 provided a "First level" estimate:

- In-place material with a grade equal to or exceeding 7% bitumen by weight; and
- Minimum thickness of ore or waste unit is 3 meters.

Step 2 provided a "Second level" estimate:

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

Step 3 provided a "Third level" estimate:

- Deposit continuity reasonable for mining (This includes small areas of TV:BIP>12 within the mining areas.) ; and
- Setback of 100m from the edge of deeply incised waterways.

Step 4 provided a "Fourth level" estimate:

- Bitumen contained within the area proposed to be produced using surface mining methods. This includes small areas of TV:BIP>12 within the mining areas.

The following factors were used in the calculation of resources:

Density of oil sands or waste material:	2.08 tonnes/m^3
Density of bitumen:	1.0122 tonnes/m^3
One barrel bitumen (42 US gal):	0.158987 m^3

Summaries of the estimated in-place bitumen resources by level, as described above, are shown in the following tables.

TABLE 1
IN-PLACE RESOURCES SUITABLE FOR EVALUATION AS SURFACE MINEABLE RESERVES
FIRST LEVEL

Area	Million Barrels	Ore (M tonnes)	Waste (M tonnes)	Grade* (wt% bit)
Lease 24/Permit 70	7,968	12,114	24,485	10.6

*weighted average

TABLE 2
IN-PLACE RESOURCES SUITABLE FOR EVALUATION AS SURFACE MINEABLE RESERVES
SECOND LEVEL

Area		Million Barrels	Ore (M Tonnes)	Waste (M Tonnes)	Grade* (wt% bit)	TV:BIP
Mineable Area	1	1,149	1,793	1,725	10.3	9.3
	2	258	380	407	10.9	9.3
	3	53	83	112	10.3	11.1
	4	119	204	204	9.4	10.3
	5	21	34	43	10.1	10.8
	6	163	246	190	10.7	8.1
	7	55	78	89	11.4	9.2
	8	921	1,350	1,544	11.0	9.5
	9	34	57	48	9.7	9.2
	Subtotal	**2,773**	**4,223**	**4,360**	**10.6**	**9.4**
In-Situ Area	10	133	197	189	10.9	8.8
	11	275	401	560	11.0	10.6
	12	84	132	164	10.3	10.6
	13	29	42	67	11.3	11.2
	14	203	295	445	11.1	11.0
	15	114	190	228	9.7	11.0
	Subtotal	**838**	**1,257**	**1,654**	**10.8**	**10.4**
Rivers	16	58	89	62	10.5	7.8
	17	35	58	48	9.9	9.0
	18	112	171	69	10.6	6.5
	Subtotal	**205**	**318**	**178**	**10.4**	**7.3**
Other Areas ("islands" not labeled)		**177**				
TOTAL		**3,993**				

*weighted average

Application of the third level criteria resulted in further refinement of the in-place resources suitable for evaluation as surface mineable reserves within Lease 24, as summarized in Table 3. The total resource estimated at the third level includes small areas of TV:BIP >12 within the larger potentially mineable regions. These areas are identified in Table 3 and shown on the Resource Map in Appendix A.

TABLE 3
IN-PLACE RESOURCES SUITABLE FOR EVALUATION AS SURFACE MINEABLE RESERVES
THIRD LEVEL

	Area	Million Barrels		Ore (M Tonnes)	Waste (M Tonnes)	Grade* (wt% bit)	TV:BIP
		TV:BIP≤12	TV:BIP>12				
Mineable Area	1	1,149		1,793	1,725	10.3	9.3
	1a		44	76	144	9.5	14.8
	1b		53	88	165	9.7	14.2
	1c		4	7	12	10.4	12.6
	1d		16	25	44	10.4	12.9
	1e		30	49	94	9.9	14.3
	Total Area 1	1,296					
		258		380	407	10.9	9.3
	2a		18	28	51	10.3	13.1
	2b		19	31	52	10.2	12.7
	Total Area 2	295					
	3	53		83	112	10.3	11.1
	4	119		204	204	9.4	10.3
	5	21		34	43	10.1	10.8
	6	163		246	190	10.7	8.1
	7	55		78	89	11.4	9.2
	8	921		1,350	1,544	11.0	9.5
	8a		5	8	15	11.2	12.8
	Total Area 8	926					
	9	34		57	48	9.7	9.2
	Subtotal	**2,773**		**4,223**	**4,360**	**10.6**	**9.4**
			189	**312**	**577**	**9.9**	**14.0**
	Total	**2,962**		**4,535**	**4,937**	**10.5**	**9.7**
In-Situ Area	10	133		197	189	10.9	8.8
	11	275		401	560	11.0	10.6
	12	84		132	164	10.3	10.6
	13	29		42	67	11.3	11.2
	14	203		295	445	11.1	11.0
	14a		4	6	12	11.9	12.5
	Total Area 14	205					
	15	114		190	228	9.7	11.0
	15a		7	11	47	10.3	25.2
	Total Area15	121					
	Subtotal	**838**		**1,257**	**1,654**	**10.8**	**10.4**
			11	**17**	**59**	**10.9**	**20.6**
	Total	**849**		**1,274**	**1,713**	**10.8**	**10.6**
TOTAL		**3,611**	**200**				
		3,811		**5,809**	**6,650**	**10.6**	**9.9**

Application of the fourth level criteria resulted in further refinement of the in-place resources suitable for evaluation as surface mineable reserves within Lease 24, as summarized in Table 4. The total resource estimated at the fourth level includes small areas of TV:BIP >12 within the larger potentially mineable regions. These areas are identified in Table 4 and shown on the Resource Map in Appendix A.

TABLE 4
IN-PLACE RESOURCES SUITABLE FOR EVALUATION AS SURFACE MINEABLE RESERVES
FOURTH LEVEL

	Area	Million Barrels		Ore (M Tonnes)	Waste (M Tonnes)	Grade* (wt% bit)	TV:BIP
		TV:BIP≤12	TV:BIP>12				
Mineable Area	**1**	1,149		1,793	1,725	10.3	9.3
	1a		44	76	144	9.5	14.8
	1b		53	88	165	9.7	14.2
	1c		4	7	12	10.4	12.6
	1d		16	25	44	10.4	12.9
	1e		30	49	94	9.9	14.3
	Total Area 1	1,296					
		258		380	407	10.9	9.3
	2a		18	28	51	10.3	13.1
	2b		19	31	52	10.2	12.7
	Total Area 2	295					
	3	53		83	112	10.3	11.1
	4	119		204	204	9.4	10.3
	5	21		34	43	10.1	10.8
	6	163		246	190	10.7	8.1
	7	55		78	89	11.4	9.2
	8	921		1,350	1,544	11.0	9.5
	8a		5	8	15	11.2	12.8
	Total Area 8	926					
	9	34		57	48	9.7	9.2
	Subtotal	**2,773**		**4,223**	**4,360**	**10.6**	**9.4**
			189	**312**	**577**	**9.9**	**14.0**
	Total	**2,962**		**4,535**	**4,937**	**10.5**	**9.7**

*weighted average

The study area, drill holes, and extent of the estimated in-place resources within Lease 24, are shown on the Resource Map in Appendix A. The resources are apportioned into two areas, labelled Surface Mineable and SAGD on the figure. The Mineable and SAGD areas are divided into sub-areas to allow for calculation of different production alternatives. These areas are labelled on the map and tabulated individually in the included tables.

3.2 RESOURCES SUITABLE FOR EVALUATION AS SAGD RESERVES

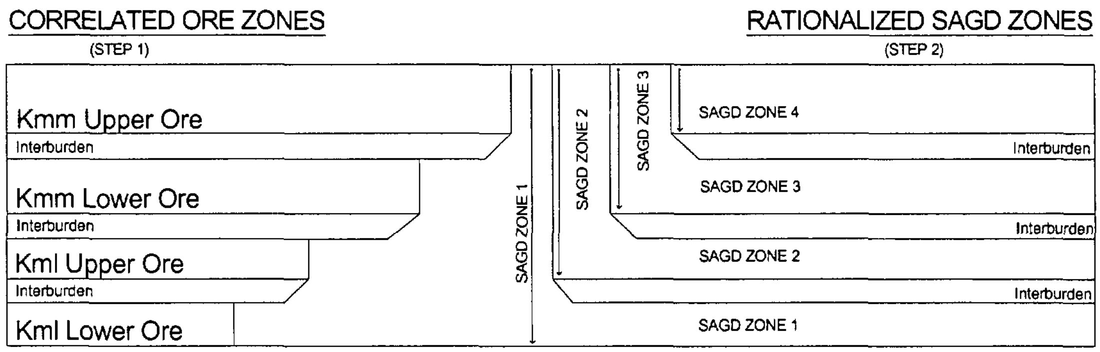
The estimation of in-place resources suitable for evaluation as SAGD reserves was completed in two levels. The first level estimate was more liberal, while the second level estimate imposed more limiting constraints. To estimate barrels contained within the SAGD zones, the following procedure was followed:

1. Potential SAGD zones were identified and correlated between drillholes. These zones were identified as being any zone of continuous ore grade with no occurrence of laterally continuous strata that would inhibit the migration of steam during SAGD extraction. Starting at the base of the sequence and working upward, they were named Kml Lower Ore, Kml Upper Ore, Kmm Lower Ore, and Kmm Upper Ore. Potential steam inhibiting strata identified in more than 1 drill hole were separated out and correlated across the model area as interburden zones.

   Interburden is defined as material that lies between two SAGD zones and does not meet the minimum pay criteria. It is a minimum of 1m thick, consists of primarily muddy facies, and is considered to be a potential barrier to steam migration.

   Material must have bitumen content equal to or exceeding 8wt% over a minimum of 1m to be counted as pay. Small amounts of non-pay material that are not correlated as interburden zones are included within the defined SAGD zones; they are interpreted as not being potential barriers to steam migration. They are either laterally discontinuous or they are just below the 8% cut-off grade and are part of a relatively permeable sandy facies. These non-pay blocks are contained within the SAGD zone but do not contribute to the SAGD resource total. A minimum thickness criteria for the SAGD zones was not applied in the first step. This allowed for continuous correlation of the zones across the property, regardless of thickness.

2. A rationalization was conducted to merge multiple SAGD zones together where the thickness of interburden between them was less than 1m. Where this occurred the SAGD zones were treated as one zone in the resource estimate. The four rationalized SAGD zones are not the same as the four ore zones that were correlated in step 1. The rationalized zones were accumulated from bottom (Zone 1) to top (Zone 4) in a column by column basis within the block model. Anywhere the interburden between two zones was less than 1m, the upper zone was merged with the lower zone. In Table 5, SAGD Zone 1 contains all barrels of bitumen from Kml Lower Ore. It may also contain barrels of bitumen from zones initially correlated as Kml Upper Ore, Kmm Lower Ore, or Kmm Upper Ore. The same procedure was used for SAGD zones 2, 3 and 4. This procedure ensured that no bitumen that met the stated SAGD criteria was omitted or double counted in the resource estimation process.



3. Volumes for the level 1 estimate were calculated by summing all pay blocks contained within the defined SAGD zones that met or exceeded 15m thickness.

4. Volumes for the level 2 estimate were calculated by summing the pay blocks contained within defined SAGD zones that contained 15% or fewer non-pay blocks, and met or exceeded 15m thickness.

Using the stated criteria, in-place resources suitable for evaluation as SAGD reserves were estimated to be:

- Level 1: 2.1 billion barrels
- Level 2: 1.1 billion barrels

These values are tabulated by area as well as by rationalized SAGD zone in Table 5.

TABLE 5
IN-PLACE RESOURCES SUITABLE FOR EVALUATION AS SAGD RESERVES

Level 1 Criteria			Level 2 Criteria		
15m thickness cutoff			Maximum 15% non-pay blocks in SAGD Zone		
Area	**SAGD Zone**	**Million Barrels**	**Area**	**SAGD Zone**	**Million Barrels**
A	1	263	A	1	152
A	2	152	A	2	86
A	3	131	A	3	69
A	4	261	A	4	154
A Total	**1+2+3+4**	**807**	**A Total**	**1+2+3+4**	**462**
B	1	157	B	1	50
B	2	39	B	2	17
B	3	166	B	3	95
B	4	140	B	4	115
B Total	**1+2+3+4**	**502**	**B Total**	**1+2+3+4**	**277**
C	1	86	C	1	63
C	2	35	C	2	8
C	3	25	C	3	23
C	4	50	C	4	24
C Total	**1+2+3+4**	**196**	**C Total**	**1+2+3+4**	**119**
D	1	231	D	1	57
D	2	4	D	2	3
D	3	146	D	3	77
D	4	115	D	4	70
D* Total	**1+2+3+4**	**495**	**D* Total**	**1+2+3+4**	**207**
E	1	310	E	1	63
E	2	10	E	2	0
E	3	97	E	3	30
E	4	200	E	4	156
E Total	**1+2+3+4**	**620**	**E Total**	**1+2+3+4**	**249**
Area Totals	**A+B+C =**	**1,505**	**Area Totals**	**A+B+C =**	**858**
	A+B+C+E =	**2,125**		**A+B+C+E =**	**1,107**
	A+B+C+D*+E=	**2,620**		**A+B+C+D*+E =**	**1,314**

*Area D is outside the Deer Creek Lease boundary
Note: Level 2 totals for Areas A and C are subject to 'rounding' effects.

4 RESOURCE COMPARISON – MINING VERSUS SAGD POTENTIAL

The distribution of both the in-place resources suitable for evaluation as surface mineable reserves and those suitable for evaluation of SAGD potential within Lease 24 and Permit 70 is shown on the Resource Map in Appendix A. The area shown on the map is divided into two portions labelled 'SAGD Area' and 'Surface Mineable Area'. The boundary was specified by Deer Creek Energy and it represents the separation of the proposed surface mining area and the proposed SAGD area. The boundary is only a first-pass at dividing the lease into areas where mining or SAGD are most likely to be the method of production and does not necessarily represent a physical or geological boundary. Since there is the potential for production of bitumen by mining some of the areas identified on the map as SAGD, the areas at TV:BIP≤12:1 are shown within the SAGD area and the volumes associated with these areas are tabulated in the corresponding charts (Tables 3 and 5).

The total resource, suitable for evaluation as surface mineable or SAGD reserves, is separated into two distinct areas as shown on the Resource Map. Resource totals apply independently to each of these areas.

To facilitate the calculation of resource volumes based on different production methods, both the surface mineable and SAGD areas have been sub-divided into smaller areas. The resource volumes for these are individually tabulated on the charts on the Resource Map as well as in Tables 3 and 5. The most notable area of overlap between mining and SAGD potential is in Mining Area 10/ SAGD Area C. For the purposes of the present report, the resources in this area have been included in the SAGD total.

5 CONCLUSIONS AND RECOMMENDATIONS

Lease 24 and Permit 70 have been explored to varying levels of detail. Our analysis of the data has identified a significant in-place resource that is suitable for evaluation as both surface mineable and SAGD reserves. Subsequent reserve calculations and classification were not included in the scope of this study.

Further evaluation of Lease 24 and Permit 70 will necessitate the acquisition of additional resource, fines, and overburden data. Primary target areas for mining include Area 1 and Area 8 which are estimated to contain in-place resources of 1.30 billion barrels and 0.93 billion barrels respectively. Detailed mine design, based on results from additional drilling, will be required to confirm these estimates, delineate ultimate pit limits and define infrastructure requirements. Areas 2, 4 and 6 are also estimated to contain significant in-place resources, of 0.30, 0.12 and 0.16 billion barrels respectively; however this is based on a limited data set. Additional drilling will be required to establish these areas as valid primary targets.

Resources suitable for evaluation as SAGD reserves are estimated to total 1.1 billion barrels in-place within the SAGD area. They have been delineated and calculated separately from the resources suitable for evaluation as surface mineable reserves. However there are areas of overlap, where recovery of the resource could be achieved through surface mining methods or through the use of SAGD technology. For the purposes of this report the SAGD area has been defined in areas that are not initially attractive as mining targets. A detailed analytical comparison between the two was not conducted; therefore the actual boundary between the mining and SAGD areas may change in the future. At this time the boundary represents a first-pass at delineating the areas that have potential to be developed using either surface mining or SAGD methods. More analysis may provide strategic direction with respect to the development approach.

SAGD areas A, B and C have been drilled to a degree of density that provides reasonable confidence in the resource estimate. Further drilling in these areas followed by detailed analysis of the SAGD potential is recommended. Area E has a drilling density of less than 1 hole per section, and although present drilling indicates the potential for significant in-place resources, additional drilling will be required to establish this area as a valid primary target.

APPENDIX A
MAPS

Surface Mineable and SAGD Resources by Area ("Resource Map")
Quaternary Isopach
Km Isopach
Devonian Structure
Average SAGD Grade
Average Mineable Grade
TV:BIP
Bitumen-in-Place (Mineable)
Bitumen-in-Place (SAGD; 15m Minimum Thickness)

DEER CREEK
Energy Limited

Joslyn Oil Sands Project
Preliminary Feasibility Study

Executive Summary

Prepared by:

Washington Group International
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7800 E. Union Ave., Suite 100
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June 2004
Updated from March 2004

Notice to Reader

This booklet is an executive summary of the Preliminary Feasibility Study for the Joslyn Oil Sands Project issued in March 2004. The table of contents from the full study has been included for reference purposes only.

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Deer Creek Energy Ltd.
Joslyn Oil Sands Project
Preliminary Feasibility Study

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(Norwest updated this report on April 30, 2004, and reissued it as *Geological Modeling and Evaluation of Bitumen Potential*)

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1.0 EXECUTIVE SUMMARY

1.1. Introduction

Deer Creek Energy Limited (Deer Creek) contracted Washington Group International Inc. (Washington Group) to prepare a Preliminary Feasibility Study for their Joslyn Oil Sands Project located near Fort McMurray, in northern Alberta. This report represents the fulfillment of that contract.

The study addresses a staged approach to reach 200,000 bbl/d bitumen capacity from mineable resources. Technologies are reviewed and selected for mine and plant. Capital and operating costs are estimated, and a economic evaluation is presented. Preliminary engineering is performed to define the project over a 30-year period and support the estimates.

Oil sands containing bitumen will be mined, using established truck and shovel methods, and processed at bitumen extraction and froth treatment facilities. Extracted and cleaned bitumen will then be blended with synthetic crude oil to meet transportation pipeline specifications. The resulting SynBit blend will be delivered via pipeline to the heavy oil terminal in Hardisty, Alberta for sale.

1.1.1. General

Nearly all of the oil resources in Alberta are associated with oil sands deposits. Table 1-1 compares Alberta's conventional crude oil reserves with those derived from oil sands (taken from Alberta Energy and Utility Board Statistical Series 2003-98).

Table 1-1
Alberta's Energy Resources (AEUB; December 2002)

Billion Barrels	Crude Oil	Oil Sands (bitumen)
Initial Volume In-Place	62.0	1,631
Remaining Established	1.6	174
Remaining Ultimate Potential	19.7	315

Production of bitumen from oil sands began in 1967 as the Great Canadian Oil Sands Ltd. (GCOS) became the first commercially successful operation in the oil sands industry. In 1979 GCOS was renamed Suncor, Inc. Syncrude, which is now the world's largest producer of crude oil from oil sands, started production in 1973. A number of other major projects are currently under development. The Joslyn Project is one of such projects and is located on Figure 1-1.

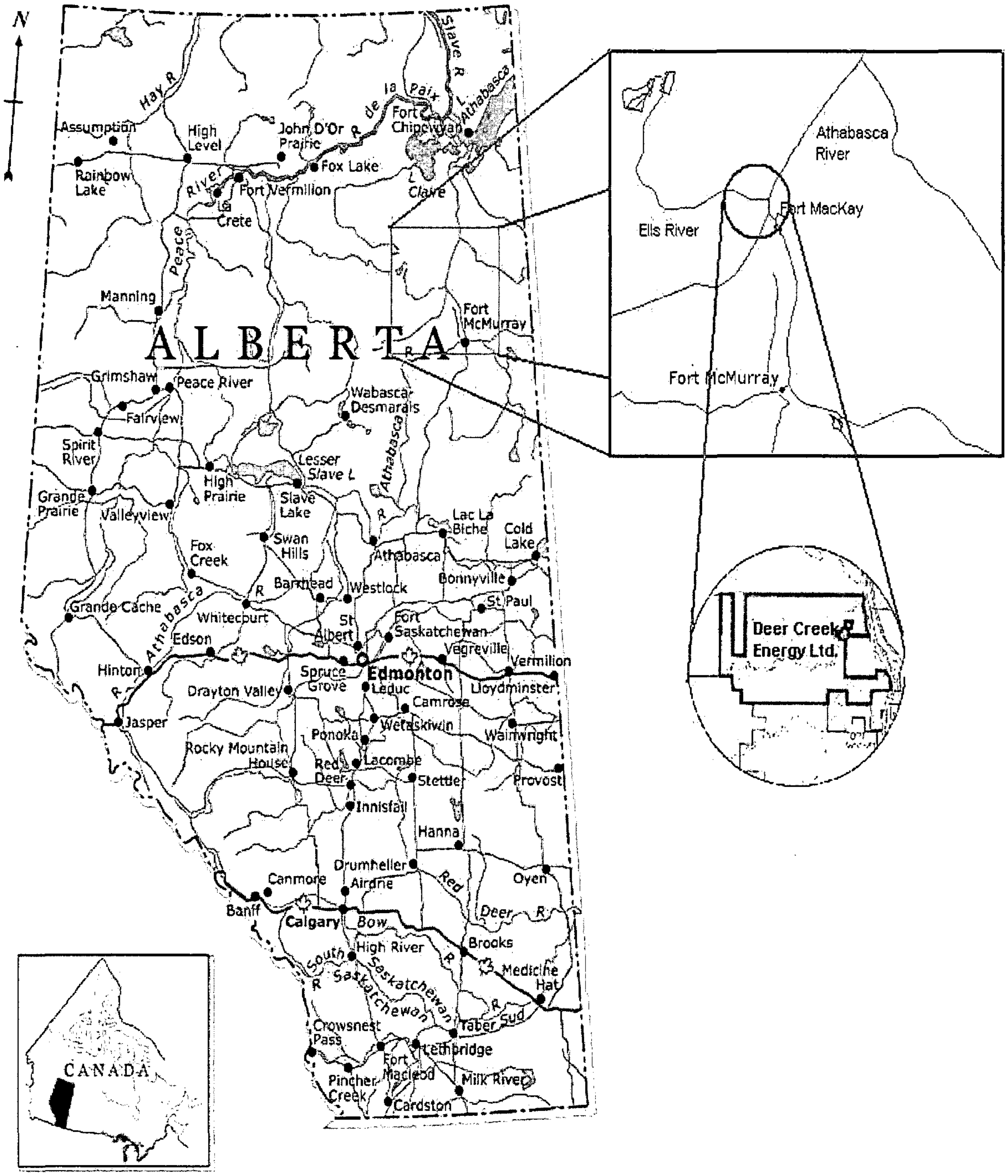


Figure 1-1
Location Map

1.1.2. Corporate Profile and Project History

Deer Creek is a private Calgary based company and began its involvement with in-situ oil sands development efforts in 1998 by acquiring the Joslyn lease from Talisman Energy Inc. The in-situ method for recovery of oil from oil sands is called steam assisted gravity drainage or SAGD. The method is designed to recover deep, confined reserves by drilling two parallel horizontal wells beneath the ore formation, injecting high pressure steam through the upper well to heat the bitumen so that it will flow by gravity to the collection pipe (lower well) and pumping the bitumen/water mixture to the surface for processing.

Deer Creek holds an 84 percent working interest in the property and is the operator of the project. Enerplus Resources Fund has a 16 percent working interest. The oil sands lease is located in the Joslyn Creek area, approximately 70 kilometers north of Fort McMurray, Alberta. More than 21,000 hectares of land make up Oil Sands Lease No. #7280060T24 (OSL 24), which is located in Townships 94, 95, 96; Ranges 11, 12, 13 W4M. A lease map including OSL 24 is shown on Figure 1-2, which also locates operating and proposed oil sands mines.

Since acquiring the lease, Deer Creek has conducted SAGD pilot projects and four exploration programs. Also several geologic and scoping studies have been undertaken for Deer Creek, which are listed in Section 1.1.4 and in Section 2. Several of these studies are directed particularly to developing mineable oil sands.

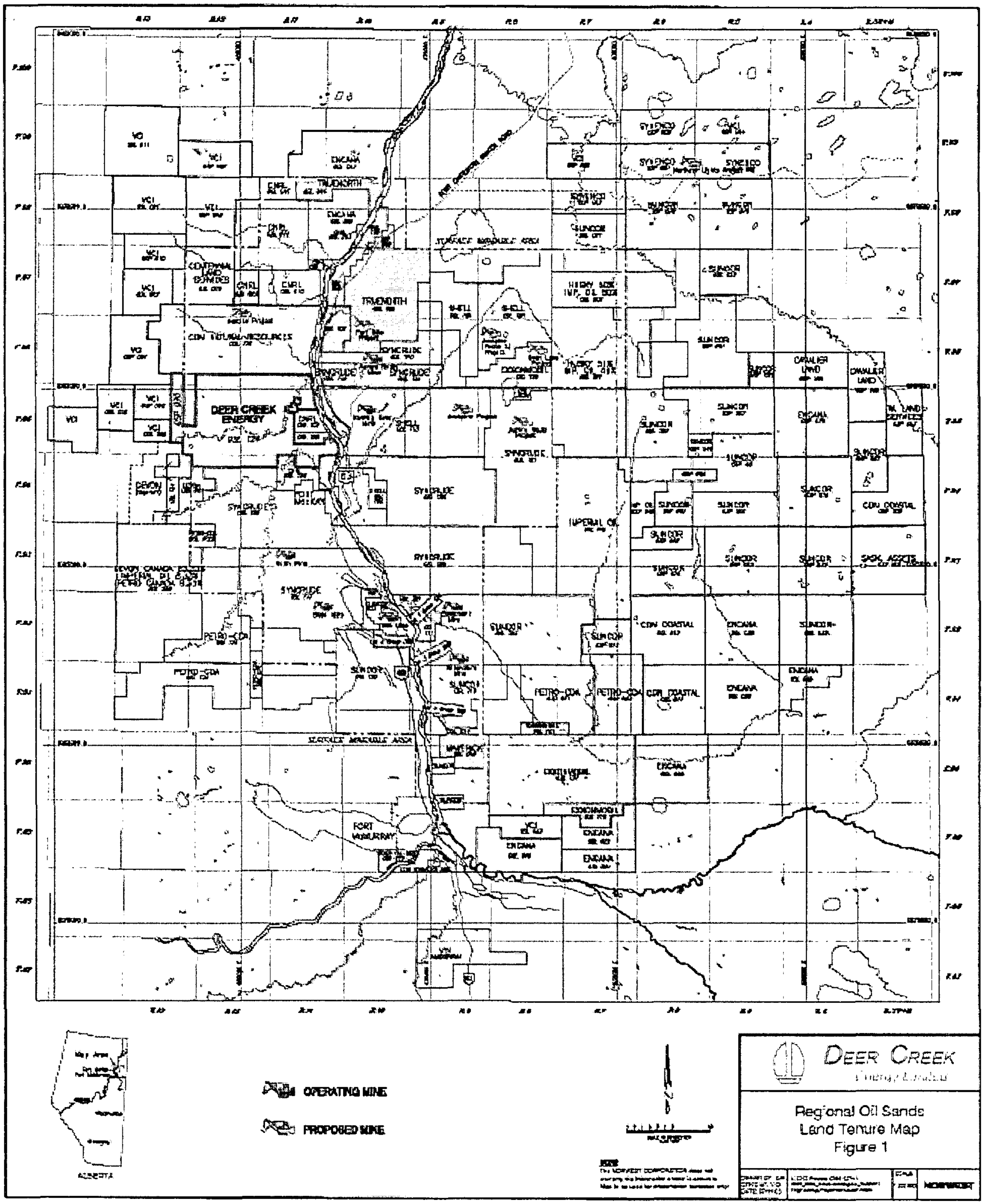


Figure 1- 2 Oil Sands Leases and Permits

1.1.3. Scope of the Study

A significant portion, of oil sands resources are recoverable by open pit mining methods. Mining of oil sands has advantages over SAGD methods, when economics allow, as mining achieves much higher overall resource utilization and bitumen recovery.

In October 2003, Deer Creek entered into an agreement with Washington Group to prepare a Preliminary Feasibility Study to investigate the economics for the development of a bitumen mine, processing facilities and infrastructure for mineable deposits on Lease 24. The study was to be evaluated independent of the SAGD operations, currently being developed, to establish a base case for the mining project. Deer Creek and selected consultants continue to investigate and identify potential synergies for future planning exercises.

The primary objective of the study was to investigate the economics of constructing an ultimate 200,000 bbl bitumen/day open pit oil sands mine, processing facilities and infrastructure in stages, to minimize the initial capital cost. The first task was to determine an economic production stage that would yield positive cash flow to fund the subsequent stages required to meet the full production target. In addition to size, Washington Group was asked by Deer Creek to review the current technology and to identify potential opportunities for improving operating efficiency and reducing capital and operating costs.

During the course of the study, a train size of 50,000 bbl/day was selected, requiring a total of four trains to be constructed to achieve the ultimate production rate. The production schedule developed for the project is summarized in Table 1-2 and allows for a 30-year mine life and construction of the four trains at three-year intervals.

Table1-2
Project Timeline for Phased Production

Year	Trains	Production Rate (bpd)
0	None	Preproduction
1	1	30,000
2	1	50,000
3	1	50,000
4	1, 2	90,000
5	1, 2	100,000
6	1, 2	100,000
7	1, 2, 3	140,000
8	1, 2, 3	150,000
9	1, 2, 3	150,000
10	1, 2, 3, 4	190,000
11 – 30	1, 2, 3, 4	200,000

An important aspect of the Study is the selection of technology for both mining and processing. In accordance with Washington Group's objective, conventional proven technologies were reviewed and an effort was made to select the most economic combination of equipment and unit processes. In addition, some step-out technologies were reviewed which would provide potential cost or operational benefits, but which would require confirmation through testing as the project advances.

Another objective was to develop a project implementation plan, which would consider the difficulties encountered during the recent construction of other projects and incorporate measures to mitigate those problems. The result would be a plan, which would minimize the potential for cost overruns.

1.1.4. Study Execution

The Study was executed by Washington Group, from its Denver, Colorado Operations Center under the direction of the Mining business unit. Other Washington business units, which contributed to the study, through the Op Center, were the Power and Infrastructure business units.

Additionally, consultants were retained to provide oil sands specific expertise to the project. The following companies made significant contributions to this study:

- Norwest Corporation (Norwest) completed two resource estimates for the Joslyn oil sands deposit, including the preparation of geologic models for both SAGD and surface mineable resources. The work was completed in their Calgary, Alberta office.
- AMEC Engineering (AMEC) provided the process design package for the study from their Calgary, Alberta office.
- Project Review & Analysis, L.L.C. (PR&A) provided cost and scheduling reviews as well as implementation planning for this study from its Kennewick, Washington office. PR&A has recently performed extensive reviews and evaluations on the implementation of oil sands projects in the Athabasca River region for major producers.

1.2. Property Description

1.2.1. Location and Access

The Joslyn Project is located in Northern Alberta, approximately 70 km north of Fort McMurray. Highway 63 connects Fort McMurray with Edmonton, which is Alberta's capital city, as seen on Figure 1-1. Fort McMurray is approximately 435 km north of Edmonton by provincial primary highway. Highway 63 continues north of Fort McMurray along the west bank of the Athabasca River. It travels past the Suncor and Syncrude oil sands operations. Just south of Fort MacKay, Highway 63 crosses the Athabasca River to the east. The road continuing on the west bank proceeds north into Fort MacKay. Canadian Natural Resources Limited (CNRL) recently constructed a main access road to their property. It starts south of Fort MacKay and extends 22 km to the Horizon Oils Sands Project. This access road transects Deer Creek's OSL 24, so it provides excellent access to several areas of the property. Shell's Muskeg River Project operates immediately across the Athabasca River from the Joslyn Project location.

1.2.2. Existing Infrastructure

Due to the ongoing development in the area, considerable infrastructure exists and more is planned. In addition to the new CNRL access road to the Joslyn Project, several utilities already exist as well. The Alberta-based ATCO Group owns and operates a natural gas pipeline and an electrical transmission line in the area, both of which cross Deer Creek's property. More information about these utilities is provided in Section 8.

The region has several communities within commuting distance of the property, including Fort McMurray with 50,000 population, which can be reached in approximately an hour's driving time.

1.2.3. Climate and Setting

The Joslyn Project is located in the mid-continental Canadian forest ecoregion and is classified as having a subhumid mid-boreal ecoclimate. It is marked by short, cool-to-warm summers and long, cold winters. The mean annual temperature ranges from -2°C to 1°C; the mean summer temperature ranges from 13°C to 15.5°C, and the mean winter temperature ranges from -17.5°C to -13.5°C. Mean annual precipitation ranges from 300 mm to 625 mm.

Elevations on the project site range from a high of 255 m asl in the south to a low of 160 m asl in the north.

The ecoregion forms part of the continuous mid-boreal mixed coniferous and deciduous forest extending from northwestern Ontario to the foothills of the Rocky Mountains. The mixed coniferous and deciduous forest is characterized by medium to tall closed stands of quaking aspen and balsam poplar with white and black spruce, and balsam fir occurring in late successional stages. Cold and poorly drained fens and bogs are covered with tamarack and black spruce, and may also include ericaceous shrubs and mosses. Deciduous stands in the uplands have a diverse understory of shrubs and herbs; while coniferous stands tend to promote feathermoss.

1.3. Geology And Mineral Resource Estimates

1.3.1. Regional Geology

The Athabasca oil sands are contained in the Cretaceous McMurray Formation. The McMurray Formation is comprised of stacked fluvial-estuarine sands and off channel silts and shales. It is subdivided into three informal members. These three divisions and their depositional environments are as follows:

- Lower McMurray (fluvial deposition)
- Middle McMurray (estuarine deposition);
- Upper McMurray (marginal marine deposition).

The Lower McMurray division is predominantly fluvial channel deposits in-filled lows on the Devonian (Paleozoic) surface resulting in thicker McMurray intervals (approximately 20 meters) of coarse- to medium-grained, bitumen saturated sands. These characteristics make this an excellent ore body.

The Middle McMurray division is a combination of thick estuarine channel successions and tidal flat deposits. Interbedded sands and muds result from this type of deposition. The Middle McMurray division is comprised of medium- to very fine-grained sands that are deposited in estuarine channels 10 to 35 meters thick; this deposition results in good quality reservoirs.

The Upper McMurray division is fine-grained to very fine-grained sand that is finely laminated. It is typically a thin bed that is not much value as a bitumen resource. The McMurray Formation sands are generally between 90 and 95 percent quartz.

1.3.2. Resource Estimate

Data continues to be collected on the Joslyn deposit, with some areas having denser coverage than others. Deer Creek has conducted four exploration programs to date in addition to data which had been gathered prior to their ownership. Norwest has completed two resource assessments; one in 2001 and the latest, done in 2003, is incorporated in this report. The latest estimate is based on information from 425 drillholes.

From the data, four distinct ore zones have been defined and correlated over the entire lease area. The four ore zones contained in the McMurray Formation and pictorially shown in Figure 1-3 are:

- Kml Lower Ore: Lower McMurray fluvial sands;
- Kml Upper Ore: Lower McMurray fluvial sands;
- Kmm Lower Ore: Middle McMurray estuarian sands;
- Kmm Upper Ore: Middle McMurray estuarian sands.

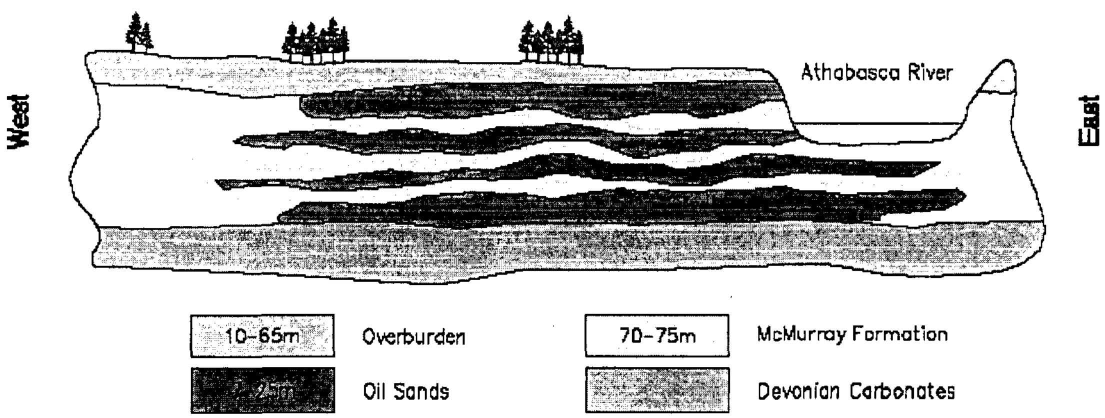


Figure 1-3 Geological Schematic

A summary of Norwest's latest resource estimates, which are differientiated between SAGD and mineable, are presented in Table 1-3 below.

Table 1-3
Resource Estimate Summary*

	Surface Mineable Resources	SAGD Resources
Bitumen (Mbbls)	2,962	1,107
Waste (Mtonnes)	4,937	
Average Grade, % bitumen	10.5	
Ore (Mtonnes)	4,535	

The division between proposed surface mining operations and SAGD operations is a preliminary boundary that has been chosen for this study and does not represent a physical or a geological boundary. There are some areas that are amenable to both recovery methods. The SAGD/mineable resource delineation can be seen on Norwest's Figure 2 at the end of the section.

Table 1-4 is a more detailed breakdown of the mineable resource areas. The estimates completed by Norwest make no allowances for dilution, mining losses, or recovery methods.

Table 1-4
In-Place Resources Suitable for Mining*

Area	Bitumen million bbls	Ore million tonnes	Waste million tonnes	Avg Grade wt% bitumen	Avg TV:BIP	Strip Ratio
1	1,296	2,038	2,184	10.3	9.9	1.1
2	295	439	510	10.9	9.8	1.2
3	53	83	112	10.3	11.1	1.3
4	119	204	204	9.4	10.3	1.0
5	21	34	43	10.1	10.8	1.3
6	163	246	190	10.7	8.1	0.8
7	55	78	89	11.4	9.2	1.1
8	926	1,358	1,559	11.0	9.5	1.1
9	34	57	48	9.7	9.2	0.8
Total	2,962	4,535	4,937	10.5	9.7	1.1

* Updated from March 2004 issue

The ratio of total volume to bitumen in-place (TV:BIP) is calculated by dividing the ore plus waste volume by the volume of the contained bitumen. The strip ratio is a measure of the relationship between waste and ore tonnages, which as such does not reflect the grade of the resource. It is calculated by dividing the tonnage of waste by the tonnage of ore.

1.4. Mining

1.4.1. General

Deer Creek's development philosophy calls for staged production increases, as previously discussed. At the onset of this study, options for incremental increases in the extraction plant train sizes and the associated production capacity were evaluated. A decision was made to set the train size at 50,000 barrels per day (bbl/d) with a new train coming into production every three years until an eventual capacity of 200,000 bbl/d is reached. Based on a 60 percent ramp-up for Train 1 during the first year of operation and an 80 percent ramp-up during the first year of production for subsequent trains, the annual bitumen production over the project life is shown in Table 1-5.

Table 1-5
Bitumen Production Schedule (million barrels)

Year	Train 1	Train 2	Train 3	Train 4	Total
1	10.95				10.95
2-3	18.25				18.25
4	18.25	14.60			32.85
5-6	18.25	18.25			36.50
7	18.25	18.25	14.60		51.10
8-9	18.25	18.25	18.25		54.75
10	18.25	18.25	18.25	14.60	69.35
11-30	18.25	18.25	18.25	18.25	73.00
Total	541.2	489.1	434.4	379.6	1,843.25

1.4.2. As-Mined Resources

The mine plan is developed to maximize the ore recovery from the area delineated by the 12:1 TV:BIP ratio applying accepted mining practices. This ratio is in accordance with Alberta Energy and Utility Board Interim Directive ID 2001-7 "Operating Criteria: Resource Recovery Requirements for Oil Sands Mine and Processing Plant Sites". The outline representing the 12:1 TV:BIP ratio cutoff is shown on Drawing 06-11-100-001. Important considerations in developing the mine plan include:

- Lease boundary;
- Rivers and drainages;
- 12:1 TV:BIP ratio limits;
- Permanent roads;
- Tailings pond requirements;
- Equipment size.

Two primary pits were developed which are labeled as Pit 1 and Pit 8 to correspond to the resource areas defined in the geologic report. These two pits account for approximately 30 years of production for the stated production schedule. Two ancillary pits were also identified and labeled as Pit 2 and Pit 4. These pits add approximately 3.3 additional years at full production. The critical design criteria used to develop the mine plan are shown in Table 1-6.

Table 1-6
Mine Design Criteria

Minimum ore grade	7% bitumen
Mining Selectivity	3 meters minimum thickness
Pit Limit Criteria	12:1 TV:BIP
Dilution Volume	5%
Dilution Grade	4.8% wt bitumen
Dilution of Ore (loss in bitumen grade)	0.3 % wt bitumen
Recovery of Ore Resource	95%
Material in-situ density	
• Muskeg/mineral soil mix	1.7 t/bcm
• Overburden / Interburden	2.08 t/bcm
• Oil Sands (ore)	2.08 t/bcm
Material Swell	
• Muskeg (placed)	90% of bank
• Overburden in dyke	10%
• Overburden in waste area	20%
Material Final Slopes	
• Muskeg Storage Areas	3H:1V
• Waste Storage Areas	4H:1V
Open Pit Wall Design Parameters	
• Bench Height	15 meters
• Bench Width	100 meters
• Final Pit Burden Slope Angle	3H:1V
• Final Pit Ore Slope Angle	3H:1V
Offset From Rivers	100 m from bank crest

Based on these criteria, the final pit limits were established. The geologic model that was created by Norwest identified the categories of burden, ore zones, and interburden. The model was converted to Mincom MineScape™ software, which was also used for all mine planning.

When the mine design criteria are applied to the four pits, the as-mined resources are calculated as presented in Table 1-7.

Table1-7
Resource Summary

PIT AREA	ORE (000 bcm)	OVER BURDEN (000 bcm)	INTER BURDEN (000 bcm)	STRIP RATIO	INSITU ORE (000 tonnes)	INSITU BITUMEN (%)	INSITU BITUMEN (000 bbls)	AS-MINED ORE (000 tonnes)	AS-MINED BITUMEN (recov %)	AS-MINED BITUMEN (000 bbls)	PRODUCED BITUMEN (000 bbls)
1	802,500	434,300	600,400	1.3	1,669,100	10.6	1,096,800	1,669,100	10.3	1,065,700	975,100
8	660,400	844,800	132,000	1.5	1,373,700	11.1	948,800	1,373,700	10.8	923,200	844,700
4	75,400	47,700	38,700	1.2	156,800	9.5	92,700	156,800	9.2	89,800	82,200
2	127,300	60,200	113,100	1.4	264,700	11.1	182,200	264,700	10.8	177,200	162,100

Definitions:

In-situ Bitumen Barrels = Ore tonnes x in-situ bitumen % grade / bitumen density x barrels per cubic meter

As-Mined Ore = In-situ Ore x 95% recovery factor plus 5% dilution factor (Ore loss volume = dilution volume)

As-Mined Bitumen % = In-situ Bitumen Grade minus 0.3% (assumes 5% dilution @ grade 4.83%)

As-Mined Bitumen Barrels = As-Mined Ore tonnes x as-mined % grade / bitumen density x barrels per cubic meter

Produced Bitumen Barrels = As-Mined Bitumen barrels x 91.5% Plant recovery factor

Bitumen density = 1.01268791

Barrels / cubic meter = 6.28998702

1.4.3. Mine Planning and Schedule

The model was used to establish annual resource volumes and bitumen quality. From these volumes, a schedule was created to match the annual production rate on a produced bitumen basis. The resulting volumes and grade for each year are shown in Table 1-8.

Table 1-8
Mining Schedule

	Ore BCM (000)	Ore Tonnes (000)	Overburden BCM (000)	Interburden BCM (000)	Strip Ratio	Bitumen Bbls (000)	Bitumen %
Preproduction	0	0	9,700	0		0	-
Year 1	8,900	18,600	6,100	5,700	1.4	11,000	10.4
Year 2	14,900	31,000	10,000	9,400	1.3	18,300	10.4
Year 3	14,900	31,000	10,200	9,400	1.3	18,300	10.4
Year 4	26,800	55,800	16,800	16,900	1.3	32,900	10.4
Year 5	29,800	61,900	11,000	18,300	1.0	36,500	10.4
Years 1 to 5 Total	95,300	198,300	54,100	59,700	1.2	117,000	10.4
Years 6 to 10 Total	220,800	459,300	126,200	132,200	1.2	266,500	10.2
Years 11 to 15 Total	300,800	625,700	182,800	259,900	1.5	365,000	10.3
Years 16 to 20 Total	294,200	611,900	270,000	174,500	1.5	365,000	10.5
Years 21 to 25 Total	279,100	580,500	304,000	42,900	1.3	365,000	11.1
Years 26 to 30 Total	268,700	558,900	323,700	69,600	1.5	341,300	10.5
30 Year Total	**1,458,900**	**3,034,600**	**1,260,800**	**738,800**	**1.4**	**1,819,800**	**10.5**

The mine plan sequenced resource Areas 1 and 8 only, resulting in a minor shortfall (23.5 million barrels of bitumen) in Year 30 of the production schedule. As previously mentioned, Areas 2 and 4 could provide additional resources, but were not scheduled for the study.

The overall mining pit plan is shown on Drawing 06-11-100-001 at the end of the section. The mine starts in the south part of Pit 1 (corresponding to Area 1) and advances in a northwestern direction along the western pit boundary. During each mine advance, in-pit dykes are constructed to store tailings. Around Year 12 mining has reached the north limits and advance proceeds back to the east. Mining continues to the east until the pit is completed in approximately Year 20. Prior to this time preparations are begun to open Pit 8 in Year 17. A transition period of about two years takes place before all mining operations have relocated to Pit 8. Operations advance first to the southwestern limb of the pit and then to the northwestern limb, providing opportunistic tailings storage areas. The mine then proceeds to the east for its final years of the production schedule.

1.4.4. Technology Selection

Of the various mining technologies available for surface oil sands operations, the truck and shovel option has been adopted throughout the Athabasca region. Past experience with dragline and bucket-wheel systems proved inflexible and costly, in comparison with the largest scale shovels and trucks which manufacturers have now developed beyond prototype trials.

For the study the conventional truck and shovel method has been selected since it remains the proven standard in the oil sands industry. Using this method much attention has been paid to the configuration and nature of the ore preparation plant (OPP), which includes the dump hopper, crushers, surge pile and slurry mixer prior to hydrotransport. The aim is to make this equipment easier and less costly to move closer to the loading face, thereby keeping truck haul distances to a minimum. Although several designs and equipment alternatives have been proposed, there is no clear advantage that is field proven.

The additional challenge for the Joslyn Project is the site geology, which displays more interbedding of ore and waste than some projects. The extent of the interbedding controls the bench height, which, in turn, dictates the size of the mining equipment that can be used. The additional benching also requires more flexible systems be employed for operational efficiencies.

The conceptual design for this study uses truck and shovel methods that haul oil sands to a permanent OPP.

1.4.5. Equipment Selection

Mining equipment has been selected to support the appropriate tasks and to minimize capital required at startup. Due to the wet surface conditions, smaller equipment is chosen for initial land preparation. Muskeg/reclamation material is loaded into 100-tonne class trucks by 11.5 cubic meter capacity front-end loaders and hauled to stockpiles. During initial production buildup, 218 tonne trucks and 32 cubic meter capacity hydraulic shovels are selected to open the mine by moving ore and waste volumes. Hydraulic shovels are more mobile than electric shovels, and can thereby more easily establish various benching levels. These trucks and shovels will also be used to move ore and interburden from the thinner benches when larger equipment is operating on thicker benches later in the mine life. As the production ramps up, 345-tonne trucks and 44 cubic meter cable shovels will be used to load and haul ore and waste from the main ore and waste zones. Dozers are used initially to push muskeg into piles. Then, as the mine production begins, they are used on the burden dumps and for tailings dyke construction. To ensure maximum flexibility, 410HP, 580HP, and 850HP dozers are utilized for mining and for dyke building operations. Haul profiles and cycle times were calculated to determine equipment numbers. Major equipment is listed in Table1-9 by production period.

Table 1-9
Major Equipment Fleet Required (# of Units)

	Pre-prod	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6-10	Year 11-15	Year 16-20	Year 21-25	Year 26-30
Loaders											
P&H 4100BOSS(44m^3)	0	0	0	0	3	3	5	9	9	9	9
Cat 992G FEL(11.5m^3)	1	1	1	1	1	1	1	1	1	1	2
Hitachi Ex5500(32m^3)	1	2	3	3	3	3	3	3	3	1	1
Trucks											
Cat 797B(345t)	0	0	0	0	0	0	11	35	41	41	40
Cat 793C(218t)	3	11	19	20	36	36	36	23	23	10	0
Cat 777D(100t)	4	2	2	2	2	2	2	2	2	2	7
Support											
Cat 777D-H20 water truck	1	1	2	2	3	3	4	4	4	4	4
Cat 16H Grader	1	2	2	2	3	3	3	3	3	3	3
Cat 24H Grader	0	0	0	0	0	1	3	3	3	3	3
Cat 844 RTD	1	1	1	1	2	2	4	6	6	6	6
Cat D-9R Dozer	1	1	2	2	3	3	5	6	6	6	6
Cat D-10R Dozer	1	2	3	3	3	3	3	6	6	6	6
Cat D-11R Dozer	0	0	0	0	1	1	3	5	5	5	5
Total	14	23	35	36	60	61	83	106	112	97	92

1.4.6. Mining Activities

The mining plan covers all of the required mining tasks including:

- Muskeg and other topsoil material removal;
- Overburden removal to burden stockpile or dykes;
- Ore mining and haulage to the OPP;
- Tailings management;
- Surface water control and subsurface depressurization;
- Reclamation of all disturbed areas.

Figure 1-4 depicts these mining activities that occur throughout the mining advance.

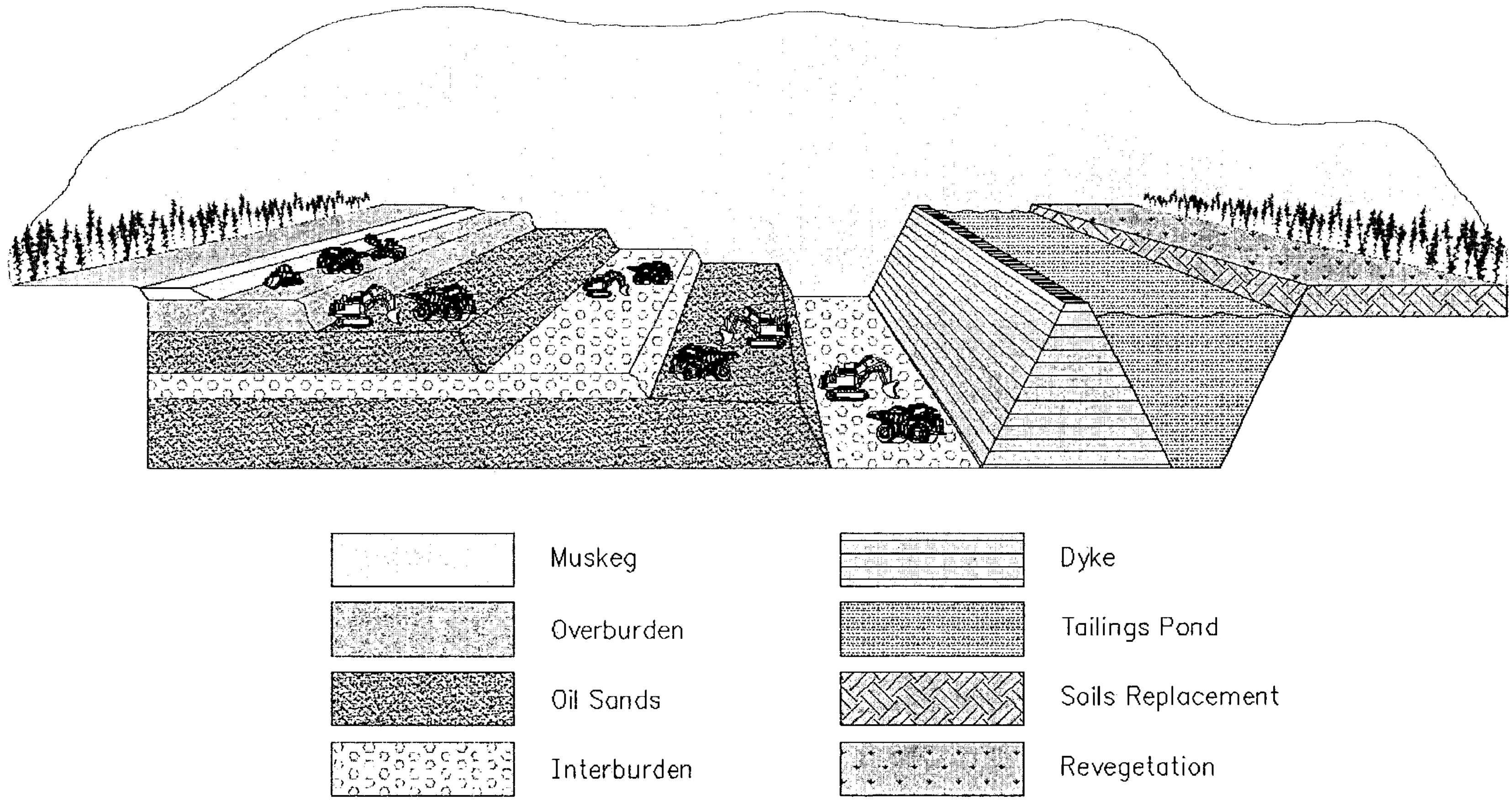


Figure 1-4 Mining Sequence

1.5. Process Selection

Rather than investigate alternative ore processing designs for the entire facility, options for each module were examined. The oil sands processing industry has reasonably well-developed processes for separating bitumen from the oil sands and the spectrum of proven technologies is relatively narrow. The alternatives investigated for the process modules are summarized in the following sections.

1.5.1. Material Handling and Slurry Preparation

Conceptually, the materials handling facility consists of shovels at the mine face, trucks to haul the ore to a dump hopper, crushers, and a surge pile. Conveyors deliver the crushed ore to a slurry preparation facility. For this study, six options were evaluated prior to selecting one option for inclusion in the study. The initial options studied were:

- Option 1 - Primary & Secondary Crushing with Screening;
- Option 2 - Double Roll Crusher and Trommell Screen;
- Option 3 – Modified Option 2. A stockpile is used for storage instead of a surge bin;
- Option 4 – Secondary Crushing with Single Screen;
- Option 5 – Use of MMD Crushers;
- Option 6 – Option 3 Without a Surge Bin or Pile.

After investigation and discussion it was decided to choose a hybrid of the options studied and to crush the entire ore feed stream (no rejects). Crushing is achieved with a primary MMD crusher and a secondary double roll crusher. A surge pile is inserted between the crushers. With this arrangement any agglomerates that form in the surge pile are crushed in the double roll crusher before entering the mix box. This configuration does not include screens.

1.5.2. Hydrotransport

As oil sand processing has evolved, transportation of ore from the mine area to the bitumen recovery plant shifted from conveyors to slurry pipelines. The slurry pipelines offer a number of advantages: the maintenance costs are lower for pipelines; the reliability of pipelines is higher than for conveyors and the ore is ablated as it travels through the pipeline. This ablation separates bitumen from the solids and enhances recovery in the gravity separation vessels that are located at the central processing plant.

1.5.3. Extraction

The extraction module of the plant separates bitumen from water and solids in a cone bottomed separation vessel by gravity called the Primary Separation Vessel (PSV). The bitumen separation from the water and solids occurs in the hydrotransport pipeline. Air is injected in the downstream section of the hydrotransport pipeline to aerate the bitumen to form a bitumen froth. The density of the froth is less than the density of water or slurry so it floats to the top of the PSV.

The PSV is supplemented by one or more trains of flotation cells for processing the middlings.

1.5.4. Froth Treatment

The bitumen froth overflow product from the PSV contains impurities at concentrations well above the levels allowed for pipeline transportation to refineries. Traditional approaches for separating the bitumen from the contaminants involved blending the bitumen with naphtha, increasing the temperature to approximately 50°C to reduce the viscosity, and separating water and solids by gravity. The remaining few percent of the contaminants are partially removed in centrifuges for final purification of bitumen. However, this practice does not meet the purity requirements that have been set by refiners.

In the Deer Creek processing plant the conventional diluent/bitumen blending and subsequent gravity and centrifuge separation were initially proposed. The inability of this process to achieve the required bitumen purity and the high levels of heat energy required to recover the diluent from both the bitumen/diluent stream and the water solids underflow prompted the investigation of an alternative approach.

The froth treatment process selected for the Joslyn Project is a combination of lower temperature gravity settling and elevated temperature pressure vessel separation. Bitumen from the PSV is blended with synthetic crude oil (SCO) from a local supplier and is fed to inclined plate settler units where bulk separation of the bitumen/SCO mixture and water/solids material is achieved. To achieve pipeline and refinery specifications for the hydrocarbons, the bitumen/SCO mixture overflowing the inclined plate separator is heated in a shell and tube exchanger, and the mixture is fed to two high-pressure, horizontal separation vessels, a free water knockout (FWKO) and a treater.

<u>IPS Underflow / Tailings</u>

The water-sediment effluent in the underflow or tailings from the inclined plate settlers contains approximately 15 percent bitumen and SCO. It is mixed with the underflow from the FWKO vessel, blended with a light diluent and the resulting blend is fed to a horizontal pressure vessel for gravity separation. The light diluent will wash most of the bitumen and SCO from the tailings solids and reduce the viscosity and density of the hydrocarbon mixture to allow gravity separation of the water-solids phase. The diluent and most of the SCO are then evaporated and recovered in a condenser. The clean underflow can be discharged directly to the tailings pond with negligible environmental impact. The bitumen/SCO/diluent blend in the overflow from the horizontal gravity separation pressure vessel is fractionated to recover the light diluent. The diluent is condensed and returned to the diluent storage tank for recycle through the process.

The design proposed for the Joslyn Project has been partially implemented in various operating plants. However, the specific combination of processes recommended in this froth treatment design has not been implemented to date. Laboratory tests and/or pilot plant work are required to verify the design.

1.5.5. Tailings

Two approaches to the processing of tailings are adopted in the industry. By definition coarse tailings refers to the discharge or underflow from the PSV. The flotation tailings refer to the underflow from the flotation cells. Tailings is defined as any blend of these two tailings streams. The two approaches for processing tailings are:

- Discharge the coarse tailings and the flotation tailings or a blend of these two streams directly to the tailings pond;
- Blend the coarse tailings with the flotation tailings, cyclone the combined tails, feed the cyclone overflow to a secondary flotation circuit for the recovery of bitumen. And, send the underflow from the flotation cells to a thickener where warm water is recovered for use by the process. Finally, the underflows from the cyclones and the thickener are combined and discharged to the tailings pond.

For the Deer Creek processing plant both options are proposed. The first option is selected for the Train 1 because it reduces initial overall plant capital costs. The second option is selected for Trains 2, 3 and 4. Train 1 will be upgraded during construction of Train 2. The second option has increased capital costs but it also results in more efficiency and higher recovery of bitumen.

1.5.6. Utilities

The Deer Creek oil sands processing plant requires three types of energy to achieve the separation of bitumen and the required product purity. They include:

- Electrical energy to drive pumps, provide HVAC heat, operate shovels, etc.;
- Low grade thermal energy, in the form of hot water, to separate the bitumen from the oil sands;
- Higher grade thermal energy, in the form of steam, to provide the required heat for froth treatment.

A number of options are available for providing the processing plant with these three levels of energy. The three most apparent are summarized below.

Option 1

Purchase electrical power from the grid; generate low grade thermal energy by the use of hot water boilers; generate steam for bitumen deaeration using steam generators similar to those used in the heavy oil industry (Once Through Steam Generators (OTSG's)); generate process heating steam (large condensate recycle) for froth treatment using industrial steam boilers.

Option 2

Install a 40 MW gas turbine generator (GTG) complete with a heat recovery unit. Include auxiliary natural gas firing in the turbine exhaust duct to generate low-grade thermal energy power to drive one train. This generator supplies sufficient power to drive one train. Utilize the heat recovered from the turbine exhaust gases and the supplementary heat generated by the auxiliary firing to supply the hot water for ore processing. The terminology currently used for this unit is Heat Recovery Hot Water Generator (HRHWG). Generate steam for deaeration of the bitumen with Once Through Steam Generators (OTSG's). Generate steam for froth treatment with industrial steam boilers.

Option 3

Install an 80MW gas turbine complete with HRHWG without auxiliary firing. This generator supplies sufficient electrical energy to run two trains and sufficient low-grade thermal energy to achieve bitumen separation for one train without auxiliary firing in the turbine exhaust duct. In the second train, the auxiliary firing to the exhaust gas duct is added. For trains 3 and 4 purchase a second 80 MW generator and repeat the approach. Excess electrical power can be sold to the power distribution grid. Generate steam for bitumen deaeration using an OTSG. Generate process heating steam for the froth treatment process using industrial steam boilers.

Following an economic evaluation of the three options, Option 2 was selected for inclusion.

1.6. Process Description

1.6.1. Process Design Criteria

The Deer Creek processing plant includes the facilities from the dump hopper to the product export facilities for the bitumen/SCO (synthetic crude oil) mixture. Support facilities such as utilities and the power plant, are also included. The modules for the processing plant are:

- Ore Preparation;
- Slurry Preparation;
- Hydrotransport;
- Extraction;
- Froth treatment;
- Tailings;
- Utilities.

The ore preparation, slurry preparation, and hydrotransport modules are frequently called the Ore Preparation Plant (OPP), as introduced in the Mining Section. Figure 1-5 is a block flow diagram that shows the inter-relationship between the various modules. An overall process flow diagram is included at the end of this Section, AMEC Drawing 142100-000-110-DD-0001. Detailed explanations of the processing modules are provided in Section 7 of this report.

The Process Design Criteria for the Deer Creek processing plant are presented in Appendix III and are summarized in Table 1-10.

Table 1-10
Process Design Criteria

Criteria	Units	Value
Life of Mine (LOM)	Years	30
Initial Production Rate – Train 1	bbls/day	50,000
Number of Production Trains	-	4
Ultimate Production Rate, Post Year 10	bbls/day	200,000
LOM Bitumen Production	bbls x 1000	1,843,250
Ore Grade	% bitumen	10.5 – 11.5
Ore Preparation Plant Production Rate	tonnes/h	5,000
Extraction Production Rate	tonnes/h	4,325
Extraction Temperature	Degrees C	40
Froth Treatment Production Rate	bbls/day	62,500
Overall Plant Availability	%	82.6
Bitumen Recovery PSV	%	84.0
Overall Bitumen Recovery	%	91.5
Product Type	-	SynBit
Product quality	% BS&W	< 0.5

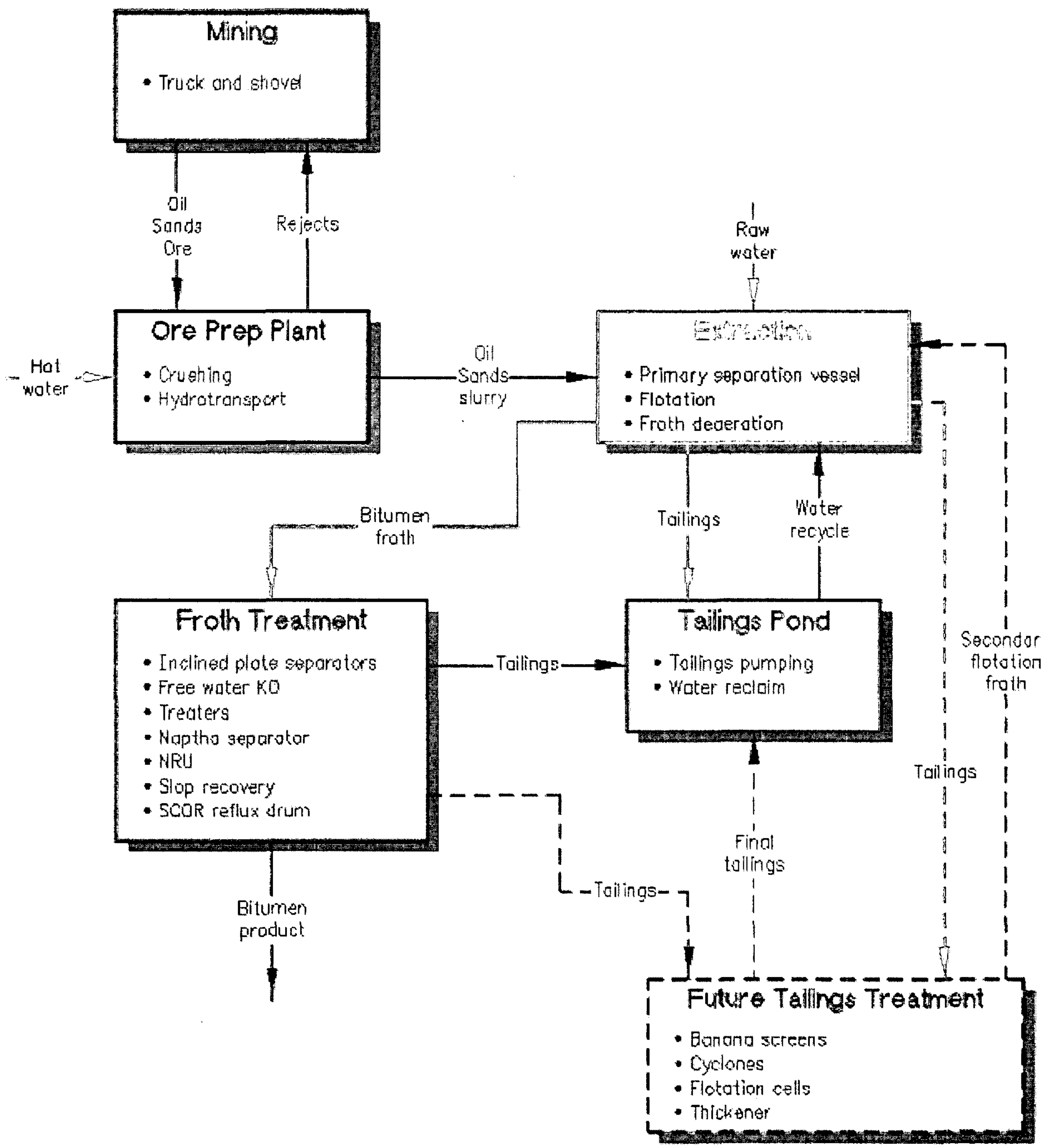


Figure 1-5 Simplified Process Flow Diagram

Based on preliminary data, the ore grade varies from approximately 8.6 percent bitumen by weight to a high of approximately 13.0 percent. In this study an operating availability of 82.6% was selected which indicates that during any year of 365 calendar days, the plant will operate at design capacity for 302 calendar days. In order to produce 50,000 bpd of bitumen, the ore feed rate to the processing plant was calculated to be 5,000 tph.

The AMEC Process Design Package is included in Appendix III. It includes process flow diagrams (PFD's), mass and energy balances, an equipment list, and cost estimates. A more detailed explanation of the process facilities is included in Section 7. A brief description of each module follows.

1.6.2. Ore Preparation & Slurry Preparation

The dump hopper is located behind a vertical 15 meter mechanically strengthened earthwork (MSE) wall. This configuration allows the trucks to dump directly into the hopper. An apron feeder transfers the ore from the dump hopper to an MMD crusher. This crusher reduces the size of the lumps in the mined ore to approximately minus 400 mm. A conveyor transfers the ore from the MMD crusher to a surge pile. Two apron feeders transfer the ore from the surge pile to a conveyor belt feeds a double roll crusher. The double roll crusher reduces the lump size from approximately 400 mm to nominally 75 mm. The double roll crusher discharges to the conveyor that feeds the mix box.

The mixbox is an open-ended, rectangular vessel with six shelves over which the slurry cascades as it falls to the pump box. Warm water is injected into the side of the mixbox. The cascade action and contact with water promotes the degradation of larger lumps of oil sands. Slurry in the pumpbox is recirculated by the pumpbox recycle pump.

1.6.3. Hydrotransport

The hydrotransport system transfers the ore from the materials handling facility to the bitumen extraction plant via a pipeline which must be a minimum of 2.5 km long for adequate conditioning of the ore. The slurry preparation plant is located adjacent to the materials handling facility.The hydrotransport pipeline has an inside diameter of 21-inches.

1.6.4. Extraction

The aerated slurry from the hydrotransport pipeline is diluted with floodwater before it enters the PSV. Once in the PSV, the bitumen froth floats to the vessel overflow launder, while the water and solids report to the underflow. The froth from the PSV, including the froth recovered in flotation cells, contains approximately 50 percent air by volume. This froth is fed to a deaerator where the bitumen flows down over an internal packing (shed decks) countercurrent to saturated low pressure steam. The volume fraction of air in the froth is reduced to the range of 5 to 10 percent. Pumps at the base of the deaerator then transfer the froth to the froth treatment plant.

Middlings slurry, containing unliberated bitumen, is tapped from the middle section of the PSV and processed in conventional flotation cells. Froth is returned to feed of the PSV for recovery. A fraction of the flotation tailings stream is returned to the PSV as upflow water to increase bitumen recovery. The remainder is discharged to the tailings system.

The underflow from the PSV, coarse tailings, is pumped to the tailings module of the process.

1.6.5. Froth Treatment

The froth from the deaerator reports to a froth storage tank. This storage tank stabilizes the flow to the froth treatment plant. Froth is pumped from the storage tank, blended with SCO, that is purchased locally, and fed to an inclined plate separator where the bulk of the water and solids are removed from the mixture. The overflow, primarily SCO and bitumen, is pumped through a series of heat exchangers that increase the temperature to 160°C using steam. The mixture then proceeds to horizontal pressure vessels, (the FWKO drum and the treater) where the gravity separation of solids and water from the bitumen/SCO mixture continues, resulting in a concentration of sediment and water less than or equal to 0.5 percent by weight.

The overflow from the FWKO and treater is cooled in heat exchangers by cross-exchange with the feed stream and fed to either the product tank or the offspec tank. The bitumen/SCO blend from these tanks is cooled with process water and pumped to the export pipeline. Trim SCO is added to the product tank to attain a marketable 50:50 blend of bitumen and SCO, which is referred to as SynBit.

<u>IPS Underflow / Tailings</u>

The underflow from the inclined plate separators, the FWKO's and the treater are combined, blended with naphtha and fed to the naphtha separator. The light naphtha dissolves the bitumen and SCO and forms a lower density, lower viscosity hydrocarbon mixture. Solids and water settle in the naphtha separator.

Water and solids from the naphtha separator flow to the naphtha recovery unit (NRU), a stripping column where the naphtha is evaporated and stripped using steam. It is proposed that this stripped water/solids stream be discharged directly to the tailings pond.

The naphtha recovered in the NRU column is condensed using process water in a shell and tube condenser. The condensed liquids are collected in a reflux drum where water and naphtha are separated. The naphtha phase proceeds to the synthetic crude oil recovery (SCOR) column and the water is blended with the underflow from the NRU and pumped to the tailings pond.

The overflow from the naphtha separator is mixed with the naphtha from the NRU and the mixture is heated with steam in a heat exchanger. This exchanger, or group of exchangers, is oriented vertically to promote vapor liquid separation and the two-phase fluid exiting the exchanger is fed to a tower that separates the light naphtha from the SCO/bitumen mixture for recycle of both products.

1.6.6. Tailings

Train 1

In Train 1, the tailings streams from the PSV and the flotation cells are combined in the tailings pump box and pumped to the tailings ponds. These tailings pumps are identical to those installed in the hydrotransport pipeline.

Reclaim water pumps return water accumulated in the tailings pond to the recycle water pond near the bitumen extraction plant. A porous dike or berm is constructed in the tailings pond to filter water as it flows into the pool that is created by the berm.

Trains 2, 3, and 4

The tailings streams from the PSV and the flotation cells are mixed and transferred to a screen feedbox and a banana screen. Screen oversize is sent to the tailings pumpbox while screen undersize is pumped to a bank of cyclones. Cyclone overflow (fines) proceed to a bank of flotation cells and the cyclone underflow is sent to the tailings pumpbox.

Froth from these flotation cells is returned to the PSV. Underflow from the flotation cells is pumped to a 65 meter diameter thickener. Thickener underflow, at approximately 30 percent solids by weight, is pumped to the tailings pumpbox. Thickener overflow water is blended with process water, heated and returned to the process.

Reclaim water pumps return water accumulated in the tailings pond to the recycle water pond in the bitumen extraction plant. A porous dike or berm is constructed in the tailings pond to filter water flowing into the pool that is created by the berm.

Train 1 will be upgraded to this tailings system when Train 2 is constructed.

1.7. Ancillary Services

For the Joslyn Project, the following process support items are included as ancillary services.

- Water Supply and Distribution;
- Electrical Power Supply and Distribution;
- Steam Supply and Distribution;
- Synthetic Crude Oil Supply;
- Bitumen Transport.

1.7.1. Water Supply and Distribution

This system includes raw water supply, intake and pump facility, raw water pipeline, discharge structure at the raw water impoundment and raw water distribution.

Also included is a hot process water system. The energy to heat the process water comes from a dedicated 40 MW natural gas fired generator with a Heat Recovery Hot Water Generator (HRHWG). The process water is heated in a closed circuit circulation system.

1.7.2. Electrical Power Supply and Distribution

Each phase of the Deer Creek Joslyn Project operation requires approximately 30 MW of electric power for the process operations, plus a steady state supply to the facilities and mining operations. The power supply can come from two separate sources: the ATCO Electric utility grid or dedicated electric generating stations located on site. It is estimated that a total of 40 MW, for each phase or train, is a sufficient power supply for the project.

Grid power is supplied from a transmission line operated at 240 kV by ATCO Electric. The tower transmission line runs along the western and northern boundaries of the lease. It is anticipated that a connection is made along the northern property border and the power will be run down to the main site location following the CNRL Access Road. Tying into the power grid provides a means of selling the excess power generated, as well as, a viable redundant source for power should an outage be experienced at the generating station. Both power sources will be tied to a common switchyard, providing a dual source configuration. From there the power supply is distributed throughout the project areas.

Additional detail about the electrical distribution and supply systems is included in Section 8.

1.7.3. Steam Supply and Distribution

Steam is utilized to provide heat for the froth treatment plant, and the second service is to supply steam to the froth deaerator. Most of the steam used in the froth treatment plant is returned as condensate. The steam to the deareator, condenses and mixes with the froth.

Steam for the exchangers in the froth treatment module is generated by two 150GJ/h steam boilers. These are standard boilers commonly used by the oil sands and other processing industries.

1.7.4. Synthetic Crude Oil Supply

SCO is piped to the project site. For the proposed design, the pipeline follows the designated pipe corridor following the CNRL Access Road. SCO is supplied from the Enbridge Terminal, which is approximately 30 kilometers south of the Joslyn property. The capital estimate includes one pipeline that is sized for a single train.

1.7.5. Bitumen Storage and Transport

The project plans to transport the SCO/bitumen blend, SynBit, to Hardisty, Alberta and to the export market. Product storage tanks and a pipeline will be constructed by Deer Creek from the Joslyn Project to the Enbridge Terminal. From the Enbridge Terminal the product will be transported in the Enbridge pipeline to Hardisty.

1.8. Infrastructure

The infrastructure for the Joslyn Project includes:

- Site access;
- Site preparation for the distribution of power, natural gas, and raw water;
- Construction of site access roads;
- Administration and laboratory buildings;
- Maintenance for mine and process;
- Fire safety;
- Sanitary sewage;
- Communications;
- Security.

Detailed information about the Infrastructure is included in Section 9 of this report.

1.8.1. Property Access

Access to the plant site and property is via the CNRL access road. The route of this road from Fort McMurray follows Highway 63, north past the Suncor and Syncrude operations to a point approximately 1 km south of Fort MacKay. From here the road turns west along the existing electricity supply line and product pipeline right-of-ways and turns northward into the Lease 24 boundary.

1.8.2. Site Layout

The site layout was developed to separate mine maintenance and operations from process maintenance and operations, as can by seen on Drawing 12-11-100-001 at the end of the section. The process and administration related facilities are located near the water impoundment source and away from resources identified as surface mineable. The location of these facilities remains fixed through the life of the project. The mine related facilities are located close to the proposed surface mine operations. They will be relocated as surface operations move from the north to the south side of the lease property in order to provide adequate support for these activities.

The waste dump and tailings pond are located near the center of the property along the CNRL Access Road. A mine haul truck underpass is required to support continuous operations without disturbance to the traffic flow along this access road. A fence is installed along each side of the CNRL Access Road to limit access to the site facilities.

1.8.3. Site Roads

Several site roads are required to enable maneuverability to key areas. These include:

- Main Entrance Road 3.4 km;
- Secondary Entrance Road: 1 km;
- Water Intake Structure Service Road: 7.8 km;
- North Mine Pit Access Road: 1 km;
- North Ore Processing Access Road: 500 meters;
- Crossover on the CNRL Access Road: 220 meters.

These roads are located on Drawing 12-11-100-001 as well.

1.8.4. Buildings and Other Infrastructure

Buildings included in the Infrastructure consists of:

- Administration Building, Laboratory and Gatehouse
- Mine Maintenance Building, Fueling Station and Tire/Truck Wash Building

Other infrastructure items include fire protection, sanitary sewage, communications, mobile radio network and property security.

1.9. Environmental and Permitting

An assessment of expected environmental and permitting considerations is included in this study. There also will be occupational health and safety issues that have to be addressed under the Alberta Occupational and Safety Act that are not discussed here. As indicated in Deer Creek Energy Limited (September 2003, Joslyn Project Phase 3 Expansion Design Basis Memorandum), the Project facilities will be designed to meet all applicable health and safety regulations.

The environmental regulatory requirements include those of both Federal and Provincial regulatory agencies, and the Municipality of Wood Buffalo. In addition, the Canadian Council of Ministries of the Environment (CCME) assists in discussions and cooperation between agencies on environmental issues. Measures agreed to by the CCME must be approved by both the Provincial cabinets and the Federal government before they can be implemented.

In Alberta the key organizations with environmental responsibilities are Alberta Environmental Protection or Alberta Environment (AEP or AENV) and the Alberta Energy and Utilities Board (AEUB). The AEUB is the regulator for energy projects with environmental aspects being one part of their decision making process.

1.10. Project Implementation

The Deer Creek Joslyn Oil Sands Project will be executed using current proven process technology, constructability methods and a phased engineering, procurement and construction (EPC) approach to ensure success. This approach produces the lowest cost project by eliminating recycle and rework to allow the proper sequence of deliverables between project phases.

The Joslyn Oil Sands Project implementation plan mitigates the risk resulting from overruns that have been experienced on recent major Alberta oil sands projects. The primary areas of risk are:

- Design changes that are made after field move in;
- Craft productivity performance and availability;
- Impacts due to the size of the project.

The implementation plan includes the following areas which can be identified on the Project Schedule, which is included at the end of this section.

Contracting

The Joslyn Oil Sands Project EPC plan requires the selection of a single prime contractor for all phases of the project. A key subcontractor that is needed to ensure project success is a module pre-assembly contractor. The selection of this subcontractor will be made during the Design Basis Memorandum (DBM) phase of the project in order to ensure that the contractor will be available to meet the project schedule.

Engineering

The Joslyn Oil Sands Project engineering plan is designed to support construction in order to ensure the success of the project. Engineering deliverables will be integrated into procurement functions in order to support construction sequencing and efficient progress.

Preliminary engineering is scheduled to begin in the first part of 2004 with feasibility studies in support of the permitting process. Coincident with the permitting process, the process and geotechnical testing programs will confirm data for input to the DBM. The DBM will be completed during this period and will include equipment sizing, specifications and the identification of long lead items. At this phase the project the engineering will be 25 percent complete.

Approval of the DBM initiates the Engineering Design Specification (EDS) effort scheduled to start in the first quarter of 2007. This phase will finalize the process flow diagrams and P&ID's; work on mechanical layouts and general arrangement drawings; finalize the size of the equipment; and prepare specifications and issue them for quotes. Completion of the EDS phase will bring the project engineering to approximately 65 percent completion.

After approval of the EDS report, Detail Engineering design will begin to finish out the engineering effort. The Detailed Engineering phase is scheduled to begin in the third quarter of 2007. Certified vendor information will be incorporated in the layout drawings, electrical design will be finalized as well as all earthwork and foundation design. This latter design work is necessary to support civil earthwork required for site clearing which is the start of the construction phase scheduled at the end of the fourth quarter 2007 and leads into the start of foundation work commencing in the first quarter 2008. Additionally, engineering design of the module packages will begin in the first quarter 2007 so it can be issued to fabricators and vendors during the second and third quarters of 2008 in order to accommodate the start of module pre-assembly during fourth quarter of 2008.

Procurement

Procurement for the project will be conducted on a worldwide basis in an effort to minimize both project cost and delivery schedule. All the while, a coordinated effort will be maintained between procurement, engineering and QA/QC to assure technical specifications, construction sequencing and constructability requirements are optimized.

Field subcontracting will follow current Alberta practices of unit pricing or lump sum contracts. This includes permanent construction facilities, temporary facilities and pre-assembly sites.

Construction

The construction approach is expected to be a combination of field fabricated systems, equipment and facilities along with field installation of pre-assemblies of items shop fabricated or manufactured offsite and shipped as complete units or interconnecting modules. These off site-manufactured pre-assemblies will be sequenced with the construction schedule to minimize costs and delays to the project.

The remote location of the project site requires camp facilities for craft personnel. The construction workweek is planned for 4 day – 10 hours per day with occasional overtime, as required.

Sequencing of construction work is scheduled to keep the construction manpower peak to less than 1,000 craft. This type of work plan also maximizes field productivity and lowers total camp and indirect support costs.

The majority of the project site construction is spread across eight quarters with civil construction starting during the fourth quarter of 2007 with site clearing, road construction and site prep. The majority of the foundation work is to be done during the second and third quarters of 2008. The completion of foundations during the fourth quarter of 2008 allows for the final setting of major equipment. First procured equipment deliveries will begin in the third quarter of 2008 and be completed by the second quarter of 2009.

Module fabrication and pipe rack pre-assembly is scheduled to begin at an Edmonton site during the fourth quarter of 2008. The first preassembled pipe racks will be completed by January 2009. They will, then, be shipped via truck to the Joslyn jobsite. The last pipe rack module shipment will complete by March 2009 prior to road restrictions that come into effect, which will limit oversize payload transport.

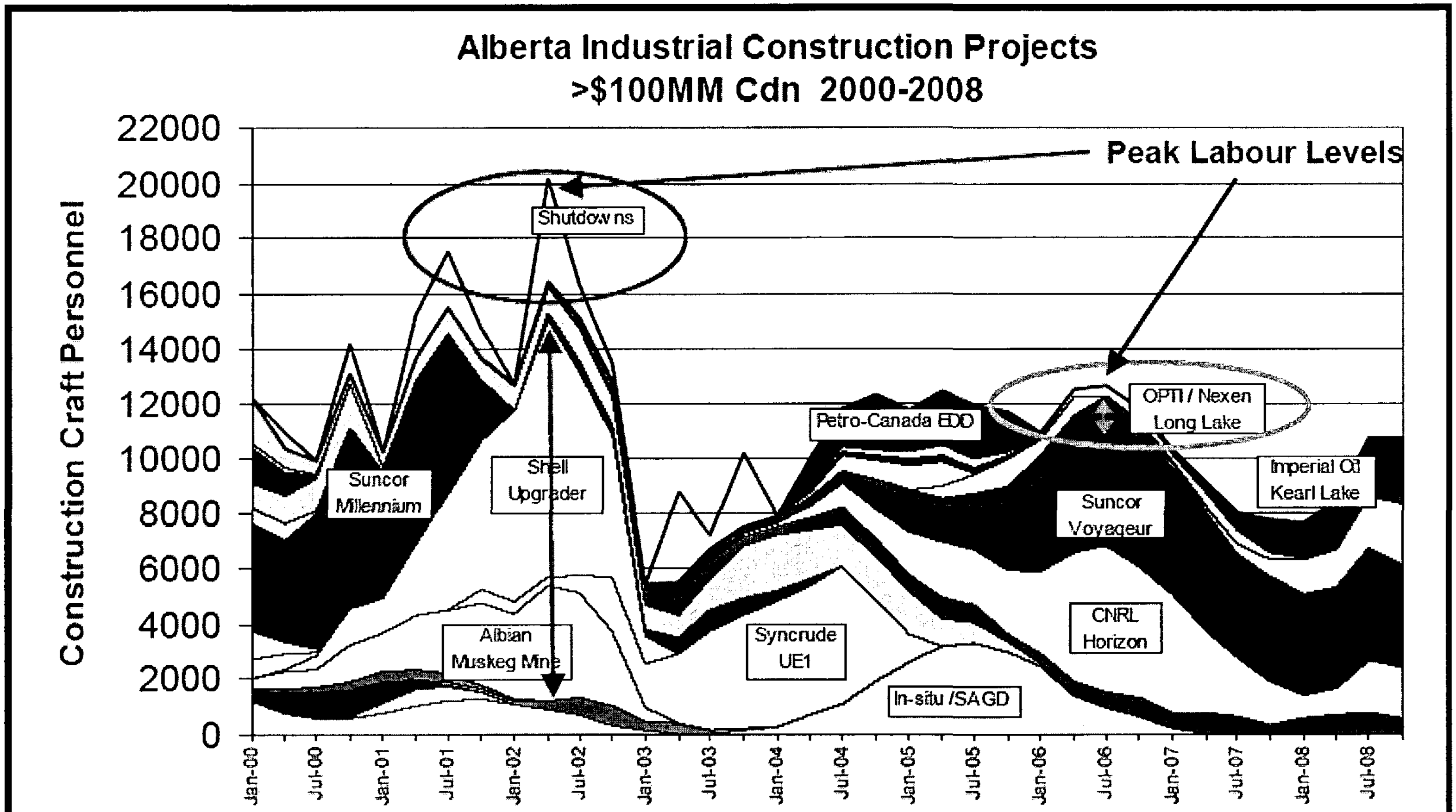
Start-up and Commissioning

Commissioning will be conducted by the EPC contractor on all mechanically complete systems. This activity will begin in the third quarter of 2009 and overlaps the construction and installation phase. It is estimated that a six-month time frame is required for commissioning and will continue until the overall plant is ready for start-up during the first quarter of 2010. Once the systems within a logical plant area have been commissioned, plant areas will methodically be transferred to the owner for maintenance responsibilities.

Logistics and Resource Planning

Logistic costs and craft performance are major risk factors contributing to cost overruns for recent Alberta Oil Sands projects. These risk areas can be mitigated by the use of a good project implementation plan. The risk of overruns on the Joslyn project will be minimized if construction begins during the fourth quarter 2007. Figure 1-6 depicts major oil sand projects and their anticipated construction schedules and manpower requirements.

The start of construction for the Joslyn Project is positioned to take advantage of craft resource availability and to obtain the most highly skilled and productive craft workers as they are released from the other projects. When construction for the project begins during the fourth quarter of 2007, other major Alberta projects, such as CNRL, will already have completed portions of their construction and begin reducing their manpower requirements. It is anticipated that craft skills will be released from these other projects in the sequence for which the Deer Creek project needs them to enter the workforce.



Source: Fluor Inc., November, 2003

Figure 1-6
Craft Personnel Demand

EPC Phase Control

The Deer Creek Joslyn Oil Sands Project will implement phase control procedures to minimize the risk of design changes during the construction phase of the project when the cost impact is highest. The Project Definition Rating Index (PDRI) from the Construction Industry Institute (CII) will be the basis for the methodology to be used on this project. This methodology ensures that project deliverables are defined before the next EPC phase is initiated. Implementation begins during the DBM, EDS and Detailed Engineering phases. Approval is required prior to proceeding to the next phase of the project whether it is engineering, procurement or construction mobilization.

1.11. Capital Cost Summary

Over the projected 30 year life of this project, there will be a phased approach that will increase the production in increments of 50,000 bbl/d up to a total of 200,000 bbl/d. These phased increases occur every three years beginning with the first in Year 1 and ending with the fourth phase in Year 10. The mining, processing, and site service areas will require capital expenditures to support the increased production rates. A summary of the phased increases is shown below in Table 1-11.

Table 1-11
Phased Production Increases

Description	Year	Production (bbl/day)	Production (bbl/yr)
Train 1	1	50,000	18,250,000
Train 2	3	100,000	36,500,000
Train 3	7	150,000	54,750,000
Train 4	10	200,000	73,000,000

The pre-production capital cost of this project is summarized below in Table 1-12.

Table 1-12
Pre-Production Capital Cost
Train 1

Description	Cost (C$)
Engineering	$34,995,000
Mining	$129,041,000
Processing	$530,545,000
Owners Cost	$10,500,000
Total Capital	**$705,081,000**

Capital cost expenditures, included in the initial project, start in year minus 4 (-4) with the beginning of the Design Basis Memorandum, DBM. The subsequent stages, the Engineering Design Specification, EDS, detailed engineering, construction and commissioning phases of the project make up the remainder of pre-production capital costs.

Owner's cost was provided by Deer Creek and includes those costs incurred after project approval (estimated to be first quarter 2007, Year –3). Costs incurred prior to this year are considered Corporate Development costs. Owner's costs include mine planning and engineering, in-fill drilling for mine design, communications and IT, technology licensing, EPC representation, operations staffing and training, and commissioning and first fills.

Table 1-13 below summarizes the total life of project capital expenditure.

Table1-13
Summary of Capital Cost
Total Life of Project

Description	Cost (C$)
Engineering	$124,723,000
Mining	$1,367,510,000
Processing	$2,772,486,000
Owners Cost	$10,500,000
Total Capital	**$4,275,219,000**

1.12. Operating Cost Summary

For the purpose of the study, overall project operating costs are divided into four primary headings:

- Power Plant;
- Mining;
- Processing;
- General and Administrative.

Included in the first three are operating and maintenance labor, parts and supplies, and major commodities. General and Administrative costs include staff to cover general management, financial and procurement, labor relations and safety, information technology, and environmental functions. Also, cost for busing employees from Fort McMurray, as well as various fees and community relation charges are applied under this heading.

In developing the operating costs for the mine and process, the following commodity prices shown on Table 1-14 were used:

Table 1-14 Commodity Prices	
Commodity	**Unit Price**
Diesel Fuel	C$0.35 per Liter
Synthetic Crude Oil	US$24.00 per bbl
Naphtha	US$23.00 per bbl
Natural Gas	C$5.00 per GJ
Purchased Power from the ATCO Grid	C$86.00 per MWh
Power Sold to the ATCO Grid	C$48.00 per MWh

Back-up power is required during the power plant maintenance outages and must be purchased from the grid. The total annual requirements are estimated to be 2,190 MWh. There may also be opportunities to sell excess power back to the grid system.

The annual Train 1 operating costs for the Joslyn Oil Sands mine and processing plant are summarized in Table 1-15 and presented graphically in Figure 1-7. Approximate work force levels are also shown.

Table 1-15 Annual Operating Costs for Train 1 (Yr 1-3)			
	Cost per Year (C$)	**$/bbl**	**Personnel**
Power	$31,172,910	$1.71	10
Mining	$63,384,073	$3.47	250
Processing	$37,211,155	$2.04	110
General & Administrative	$10,322,018	$0.57	45
Total	**$142,090,155**	**$7.79**	**415**

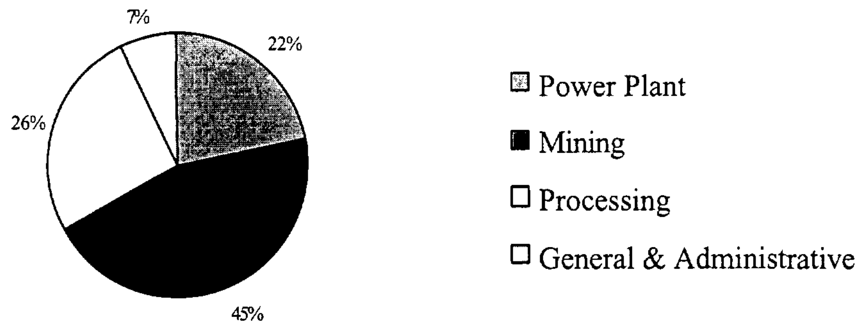


Figure 1-7
Summary of Annual Operating Costs
Train 1

As can be seen from the summaries, mining accounts for 45 percent of the total annual operating cost. This is followed by processing at 26 percent, the power plant at 22 percent, and G&A at 7 percent.

The cost of natural gas for power generation and thermal heating requirements make up more than 30 percent of the total operating cost. Total labor, including G&A labor, account for 12.5 percent of the total operating cost.

Below are Tables 1-16 through 1-18 summarizing the total annual operating costs in years 5, 8, and 11. These years represent operating conditions with 2 trains (100,000 bbls/d), 3 trains (150,000 bbls/d), and 4 trains (200,000 bbls/d) in operation.

Table 1-16
Annual Operating Costs for Trains 1-2 (Yr 4-6)

	Cost per Year (C$)	$/bbl	Personnel
Power	$62,345,820	$1.71	20
Mining	$119,882,875	$3.28	400
Processing	$68,465,414	$1.88	155
General & Administrative	$12,278,396	$0.34	60
Total	**$262,972,505**	**$7.20**	**635**

Table 1-17 Annual Operating Costs for Train 1-3 (Yr 7-9)			
	Cost per Year (C$)	$/bbl	Personnel
Power	$93,518,730	$1.71	30
Mining	$165,791,767	$3.03	600
Processing	$100,711,919	$1.84	210
General & Administrative	$14,112,972	$0.26	75
Total	**$374,135,388**	**$6.83**	**915**

Table 1-18 Annual Operating Costs for Train 1-4 (Yr 10-30)			
	Cost per Year (C$)	$/bbl	Personnel
Power	$124,691,640	$1.71	40
Mining	$235,103,541	$3.22	700
Processing	$131,399,793	$1.80	250
General & Administrative	$15,592,088	$0.21	85
Total	**$506,787,062**	**$6.94**	**1,075**

By the Year 30, total operating cost are expected to decrease to $6.08 per barrel. Life of project operating costs total $12,882,711,000, resulting in an average operating cost for the life of the project of $6.99 per barrel. A more detailed annual operating cost summary for the duration of the project is included in the Economic Analysis Summary.

1.13. Economic Analysis Summary

1.13.1. Results

The capital and operating costs developed for the Joslyn Project were combined with the project development plan and production schedule to produce a cash flow model to evaluate the relative economics of the project. All capital and operating costs, for the purposes of this model, are presented in constant December 2003 Canadian dollars and have not been escalated. Where necessary, U.S. Dollars are converted to Canadian Dollars using an exchange rate of C$1.30 per US$1.00.

Table 1-19 contains a summary of the results of the cash flow analysis.

Table 1-19
Results of Cash Flow Analysis

Statistic	Units	Value
Life of Mine (LOM)	Years	30
Initial Production Rate	bbls/day	50,000
Ultimate Production Rate, Post Year 10	bbls/day	200,000
LOM Bitumen Production	bbls x 1000	1,843,250
WTI Crude Oil Price – Long Term Ave.	US$	25.00
Synthetic Crude Oil Price	US$	24.00
Lloyd Blend Price	C$	17.75
Bitumen Netback Price	C$	16.36
LOM Revenue	C$ x 1,000	26,902,728
LOM Capital Cost	C$ x 1,000	4,275,219
LOM Operating Cost	C$ x 1,000	12,882,711
Average Unit Operating Cost	C$/bbl	6.99
Internal Rate of Return	%	14.1
Net Present Value @ 8% discount rate	C$ x 1,000	773,961

1.13.2. Production Schedule and Assumptions

The mine as currently defined has a 30-year operating life. Capital costs included in the project begin in year minus 4 with the initiation of the Design Basis Memorandum, DBM. The subsequent stages, the Engineering Design Specification, EDS, detailed engineering, construction and commissioning phases of the project make up the remainder of pre-production capital costs. The design and construction of the ultimate, 200,000 bbl/day production facility is divided into four 50,000 bbl/day stages, which begin production at three year intervals, years 1, 4, 7 and 10. The stages are not step changes but are incorporated to allow for construction and startup of each train plus a one-year production ramp up period for each stage. The production assumed for stage 1, in its first year is 60 percent of design capacity and for stages 2, 3 and 4; 80 percent of production capacity in each of their ramp up years. The next significant period in the schedule will be the move from the northern ore body to the southern ore body in Year 18. Engineering and construction in preparation for this move will occur in Years 16 through 19.

1.13.3. Sales and Revenue

The revenue for the project is based on the sale of bitumen as a 50:50 blend of synthetic crude oil and bitumen, termed SynBit, and secondarily, the sale of excess power, produced in the power plant, to the grid.

The Deer Creek bitumen will be blended with synthetic crude oil and pumped from the Joslyn Project to the Enbridge terminal facilities in Fort McMurray. From there it will be pumped to Hardisty, Alberta and on through the Enbridge pipeline to refineries in the Midwest, likely Chicago. The price for SynBit will be based on an adjustment to the price of Lloyd Blend at Hardisty, Alberta. The Lloyd Blend, LLB, price is in turn based on the price of West Texas Intermediate crude at Cushing, Oklahoma, WTI, price.

Revenue in the cash flow is determined from the netback price of bitumen at the Joslyn Project. Payment is received based on sales of the SynBit blend at Hardisty. The netback price of bitumen includes the cost of synthetic crude oil in the blend and the transportation of the SynBit from the Joslyn Mine to Hardisty. The components of the price calculation are included in the price data section of the cash flow model and are as follows:

- The base price for the calculation is the WTI price.
- Synthetic crude oil typically trades at a discount of US$1.00 to the WTI price.
- The differential between the Lloyd Heavy Blend, LLB, price and the WTI price is a relatively constant 29%. LLB price is approximately 71% of WTI.
- The SynBit price is approximately US$ 0.85 higher than the LLB price.

- Transportation costs from the Joslyn Project to Ft. McMurray are approximately US$0.18/bbl, which represents the operating and maintenance costs of the pumps and pipeline, which are owned and operated by Deer Creek.
- Transportation costs from Ft. McMurray to Hardisty is the Enbridge pipeline toll of C$ 1.00 or US$ 0.70.
- The netback price of bitumen is the sale price of SynBit in Hardisty less the transportation charges from Joslyn to Hardisty and the cost of the synthetic crude oil in the blend. The remaining revenue is assigned to the bitumen. The netback price is the value of the bitumen normalized to a full barrel.

The netback bitumen price used in the model is based on a long term WTI price of US$ 25.00, an SCO price of US $24/bbl and an LLB price of US$17.75. The resulting netback price of bitumen at the Joslyn Mine is C$ 16.36. A list of references is provided in Section 14.

1.13.4. Cash Flow Projections

The unlevered cash flow model developed for the project is included at the end of Section 14. The model includes revenue capital and operating costs for the entire 30-year life of mine and includes royalties and taxes. Cash flow begins in year minus four, with commencement of the DBM. The construction of the ultimate facilities is staged in three-year intervals. Tables 1-20 and 1-21 show capital and operating costs by year.

Capital Costs

The capital cost of the Joslyn Project is presented in detail in Section 12. A summary of the initial and total capital costs for the mine, process facilities and infrastructure including the power plant are given in Tables 12-2 and 12-3 in Section 12. The complete annual capital cost for the life of the project is provided at the end of this section.

Sustaining Capital

Mine capital requirements primarily include purchased equipment and replacement of that equipment throughout the life of the mine. Process sustaining capital consists primarily of the addition of new ore preparation facilities during years 17, 18 and 19, when mine production shifts to the southern ore body.

Owner's Costs

Owner's costs, provided by Deer Creek, include pre-production capital costs beginning after project approval in 2007 or year minus 3. Owner's costs prior to 2007 are deemed Corporate Development Costs and have been excluded from the cost of the project. A total of

C$10,500,000 are included in the Owner's Costs and are distributed in the year of occurrence in the cash flow model.

Working Capital

Working capital is the amount of capital required to operate and maintain the mine and process facilities for the delay period between initiating production and receiving payment for the product.

Operating Costs

Operating costs are presented in Section 13 of this report and are divided into three main categories, mining, process, and general and administrative. The complete annual operating cost for the life of the project is provided at the end of this section.

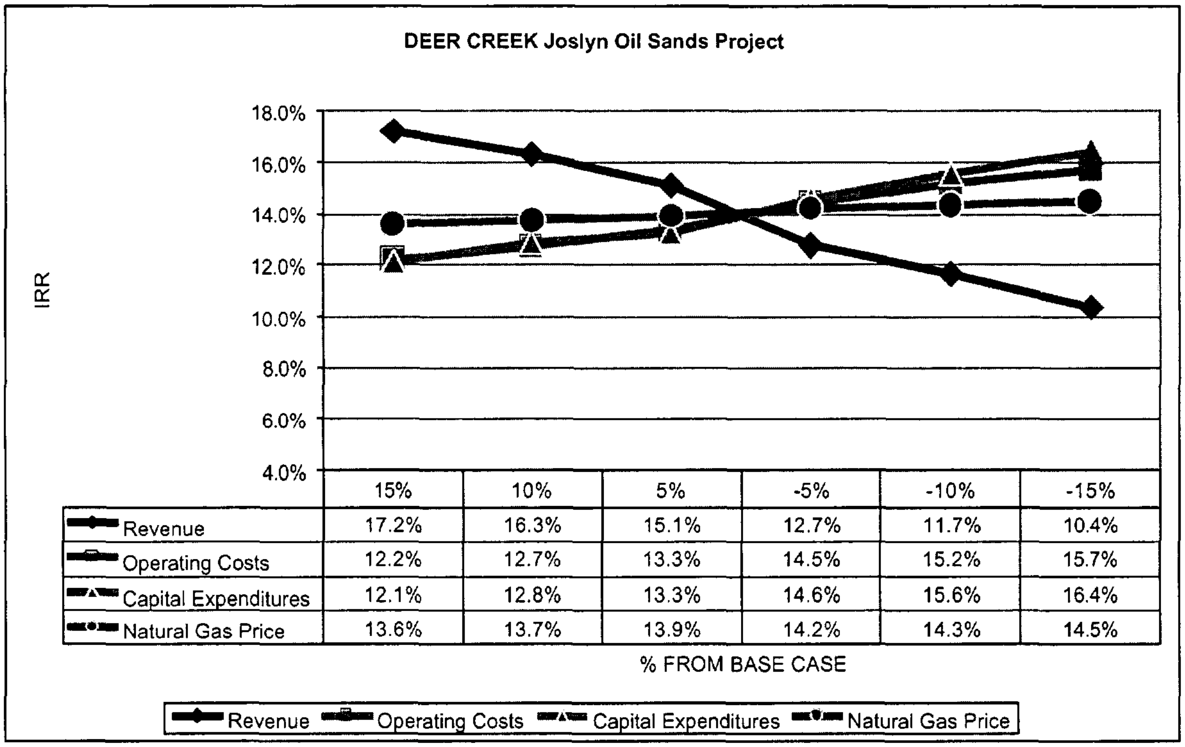
1.13.5. Depreciation, Taxes and Royalties

Capital Expenditures were grouped into capital cost allowance category Class 41 for depreciation purposes. Normally, Class 41 assets receive a 25 percent declining balance rate. An exception, known as Class 41 (a) provision is permitted for a new mine or a major expansion of an existing mine. Class 41 (a) allows a taxpayer to deduct at a rate of up to 100 percent of project income. The model takes advantage of this assumption to shift the first year of income taxes paid to Year 9. Royalties were calculated at 1 percent of Revenues or 25 percent of Revenues minus Operating Costs. Revenue for the royalty calculation excludes power sales and operating costs exclude interest and depreciation. The long bond rate, to calculate the return on capital, was assumed to be 5.5 percent.

1.13.6. Sensitivities

Sensitivities were performed to determine the affect of changes in the key economic parameters on the internal rate of return, IRR, for the Joslyn Project. Sensitivity curves for capital cost, operating cost and revenue are presented in Figure 14-1. Revenue is the parameter with the greatest effect on the internal rate of return. The effects of capital cost and operating cost are similar for the base case and are slightly less sensitive than revenue.

Figure 1-8
Joslyn Sensitivity Analysis



	15%	10%	5%	-5%	-10%	-15%
Revenue	17.2%	16.3%	15.1%	12.7%	11.7%	10.4%
Operating Costs	12.2%	12.7%	13.3%	14.5%	15.2%	15.7%
Capital Expenditures	12.1%	12.8%	13.3%	14.6%	15.6%	16.4%
Natural Gas Price	13.6%	13.7%	13.9%	14.2%	14.3%	14.5%

Revenue is dependent on the production rate, the WTI price of crude oil, and the price of synthetic crude oil, which must be purchased from a local refiner for blending with the recovered bitumen for transportation.

Factored Order Of Magnitude 30,000 bbl/day Case

For an order of magnitude comparison, the capital and operating costs, and revenue, for the 50,000 bbl/day case were reduced by factoring to represent a 30,000 bbl/day case. The results were entered into the Deer Creek cash flow model and the relative economics were observed. The ultimate production rate was 200,000 bbl/day after Year 10 and the production facilities were staged at 30,000; 56,667; 56,667; 56,667 bbls/day in Years 1, 4, 7 and 10. The results are summarized in Table 1-20.

Table 1-20
Results of Factored 30,000 bbl/day Cash Flow Analysis

Statistic	Units	Value
Life of Mine (LOM)	Years	30
Initial Production Rate	bbl/day	30,000
Ultimate Production Rate, Post Year 10	bbl/day	200,000
LOM Bitumen Production	bbls x 1000	1,800,920
LOM Revenue	C$ x 1,000	26,136,200
LOM Capital Cost	C$ x 1,000	4,223,062
LOM Operating Cost	C$ x 1,000	12,564,083
Average Unit Operating Cost	C$/bbl	6.98
Internal Rate of Return	%	13.5
Net Present Value @ 8% discount rate	C$ x 1,000	682,453

The IRR for the order of magnitude 30,000 bbl/day case was 13.5 percent versus 14.1 percent for the 50,000 bbl/day case and the NPV at 8% for the 30,000 bbl/day and 50,000 bbl/day cases were $682,453,000 and $773,961,000 respectively. The two cases behaved similarly, though the real difference was in the net cash flow. The 50,000 bbl/day case generated positive net cash flow in year 4, while the 30,000 bbl/day had positive net cash flow in Year 7. With respect to the overall project economics and time to positive cash flow, the higher the initial production rate, the better. In choosing an initial production rate, the availability of financing would be the significant factor.

1.14. Conclusions and Recommendations

This section presents the overall findings of the study and offers suggestions to further develop the project.

1.14.1. Conclusions

Analysis of the geologic data has identified a significant in-place resource that is suitable for evaluation as both surface mineable and SAGD bitumen reserves.

The Study has demonstrated that conventional truck/shovel methods can be applied to mining the Joslyn Project deposit.

Based on data from similar deposits and projects in the area, the field-proven process technology selected can be effectively implemented to produce a synthetic crude oil / bitumen blend for sale.

With proper management and open dialogue with primary stakeholders, environmental issues and permitting should not present an undue risk to project development.

Staged production increases are a favorable approach to limiting initial capital, while providing significant cash flow for future expansion.

Based on projected craft labor demand curves for projects in the region, the first production train can be constructed most efficiently during the projected low starting in 2007. It is also recommended that a single prime contractor be used, that project phase controls be employed and that engineering be sufficiently completed prior to beginning field activity.

Current market information on bitumen and sythetic crude oil pricing and transport supports the economics of the project. The economic evaluation results indicate a viable project with an internal rate of return of 14.1 percent assuming a long term WTI oil price of US$ 25.00 and a bitumen netback price of C$16.36.

The final conclusion is that the project warrants advancing to the next stage of development, which includes more geologic exploration, process flowsheet engineering and permit application.

1.14.2. Risks and Opportunities

Risks and opportunities have been identified in each area of the study, for future consideration. The principle issues are summarized below.

Further geological evaluation will necessitate the acquisition of additional resource, fines and overburden data through exploration programs. Additional data should then be incorporated into current databases and models.

Site specific groundwater and geotechnical data were not available for mine planning. It was not needed for this level of study, but such data will need to be acquired and evaluated in the next stage of engineering.

Also relating to the mine, advancements in technology such as moveable OPP's and ore slurrying will continue to evolve to help minimize truck haulage costs. Although the Study selected permanent OPP installations, opportunities may develop for more mobile and relocatable designs to bring cost savings. These should be given more consideration in advanced stages of project engineering. This applies as well to the Year 17 move to Pit 8 in the south, where large capital expenditures have been estimated. These could be dramatically reduced using mine equipment, personnel and management.

The particle size distribution and especially the fraction of fines in the ore, has yet to be determined through testing. This poses a risk on the proposed crushing circuit, the preliminary hydrotransport design and the performance of the primary separation vessel in extraction. It also has a significant affect on the assumed overall bitumen recovery. The overall bitumen recovery for this study was based on current best available information from similar operations and was not verified by test work. While the proposed froth treatment process is not new (currently used in the oil & gas industry), it is unproven in the oil sands industry and may require pilot test work.

There are two pressing issues that affect environmental permitting. The first involves the need for early muskeg dewatering in the plant site areas prior to application approval. This may require a special permit to keep the project on schedule. Secondly, a small resource area is being sterilized from surface mining due to conflict with the CNRL access road and the project tailings pond. This will complicate the application and approval process.

Construction of Train 1 on schedule and within budget is extremely important. It is critical that construction is underway in 2007 and 2008, which is projected to be a period of low craft labor demand in the area. This is a planned opportunity, when labor availability and productivity is expected to be high. Using a single prime EPC contractor, to optimize project activities between the engineering, procurement and construction phases is another opportunity. The third opportunity for success is to maximize modularization, including assembly of amenable plant systems in off-site fabrication and assembly shops, to reduce the cost of construction and reduce required onsite manpower.

There are issues that relate to project economics that are just as important. Pricing for bitumen sales and transport, synthetic crude purchases and transport, and natural gas supplies have been based on the best information available. The project's economic dependence on these issues, warrant a more refined level of definition, either by detailed market study or negotiation with suppliers for option contracts.

1.14.3. Recommendations

Although this study excluded potential synergies associated with SAGD development, it is obvious that they should be addressed in the next level of development planning. An optimization study for co-development should guide the project scope for future study of both SAGD and mineable resources.

During the economic analysis, it became apparent that the availability and price of synthetic crude oil for blending was of paramount significance. In addition to the suggestions above, an option to upgrade enough bitumen to synthetic crude oil for the plant needs may be advisable. This would secure a critical aspect of the project.

The next steps of project development should address geologic infill exploration and evaluation, process engineering to refine the flowsheet and permit application. Drilling programs should be scheduled to gain additional information on the deposit, and evaluation studies should immediately follow to update current information. Process flowsheets should be finalized through lab or pilot testwork in conjunction with technology suppliers, which include vendors and licensers. Baseline studies for preparation of the EIA are underway and should continue along with the engineering required to support permit application preparation and the ongoing permitting process.

1.15. Drawings

	Party	Identification	Title
1	Norwest	Figure 2	Surface Mineable and SAGD Resources by Area
2	Washington	06-11-100-001	Overall Mining Pit Plan
3	AMEC	142100-000-110-DD-0001	Oil Sands Bitumen Production Plant Overall PFD
4	Washington	12-11-100-001	Site Plan
5	AMEC	142100-000-131-DL-0001	Oil Sands Production Plant Plot Plan for 4 Trains
6	AMEC	142100-100-131-DL-0001	Ore Preparation Plant General Arrangement
7	Washington	18-11-300-002	Partial Site Plan Process Maintenance Area
8	Washington	18-11-300-001	Partial Site Plan Truck Maintenance Area
9	Washington	Sheets 1 & 2	Deer Creek Project Preliminary Feasibility Schedule

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OFFICE OF INTERNATIONAL CORPORATE FINANCE

July 21, 2004

Deer Creek Energy Limited
2600 Bow Valley Square 2
205 – 5th Avenue S. W.
Calgary, Alberta
T2P 2V7

Attention: Mr. Glen C. Schmidt, President and Chief Executive Officer

Dear Sirs:

Re: Initial Public Offering of Common Shares

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**") understand that Deer Creek Energy Limited (the "**Corporation**") proposes to issue and sell 16,900,000 Common Shares (as hereinafter defined) (the "**Firm Shares**") pursuant to the Prospectus (as hereinafter defined) and this Agreement.

Upon and subject to the terms and conditions hereof, the Underwriters hereby severally, and not jointly, offer to purchase from the Corporation, in the respective percentages set out in Section 22, and the Corporation hereby agrees to sell to the Underwriters all but not less than all of the Firm Shares, at a purchase price of $9.50 per Firm Share.

The Corporation hereby grants to the Underwriters an option (the "**Over-Allotment Option**") to purchase up to that number of Common Shares equal to 10% of the Firm Shares (the "**Over-Allotment Shares**"), at the Underwriters' election, exercisable in whole or in part, for a period of 30 days from the Closing Date (as hereinafter defined) for the purpose of covering over-allotments, if any, and for market stabilization purposes. In the event and to the extent that the Underwriters exercise the Over-Allotment Option, subject to the terms and conditions hereof, the Underwriters hereby severally, and not jointly, agree to purchase from the Corporation the number of Over-Allotment Shares as to which the Over-Allotment Option shall have been exercised in the respective percentages set forth in Section 22, and the Corporation hereby agrees to sell such number of Over-Allotment Shares to the Underwriters at a purchase price of $9.50 per Over-Allotment Share.

The Underwriters understand that the Corporation will prepare and file, in accordance with the terms hereof, the Prospectus and all other necessary documents in order to qualify the Offered Shares for distribution to the public in each of the Qualifying Provinces (as hereinafter defined).

1. Definitions

In this Agreement:

(a) "**ABCA**" means the *Business Corporations Act* (Alberta);

(b) "**Additional Closing Date**" and "**Additional Closing Time**" have the meanings ascribed thereto in Section 15(b);

(c) "**Agreement**" means this agreement between the Underwriters and the Corporation and not any particular Article or Section or other portion except as may be specified, and words such as "hereto", "herein", "hereunder" and "hereby" refer to this Agreement as the context requires;

(d) "**Applicable Securities Laws**" means all applicable securities and corporate laws, rules, regulations, instruments, notices, blanket orders, statements, circulars, procedures and policies in the Qualifying Provinces;

(e) "**ASC**" means the Alberta Securities Commission;

(f) "**Business Day**" means a day which is not Saturday or Sunday or a statutory holiday in the City of Calgary, Alberta;

(g) "**Closing Date**" means July 29, 2004 or such other date as the Underwriters and the Corporation may agree which, subject to the entitlement of the Underwriters pursuant to Section 13 to terminate their obligations hereunder, is not later than September 1, 2004;

(h) "**Closing Time**" means 6:30 a.m. (Calgary time) or such other time, on the Closing Date, as the Underwriters and the Corporation may agree;

(i) "**Common Shares**" means the common shares in the capital of the Corporation;

(j) "**Continuing Underwriters**" has the meaning ascribed thereto in Section 22(b);

(k) "**Corporation's Counsel**" means Bennett Jones LLP or such other legal counsel as the Corporation, with the consent of the Underwriters acting reasonably, may appoint;

(l) "**Environmental Laws**" means applicable federal, provincial, state, municipal or local laws, regulations, orders, government decrees or ordinances with respect to environmental, health or safety matters;

(m) "**Exchange**" means the Toronto Stock Exchange;

(n) "**Final MRRS Decision Document**" means a decision document in respect of the Prospectus issued by the ASC in accordance with the MRRS;

(o) "**Financial Statements**" means the audited financial statements of the Corporation as at and for the years ended December 31, 2003, 2002 and 2001 and the unaudited financial statements of the Corporation as at and for the three months ended March 31, 2004 and 2003 as set forth in the Prospectus;

(p) "**GLJ Associates**" means Gilbert Laustsen Jung Associates Ltd.;

(q) "**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;

(r) "**GST**" means Goods and Services Tax provided for in the *Excise Tax Act* (Canada);

(s) "**Joslyn Lease**" means the sections of land contained within Alberta Oil Sands Lease No. 7280060T24 and Alberta Oil Sands Permit No. 7099110070;

(t) "**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 Resources Fund;

(u) "**Material Agreements**" means this Agreement, the Joint Venture Agreement and the Talisman Debenture;

(v) "**MRRS**" means the mutual reliance review system for prospectuses and annual information forms provided for under National Policy 43-201 "Mutual Reliance Review System for Prospectuses and Annual Information Forms" among the Securities Commissions and the MRRS MOU, as defined therein;

(w) "**Norwest**" means Norwest Corporation;

(x) "**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);

(y) "**Offered Shares**" means collectively, the Firm Shares and the Over-Allotment Shares;

(z) "**Offering**" means the offering of Firm Shares and Over-Allotment Shares contemplated by this Agreement and the Prospectus;

(aa) "**Preliminary Prospectus**" means the preliminary prospectus in respect of the distribution of the Offered Shares dated June 11, 2004, in the English and French languages;

(bb) "**Prospectus**" means the (final) prospectus dated July 21, 2004 and any amendments thereto in respect of the distribution of the Offered Shares, in the English and French languages;

(cc) "**Public Record**" means all information filed by or on behalf of the Corporation with the Securities Commissions, including, without limitation, the Preliminary Prospectus, the Prospectus, any Supplementary Material and any other information filed with any Securities Commission in compliance, or intended compliance, with any Applicable Securities Laws;

(dd) "**Qualifying Provinces**" means each of the provinces of Canada;

(ee) "**Refusing Underwriters**" and "**Refusing Underwriters' Shares**" have the meanings ascribed thereto in Section 22(b);

(ff) "**Securities Commissions**" means the securities commissions or similar regulatory authorities in the Qualifying Provinces;

(gg) "**Selling Dealer Group**" means the dealers and brokers other than the Underwriters who participate in the offer and sale of the Offered Shares pursuant to this Agreement;

(hh) "**subsidiary**" has the meaning ascribed thereto in the *Business Corporations Act* (Alberta);

(ii) "**Supplementary Material**" means, collectively, any amendment to the Preliminary Prospectus or the Prospectus, any amendment or supplemental prospectus or ancillary materials that may be filed by or on behalf of the Corporation under the Applicable Securities Laws relating to the qualification for distribution of the Offered Shares under Applicable Securities Laws;

(jj) "**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;

(kk) "**Underwriters' Counsel**" means Stikeman Elliott LLP or such other legal counsel as the Underwriters may appoint;

(ll) "**United States**" or "**U.S.**" means the United States of America, its territories and possessions, any state of the United States and the District of Columbia;

(mm) "**U.S. Placement Memorandum**" has the meaning ascribed thereto in Section 18(a)(xi); and

"**misrepresentation**", "**material change**" and "**material fact**" shall have the meanings ascribed thereto under the Applicable Securities Laws; "**distribution**" means "distribution" or "distribution to the public", as the case may be, as defined under the Applicable Securities Laws and "**distribute**" has a corresponding meaning. Wherever the singular or masculine is used in this Agreement, the same shall be read as plural, feminine or body corporate as the context requires.

2. Fee

In consideration for their services in underwriting the distribution to the public of the Offered Shares in the Qualifying Provinces and, in accordance with Section 18, in the United States: (a) the Corporation agrees to pay the Underwriters at the Closing Time a fee of 5.0% of the gross proceeds of the sale of Firm Shares, being $0.475 per Firm Share purchased (an aggregate amount of $8,027,500 in respect of the Firm Shares); and (b) the Corporation agrees to pay the Underwriters at the Additional Closing Time a fee of 5.0% of the gross proceeds of the sale of Over-Allotment Shares, being $0.475 per Over-Allotment Share (an aggregate amount of $802,750 in respect of the Over-Allotment Shares if the Over-Allotment Option is exercised in full).

For greater certainty, the services provided by the Underwriters in connection herewith will not be subject to GST and taxable supplies provided will be incidental to the exempt financial services provided. However, in the event that Canada Revenue Agency determines that GST is exigible on the fees payable to the Underwriters hereunder, the Corporation agrees to pay the amount of GST exigible on the fees payable to the Underwriters hereunder by the Corporation forthwith upon the request of the Underwriters.

3. Distribution and Certain Obligations of the Underwriters

(a) During the course of the distribution of the Offered Shares to the public by or through the Underwriters, the Underwriters will offer and sell the Offered Shares to the public only in those jurisdictions where they may be lawfully offered for sale or sold. For the purposes of this Section 3, the Underwriters shall be entitled to assume that the Offered Shares may be lawfully offered for sale and sold in the Qualifying Provinces if the Final MRRS Decision Document has been issued evidencing that a receipt for the Prospectus has been issued by the Securities Commissions of each of the Qualifying Provinces, provided the Underwriters have not been notified in writing by the Corporation of any circumstance that would legally prohibit such distribution. The Underwriters will comply with applicable laws, including the Applicable Securities Laws, in connection with the offer to sell or distribution of the Offered Shares. Except in the Qualifying Provinces, the Underwriters will not, directly or indirectly, solicit offers to purchase or sell the Offered Shares or deliver the Preliminary Prospectus, the Prospectus or any Supplementary Material so as to require registration of the Offered Shares or filing of a prospectus with respect to the Offered Shares under the laws of any jurisdiction, including, without limitation, the United States. Any offer or sale of Offered Shares in the United States will be made in accordance with Section 18 of this Agreement. Each Underwriter will cause similar undertakings to be contained in any agreements among the members of any Selling Dealer Group formed for the distribution of the Offered Shares and will require any member of the Selling Dealer Group formed for the distribution of the Offered Shares to comply with Applicable Securities Laws and U.S. securities laws, as applicable;

(b) The Underwriters will complete and will use their reasonable efforts to cause members of the Selling Dealer Group (if any) to complete the distribution of the Offered Shares promptly after the Closing Time. Peters & Co. Limited and RBC Dominion Securities Inc. will promptly notify the Corporation when, in the Underwriters' opinion, the Underwriters and the members of the Selling Dealer Group (if any) have ceased distribution of the Offered Shares and, promptly after completion of the distribution, will provide the Corporation, in writing, with a breakdown of the number of Offered Shares distributed in each of the Qualifying Provinces; and

(c) No Underwriter will be liable to the Corporation under this Section 3, with respect to a default by any of the other Underwriters.

4. Qualification for Sale

(a) The Corporation shall file the Prospectus and related documents no later than 5:00 p.m. (Calgary time) on July 21, 2004, and a Final MRRS Decision Document dated no later than July 22, 2004 shall be obtained from the ASC evidencing that a receipt for the Prospectus in each of the Qualifying Provinces has been issued;

(b) Until the completion of the distribution of the Offered Shares, the Corporation shall promptly take all additional steps and proceedings that from time to time may be required under the Applicable Securities Laws to continue to qualify the Offered Shares for distribution or, in the event that the Offered Shares have, for any reason, ceased to so qualify, to again qualify the Offered Shares for distribution; and

(c) The Corporation shall take or cause to be taken all other steps and proceedings as may be necessary to enable the Offered Shares to be offered and sold to the public in all of the Qualifying Provinces through the Underwriters or any other registrant who complies with the relevant provisions of Applicable Securities Laws.

5. Delivery of Prospectus, U.S. Placement Memorandum and Related Documents

The Corporation shall deliver or cause to be delivered to the Underwriters the documents set out below at the respective times indicated:

(a) As soon as they are available and upon request of the Underwriters, copies of the Prospectus, each in the English and French languages, signed as required by Applicable Securities Laws;

(b) As soon as they are available and upon request of the Underwriters, copies of the U.S. Placement Memorandum prepared as contemplated herein including copies of any documents incorporated by reference therein which have not previously been delivered to the Underwriters;

(c) As soon as they are available and upon request of the Underwriters, copies of any Supplementary Materials required to be filed under Applicable Securities Laws or U.S. securities laws, as applicable, signed as required by Applicable Securities Laws or applicable U.S. securities laws;

(d) Prior to the filing of the Prospectus with the Securities Commissions, a "comfort letter" from the auditors of the Corporation dated the date of the Prospectus, addressed to the Board of Directors of the Corporation and the Underwriters and reasonably satisfactory in form and substance to the Underwriters, to the effect that they have carried out certain procedures performed for the purposes of comparing certain specified financial information and percentages appearing in the Prospectus with indicated amounts in the financial statements or accounting records of the Corporation and have found such information and percentages to be in agreement, which comfort letter shall be based on a review having a cut-off date of not more than two Business Days prior to the date of the Prospectus;

(e) At the time of delivery to the Underwriters of the Prospectus, the Corporation shall deliver to the Underwriters:

(i) one or more opinions of local counsel in the Province of Québec, addressed to the Underwriters and Underwriters' Counsel dated the date of the filing of the Preliminary Prospectus and Prospectus, in form acceptable to the Underwriters, acting reasonably, to the effect that, except for information in the Preliminary Prospectus or Prospectus as the case may be, translated by the auditors described in clause (ii) below, the text of the French language version of such document is in all material respects a complete and accurate translation of the English language version thereof; and

(ii) a letter from the auditors of the Corporation, addressed to the Underwriters and Underwriters' Counsel dated the date of the filing of the Preliminary Prospectus and the Prospectus, in form acceptable to the Underwriters, acting reasonably, to the effect that, except for information translated by local counsel described in clause (i) above, the text of the French language version of such document is in all material respects a complete and proper translation of the information contained in the English language version thereof;

(f) Opinions and comfort letters similar to the foregoing shall be provided to the Underwriters with respect to any amendment to the Prospectus and any other relevant document at the time the same is presented to the Underwriters for their signature or, if the Underwriters' signature is not required, at the time the same is filed. All such letters shall be in form and substance satisfactory to the Underwriters and the Underwriters' Counsel, each acting reasonably, as contemplated by this Section 5; and

(g) Such delivery shall also constitute the Corporation's consent to the use by the Underwriters and other members of the Selling Dealer Group of the Prospectus and any amendment to the Prospectus in connection with the offering and sale of the Offered Shares in the Qualifying Provinces. Each delivery of the U.S. Placement Memorandum shall constitute consent by the Corporation to the use of the U.S. Placement Memorandum and any Supplementary Material required to be prepared and/or filed under U.S. securities laws by the U.S. broker affiliates of the Underwriters and members of the Selling Dealer Group for the distribution of the Offered Shares for sale by them in the United States in accordance with this Agreement.

6. **Commercial Copies**

(a) The Corporation shall, as soon as possible but in any event not later than noon (local time at the place of delivery) on July 23, 2004 in Calgary, Toronto, Vancouver and Montreal, cause to be delivered to the Underwriters, without charge, commercial copies of the Prospectus in such numbers and in such locations in Calgary, Toronto, Vancouver and Montreal as the Underwriters may reasonably request by written instructions to the printer thereof given no later than the time when the Corporation authorizes the printing of the commercial copies of such documents. Commercial copies of any amendment to the Prospectus shall be delivered within similar time periods on the next Business Day following the date of filing such amendment in the Qualifying Provinces in such numbers and in such locations in Calgary, Toronto, Vancouver, and Montreal as the Underwriters may reasonably request; and

(b) The Corporation shall cause to be delivered to the Underwriters, contemporaneously with the deliveries contemplated by clause (a), at those delivery points that the Underwriters may reasonably request, commercial copies of a U.S. Placement Memorandum and any Supplementary Material required to be delivered to purchasers or prospective purchasers of the Offered Shares.

7. **Material Change**

(a) During the period of distribution of the Offered Shares, the Corporation will promptly inform the Underwriters of the full particulars of:

(i) any material change (actual, anticipated or threatened) in the business, operations, capital or condition (financial or otherwise) of the Corporation or its properties, assets or liabilities;

(ii) any change in any material fact contained or referred to in the Prospectus, the U.S. Placement Memorandum or any Supplementary Material; and

(iii) the occurrence of a material fact or any event, which, in any such case, is, or may be, of such a nature as to:

(A) render the Prospectus, the U.S. Placement Memorandum or any Supplementary Material untrue, false or misleading in any material respect;

(B) result in a misrepresentation in the Prospectus, the U.S. Placement Memorandum or any Supplementary Material; or

(C) result in the Prospectus, the U.S. Placement Memorandum or any Supplementary Material not complying with Applicable Securities Laws and U.S. securities laws, as applicable,

provided that if the Corporation is uncertain as to whether a material change, change, occurrence or event of the nature referred to in this paragraph has occurred, the Corporation shall promptly inform the Underwriters of the full particulars of the occurrence giving rise to the uncertainty and shall consult with the Underwriters as to whether the occurrence is of such nature;

(b) During the period of distribution of the Offered Shares, the Corporation will promptly inform the Underwriters of the full particulars of:

(i) any request of any Securities Commission or any similar regulatory authority for any amendment to the Preliminary Prospectus, the Prospectus, the U.S. Placement Memorandum, any Supplementary Material or any other part of the Public Record or for any additional information;

(ii) the issuance by any Securities Commission, the Exchange or any similar regulatory authority of any order to cease or suspend trading of any securities of the Corporation (including the distribution of the Offered Shares) or of the institution or threat of institution of any proceedings for that purpose;

(iii) the receipt by the Corporation of any communication from any Securities Commission or similar regulatory authority or the Exchange relating to the Preliminary Prospectus, the Prospectus, the U.S. Placement Memorandum, any Supplementary Material or any other part of the Public Record or the distribution of the Offered Shares;

and except as otherwise agreed by the Underwriters, the Corporation will use its best efforts to prevent the issuance of any such cease trading order or suspension order and, if issued, to obtain the withdrawal thereof as soon as possible;

(c) The Corporation will promptly comply to the reasonable satisfaction of the Underwriters and the Underwriters' Counsel with Applicable Securities Laws and U.S. securities laws, as applicable, with respect to any material change, change, occurrence or event of the nature referred to in Sections 7(a) and (b) above and the Corporation will prepare and file promptly at the Underwriters' request any Supplementary Material or amended U.S. Placement Memorandum which in the Underwriters' opinion, acting reasonably, may be necessary or advisable to comply with Applicable Securities Laws or U.S. securities laws, as applicable; provided that the Corporation shall have allowed the Underwriters and the Underwriters' Counsel to participate fully in the preparation of any Supplementary Material or amended U.S. Placement Memorandum, to have reviewed any other documents incorporated by reference therein and conduct all due diligence investigations which the Underwriters may reasonably require in order to fulfill their obligations as underwriters and in order to enable the Underwriters responsibly to execute the certificate required to be executed by them in, or in connection with, any Supplementary Material, such approval not to be unreasonably withheld and to be provided in a timely manner; and

(d) During the period of distribution of the Offered Shares, the Corporation will promptly provide to the Underwriters, for review by the Underwriters and the Underwriters' Counsel, prior to filing or issuance:

(i) any financial statements of the Corporation; and

(ii) any press release of the Corporation.

8. Covenants of the Corporation

The Corporation covenants and agrees with the Underwriters and undertakes that:

(i) the Corporation will use the net proceeds from the issuance and sale of the Firm Shares and, if applicable, the Over-Allotment Shares in accordance with the disclosure in the Prospectus; and

(ii) the Corporation will provide to the Underwriters and Underwriters' Counsel and consultants reasonable access to the Corporation's properties, senior management personnel and corporate, financial and other records, for the purposes of conducting such due diligence reviews, before the Closing Date, as the Underwriters consider necessary or appropriate; and

(iii) the Corporation will duly, punctually and faithfully perform all of the obligations to be performed by it under this Agreement.

9. Representations of the Corporation

(a) Each delivery of the Prospectus, the U.S. Placement Memorandum and any Supplementary Material pursuant to Section 5 shall constitute a representation and warranty to the Underwriters by the Corporation that:

(i) all of the information and statements (except information and statements furnished by and relating solely to the Underwriters) contained in the Prospectus, the U.S. Placement Memorandum and any Supplementary Material, as the case may be:

(A) are at the respective dates of such documents, true and correct in all material respects;

(B) contain no misrepresentation; and

(C) constitute full, true and plain disclosure of all material facts relating to the Corporation and the Offered Shares; and

(ii) the Prospectus and any Supplementary Material comply in all material respects with the Applicable Securities Laws, and the U.S. Placement Memorandum and any related Supplementary Material comply in all material respects with U.S. securities laws; and

(iii) except as is disclosed in the Prospectus, the U.S. Placement Memorandum or any Supplementary Materials, there has been no intervening material change (actual, proposed or prospective, whether financial or otherwise), from the date of the Prospectus, the U.S. Placement Memorandum and any Supplementary Material to the time of delivery thereof, in the business, operations, capital, properties, assets, liabilities (absolute, accrued, contingent or otherwise), condition (financial or otherwise) or results of operations or ownership of the Corporation.

(b) In addition to the representations and warranties contained in clause (a) hereof, the Corporation represents and warrants to the Underwriters, and acknowledges that each of the Underwriters is relying upon such representations and warranties in entering into this Agreement, that:

(i) the Corporation has full corporate power and authority to issue the Firm Shares and to grant the Over-Allotment Option and, at the Closing Time, the Firm Shares will be duly and validly created and upon receipt of the purchase price therefor will be issued as fully paid and non-assessable Common Shares and at the Additional Closing Time, the Over-Allotment Shares will be duly and validly created and upon receipt of the purchase price therefor will be issued as fully paid and non-assessable Common Shares;

(ii) the Corporation has been duly incorporated and organized and is validly existing under the ABCA, and has all the requisite corporate power and authority to carry on its business, as now conducted and as presently proposed to be conducted, and to own its properties and assets;

(iii) the Corporation has no subsidiaries other than 703090 Alberta Inc., which subsidiary neither carries on any business nor holds any assets other than a photocopier lease, and has no material shareholdings in any other corporation or business organization;

(iv) the Corporation has conducted and is conducting its business in all material respects in compliance with all applicable laws, rules and regulations of each jurisdiction in which it carries on business and holds all material licences, registrations and qualifications in all jurisdictions in which it carries on business necessary to carry on its business as now conducted and as contemplated to be conducted in the Prospectuses, including, without limitation, performing its obligations under the Material Agreements;

(v) each of the Material Agreements is properly described as to parties, dates, terms, conditions and amendments thereto, each of such agreements is a legal, valid and binding obligation of the Corporation enforceable against the Corporation in accordance with its terms subject to the general qualifications that:

(A) enforceability may be limited by bankruptcy, insolvency or other laws affecting creditors' rights generally;

(B) equitable remedies, including the remedies of specific performance and injunctive relief, are available only in the discretion of the court and the courts have statutory and inherent powers to stay proceedings before them;

(C) rights to indemnity and contribution thereunder may be limited under applicable law;

(D) applicable laws regarding limitations of actions; and

(E) the validity, binding nature and enforceability of provisions in this Agreement which purport to sever therefrom any provision which is unenforceable or invalid under applicable law without affecting the enforceability or validity of the remainder of this Agreement would be determined in the discretion of the court; and

the Corporation is in compliance with the terms of such Material Agreements and the Corporation is not aware of any default or breach of a material nature under any of such Material Agreements by any other party thereto;

(vi) the authorized capital of the Corporation consists of an unlimited number of Common Shares and an unlimited number of first preferred shares, issuable in series, of which there are 29,898,458 Common Shares currently issued and outstanding, all of which are issued as fully paid and non-assessable shares of the Corporation, and no other securities of the Corporation are issued or outstanding except as disclosed in clause (vii) hereof;

(vii) no person, firm or corporation holds any securities convertible or exchangeable into securities of the Corporation or has any agreement, warrant, option, right or privilege (whether pre-emptive or contractual) being or capable of becoming an agreement, warrant, option or right for the purchase, subscription or issuance of any unissued Common Shares or other securities of the Corporation other than an aggregate of 2,348,600 Common Shares issuable on exercise of outstanding stock options, rights to purchase an aggregate of 171,114 Common Shares granted under the Corporation's stock rights plan and as described under the heading "Enerplus Joint Venture" in the Prospectus;

(viii) immediately after the Common Shares have been listed and posted for trading on the Exchange, to the knowledge of the Corporation there will be no agreement in force or effect which in any manner affects or will affect the voting or control of any of the securities of the Corporation;

(ix) the Corporation does not, directly or indirectly, hold any shares, other securities, options or rights to subscribe for shares or other securities of any corporation, partnership or other entity other than the shares of 703090 Alberta Inc.;

(x) except as disclosed in the Prospectus, none of the directors, officers or employees of the Corporation, any person who owns, directly or indirectly, more than 10% of any class of securities of the Corporation, or any associate or affiliate of any of the foregoing, had or has any material interest, direct or indirect, in any material transaction or any proposed material transaction with the Corporation which materially affects, is material to or will materially affect the Corporation;

(xi) the Financial Statements, including the notes thereto, fairly represent in accordance with generally accepted accounting principles in Canada applied on a consistent basis, the financial position and condition of the Corporation as at the dates thereof and results of operations for the periods covered thereby and reflect all material liabilities (absolute, accrued, contingent or otherwise) of the Corporation as at the dates thereof and for the periods covered thereby required to be disclosed in accordance with generally accepted accounting principles in Canada;

(xii) there have not been any material changes in the capital, assets, liabilities or obligations (absolute, accrued, contingent or otherwise) of the Corporation from the position set forth in the Financial Statements that have not otherwise been disclosed in the Preliminary Prospectus, the Prospectus and the U.S. Placement Memorandum and there has not been any material adverse change in the business, operations or condition (financial or otherwise), results of the operations of the Corporation since December 31, 2003 or prospects that has not otherwise been disclosed in the Preliminary Prospectus, the Prospectus and the U.S. Placement Memorandum, and there are no material facts, transactions, events or occurrences which could negatively impact on such capital, assets, liabilities, obligations, business, operations, condition, results or prospects of the Corporation;

(xiii) there has not been a reportable disagreement (within the meaning of National Instrument 51-102 - Continuous Disclosure Obligations) with the auditors of the Corporation;

(xiv) except as disclosed in the Prospectus or in writing to the Underwriters, there are no actions, suits, proceedings or inquiries pending or threatened against or affecting the Corporation at law or in equity or before or by any federal, provincial, municipal or other governmental department, commission, board, bureau or agency which may in any way materially adversely affect the business, operations or condition (financial or otherwise) of the Corporation or which affects or may affect the distribution of the Offered Shares and the Corporation is not aware of any existing ground on which such action, suit, proceeding or inquiry might be commenced with any reasonable likelihood of success;

(xv) the Corporation is not in material default or breach of, and the execution and delivery of this Agreement, the performance and compliance with the terms of this Agreement and the sale of the Firm Shares and the Over-Allotment Shares by the Corporation will not result in any material breach of, or be in material conflict with or constitute a material default under, or create a state of facts which, after notice or lapse of time, or both, would constitute a material default under any term or provision of the constating documents, by-laws or resolutions of the directors and shareholders of the Corporation, or any mortgage, note, indenture, contract, agreement (written or oral), including, without limitation, any Material Agreement, instrument, lease or other document to which the Corporation is a party or by which it is bound or any judgment, decree, order, statute, rule or regulation applicable to the Corporation which default or breach might reasonably be expected to materially adversely affect the business, operations, capital or condition (financial or otherwise) of the Corporation or its properties or assets;

(xvi) the Corporation is not a party to any material mortgage, note, indenture, deed of trust, contract, agreement (written or oral), instrument, lease, licence or other document other than as described in the Prospectus;

(xvii) no Securities Commission, the Exchange or any other similar regulatory authority has issued any order preventing or suspending trading of any securities of the Corporation, no such proceeding is, to the knowledge of the Corporation, pending, contemplated or threatened, and the Corporation is not in default of any requirement of Applicable Securities Laws or applicable U.S. securities laws that would have a material effect on this Offering or the Corporation;

(xviii) the Corporation has full corporate power and authority to enter into this Agreement and to perform its obligations set out herein, and this Agreement has been duly authorized, executed and delivered by the Corporation, and this Agreement is a legal, valid and binding obligation of the Corporation enforceable against the Corporation in accordance with its terms, subject to the general qualifications that:

(A) enforceability may be limited by bankruptcy, insolvency or other laws affecting creditors' rights generally;

(B) equitable remedies, including the remedies of specific performance and injunctive relief, are available only in the discretion of the court and the courts have statutory and inherent powers to stay proceedings before them;

(C) rights to indemnity and contribution thereunder may be limited under applicable law;

(D) applicable laws regarding limitations of actions; and

(E) the validity, binding nature and enforceability of provisions in this Agreement which purport to sever therefrom any provision which is unenforceable or invalid under applicable law without affecting the enforceability or validity of the remainder of this Agreement would be determined in the discretion of the court;

(xix) except as disclosed in writing to the Underwriters, the Corporation has duly and on a timely basis filed all tax returns required to be filed by it, has paid all taxes due and payable by it and has paid all assessments and reassessments and all other taxes, governmental charges, penalties, interest and other fines due and payable by it and which are claimed by any governmental authority to be due and owing and adequate provision has been made for taxes payable for any completed fiscal period for which tax returns are not yet required and there are no agreements, waivers, or other arrangements providing for an extension of time with respect to the filing of any tax return or payment of any tax, governmental charge or deficiency by the Corporation and there are no actions, suits, proceedings, investigations or claims threatened or pending against the Corporation in respect of taxes, governmental charges or assessments or any matters under discussion with any governmental authority relating to taxes, governmental charges or assessments asserted by any such authority;

(xx) all filings made by it under which it has received or is entitled to government incentives, have been made in accordance, in all material respects, with all applicable legislation and contain no misrepresentations of material fact or omit to state any material fact which could cause any amount previously paid to the Corporation or previously accrued on the accounts thereof to be recovered or disallowed;

(xxi) except to the extent that any violation or other matter referred to in this subparagraph does not have a material adverse effect on the Corporation:

(A) to the best of its knowledge, information and belief after due enquiry, it is not in violation of any Environmental Laws;

(B) to the best of its knowledge, information and belief after due enquiry, it has operated their business at all times and has received, handled, used, stored, treated, shipped and disposed of all contaminants without violation of Environmental Laws;

(C) there have been no spills, releases, deposits or discharges of hazardous or toxic substances, contaminants or wastes into the earth, air or into any body of water or any municipal or other sewer or drain water systems by the Corporation that have not been remedied;

(D) to the best of its knowledge, information and belief after due enquiry, no orders, directions or notices have been issued and remain outstanding pursuant to any Environmental Laws relating to the business or assets of the Corporation;

(E) it has not failed to report to the proper federal, provincial, municipal or other political subdivision, government, department, commission, board, bureau, agency or instrumentality, domestic or foreign ("**Government Authority**") the occurrence of any event which is required to be so reported by any Environmental Law; and

(F) it holds all licenses, permits and approvals required under any Environmental Laws in connection with the operation of its business and the ownership and use of its assets, all such licenses, permits and approvals are in full force and effect, and except for (A) notifications and conditions of general application to assets of the type owned by the Corporation, and (B) notifications relating to reclamation obligations under the *Environmental Protection and Enhancement Act* (Alberta), the Corporation has not received any notification pursuant to any Environmental Laws that any work, repairs, constructions or capital expenditures are required to be made by it as a condition of continued compliance with any Environmental Laws, or any licence, permit or approval issued pursuant thereto, or that any licence, permit or approval referred to above is about to be reviewed, made subject to limitation or conditions, revoked, withdrawn or terminated it being understood, notwithstanding the foregoing, that the Corporation, to the extent it does not have all such licences, permits or approvals given the current status of the development of its oil sands project, will seek and obtain them in a timely fashion;

(xxii) any and all operations of the Corporation, and to the best of the Corporation's knowledge, any and all operations by third parties, on or in respect of the assets and properties of the Corporation, have been conducted in accordance with good oil and gas industry and mining industry practices where the failure to so operate would have a material adverse effect on the Corporation;

(xxiii) subject only to the Talisman Debenture, the Joint Venture Agreement and reservations to the Crown in the original grant thereof, the Corporation holds good, valid and marketable legal and beneficial title to the Joslyn Lease free and clear of any and all liens, encumbrances or other third party rights of any nature whatsoever, subject only to the terms and conditions of the respective lease and permit;

(xxiv) in respect of the assets and properties of the Corporation that are operated by it, if any, the Corporation holds all valid licenses, permits and similar rights and privileges that are required and necessary under applicable law to operate the assets and properties of the Corporation as presently operated and where the failure to so hold such licences and permits would have a material adverse effect on the Corporation, it being understood, notwithstanding the foregoing, that the Corporation, to the extent it does not have all such licences, permits and similar rights and privileges given the current status of the development of its oil sands project, will seek and obtain them in a timely fashion;

(xxv) upon the listing of the Common Shares on the Exchange, the Corporation will be in material compliance with the bylaws, rules and regulations of the Exchange;

(xxvi) provided the Corporation has received the Final MRRS Decision Document, prior to the Closing Date, the Corporation will be a reporting issuer in good standing and not in default in each of the Qualifying Provinces;

(xxvii) Valiant Trust Company at its principal offices in the City of Calgary and, through its agent, the City of Toronto is the duly appointed registrar and transfer agent of the Corporation with respect to the Common Shares;

(xxviii) to the knowledge of the Corporation, no insider of the Corporation has a present intention to sell any securities of the Corporation held by it, other than as disclosed to the Underwriters;

(xxix) except as disclosed in the Prospectus, the Corporation has no liabilities (whether absolute, contingent, present, future or otherwise), including without limitation, under or pursuant to Environmental Laws, which individually or in the aggregate would have a material adverse effect on the condition (financial or otherwise), prospects, earnings, business or properties of the Corporation, whether or not it arises from transactions in the ordinary course of business;

(xxx) except in the normal course of business, or as disclosed in the Prospectus, the Corporation has not advanced funds, extended credit or been a creditor of any insider of the Corporation or any person not dealing at arm's length with such person and the Corporation has not borrowed funds from, received extensions of credit from or otherwise been a debtor of any insider of the Corporation or any person not dealing at arm's length with such person;

(xxxi) the form of the certificate for the Common Shares complies with all legal requirements, including the rules of the Exchange;

(xxxii) except for the Underwriters, there is no other person, firm or corporation acting or purporting to act at the request of the Corporation who is entitled to any brokerage, finder's, underwriter's or agency fee in connection with the transactions contemplated hereby;

(xxxiii) no authorization, approval or consent of any court or governmental authority or agency is required to be obtained by the Corporation in connection with the sale and delivery of the Offered Shares except as has been obtained or is contemplated hereby;

(xxxiv) the minute books for the Corporation (including in respect of committee meetings since January 1, 2003) contain full, true and correct copies of the constating documents of the Corporation and contain copies of all minutes of all meetings and all consent resolutions of the directors, committees of the directors (since January 1, 2003) and shareholders of the Corporation and all such meetings were duly called, properly held and all such consent resolutions were properly adopted;

(xxxv) the Corporation has made available to Norwest prior to the issuance of the Norwest Report, for the purpose of preparing the Norwest Report, all information requested by Norwest, which information did not contain any material misrepresentation. The Corporation has no knowledge of a material adverse change in any information provided to Norwest since the date that such information was so provided. The Corporation believes that the Norwest Report reasonably presents the quantity of bitumen-in-place within the Joslyn Lease based upon the criteria therein specified and information available at the time the Norwest Report was prepared; and

(xxxvi) the Corporation has made available to GLJ Associates prior to the issuance of the GLJ Report, for the purpose of preparing the GLJ Report, all information requested by GLJ, which information did not contain any material misrepresentation. The Corporation has no knowledge of a material adverse change in any information provided to GLJ since the date that such information was so provided. The Corporation believes that the GLJ Report reasonably presents the quantity of bitumen reserves and resources of the Joslyn Lease based upon information available at the time the GLJ Report was prepared.

10. Indemnity

(a) The Corporation (the "**Indemnitor**") shall indemnify and save the Underwriters, and the Underwriters' agents, directors, officers, shareholders and employees, harmless against and from all liabilities, claims, demands, losses (other than losses of profit in connection with the distribution of the Firm Shares and Over-Allotment Shares), costs, damages and expenses to which the Underwriters, or any of the Underwriters' agents, directors, officers, shareholders or employees may be subject or which the Underwriters, or any of the Underwriters' agents, directors, officers, shareholders or employees may suffer or incur, whether under the provisions of any statute or otherwise, in any way caused by, or arising directly or indirectly from or in consequence of:

(i) any information or statement contained in the Preliminary Prospectus, the Prospectus, the U.S. Placement Memorandum, any Supplementary Material or in any other document or material filed or delivered pursuant hereto (other than any information or statement relating solely to the Underwriters and furnished to the Corporation by the Underwriters expressly for inclusion in the Preliminary Prospectus, Prospectus, U.S. Placement Memorandum or Supplementary Materials) which is or is alleged to be untrue or any omission or alleged omission to provide any information or state any fact the omission of which makes or is alleged to make any such information or statement untrue or misleading in light of the circumstances in which it was made;

(ii) any misrepresentation or alleged misrepresentation (except a misrepresentation which is based upon information relating solely to the Underwriters and furnished to the Corporation by the Underwriters expressly for inclusion in the Preliminary Prospectus, Prospectus, U.S. Placement Memorandum or Supplementary Materials) contained in the Preliminary Prospectus, Prospectus, U.S. Placement Memorandum or any Supplementary Materials;

(iii) any prohibition or restriction of trading in the securities of the Corporation or any prohibition or restriction affecting the distribution of the Firm Shares or Over-Allotment Shares imposed by any competent authority if such prohibition or restriction is based on any misrepresentation or alleged misrepresentation of a kind referred to in Section 10(a)(ii);

(iv) any order made or any inquiry, investigation (whether formal or informal) or other proceeding commenced or threatened by any one or more competent authorities (not based upon the activities or the alleged activities of the Underwriters or their Selling Dealer Group members, if any) relating to or materially affecting the trading or distribution of the Firm Shares or Over-Allotment Shares;

(v) any breach of, default under or non-compliance by the Indemnitor with any requirements of the Applicable Securities Laws, applicable U.S. securities laws, the by-laws, rules or regulations of the Exchange or any representation, warranty, term or condition of this Agreement provided by the Corporation or in any certificate or other document delivered by or on behalf of the Corporation hereunder or pursuant hereto; or

(vi) the Corporation not complying with any requirement of Applicable Securities Laws or applicable U.S. securities laws in connection with the transactions contemplated herein;

(b) Notwithstanding the provisions of Section 10(a), no party who has engaged in any fraud, fraudulent misrepresentation, wilful default or gross negligence shall be entitled, to the extent that the liabilities, claims, losses, costs, damages or expenses were caused by such activity, to claim indemnification from any person who has not engaged in such fraud, fraudulent misrepresentation, wilful default or gross negligence;

(c) If any claim contemplated by Section 10(a) shall be asserted against any of the individuals, persons or corporations in respect of which indemnification is or might reasonably be considered to be provided for in such section, such individual, person or corporation (the "**Indemnified Person**") shall notify the Indemnitor as soon as possible of the nature of such claim (provided that failure to so notify the Indemnitor of the nature of such claim in a timely fashion shall relieve the Indemnitor of liability hereunder only if and to the extent that such failure materially prejudices the Indemnitor's ability to defend such claim) and the Indemnitor shall be entitled (but not required) to assume the defence of any suit brought to enforce such claim, provided however, that the defence shall be through legal counsel selected by the Indemnitor and acceptable to the Indemnified Person acting reasonably and that no settlement may be made by the Indemnitor or the Indemnified Person without the prior written consent of the other, such consent not to be unreasonably withheld. The Indemnified Person shall have the right to retain its own counsel in any proceeding relating to a claim contemplated by Section 10(a) if:

(i) the Indemnified Person has been advised by counsel that there may be a reasonable legal defence available to the Indemnified Person which is different from or in addition to a defence available to the Indemnitor (in which case the Indemnitor shall not have the right to assume the defence of such proceedings on the Indemnified Person's behalf);

(ii) the Indemnitor shall not have taken the defence of such proceedings and employed counsel within ten (10) days after receipt of notice of commencement of such proceedings; or

(iii) the employment of such counsel has been authorized by the Indemnitor in writing in connection with the defence of such proceeding;

and, in any such event, the reasonable fees and expenses of such Indemnified Person's counsel (on a solicitor and his client basis) shall be paid by the Indemnitor, provided that the Indemnitor shall not, in connection with any one such action or separate but substantially similar or related actions in the same jurisdiction arising out of the same general allegations or circumstances, be liable for the fees and expenses of more than one separate law firm (in addition to any local counsel) for all such Indemnified Persons;

(d) The Indemnitor hereby waives any rights to recover contribution from the Underwriters with respect to any liability of the Indemnitor by reason of or arising out of any misrepresentation in the Preliminary Prospectus, the Prospectus, the U.S. Placement Memorandum or any Supplementary Material, provided, however, that such waiver shall not apply in respect of liability caused or incurred by reason of any misrepresentation which is based upon information relating solely to the Underwriters contained in such document and furnished to the Corporation by the Underwriters or Underwriters' Counsel expressly for inclusion in the Preliminary Prospectus, the Prospectus, the U.S. Placement Memorandum or such Supplementary Material;

(e) If any legal proceedings shall be instituted against the Indemnitor in respect of the Preliminary Prospectus, the Prospectus, the U.S. Placement Memorandum or any Supplementary Material or the offering of Offered Shares, or if any regulatory authority or stock exchange shall carry out an investigation of the Indemnitor in respect of the Preliminary Prospectus, the Prospectus, the U.S. Placement Memorandum or any Supplementary Material or the offering of Offered Shares and, in any such case, any Indemnified Person is required to testify, or respond to procedures designed to discover information, in connection with or by reason of the services performed by the Underwriters hereunder, the Indemnified Persons may employ their own legal counsel and the Indemnitor shall pay and reimburse the Indemnified Persons for the reasonable fees, charges and disbursements (on a full indemnity basis) of such legal counsel, the other expenses reasonably incurred by the Indemnified Persons in connection with such proceedings or investigation and a fee at the normal per diem rate for any director, officer or employee of the Underwriters involved in the preparation for or attendance at such proceedings or investigation;

(f) The rights and remedies of the Indemnified Persons set forth in Sections 10, 11 and 12 hereof are to the fullest extent possible in law cumulative and not alternative and the election by any Underwriter or other Indemnified Person to exercise any such right or remedy shall not be, and shall not be deemed to be, a waiver of any other rights and remedies;

(g) The Indemnitor hereby acknowledges that the Underwriters are acting as agents for the Underwriters' respective agents, directors, officers, shareholders and employees under this Section 10 and under Section 11 with respect to all such agents, directors, officers, shareholders and employees;

(h) The Indemnitor waives any right it may have of first requiring an Indemnified Person to proceed against or enforce any other right, power, remedy or security or claim or to claim payment from any other person before claiming under this indemnity. It is not necessary for an Indemnified Person to incur expense or make payment before enforcing such indemnity;

(i) The Underwriter's rights of indemnity contained in this Section 10 shall not apply if the Corporation has complied with the provisions of Sections 4 and 5 and the person asserting any claim contemplated by this Section 10 was not provided with a copy of the Preliminary Prospectus, the Prospectus, the U.S. Placement Memorandum or any Supplemental Material or amendment to the U.S. Placement Memorandum or other document which corrects any misrepresentation or alleged misrepresentation which is the basis of such claim and which was required, under Applicable Securities Laws and U.S. securities laws, as applicable, to be delivered to such person by the Underwriters; and

(j) If the Indemnitor has assumed the defense of any suit brought to enforce a claim hereunder, the Indemnified Person shall provide the Indemnitor copies of all documents and information in its possession pertaining to the claim, take all reasonable actions necessary to preserve its rights to object to or defend against the claim, consult and reasonably cooperate with the Indemnitor in determining whether the claim and any legal proceeding resulting therefrom should be resisted, compromised or settled and reasonably cooperate and assist in any negotiations to compromise or settle, or in any defense of, a claim undertaken by the Indemnitor, provided that such Indemnified Person shall be reimbursed as contemplated by Section 10(e).

11. Contribution

(a) In order to provide for just and equitable contribution in circumstances in which the indemnification provided for in this Agreement is due in accordance with its terms but is, for any reason, held by a court to be unavailable from the Indemnitor on grounds of policy or otherwise, the Indemnitor and the party or parties seeking indemnification shall contribute to the aggregate liabilities, claims, demands, losses (other than losses of profit in connection with the distribution of the Firm Shares and Over-Allotment Shares), costs, damages and expenses (including legal or other expenses reasonably incurred in connection with investigation or defence of the same) to which they may be subject or which they may suffer or incur:

(i) in such proportion as is appropriate to reflect the relative benefit received by the Indemnitor on the one hand, and by the party or parties seeking indemnity on the other hand, from the offering of the Firm Shares and Over-Allotment Shares; or

(ii) if the allocation provided by Section 11(a)(i) above is not permitted by applicable law, in such proportion as is appropriate to reflect not only the relative benefits referred to in Section 11(a)(i) above but also to reflect the relative fault of the party or parties seeking indemnity, on the one hand, and the Indemnitor on the other hand, in connection with the statements, commissions or omissions or other matters which resulted in such liabilities, claims, demands, losses, costs, damages or expenses as well as any other relevant equitable considerations;

(b) The relative benefits received by the Indemnitor, on the one hand, and the Underwriters, on the other hand, shall be deemed to be in the same proportion that the total proceeds of the Offering received by the Corporation (net of fees but before deducting expenses) bear to the fees received by the Underwriters. In the case of liability arising out of the Preliminary Prospectus, the Prospectus, the U.S. Placement Memorandum or any Supplementary Material, the relative fault of the Indemnitor, on the one hand, and of the Underwriters, on the other hand, shall be determined by reference, among other things, to whether the misrepresentation or alleged misrepresentation, order, inquiry, investigation or other matter or thing referred to in Section 10 relates to information supplied or which ought to have been supplied by, or steps or actions taken or done on behalf of or which ought to have been taken or done on behalf of the Indemnitor or the Underwriters and the party's relative intent, knowledge, access to information and opportunity to correct or prevent such misrepresentation or alleged misrepresentation, order, inquiry, investigation or other matter or thing referred to in Section 10;

(c) The amount paid or payable by an Indemnified Person as a result of liabilities, claims, demands, losses (other than losses of profit in connection with the distribution of the Firm Shares and Over-Allotment Shares), costs, damages and expenses (or claims, actions, suits or proceedings in respect thereof) referred to above shall, without limitation, include any legal or other expenses reasonably incurred by the Indemnified Person in connection with investigating or defending such liabilities, claims, demands, losses, costs, damages and expenses (or claims, actions, suits or proceedings in respect thereof) whether or not resulting in any action, suit, proceeding or claim;

(d) The Indemnitor agrees that it would not be just and equitable if contributions pursuant to this Agreement were determined by pro rata allocation or by any other method of allocation which does not take into account the equitable considerations referred to in the immediately preceding paragraphs. The rights to contribution provided in this Section 11 shall be in addition to, and without prejudice to, any other right to contribution which the Underwriters or any other Indemnified Person may have; and

(e) Any liability of the Underwriters under this Section 11 shall be limited to the amount actually received by the Underwriters under Section 2.

12. Expenses

Whether or not the transactions contemplated herein shall be completed, all costs and expenses of or incidental to the distribution of the Offered Shares shall be borne by the Corporation, including, without limitation: (i) all costs and expenses of or incidental to the preparation, filing and reproduction of the Preliminary Prospectus, the Prospectus, the U.S. Placement Memorandum, any Supplementary Materials, the fees and expenses of the Corporation's counsel, the costs relating to road show meetings and presentations (including all printing and travel costs for employees of the Corporation), listing fees, the fees and expenses of agent counsel retained by the Corporation's counsel, the fees and expenses of the Corporation's auditors and the Corporation's engineers, translation costs and the fees and expenses related to any newspaper advertisements and the road show expenses; (ii) the out-of-pocket expenses of the Underwriters, including, but not limited to, travel expenses and the Underwriters' reasonable legal fees and expenses (collectively not to exceed $125,000 plus GST); and (iii) all other costs and expenses relating to the transactions contemplated herein.

13. Termination

(a) Each of the Underwriters may, without liability, terminate its obligations hereunder, by written notice to the Corporation, in the event that after the date hereof and at or prior to the Closing Time:

(i) there should develop, occur or come into effect or existence any event, action, state, condition or major financial occurrence of national or international consequence, acts of hostilities or escalation thereof or other calamity or crisis or any change or development involving a prospective change in national or international political, financial or economic conditions or any governmental action, law, regulation, inquiry or other occurrence of any nature whatsoever which, in the sole opinion of the Underwriter, acting reasonably, seriously adversely affects or involves, or may seriously adversely affect or involve, the financial markets or the business, operations or affairs of the Corporation;

(ii) the state of the financial markets is such that the Offered Shares cannot in the reasonable opinion of the Underwriter be profitably marketed;

(iii) any order to cease or suspend trading in any securities of the Corporation or prohibiting or restricting the distribution of the Offered Shares is made, or any proceedings are announced, commenced or threatened for the making of any such order, by any stock exchange, Securities Commission or similar regulatory or judicial authority (other than as a result of any act or omission of such Underwriter contrary to the terms of this Agreement), and the same has not been rescinded, revoked or withdrawn;

(iv) the Corporation is in breach or non-performance of or default under a material covenant, representation, warranty, term or condition of the Corporation contained herein that has not been waived or rectified or remedied to the satisfaction of the Underwriter;

(v) any inquiry, investigation or other proceeding (whether formal or informal) in relation to the Corporation or its directors or senior officers is announced, commenced or threatened by any stock exchange, Securities Commission or similar regulatory or judicial authority (unless based on the activities or alleged activities of an Underwriter), or there is any change in law, regulation or policy or the interpretation or administration thereof, and the same has not been rescinded, revoked or withdrawn, if, in the sole opinion of the Underwriter, acting reasonably, the inquiry, investigation or other proceeding, change, announcement, commencement or threatening thereof materially prevents or restricts or may materially prevent or restrict the trading or distribution of the Offered Shares or would be expected to have a material adverse effect on the market price or value of the Offered Shares;

(vi) there should occur any material change (actual, contemplated or threatened), change in any material fact, occurrence or event of the nature referred to in Section 7(a) or any development that could result in such a material change (actual, contemplated or threatened), change in any material fact, occurrence or event, which, in the sole opinion of the Underwriter, could reasonably be expected to have a material adverse effect on the market price or value of the Offered Shares or the marketability of the Offered Shares; or

(vii) the Underwriter shall become aware of any adverse material change (actual, contemplated or threatened) or adverse material fact with respect to the Corporation which has not been publicly disclosed or disclosed in writing to the Underwriters at or prior to the date hereof.

(b) The Underwriters, or any of them, may exercise any or all of the rights provided for in Section 13(a) or Section 14 or Section 20 notwithstanding any material change, change, event or state of facts (except where the Underwriter purporting to exercise any of such rights is in breach of its obligations under this Agreement) and notwithstanding any act or thing taken or done by the Underwriters or any inaction by the Underwriters, whether before or after the occurrence of any material change, change, event or state of facts including, without limitation, any act of the Underwriters related to the offering or continued offering of the Offered Shares for sale and any act taken by the Underwriters in connection with any amendment to the Prospectus (including the execution of any amendment) and the Underwriters shall only be considered to have waived or be estopped from exercising or relying upon any of their rights under or pursuant to Section 13(a) or Section 14 or 20 if such waiver or estoppel is in writing and specifically waives or estops such exercise or reliance; and

(c) Any termination pursuant to the terms of this Agreement shall be effected by notice in writing delivered to the Corporation, provided that no termination shall discharge or otherwise affect any obligation of the Corporation under Section 10, 11, 12 or 20. The rights of the Underwriters to terminate their obligations hereunder are in addition to, and without prejudice to, any other remedies they may have.

14. Closing Documents

The following are conditions precedent to the obligations of the Underwriters to complete the transactions contemplated in this Agreement:

(a) There shall be delivered to the Underwriters legal opinions of the Corporation's Counsel and the Underwriters' Counsel addressed to the Underwriters, in form and substance satisfactory to the Underwriters, acting reasonably, with respect to such matters as the Underwriters may reasonably request relating to the offering of the Offered Shares, including, without limitation, that:

(i) the Corporation has been duly incorporated and is validly subsisting under the ABCA and has all requisite corporate power and authority to carry on its business and to own its properties and assets;

(ii) the Corporation has full corporate power and capacity to enter into this Agreement and to perform its obligations set out herein, and this Agreement has been duly authorized, executed and delivered by the Corporation and constitutes (subject to the usual qualifications) legal, valid and binding obligations of the Corporation enforceable against the Corporation;

(iii) the execution and delivery of this Agreement, the performance and compliance with the terms of this Agreement and the sale of the Firm Shares by the Corporation do not and will not result in a breach of, or constitute a default under, and do not and will not create a state of facts which, after notice or lapse of time or both, will result in a breach of or constitute a default under: (A) any applicable laws of the Province of Alberta; (B) any term or provision of the articles, by-laws or, to the knowledge of counsel, resolutions of the directors or shareholders of the Corporation; (C) to the knowledge of counsel, any mortgage, note, indenture, contract, agreement (written or oral), instrument, lease or other document to which the Corporation is a party or by which the Corporation is bound on the Closing Date; or (D) to the knowledge of counsel, any judgement, decree, order, statute, rule or regulation applicable to the Corporation, which breach or default might reasonably be expected to materially adversely affect the business, operations, capital or condition (financial or otherwise) of the Corporation;

(iv) all necessary action has been taken by the Corporation to validly allot and issue to the Underwriters the Firm Shares;

(v) the Firm Shares, when delivered and sold in accordance with this Agreement, will be duly and validly created and issued as fully paid and non-assessable Common Shares;

(vi) the form and terms of the certificates representing the Common Shares have been approved by the directors of the Corporation and comply with all legal requirements relating thereto;

(vii) no consent, approval, authorization or order of or qualification with any governmental or regulatory body or agency in the Province of Alberta (or pursuant to the federal laws of Canada applicable therein) is required to be obtained by the Corporation for the offer and sale of the Firm Shares by the Underwriters in the manner contemplated hereby, except such as have been obtained;

(viii) the Corporation has the necessary corporate power and authority to execute and deliver the Prospectus and to deliver the U.S. Placement Memorandum and all necessary corporate action has been taken by the Corporation to authorize the execution and delivery by or on behalf of the Corporation of the Prospectus and to authorize the delivery by or on behalf of the Corporation of the U.S. Placement Memorandum in each of the Qualifying Provinces in accordance with Applicable Securities Laws;

(ix) the authorized capital of the Corporation and the attributes of the Common Shares conform in all material respects with the description thereof in the Prospectus;

(x) the Firm Shares, when issued, will be qualified investments as set out under the heading "Eligibility for Investment" in the Prospectus;

(xi) all necessary documents have been filed, all necessary proceedings have been taken and all legal requirements have been fulfilled as required under the Applicable Securities Laws in order to qualify the Firm Shares for distribution and sale to the public in each of the Qualifying Provinces by or through investment dealers and brokers duly registered under the applicable laws of such provinces who have complied with the relevant provisions of such Applicable Securities Laws;

(xii) all laws of the Province of Québec relating to the use of the French language (other than those relating to oral communications) will have been complied with in connection with the sale of the Offered Shares to purchasers in the Province of Québec if such purchasers receive copies of the Prospectus and of all documents which constitute the contract of sale, including forms of order and confirmation, invoices and receipts, in the French and English language or the French language only;

(xiii) the Corporation is a reporting issuer in each of the Qualifying Provinces and is not on the list of defaulting issuers maintained by the Securities Commissions of each of such provinces; and

(xiv) the Offered Shares have been conditionally accepted for listing upon the Exchange subject to any applicable filing requirements;

and as to all other legal matters, including compliance with Applicable Securities Laws, in any way connected with the issuance, sale and delivery of the Offered Shares as the Underwriters may reasonably request.

It is understood that the respective counsel may rely on the opinions of local counsel acceptable to them as to matters governed by the laws of jurisdictions other than Alberta or Canada and on certificates of officers of the Corporation, the transfer agent and the auditors of the Corporation as to relevant matters of fact. It is further understood that the Underwriters' Counsel may rely on the opinion of the Corporation's Counsel as to matters which specifically relate to the Corporation and the Offered Shares, including the issuance of the Offered Shares;

(b) In connection with the sale of the Over-Allotment Shares, there shall be delivered to the Underwriters on the Additional Closing Date legal opinions of the Corporation's Counsel and the Underwriters' Counsel addressed to the Underwriters, in form and substance satisfactory to the Underwriters, acting reasonably, with respect to such matters as the Underwriters may reasonably request relating to the offering of the Over-Allotment Shares, including, without limitation, in respect of the Corporation's Counsel as to the matters referred to in 15(a) insofar as they relate to Over-Allotment Shares;

(c) There shall be delivered to the Underwriters a certificate of the Corporation dated the Closing Date and the Additional Closing Date, addressed to the Underwriters and signed on the Corporation's behalf by any two senior officers of the Corporation satisfactory to the Underwriters, acting reasonably, certifying that:

(i) the Corporation has complied with and satisfied all terms and conditions of this Agreement on its part to be complied with or satisfied at or prior to the Closing Time or the Additional Closing Time, as the case may be;

(ii) the representations and warranties of the Corporation set forth in this Agreement are true and correct in all material respects at the Closing Time, as if made at such time; and

(iii) no event of a nature referred to in Sections 7(a), 7(b) or 13(a)(iii), (iv), (v) or (vi) has occurred or to the knowledge of such officers is pending, contemplated or threatened, excluding with respect to Section 13(a)(v) and (vi) any obligation of the Underwriters to make a determination as to whether or not any event or change has, in the Underwriter's opinion, occurred;

and the Underwriters shall have no knowledge to the contrary;

(d) There shall be delivered to the Underwriters comfort letters of the auditors referred to in Section 5(d) addressed to the Underwriters and dated the Closing Date and the Additional Closing Date, in the format satisfactory to the Underwriters, acting reasonably, bringing the information contained in the comfort letter referred to in Section 5(d) hereof up to the Closing Time or the Additional Closing Time, as the case may be, which updated comfort letter shall be based on a review having a cut off date not more than two Business Days prior to the Closing Date;

(e) There shall be delivered to the Underwriters evidence satisfactory to the Underwriters that the Corporation has obtained all necessary approvals of the

Exchange for the listing of the Offered Shares subject only to the filing of documents which may be required by the Exchange;

(f) The Underwriters shall have obtained satisfactory results of all due diligence investigations relating to any Supplementary Material;

(g) The Beacon Group Energy Investment Fund II, L.P., Riverside Investments LLC on behalf of The Beacon Group Energy Investment Fund II, L.P., Friends of Lime Rock LP and each of the directors and officers of the Corporation shall have entered into an agreement with Peters & Co. Limited and RBC Dominion Securities Inc., on behalf of the Underwriters, in substantially the form set forth in Schedule C; and

(h) There shall be delivered to the Underwriters such other certificates and documents as the Underwriters may request, acting reasonably.

15. Deliveries

(a) The sale of the Firm Shares, if any, shall be completed at the Closing Time at the offices of the Corporation's Counsel in Calgary, Alberta or at such other place as the Corporation and the Underwriters may agree. Subject to the conditions set forth in Section 14, the Underwriters, at the Closing Time, shall deliver by wire transfer(s) to the Corporation, in immediately available Canadian funds, the amount of $160,550,000 (after deduction of any wire and other charges) against delivery by the Corporation of:

(i) the opinions, certificates and documents referred to in Section 14;

(ii) definitive certificates representing, in the aggregate, all of the Firm Shares registered in such name or names as the Underwriters shall notify the Corporation in writing not less than twenty-four (24) hours prior to the Closing Time; and

(iii) a certified cheque or bank draft payable to Peters & Co. Limited representing the fee provided for in Section 2 in respect of the Firm Shares;

provided however that the payment to Peters & Co. Limited pursuant to paragraph (iii) may be made by way of set-off against the payment to be made by the Underwriters to the Corporation in this Section 15(a); and

(b) The sale of the Over-Allotment Shares, if any, shall be completed at the offices of the Corporation's Counsel in Calgary, Alberta or at such other place as the Corporation and the Underwriters may agree, on the date (the "**Additional Closing Date**") and at the time ("**Additional Closing Time**") specified by the Underwriters in the written notice given by the Underwriters pursuant to their election to purchase such Over-Allotment Shares provided that in no event shall such time be earlier than the Closing Time or earlier than two or later than 10

Business Days after the date of the written notice of the Underwriters to the Corporation in respect of the Over-Allotment Shares, and further provided that the Additional Closing Date shall not be later than 30 days after the Closing Date, or at such other time and date as the Underwriters and the Corporation may agree upon in writing. Subject to the conditions set forth in Section 14, the Underwriters, at the Additional Closing Time, shall deliver by wire transfer to the Corporation, in immediately available Canadian funds, the amount of $9.50 per Over-Allotment Share agreed to be purchased by the Underwriters from the Corporation pursuant to their exercise of the Over-Allotment Option, against delivery by the Corporation of:

(i) to the extent applicable, the opinions, certificates and documents referred to in Section 14;

(ii) definitive certificates representing, in the aggregate, all of the Over-Allotment Shares agreed to be purchased by the Underwriters registered in such name or names as the Underwriters shall notify the Corporation in writing not less than twenty-four (24) hours prior to the Additional Closing Time; and

(iii) a certified cheque or bank draft of the Corporation payable to Peters & Co. Limited representing the fee provided for in Section 2 in respect of the Over-Allotment Shares;

provided however that the payment to Peters & Co. Limited pursuant to paragraph (iii) may be made by way of set-off against the payment to be made by the Underwriters to the Corporation, in this Section 15(b).

16. Due Diligence

During the period from the date hereof until completion of the distribution of the Offered Shares, the Corporation shall allow the Underwriters to participate fully in the preparation of the Prospectus, the U.S. Placement Memorandum and any Supplementary Material and allow the Underwriters to conduct all due diligence which the Underwriters may reasonably require in order to fulfil the Underwriters' obligations as underwriters and to enable the Underwriters to responsibly execute the certificate in the Prospectus and any Supplementary Material required to be executed by the Underwriters.

17. Restrictions on Offerings

During the period commencing on the date hereof and ending on the day which is 180 days following the Closing Date, the Corporation shall not, without the prior written consent of Peters & Co. Limited and RBC Dominion Securities Inc., on behalf of the Underwriters, which consent shall not be unreasonably withheld, directly or indirectly, offer, nor announce the offering of, nor make any agreement to issue any additional Common Shares or securities convertible or exercisable into Common Shares, other than for purposes of the stock option plan of the Corporation, the performance share unit plan of the Corporation, or pursuant to any presently outstanding rights or agreements and the previously discussed issuance of up to $15 million of flow-through Common Shares.

18. Offering in the United States.

(a) For the purposes of this Agreement, the following terms will have the meanings indicated:

(i) "**Directed Selling Efforts**" means "directed selling efforts" as defined in Regulation S and, without limiting the foregoing, but for greater clarity, it means, subject to the exclusions from the definition of directed selling efforts contained in Regulation S, any activity undertaken for the purpose of, or that could reasonably be expected to have the effect of, conditioning the market in the United States for the Offered Shares, and includes the placement of any advertisement in a publication with a general circulation in the United States that refers to the offering of the Offered Shares;

(ii) "**General Solicitation**" and "**General Advertising**" means "general solicitation" and "general advertising", respectively, as used in Rule 502(c) under the U.S. Securities Act, including advertisements, articles, notices or other communications published in any newspaper, magazine or similar media or broadcast over radio or television, or any seminar or meeting whose attendees had been invited by general solicitation or general advertising;

(iii) "**Institutional Accredited Investor**" means those institutional "accredited investors" specified in Rule 501(a)(1), (2), (3) and (7) of Regulation D;

(iv) "**Qualified Institutional Buyer**" means a "qualified institutional buyer" as defined in Rule 144A;

(v) "**Regulation D**" means Regulation D promulgated under the U.S. Securities Act;

(vi) "**Regulation S**" means Regulation S promulgated under the U.S. Securities Act;

(vii) "**Rule 144A**" means Rule 144A promulgated under the U.S. Securities Act;

(viii) "**SEC**" means the United States Securities and Exchange Commission;

(ix) "**Substantial U.S. Market Interest**" means "substantial U.S. market interest" as defined in Regulation S;

(x) "**U.S. Exchange Act**" means the *United States Securities Exchange Act* of 1934, as amended;

(xi) "**U.S. Placement Memorandum**" means (i) the Preliminary Prospectus supplemented with wrap pages dated the date of the Preliminary Prospectus describing restrictions imposed under the U.S. Securities Act; and (ii) the Prospectus supplemented with wrap pages dated the date of the Prospectus describing restrictions imposed under the U.S. Securities Act; and

(xii) "**U.S. Securities Act**" means the *United States Securities Act* of 1933, as amended.

(b) The Underwriters may offer and sell the Offered Shares within the United States on the terms and subject to the conditions of this Section 18. In connection therewith, the Corporation represents, warrants and covenants that:

(i) the Corporation is a "foreign issuer" (within the meaning of Regulation S) and reasonably believes there is no Substantial U.S. Market Interest with respect to the Offered Shares;

(ii) none of the Corporation, its affiliates or any person acting on its or their behalf (other than the Underwriters, U.S. affiliates of the Underwriters ("**U.S. Affiliates**"), or any members of the banking and selling group formed by them (collectively, the "**Selling Firms**"), as to whom the Corporation makes no representation), has engaged or will engage in any Directed Selling Efforts in the United States with respect to the Offered Shares;

(iii) the Corporation is not, and following the application of the proceeds of the sale of the Offered Shares in the manner described in the Prospectus will not be, an open-end investment company, unit investment trust or face amount certificate company that is or is required to be registered or a closed-end investment company that is required to be, but is not, registered under Section 8 of the *United States Investment Company Act* of 1940, as amended;

(iv) none of the Corporation, its affiliates or any person acting on its or their behalf (other than the Underwriters, U.S. Affiliates, or any of the Selling Firms, as to whom the Corporation makes no representation), has engaged in any form of General Solicitation or General Advertising or in any conduct involving an offering within the meaning of Section 4(2) of the U.S. Securities Act in connection with any offer or sale of the Offered Shares or any security convertible or exchangeable into Common Shares in the United States within the six month period prior to the date of this Agreement;

(v) so long as any of the Offered Shares resold pursuant to Rule 144A are outstanding and are "restricted securities" within the meaning of Rule 144(a)(3) under the U.S. Securities Act and cannot be sold pursuant to

Rule 144(k) under the U.S. Securities Act, the Corporation will, if it no longer is subject to the reporting requirements of Section 13 or Subsection 15(d) of the *U.S. Exchange Act* or the information furnishing requirements of Rule 12g3-2(b) thereunder or if it is subject to such reporting requirements and fails to comply therewith, provide to any holder of those restricted securities, or to any prospective purchaser of those restricted securities designated by a holder, upon the request of that holder or prospective purchaser, at or prior to the time of sale, the information required to be provided by Rule 144A(d)(4) under the U.S. Securities Act (so long as that requirement is necessary in order to permit holders of the restricted securities to effect resales under Rule 144A) to a Qualified Institutional Buyer which is a holder of the restricted securities;

(vi) none of the Corporation or its affiliates will take any action that would cause the registration exemptions in Regulation S or Rule 144A to be unavailable for the offer and sale of the Offered Shares pursuant to this Agreement;

(vii) the Common Shares are not, and as of the Time of Closing the Common Shares will not be, and no securities of the same class as the Common Shares are or will be, listed on a national securities exchange in the United States, registered under Section 6 of the *U.S. Exchange Act*, quoted in an "automated inter-dealer quotation system", as such term is used in the *U.S. Exchange Act*, or convertible or exchangeable at an effective conversion premium (calculated as specified in Section (a)(6) of Rule 144A) of less than ten percent for securities so listed or quoted;

(viii) the Corporation will, within prescribed time periods, prepare and file any forms or notices required under the U.S. Securities Act or applicable blue sky laws; and

(ix) the Corporation will notify Valiant Trust Company as soon as practicable upon it becoming a "domestic issuer", as defined in Regulation S.

(c) Each Underwriter acknowledges that the Offered Shares have not been and will not be registered under the U.S. Securities Act and may be offered and sold only in transactions exempt from or not subject to the registration requirements of the U.S. Securities Act. Accordingly, each Underwriter separately and not jointly represents, warrants and covenants, and will cause its U.S. Affiliates to comply with such representations, warranties and covenants, that:

(i) it has not offered or sold, and will not offer or sell, any Offered Shares constituting part of its allotment within the United States except as provided in this Section 18 or outside of the United States in accordance with Rule 903 of Regulation S. Accordingly, neither it nor any of its affiliates nor any person acting on its or their behalf has engaged or will engage in: (i) any offer to sell or any solicitation of an offer to buy, any

Offered Shares to any person in the United States, (ii) any sale of Offered Shares to any purchaser unless, at the time the buy order was or will have been originated, the purchaser was outside the United States, or such Underwriter, affiliate or person acting on behalf of either reasonably believed that such purchaser was outside the United States, or (iii) any Directed Selling Efforts with respect to the Offered Shares, except as permitted in this Section 18;

(ii) neither it nor any of its affiliates nor any person acting on its or their behalf has engaged or will engage in any form of General Solicitation or General Advertising or in any conduct involving a public offering that would make the exemption from registration provided in Section 4(2) of the U.S. Securities Act unavailable for offers or sales of the Offered Shares in the United States;

(iii) all offers and sales of the Offered Shares in the United States will be effected through its U.S. Affiliate duly registered under the *U.S. Exchange Act* and all applicable state securities laws, in accordance with all applicable United States state and federal securities (including broker-dealer) laws;

(iv) each U.S. Affiliate which is purchasing Offered Shares in the United States is a Qualified Institutional Buyer and is a member of, and in good standing with, the National Association of Securities Dealers, Inc. on the date hereof;

(v) it has not used and will not use any written material other than the U.S. Placement Memorandum relating to the offering of the Offered Shares in the United States, and it agrees to deliver, through the U.S. Affiliates, a copy of the U.S. Placement Memorandum to each person in the United States purchasing Offered Shares in an initial resale transaction in the United States;

(vi) any offer, sale or solicitation of an offer to buy Offered Shares that has been made or will be made in the United States was or will be made only to a person it reasonably believes to be a Qualified Institutional Buyer or an Institutional Accredited Investor who is acquiring the Offered Shares (i) for its own account or (ii) for the account of a Qualified Institutional Buyer or an Institutional Accredited Investor, as the case may be, with respect to which it exercises sole investment discretion in a transaction that is exempt from registration under the U.S. Securities Act;

(vii) all purchasers of Offered Shares who are buying such shares pursuant to Rule 144A shall be informed that the Offered Shares are being offered and sold to such purchasers in reliance on an exemption from the registration requirements of the U.S. Securities Act provided by Rule 144A;

(viii) immediately prior to soliciting such offerees, the Underwriter has reasonable grounds to believe and did believe that each offeree was a Qualified Institutional Buyer or an Institutional Accredited Investor, as the case may be;

(ix) prior to completion of any sale of Offered Shares in the United States, each U.S. Purchaser thereof (a "**U.S. Purchaser**") that is a Qualified Institutional Buyer will be deemed to have provided the representations, warranties and covenants in the U.S. Placement Memorandum; and

(x) prior to any sale of Shares in the United States, it caused each U.S. Purchaser that is an Institutional Accredited Investor to sign a U.S. purchaser's letter containing representations, warranties and agreements to the Corporation substantially similar to the form set out in Schedule B.

(d) Each Underwriter agrees that:

(i) prior to the Closing Date, it will request Peters & Co. Limited to provide Valiant Trust Company with a list of all purchasers of Offered Shares in the United States;

(ii) at closing, it, together with its U.S. Affiliate selling Offered Shares in the United States, will provide a certificate, substantially in the form of Schedule A to this Agreement relating to the manner of the offer and sale of the Offered Shares in the United States;

(iii) if the Underwriters authorize any member of the Selling Dealer Group (if any) to offer and sell Offered Shares in the United States through the U.S. Affiliates, the Underwriters will cause each such firm to acknowledge in writing, for the benefit of the Corporation, its agreement to be bound by the provisions of this Section 18 in connection with all offers and sales of the Offered Shares in the United States. The Underwriters have not made and will not make any other contractual arrangement for the distribution of the Offered Shares in the United States without the prior written consent of the Corporation; and

(iv) it understands that all Offered Shares sold in the United Shares as part of this Offering will bear a legend to the following effect:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**SECURITIES ACT**") OR STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF DEER CREEK ENERGY LIMITED (THE "**CORPORATION**") THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF

REGULATION S UNDER THE SECURITIES ACT, (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 144A UNDER THE SECURITIES ACT, (D) PURSUANT TO THE EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER, OR (E) PURSUANT TO ANOTHER EXEMPTION FROM REGISTRATION AFTER PROVIDING A LEGAL OPINION SATISFACTORY TO THE CORPORATION.

A NEW CERTIFICATE BEARING NO LEGEND MAY BE OBTAINED FROM VALIANT TRUST COMPANY UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO VALIANT TRUST COMPANY AND THE CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE SECURITIES ACT."

If the Offered Shares are being sold in compliance with the requirements of Rule 904 of Regulation S, the legend may be removed by providing a declaration to Valiant Trust Company to the following effect (or as the Corporation may prescribe from time to time):

"The undersigned (A) acknowledges that the sale of the common shares to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the U.S. Securities Act of 1933, as amended, and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the *Securities Act*, as amended) of the Corporation, (2) the offer of such common shares was not made to a person in the United States and either (a) at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States or (b) the transaction was executed on or through the facilities of the Toronto Stock Exchange or the TSX Venture Exchange and neither the seller nor any person acting on its behalf knows that the transaction has been prearranged with a buyer in the United States and (3) neither the seller nor any person acting on its behalf engaged in any directed selling efforts in connection with the offer and sale of such common shares. Terms used herein have the meanings given to them by Regulation S."

If the Offered Shares are being sold under Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to Valiant Trust Company of an opinion of counsel of recognized standing and reasonably satisfactory to the Corporation, to the effect that such legend is no longer required under the U.S. Securities Act or state securities laws.

(e) It is understood and agreed by the Underwriters that the Offered Shares may be offered and resold by the Underwriters and members of the Selling Dealer Group in the United States pursuant to the provisions of Rule 144A to persons who are, or are reasonably believed by them to be, Qualified Institutional Buyers in transactions meeting the requirements of Rule 144A and in compliance with any applicable state securities laws of the United States, provided that prior to any such sale each purchaser shall have been provided with the U.S. Placement Memorandum and by purchasing Offered Shares, each purchaser shall be deemed to have represented and warranted for the benefit of the Corporation and the Underwriters that:

(i) it is a Qualified Institutional Buyer and acknowledges that the sale of Offered Shares to it is being made in reliance on Rule 144A, and it is acquiring such Offered Shares for its own account or for the account of one or more Qualified Institutional Buyers with respect to which it exercises sole investment discretion;

(ii) it understands and acknowledges that the Offered Shares will not be and have not been registered under the U.S. Securities Act or the securities laws of any state of the United States, and are therefore "restricted securities" within the meaning of Rule 144, and that if in the future it shall decide to resell, pledge or otherwise transfer such Offered Shares, the same may be resold, pledged or otherwise transferred only (A) to the Corporation, (B) in the United States, in accordance with Rule 144A to a person it reasonably believes is a Qualified Institutional Buyer that purchases for its own account or for the account of a Qualified Institutional Buyer and to whom notice is given that the offer, sale or transfer is being made in reliance on Rule 144A, (C) outside the United States, in accordance with Rule 904 of Regulation S and in compliance with applicable local laws and regulations, (D) in a transaction exempt from registration under the U.S. Securities Act pursuant to Rule 144 and in compliance with any applicable state securities laws of the United States, or (E) in a transaction that does not require registration under the U.S. Securities Act or any applicable United States state securities laws, and it has furnished to the Corporation an opinion of counsel of recognized standing reasonably satisfactory to the Corporation to that effect;

(iii) it understands that all Offered Shares sold in the United States as part of this offering will bear a legend as set out in paragraph (d)(iv) of this Section 18; and

(iv) it understands and acknowledges that it is making the representations and warranties and agreements contained herein with the intent that they may be relied upon by the Corporation and the Underwriters in determining its eligibility or (if applicable) the eligibility of others on whose behalf it is contracting hereunder to purchase the Offered Shares.

19. Notices

Any notice under this Agreement shall be given in writing and either sent by facsimile or hand delivered to the party to receive such notice at the address indicated below:

(a) to the Corporation at:

Deer Creek Energy Limited
2600 Bow Valley Square 2
205 – 5th Avenue S.W.
Calgary, Alberta T2P 2V7

Attention: Mr. Glen C. Schmidt
Facsimile No: (403) 264-3700

with a copy to:

Bennett Jones LLP
4500, 822 – 2nd Street S.W.
Calgary, Alberta T2P 4K7

Attention: Mr. Robert Lehodey, Q.C.
Facsimile No.: (403) 265-7219

(b) to the Underwriters at:

Peters & Co. Limited
3900, 888 – 3rd Street S.W.
Calgary, Alberta T2P 5C5

Attention: Mr. Ian D. Bruce
Facsimile No.: (403) 261-7570

and to:

RBC Dominion Securities Inc.
7th Floor, 333 – 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Attention: Mr. Evan J. Hazell
Facsimile No.: (403) 299-6901

and to:

Merrill Lynch Canada Inc.
1650, 250 – 6th Avenue S.W.
Calgary, Alberta T2P 3H7

Attention: Mr. Drew M. Ross
Facsimile No.: (403) 237-7372

and to:

CIBC World Markets Inc.
900, 855 – 2nd Street S.W.
Calgary, Alberta T2P 4J7

Attention: Mr. T. Timothy Kitchen
Facsimile No.: (403) 260-0524

and to:

Scotia Capital Inc.
2000, 700 – 2nd Street S.W.
Calgary, Alberta T2P 2W1

Attention: Mr. Mark Herman
Facsimile No.: (403) 298-4099

and to:

Canaccord Capital Corporation
400, 409 – 8th Avenue S.W.
Calgary, Alberta T2P 1E3

Attention: Mr. Karl B. Staddon
Facsimile No.: (403) 508-3866

and to:

First Associates Investments Inc.
2200, 440 – 2nd Avenue S.W.
Calgary, Alberta T2P 5E9

Attention: Mr. John M. Peltier
Facsimile No.: (403) 260-5751

and to:

FirstEnergy Capital Corp.
1600, 333 – 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Attention: Mr. M. Scott Bratt
Facsimile No.: (403) 262-0688

and to:

Raymond James Ltd.
2500, 707 – 8th Avenue S.W.
Calgary, Alberta T2P 1H5

Attention: Mr. Edward J. Bereznicki
Facsimile No.: (403) 509-0535

and to:

Salman Partners Inc.
4450, 888 – 3rd Street S.W.
Calgary, Alberta T2P 5C5

Attention: Mr. Francesco G. Mele
Facsimile No.: (403) 266-6099

with a copy to:

Stikeman Elliott LLP
4300 Bankers Hall West
888 – 3rd Street S.W.
Calgary, Alberta T2P 5C5

Attention: Mr. Christopher Nixon
Facsimile No.: (403) 266-9034

or to such other address as the party may designate by notice given to the other. Each communication shall be personally delivered to the addressee or sent by fax transmission to the address, and:

(a) a communication which is personally delivered shall, if delivered before 4:00 p.m. (local time) on a Business Day, be deemed to be given and received on that day and, in any other case, be deemed to be given and received on the first Business Day following the day on which it is delivered; and

(b) a communication which is sent by fax transmission shall, if sent on a Business Day before 4:00 p.m. (local time), be deemed to be given and received on that day and, in any other case, be deemed to be given and received on the first Business Day following the day on which it is sent.

20. Conditions

(a) All terms and conditions of this Agreement to be performed by the Corporation shall be construed as conditions, and any breach or failure to comply with any material terms and conditions shall entitle the Underwriters to terminate their obligations to purchase the Firm Shares and Over-Allotment Shares by written notice to that effect given to the Corporation on or prior to the Closing Date. The Underwriters may waive in whole or in part any breach of, default under or non-compliance with any representation, warranty, term or condition hereof, or extend the time for compliance therewith, without prejudice to any of their rights in respect of any other representation, warranty, term or condition hereof or any other breach of, default under or non-compliance with any other representation, warranty, term or condition hereof, provided that any such waiver or extension shall be binding on the Underwriters only if the same is in writing; and

(b) All terms and conditions of this Agreement to be performed by the Underwriters shall be construed as conditions, and any breach or failure to comply with any material terms and conditions shall entitle the Corporation to terminate its obligation to sell the Firm Shares and Over-Allotment Shares by written notice to that effect given to the Underwriters on or prior to the Closing Date. The Corporation may waive in whole or in part any breach of, default under or non-compliance with any representation, warranty, term or condition hereof, or extend the time for compliance therewith, without prejudice to any of its rights in respect of any other representation, warranty, term or condition hereof or any other breach of, default under or non-compliance with any other representation, warranty, term or condition hereof, provided that any such waiver or extension shall be binding on the Corporation only if the same is in writing.

21. Survival of Representations and Warranties

It is understood that all warranties, representations, covenants and agreements herein contained or contained in certificates or documents submitted pursuant to or in connection with the transaction provided for herein shall survive the issuance of the Offered Shares and the termination of this Agreement and shall continue in full force and effect for the benefit of the Corporation and the Underwriters regardless of any investigation by or on behalf of the Underwriters with respect thereto and regardless of whether transactions contemplated herein have been completed.

22. Several Liability of Underwriters

The Underwriters' rights and obligations under this Agreement are several and not joint and several including, without limitation, that:

(a) each of the Underwriters shall be obligated to purchase only the percentage of the total number of Offered Shares set forth opposite its name in this Section 22;

(b) if any one or more of the Underwriters (the "**Refusing Underwriters**") does not purchase its applicable percentage of the total number of Offered Shares, and the aggregate number of Offered Shares not purchased by the Refusing Underwriters is less than 10% of the Offering, the other Underwriters (the "**Continuing Underwriters**") shall continue to be obligated to purchase their applicable percentage of the Offered Shares and shall be entitled, at their option but shall not be obligated, to purchase all, but not less than all, of the Offered Shares (the "**Refusing Underwriters' Shares**") which would otherwise have been purchased by the Refusing Underwriters. In the event that such option is not exercised, the

Continuing Underwriters shall have no obligation to the Corporation in respect of the Refusing Underwriters' Shares; and

(c) if one or more of the Refusing Underwriters shall not purchase its applicable percentage of the total number of the Offered Shares, and the aggregate number of Offered Shares not purchased by the Refusing Underwriters is equal to or greater than 10% of the Offering, the other Continuing Underwriters shall be entitled, at their option but shall not be obligated, to purchase all, but not less than all, of the Refusing Underwriters' Shares which would otherwise have been purchased by the Refusing Underwriters. In the event that such option is not exercised the Continuing Underwriters shall be entitled to terminate their obligations under this Agreement and in such event shall have no liability and no obligations to the Corporation under this Agreement.

The applicable percentage of the total number of Offered Shares which each of the Underwriters shall be separately obligated to purchase is as follows:

Peters & Co. Limited	27.5%
RBC Dominion Securities Inc.	27.5%
Merrill Lynch Canada Inc.	15.0%
CIBC World Markets Inc.	10.0%
Scotia Capital Inc.	10.0%
Canaccord Capital Corporation	2.0%
First Associates Investments Inc.	2.0%
FirstEnergy Capital Corp.	2.0%
Raymond James Ltd.	2.0%
Salman Partners Inc.	2.0%

Nothing in this Section 22 shall relieve any defaulting Underwriter from liability to the Corporation in respect of such default hereunder. Nothing in this Section 22 shall obligate the Corporation to sell to the Underwriters less than all of the Firm Shares pursuant to the terms of this Agreement.

23. Authority to Bind Underwriters

The Corporation shall be entitled to and shall act on any notice or other communication given by or on behalf of the Underwriters by Peters & Co. Limited and RBC Dominion Securities Inc., which shall represent the Underwriters and which has the authority to bind the Underwriters except in respect of a notice of termination given pursuant to Section 13, which notice may be given by any Underwriter, an agreement of settlement given under Section 10, which may be given only by the Underwriter affected thereby or the exercise of the option to purchase the Refusing Underwriters' Shares pursuant to Section 22. Peters & Co. Limited and RBC Dominion Securities Inc. shall consult with the other Underwriters with respect to any such notice or other communication. Acceptance of this offer by the Corporation shall constitute its authority for accepting notification of any such matters from Peters & Co. Limited and RBC Dominion Securities Inc.

24. Severance

If one or more of the provisions contained herein shall, for any reason, be held to be invalid, illegal or unenforceable in any respect, such invalidity, illegality or unenforceability shall not affect any other provision of this Agreement, but this Agreement shall be construed as if such invalid, illegal or unenforceable provision or provisions had never been contained herein.

25. Relationships of the Underwriters

The Corporation: (i) acknowledges and agrees that the Underwriters have certain statutory obligations as registrants under the Applicable Securities Laws and have fiduciary relationships with their clients; and (ii) consents to the Underwriters acting hereunder while continuing to act for their clients. To the extent that the Underwriters' statutory obligations as registrants under Applicable Securities Laws or fiduciary relationships with their clients conflict with their obligations hereunder, the Underwriters shall be entitled to fulfil their statutory obligations as registrants under Applicable Securities Laws and their duties to their clients. Nothing in this Agreement shall be interpreted to prevent the Underwriters from fulfilling their statutory obligations as registrants under Applicable Securities Laws or to act as a fiduciary of their clients.

26. Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Province of Alberta and the laws of Canada applicable therein. Each of the Corporation and the Underwriters hereby attorns to the non-exclusive jurisdiction of the courts of the Province of Alberta.

27. Time of the Essence

Time shall be of the essence of this Agreement.

28. Counterpart Execution

This Agreement may be executed in one or more counterparts and by facsimile each of which so executed shall constitute an original and all of which together shall constitute one and the same agreement.

29. Further Assurances

Each party to this Agreement covenants and agrees that, from time to time, it will, at the request of the requesting party, execute and deliver all such documents and do all such other acts and things as any party hereto, acting reasonably, may from time to time request be executed or done in order to better evidence or perfect or effectuate any provision of this Agreement or of any agreement or other document executed pursuant to this Agreement or any of the respective obligations intended to be created hereby or thereby.

30. Distributions

The Corporation agrees that it will not prior to the Closing Date declare or pay out any dividends to shareholders of the Corporation or set any record date in respect thereof.

31. Entire Agreement

It is understood that the terms and conditions of this Agreement supersede any previous verbal or written agreement between the Underwriters and the Corporation.

If the foregoing is in accordance with your understanding and is agreed to by you, please confirm your acceptance by signing the enclosed copies of this letter at the place indicated and by returning the same to Peters & Co. Limited.

PETERS & CO. LIMITED

By: *"Ian D. Bruce"*

RBC DOMINION SECURITIES INC.

By: *"Evan J. Hazell"*

MERRILL LYNCH CANADA INC.

By: *"Drew M. Ross"*

CIBC WORLD MARKETS INC.

By: *"T. Timothy Kitchen"*

SCOTIA CAPITAL INC.

By: *"Mark Herman"*

CANACCORD CAPITAL CORPORATION

By: *"Karl B. Staddon"*

FIRST ASSOCIATES INVESTMENTS INC.

By: *"Charles A.V. Pennock"*

FIRSTENERGY CAPITAL CORP.

By: *"M. Scott Bratt"*

RAYMOND JAMES LTD.

By: *"Edward J. Bereznicki"*

SALMAN PARTNERS INC.

By: *"Francesco Mele"*

ACCEPTED AND AGREED TO as of July 21, 2004.

DEER CREEK ENERGY LIMITED

By: *"Glen C. Schmidt"*

Glen C. Schmidt
President and Chief Executive Officer

By: *"John S. Kowal"*

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

SCHEDULE A

UNDERWRITERS' CERTIFICATE

In connection with the private placement in the United States of the common shares of Deer Creek Energy Limited (the "**Corporation**") pursuant to the underwriting agreement dated July 21, 2004 among the Corporation and the Underwriters named therein (the "**Underwriting Agreement**"), each of the undersigned does hereby certify in favour of the Corporation as follows:

I. Peters & Co. Equities Inc. (the "**U.S. Affiliate**") is a duly registered broker or dealer with the United States Securities and Exchange Commission (the "**SEC**") and is a member of and in good standing with the National Association of Securities Dealers, Inc. on the date hereof and all offers and sales of Securities in the United States will be effected by the U.S. Affiliate in accordance with U.S. broker-dealer agreements;

II. each offeree was provided with a copy of the U.S. Placement Memorandum for the offering of the Offered Shares in the United States, and no other written material has been or will be used;

III. immediately prior to our transmitting such U.S. Placement Memorandum to such offerees, we had reasonable grounds to believe and did believe that each offeree was, and continue to believe that each such offeree who is a U.S. person purchasing Offered Shares from us is, either a "qualified institutional buyer", as defined in Rule 144A under the *Securities Act* of 1933, as amended (the "**1933 Act**"), or an institutional "accredited investor" as defined in Rule 501(a)(1), (2), (3) or (7) of Regulation D under the *1933 Act* (an "**Institutional Accredited Investor**");

IV. no form of general solicitation or general advertising (as those terms are used in Regulation D under the *1933 Act*) was used by us, including advertisements, articles, notices or other communications published in any newspaper, magazine or similar media or broadcast over radio or television, or any seminar or meeting whose attendees had been invited by general solicitation or general advertising, in connection with the offer or sale of the Offered Shares in the United States;

V. prior to any sale of Offered Shares to an Institutional Accredited Investor in the United States, we caused such U.S. Purchaser to sign a U.S. Purchaser's letter containing representations, warranties and agreements to the Corporation substantially similar to those set forth in Schedule B to the Underwriting Agreement;

VI. neither we nor any member of the Selling Dealer Group (as defined in the Underwriting Agreement), nor any of our or their affiliates, have taken or will take any action which would constitute a violation of Regulation M of the SEC under the *United States Securities Exchange Act* of 1934, as amended; and

VII. the offering of the Offered Shares in the United States has been conducted by us in accordance with the terms of the Underwriting Agreement.

Unless otherwise defined, terms used in this certificate have the meanings given to them in the Underwriting Agreement.

Dated ●, 2004.

PETERS & CO. LIMITED

By: ______________________________

PETERS & CO. EQUITIES INC.

By: ______________________________

SCHEDULE B

FORM OF U.S. PURCHASER'S LETTER

Deer Creek Energy Limited
2600 Bow Valley Square 2
205 – 5th Avenue S. W.
Calgary, Alberta
T2P 2V7

Attention: Mr. Glen C. Schmidt, President and Chief Executive Officer

Dear Sirs:

In connection with our proposed purchase of common shares (the "**Shares**") of Deer Creek Energy Limited (the "**Corporation**"), we confirm and agree as follows:

(a) we are authorized to consummate the purchase of the Shares;

(b) we understand that the Shares have not been and will not be registered under the *United States Securities Act* of 1933, as amended (the "**U.S. Securities Act**"), and that the sale contemplated hereby is being made to Institutional Accredited Investors (as defined in paragraph (c) below) in reliance on a private placement exemption;

(c) we are an institutional "accredited investor" within the meaning of Rule 501(a)(1), (2), (3) or (7) under the U.S. Securities Act ("**Institutional Accredited Investor**") and are acquiring the Shares for our own account or for one or more investor accounts for which we are acting as fiduciary or agent and each such investor account is an Institutional Accredited Investor;

(d) we agree that if we decide to offer, sell or otherwise transfer or pledge all or any part of the Shares, we will not offer, sell or otherwise transfer or pledge any of such Shares (other than pursuant to an effective registration statement under the U.S. Securities Act), directly or indirectly unless:

(i) the sale is to the Corporation; or

(ii) the sale is made outside the United States in accordance with the requirements of Rule 904 of Regulation S under the U.S. Securities Act and in compliance with applicable local laws and regulations; or

(iii) the sale is made pursuant to the exemption from registration under the U.S. Securities Act provided by Rule 144 thereunder; or

(iv) the sale is made in the United States, in accordance with Rule 144A to a person it reasonably believes is a Qualified Institutional Buyer that purchases for its own account or for the account of a Qualified Institutional Buyer and to whom notice is given that the offer, sale or transfer is being made in reliance on Rule 144A; or

(v) the Shares are sold in a transaction that does not require registration under the U.S. Securities Act or any applicable United States state laws and regulations governing the offer and sale of Shares, and we have furnished to the Corporation an opinion of counsel, of recognized standing reasonably satisfactory to the Corporation, to that effect; or

(vi) the sale is to an Institutional Accredited Investor and a purchaser's letter containing representations, warranties and agreements substantially similar to those contained in this purchaser's letter (except that such subsequent purchaser's letter need not contain the representation set forth in paragraph (f) below) is executed by the subsequent purchaser and delivered to the Corporation prior to the sale;

(e) we understand and acknowledge that the Shares are "restricted securities" as defined in Rule 144 under the U.S. Securities Act, and upon the original issuance thereof, and until such time as the same is no longer required under applicable requirements of the U.S. Securities Act or state securities laws, the certificates representing the Shares, and all certificates issued in exchange therefor or in substitution thereof, shall bear on the face of such certificates the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "**SECURITIES ACT**") OR STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, AGREES FOR THE BENEFIT OF DEER CREEK ENERGY LIMITED (THE "**CORPORATION**") THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE CORPORATION, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE SECURITIES ACT, (C) INSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 144A UNDER THE SECURITIES ACT, (D) PURSUANT TO THE EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT PROVIDED BY RULE 144 THEREUNDER, OR (E) PURSUANT TO ANOTHER EXEMPTION FROM REGISTRATION AFTER PROVIDING A LEGAL OPINION SATISFACTORY TO THE CORPORATION.

A NEW CERTIFICATE BEARING NO LEGEND MAY BE OBTAINED FROM VALIANT TRUST COMPANY UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO VALIANT TRUST COMPANY AND THE

CORPORATION, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE SECURITIES ACT.";

If the Shares are being sold in compliance with the requirements of Rule 904 of Regulation S, the legend may be removed by providing a declaration to Valiant Trust Company to the following effect (or as the Corporation may prescribe from time to time):

"The undersigned (A) acknowledges that the sale of the common shares to which this declaration relates is being made in reliance on Rule 904 of Regulation S under the U.S. Securities Act of 1933, as amended, and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the Securities Act, as amended) of the Corporation, (2) the offer of such common shares was not made to a person in the United States and either (a) at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States or (b) the transaction was executed on or through the facilities of the Toronto Stock Exchange or the TSX Venture Exchange and neither the seller nor any person acting on its behalf knows that the transaction has been prearranged with a buyer in the United States and (3) neither the seller nor any person acting on its behalf engaged in any directed selling efforts in connection with the offer and sale of such common shares. Terms used herein have the meanings given to them by Regulation S.";

if the Shares are being sold under Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to Valiant Trust Company of an opinion of counsel of recognized standing and reasonably satisfactory to the Corporation, to the effect that such legend is no longer required under the U.S. Securities Act or state securities laws;

(f) we have received a copy of the U.S. Placement Memorandum (as defined in the Underwriting Agreement) and we have been afforded the opportunity (i) to ask such questions as we have deemed necessary of, and to receive answers from, representatives of the Corporation concerning the terms and conditions of the offering of the Shares and (ii) to obtain such additional information which the Corporation possesses or can acquire without unreasonable effort or expense that is necessary to verify the accuracy and completeness of the information contained in the U.S. Placement Memorandum and that we have considered necessary in connection with our decision to invest in the Shares;

(g) we acknowledge that we are not purchasing the Shares as a result of any general solicitation or general advertising, as those terms are used in Regulation D under the U.S. Securities Act including, without limitation, advertisements, articles, notices and other communications published in any newspaper, magazine or similar media or broadcast over television or radio or any seminar or meeting whose attendees have been invited by general solicitation or general advertising; and

(h) we understand and acknowledge that the Corporation (i) is under no obligation to be or to remain a "foreign issuer," (ii) may not, at the time we sell the Shares or at any other time, be a "foreign issuer," and (iii) may engage in one or more transactions which could cause the Corporation not to be a "foreign issuer." If the Corporation is not a "foreign issuer" at the time of any sale pursuant to Rule 904 of Regulation S, the certificate delivered to the buyer may continue to bear the legend contained in paragraph (e) above.

We acknowledge that the representations and warranties and agreements contained herein are made by us with the intent that they may be relied upon by you and by the U.S. Affiliate, in determining our eligibility or (if applicable) the eligibility of others on whose behalf we are contracting hereunder to purchase the Shares. We further agree that by accepting the Shares we shall be representing and warranting that the foregoing representations and warranties are true as at the closing time with the same force and effect as if they had been made by us at the closing time and that they shall survive the purchase by us of the Shares and shall continue in full force and effect notwithstanding any subsequent disposition by us of the Shares.

You and the U.S. Affiliate are irrevocably authorized to produce this letter or a copy hereof to any interested party in any administrative or legal proceeding or official inquiry with respect to the matters covered hereby.

Dated ●.

[Name of Purchaser]

By: ______________________________

Name: ●

Title: ●

SCHEDULE C

FORM OF LOCK-UP LETTER

•, 2004

Peters & Co. Limited
RBC Dominion Securities Inc.
c/o Peters & Co. Limited
3900, 888 – 3rd Street S.W.
Calgary, Alberta
T2P 5C5

Attention: Christopher S. Potter

Dear Sirs:

Re: Deer Creek Energy Limited (the "Corporation") Common Share Offering

The undersigned refers to the Underwriting Agreement dated July 21, 2004 (the "Underwriting Agreement") between the Corporation and the Underwriters (as defined therein) with respect to an offering of Common Shares. Capitalized terms used but not defined in this letter have the meaning given them in the Underwriting Agreement.

The undersigned is a holder of Common Shares and is providing this lock-up letter to the Underwriters in order to facilitate the offering of Offered Shares pursuant to the Prospectus.

The undersigned irrevocably agrees that, during the period commencing on the date of this lock-up letter and ending on the day which is 180 days following the Closing Date, the undersigned will not, directly or indirectly, without the prior written consent of Peters & Co. Limited and RBC Dominion Securities Inc. (which consent may not be unreasonably withheld), (a) 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, (b) 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 Common Shares, regardless of whether any such transaction described in clauses (a) or (b) is to be settled by delivery of Common Shares, other securities or cash or otherwise, or (c) announce publicly any intention to effect any of the foregoing, other than to give effect to the Over-Allotment Option. In the circumstance of an unsolicited offer for all, or substantially all, of the Common Shares, which offer has been recommended to the shareholders by the Corporation's board of directors, the undersigned will be released from this agreement for the sole purpose of tendering to such unsolicited offer.

Yours truly,

ACCEPTED AND AGREED TO as of this
_____ day of _______________, 2004.

PETERS & CO. LIMITED

By: _________________________________

RBC DOMINION SECURITIES INC.

By: _________________________________

JOINT VENTURE AGREEMENT

Agreement dated for reference the 1st day of July, 2002.

BETWEEN:

DEER CREEK ENERGY LIMITED, a corporation incorporated under the *Business Corporations Act* (Alberta)

OF THE FIRST PART

and

ENERMARK INC., a corporation incorporated under the *Business Corporations Act* (Alberta)

OF THE SECOND PART

WHEREAS the Parties individually own or are entitled to acquire, undivided interests, as tenants in common, in the Lands, in the following proportions:

DCE	84%
EnerMark	16%

AND WHEREAS the Parties desire to more particularly set forth and define their respective rights and obligations in respect of their holding and the exploration and development of the Lands for the production of petroleum substances and the construction of related facilities and equipment and the maintenance and operation thereof.

WITNESSETH that in consideration of the mutual covenants herein contained the parties hereto covenant and agree, each with the other, as follows:

ARTICLE 1
DEFINITIONS, INTERPRETATION & SCHEDULES

1.1 Definitions

In this Agreement including the recitals hereto, except as otherwise expressly provided, or unless the context otherwise requires, the following words and phrases (and derivatives thereof) have the following meanings:

(a) "**Accounting Procedure**" has the meaning set out in the Operating Procedure;

(b) "**A.F.E.**" has the meaning set out in the Operating Procedure;

(c) "**Affiliate**" has the meaning set out in the Operating Procedure;

(d) **"Business Day"** means a day other than a Saturday, Sunday or holiday on which banks are generally open for business in Calgary Alberta;

(e) "**Change of Control of DCE**" means any of the following events:

(i) the purchase or acquisition of voting shares or securities convertible into voting shares (in this subsection called the "Convertible Securities") of DCE as a result of which the holders of voting shares and Convertible Securities of DCE (in this subsection collectively called the "Security Holders") immediately prior thereto, together with funds managed by Lime Rock Management LP or its affiliates (collectively called "Lime Rock"), do not immediately thereafter beneficially own voting shares or Convertible Securities of DCE which, assuming conversion of all Convertible Securities, would entitle the Security Holders and Lime Rock voting in concert to elect a majority of the directors of DCE; or

(ii) the completion of:

(A) an amalgamation, arrangement, merger or other consolidation or combination of DCE with another Person pursuant to which the Security Holders immediately prior thereto together with Lime Rock do not immediately thereafter beneficially own voting shares or Convertible Securities of the successor or continuing corporation which, assuming the conversion of all Convertible Securities, would entitle the Security Holders and Lime Rock voting in concert to elect a majority of the directors of that corporation, or

(B) a sale, lease or other disposition of all or substantially all of the assets of DCE other than a sale, lease or other disposition of all or substantially all of the assets of DCE in connection with a transaction which would itself not constitute a Change of Control;

For the purposes of the definition of Change of Control:

(C) persons are "associates" or "affiliates" if they would be associates or affiliates under the provision of *The Business Corporations Act* (Alberta) in force on the date hereof; and

(D) "event" shall not include the issuance of shares pursuant to any Initial Public Offering made by Deer Creek nor any sale or other disposition of shares by any shareholder that increases the number of shareholders except as set out in subsection 1.1(e)(ii)(A);

(f) "**Commitment Amount**" has the meaning set out in subsection 7.5(a)(i);

(g) "**DCE**" means Deer Creek Energy Limited, the party of the first part;

(h) “**DCE Call Option**” has the meaning set out in subsection 7.2(d)(ii);

(i) “**Effective Date**” means the date that this Agreement becomes effective between the parties as provided in section 3.1;

(j) “**EnerMark**” means EnerMark Inc., the party of the second part;

(k) “**EnerMark Put Option**” has the meaning set out in subsection 7.2(d)(i);

(l) “**G & A**“ means gross expenditures less recoveries from third parties, other than EnerMark, required to facilitate the day-to-day operations of DCE under normal business conditions and as defined in the DCE chart of accounts. Expenditures shall be classified as G & A using generally accepted accounting principles and in accordance with normal industry practice. For clarification, G &A will not include DCE financing costs or advisory fees;

(m) “**Joint Venture Interest**” when used in relation to a Party, means the entire interest of that Party in and to:

(i) the Lands;

(ii) the production facilities;

(iii) all unsold petroleum substances produced from the Lands; and

(iv) all other benefits accruing to that Party under or by virtue of its interest in any of the foregoing;

together with the benefits accruing to such Party and the obligations imposed upon such Party by virtue of the provisions of this Agreement;

(n) “**Lands**” means the lands described in Schedule 1.1(n);

(o) “**Mining Area**” means, initially, the area of the Lands outlined by crosshatching on the map attached as Schedule 1.1(o), which area may from time to time be amended by agreement between the Parties;

(p) “**Non-Participating Expenditure**” has the meaning set out in subsection 7.5(b)(i);

(q) “**Operating Procedure**” means the form of Operating Procedure attached as Schedule 1.1(q);

(r) “**Operator**” means DCE and includes any replacement operator appointed under the Operating Procedure;

(s) “**Outside Project**” means a capital investment by DCE other than an investment on or in relation to the Lands;

(t) "**Parties**" means DCE and EnerMark;

(u) "**Party**" means either DCE or EnerMark and, if "Party" is used in relation to a Person that is both a Party and the Operator, "Party" means that Person in its capacity as a Party and not in its capacity as Operator;

(v) "**Percentage Interest**" means the interest of a Party, expressed as a percentage, in:

(i) the Lands;

(ii) the Project Facilities;

(iii) all petroleum substances produced from the Lands; and

(iv) all other benefits accruing to the Parties under or by virtue of its interest in any of the foregoing or under or by virtue of the provisions of this Agreement;

(w) "**petroleum substances**" has the meaning set out in the Operating Procedure;

(x) "**production facility**" has the meaning set out in the Operating Procedure;

(y) "**proportionate share**" has the meaning set out in the Operating Procedure;

(z) "**Recovery Amount**" has the meaning set out in subsection 7.5(b)(i)(A) or subsection 7.5(b)(i)(B), as applicable;

(aa) "**SAGD**" has the meaning set out in subsection 7.4(d);

(bb) "**SAGD Area**" means the area of the Lands other than the Mining Area; and

(cc) "**Year**" means a calendar year.

1.2 Interpretation

In this Agreement and any amendments thereto, except as otherwise provided, or unless the context otherwise requires:

(a) "this Agreement" means this Agreement as it may from time to time be supplemented or amended by one or more agreements entered into pursuant to the applicable provisions hereof;

(b) this Agreement is divided into numbered sections and subdivisions of each called, "subsections". In this Agreement references to a particular section or subsection includes all subdivisions thereof;

(c) the words "herein" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular section or other subdivision;

(d) the headings and subheadings inserted in this Agreement are designed for convenience only and do not form a part of this Agreement nor are they intended to interpret, define or limit the scope, extent or intent of this Agreement or any provision hereof;

(e) words and phrases like "including", "specifically" and "particularly" when following any general statement, term or matter, shall not be construed to limit such general statement, term or matter to the specific items or matters set forth immediately following such word or to similar items or matters, whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto but rather shall be deemed to refer to all other items or matters that could reasonably fall within the broadest possible scope of such general statement, term or matter;

(f) all references to currency herein are deemed to mean Canadian currency;

(g) any reference to a statute shall include and shall be deemed to be a reference to such statute and to the regulations made pursuant thereto, with all amendments made thereto and in force from time to time, and to any statute or regulation that may be passed which has the effect of supplementing or superseding the statute so referred to or the regulations made pursuant thereto;

(h) any reference to "approval", "authorization" or "consent" of a party means, respectively, the written approval, the written authorization and the written consent of such party;

(i) words importing the masculine gender include the feminine or neuter gender and words in the singular include the plural, and vice versa and words importing individuals shall include firms and corporations, and vice versa;

(j) any reference to a Person shall include and shall be deemed to be a reference to that Person's successor; and

(k) "Person" means and includes any individual, corporation, partnership, firm, joint venture, syndicate, association, trust, government, governmental agency or board or commission or authority, and other forms of entity or organization.

1.3 Schedules

The following schedules are attached hereto, incorporated herein by reference and shall be deemed to form a part hereof:

Schedule "1.1(n)"	-	The Lands
Schedule "1.1(o)"	-	Map
Schedule "1.1(q)"	-	Operating Procedure

ARTICLE 2
SCOPE, OTHER INTERESTS AND RELATIONSHIP

2.1 Scope

Unless otherwise referred to herein, this agreement and the obligation of any Party to the other Party shall be limited specifically to the operations on the Lands.

2.2 Other Business Activities

Each Party shall devote such time as may be required to fulfil any obligation assumed by it hereunder but, subject to subsection 7.2(c):

(a) each Party shall be at liberty to engage in any other business or activity outside the Joint Venture, including the ownership and operation of any other interests in lands for the production of petroleum substances;

(b) no Party shall be under any fiduciary or other obligation to the other Party which shall prevent or impede such Party from participating in, or enjoying the benefits of, a competing endeavour to the business or activity undertaken by the Parties hereunder; and

(c) the legal doctrines of "corporate opportunity" or "business opportunity" sometimes applied to Persons occupying a relationship similar to that of the Parties shall not apply with respect to participation by any Party in any business activity or endeavour outside the Joint Venture, and, without limitation thereto, a Party shall not be accountable to the others for participation in any such business activity or endeavour outside the Joint Venture which is in direct competition with the business or activity undertaken by the Joint Venture.

2.3 No Partnership

From and after the Effective Date, the rights and obligations of the Parties shall be, in each case, several, and shall not be or be construed to be either joint or joint and several. Nothing contained in this Agreement shall, except to the extent specifically authorized hereunder, be deemed to constitute a Party a partner, an agent or legal representative of any other Party. It is intended that this Agreement shall not create the relationship of a partnership between the Parties and that no act done by any Party pursuant to the provisions hereof shall operate to create such a relationship. In that regard, it is not the intention of the Parties that this Agreement be construed as one for carrying on business together but rather that it be construed as an agreement for the regulation of their respective rights and obligations as co-owners of the Joint Venture Interests and the sharing of gross returns therefrom.

ARTICLE 3
EFFECTIVE DATE AND TERM

3.1 Effective Date

This Agreement has been dated for reference as of the 1st day of July, 2002 but shall not become effective until EnerMark shall have completed the acquisition of a 16% working interest in the Lands under the Purchase And Sale Agreement also dated for reference the 1st day of July, 2002 between DCE, as vendor, and EnerMark, as purchaser. Upon closing of the acquisition, this Agreement shall become effective between the Parties and the Joint Venture shall be deemed to have been formed as of such date.

3.2 Term of Agreement

Subject to the terms and conditions hereinafter set forth, this Agreement shall remain in force and effect until the earlier of:

(a) expiry of the term set out Article XXIX of the Operating Procedure; and

(b) the date that one Party acquires all of the Joint Venture Interests.

ARTICLE 4
FORMATION OF JOINT VENTURE

4.1 The Parties enter into and form a joint venture for the purposes of exploring, developing and operating the Lands for the recovery and sale of petroleum substances in accordance with the terms of this Agreement.

ARTICLE 5
OPERATING PROCEDURE AND APPOINTMENT OF OPERATOR

5.1 Operating Procedure

The Lands shall be operated and all operations on the Lands shall be carried out as provided in this Agreement, the Operating Procedure and the Accounting Procedure, and the Parties shall be governed with relation to each other and all matters concerning the Lands as provided in this Agreement, the Operating Procedure and the Accounting Procedure, in each case to the same effect as if the provisions of the Operating Procedure and the Accounting Procedure were fully set out in this Agreement.

5.2 Appointment of DCE as Operator

DCE is hereby designated and appointed as Operator of the Joint Venture and the Lands until such time as it is replaced under the terms of the Operating Procedure or this Agreement.

5.3 Powers and Duties of Operator

As Operator of the Joint Venture, DCE shall perform all of the duties and obligations and shall have all of the rights, powers and benefits of Operator under the Operating Procedure.

5.4 No Liability for Special Damages

Notwithstanding anything in this Agreement or the Operating Procedure to the contrary, the Operator shall not be liable to any Party nor shall any Party be liable to the Operator in its capacity as such, in contract, tort or otherwise for special or consequential damages, including, without limitation thereto, loss of profits or revenues.

ARTICLE 6
PERCENTAGE INTERESTS OF THE PARTIES

6.1 At the Effective Date, the respective undivided interests of the Parties in the Lands and their respective Percentage Interest is as follows:

DCE	84%
EnerMark	16%.

ARTICLE 7
JOINT VENTURE STAGES

The Joint Venture shall have two stages.

7.1 Stage 1

(a) Stage 1 will be deemed to have commenced on the Effective Date and will end on the earlier of:

(i) 2400 hours on December 31, 2007;

(ii) the date that there is a Change of Control of DCE;

(iii) the replacement of DCE as Operator under section 202(a)(i) of the Operating Procedure; and

(iv) the expiry of the term as set out in section 3.2 of this Agreement.

7.2 Special Terms Applicable during Stage 1

During Stage 1 of the Joint Venture, the following terms shall apply:

(a) **EnerMark's Right to Nominate DCE Director**

(i) EnerMark shall have the right to nominate one member to the Board of Directors of DCE, which nominee must be acceptable to DCE acting reasonably, legally eligible to serve as a director and, unless otherwise consented to by DCE, must be a resident Canadian. On the Effective Date or immediately following the Effective Date, EnerMark shall advise DCE in writing of the name of EnerMark's nominee and DCE will cause its Board of Directors to pass a resolution appointing EnerMark's nominee as an additional director. At least 60 days prior to the date of each meeting of shareholders of DCE occurring after the Effective Date at which directors are to be elected, EnerMark will provide DCE with the name of EnerMark's nominee, together with all relevant information regarding such nominee for inclusion in proxy solicitation materials. Subject to the foregoing, DCE will name EnerMark's representative in proxy solicitation materials as a proposed nominee for election as a director at the meeting and will solicit proxies for his election in the same manner as proxies are solicited for the election of other management nominees. If for any reason (other than failure of EnerMark to timely provide DCE with the name of EnerMark's nominee and relevant information for proxy solicitation materials) EnerMark's representative is not elected as a director of DCE, then, EnerMark will no longer be obligated to contribute to G&A under subsection 7.2(b) and, three months following the date that EnerMark ceases to be obligated to contribute to G&A, EnerMark will no longer be entitled to participate in Outside Projects. If for any reason (other than failure of EnerMark to timely provide DCE with the name of EnerMark's nominee and relevant information for proxy solicitation materials) EnerMark's representative ceases to be a director of DCE, EnerMark shall be entitled to name a replacement and DCE shall cause its Board of Directors to pass a resolution appointing the replacement to fill the vacancy created by reason of EnerMark's nominee ceasing to be a director. EnerMark acknowledges that DCE's Board of Directors currently consists of seven directors but DCE reserves the right to increase the size of the Board without EnerMark being entitled to increase its representation on the Board.

(ii) If requested by DCE, EnerMark will cause its representative then serving on DCE's Board of Directors to resign at the end of Stage 1 of the Joint Venture.

(b) **Contribution to G & A**

(i) Subject to and in accordance with the terms of this subsection 7.2(b), EnerMark will reimburse DCE for its proportionate share of DCE's G & A during Stage 1 of the Joint Venture.

(ii) On the Effective Date, EnerMark will advance the sum of $112,000 against EnerMark's proportionate share of DCE's remaining estimated G & A for 2002. After receipt of DCE audited financial statements for the year ended December 31, 2002, the advance will be reconciled to EnerMark's actual proportionate share of G & A. Any amount found owing from EnerMark to DCE as a result of such reconciliation will be paid by EnerMark to DCE within 30 days of receipt of an invoice from DCE. Any amount found owing from DCE to EnerMark as a result of such reconciliation will be credited to EnerMark on account of EnerMark's proportionate share of G & A for succeeding periods.

(iii) Commencing with the month January, 2003 and each month thereafter, DCE will bill EnerMark for its proportionate share of G & A. After receipt of DCE audited financial statements for each Year after December 31, 2002, the amount paid by EnerMark on account of G & A during the Year will be reconciled to EnerMark's actual proportionate share of G & A as set out in the statements. Any amount found owing from EnerMark to DCE as a result of such reconciliation will be paid by EnerMark to DCE within 30 days of receipt of an invoice from DCE. Any amount found owing from DCE to EnerMark as a result of such reconciliation will be credited to EnerMark on account of EnerMark's proportionate share of G & A for succeeding periods.

(iv) Notwithstanding subsection 7.2(b)(i):

(A) EnerMark shall not be obligated to reimburse DCE for its proportionate share of DCE's G & A in excess of $3,000,000 in any Year unless EnerMark has agreed to the excess G & A. The vote of EnerMark's nominee on DCE's Board of Directors for the approval of a budget which contains an estimate of G & A in excess of $3,000,000 shall be deemed to be EnerMark's agreement to the excess G & A disclosed in the budget. If EnerMark's representative on DCE's Board of Directors votes against the approval of a budget that contains an estimate of G & A in excess of $3,000,000 or is absent from the meeting where such a budget is approved and does not thereafter ratify the approval in writing, EnerMark shall not be obligated to reimburse DCE for any portion of G & A in excess of $3,000,000 in the year to which the budget relates unless EnerMark agrees to the excess G & A. DCE and EnerMark agree that an annual G & A of $3,000,000 is reasonable having regard to the anticipated activities of the Joint Venture during Stage 1, however it is acknowledged that G & A may exceed $3,000,000 as a result of increased activities of the Joint Venture. In the event of an increase in Joint Venture activities beyond those currently anticipated, DCE and EnerMark will meet and in good faith attempt to determine a reasonable annual G & A for DCE having regard to the increased activities and any amount so agreed upon may be used (instead of $3,000,000) for purposes of this subsection.

(B) EnerMark's obligation to reimburse DCE for G & A will terminate if EnerMark's interest in the Joint Venture and the Lands is transferred to DCE in exchange for Common Shares, as contemplated in subsection 7.2(d);

(C) the percentage of DCE G & A which EnerMark will be obligated to reimburse to DCE will be reduced if either or both of the following events occur:

(1) DCE acquires an Outside Project and EnerMark elects not to participate in the Outside Project;

(2) EnerMark exchanges its interest in the Mining Area and its other Joint Venture Interest associated exclusively with the Mining Area for Common Shares of DCE as contemplated in subsection 7.2(d)(i)(B);

and in any such event, EnerMark's obligation to reimburse DCE for G & A will be limited to that portion of G & A fairly attributable to:

(3) operations on the Lands, if DCE develops an Outside Project and EnerMark elects not to participate in the Outside Project; or

(4) operations on the Lands, exclusive of operations on the Mining Area, if EnerMark exchanges its interest in the Mining Area and its other Joint Venture Interest associated exclusively with the Mining Area for Common Shares of DCE as contemplated in subsection 7.2(d)(i)(B).

(c) **Right of Participation in DCE Outside Projects**

(i) If DCE wishes make an offer or invest capital in an Outside Project DCE will first consult with EnerMark at least 5 Business Days prior to submitting its offer, to attempt to establish a joint offer to acquire the Outside Project. If unanimous agreement is reached by the Parties for joint acquisition of the Outside Project, DCE (or the agreed upon Party) will submit that offer on behalf of all Parties. If the Parties do not agree on the terms of a joint offer, DCE may (but EnerMark may not) submit an independent offer for the Outside Project, subject to subsection 7.2(c)(ii)(B). Each Party participating in an offer under this subsection will pay its share of the acquisition price at the same time as the Party submitting the offer.

(ii) If DCE acquires an Outside Project (either by making an offer to a third party or by accepting an offer from a third party):

(A) without consulting EnerMark or as required by subsection 7.2(c)(i); or

(B) under an offer where unanimous agreement was not reached pursuant to subsection 7.2(c)(i) and the price paid to acquire the Outside Project is 95% (or less) of the last price DCE disclosed to EnerMark that it was prepared to offer for the joint acquisition of the Outside Project;

DCE will deliver notice to EnerMark describing the material provisions of the acquisition within five (5) days of the third party's acceptance of DCE's offer or DCE's acceptance of the third party's offer, as the case may be.

(iii) Upon receiving a notice under subsection 7.2(c)(ii) EnerMark may elect to participate in the acquisition of the applicable Project by notice to DCE within seven (7) days of the receipt of the said notice. If EnerMark elects to participate in the acquisition, EnerMark will pay to DCE its proportionate share of the cash consideration for the acquisition within 7 days of receipt of DCE's invoice therefor.

(iv) If an Outside Project is to be acquired under a farmin or other earning arrangements with third parties and the consideration or any part of the consideration for the acquisition of the Outside Project is the drilling of a well or the conduct of certain operations, and EnerMark elects to acquire its propionate share of DCE's interest in the Outside Project, EnerMark will be required to assume a corresponding share of the cost, risk and expense of the applicable operations. If the terms of the acquisition enable DCE to earn additional interests by conducting optional operations and EnerMark does not agree to exercise that option, EnerMark will not be entitled to any of the interest earned by the optional operations and the interest earned DCE by conducting such optional operations shall not be subject to the provisions of this section.

(v) If the Outside Project is subject to an overriding royalty, production payment or other charge of a similar nature, DCE must disclose that encumbrance in the notice of acquisition that it gives to EnerMark under this subsection 7.2(c)(ii). If EnerMark elects to acquire an interest in the Outside Project, it will assume a corresponding share of that disclosed encumbrance. However, the obligation to assume an encumbrance under this subsection will not apply to any encumbrance created directly or indirectly by or through DCE with an Affiliate, director, officer, agent, employee, independent contractor or consultant of DCE in conjunction with that acquisition.

(vi) In connection with any consultation under subsection 7.2(c)(i) or any notice given under subsection 7.2(c)(ii), subject to compliance with any applicable confidentiality obligations, EnerMark will be entitled to review any geological, geophysical engineering, project economics and relevant agreements or other data acquired by DCE in relation to the Outside Project and any interpretation thereof developed by DCE, but nothing in this subsection 7.2(c) requires DCE to disclose to EnerMark any other information. EnerMark acknowledges that notwithstanding any information or interpretation provided to it by DCE under this section, EnerMark will be responsible for making its own independent investigation, analysis, evaluation and inspection of any Outside Project and will rely on its own investigation, analysis, evaluation and inspection of the Outside Project in making its assessment of the Outside Project and in making its decision to participate or not participate in the Outside Project. EnerMark acknowledges and agrees that DCE shall not be responsible to ensure the validity of any information or interpretation provided to EnerMark hereunder and DCE does not guarantee the accuracy thereof. Use by EnerMark of any information or interpretation provided by DCE shall constitute a release by and agreement of EnerMark to defend and indemnify DCE and its directors, officers, employees and consultants from and against any liability (including but not limited to liability for special, indirect or consequential damages) in connection with or resulting from such use. Such release from and indemnification against liability shall apply in contract, tort (including negligence of DCE or its directors, officers, employees and consultants, whether active, passive, joint or concurrent), strict liability, or other theory of legal liability; provided, however, such release, limitation and indemnity provisions shall be effective to, and only to, the maximum extent, scope or amount allowable by law.

(vii) Unless otherwise agreed in writing by EnerMark and DCE, EnerMark's participation in a joint bid for an Outside Project under subsection 7.2(c)(i) or EnerMark's election to participate in the acquisition of an Outside Project under subsection 7.2(c)(iii), shall be limited to 16% of the interest acquired by DCE. EnerMark acknowledges that DCE is subject to an area of mutual interest with Talisman Energy Inc. ("Talisman") in the Athabasca Oil Sands region and that EnerMark's 16% participation right will be calculated after satisfying area of mutual interest obligations to Talisman.

(viii) Nothing in this subsection applies to an internal reorganization by amalgamation or otherwise or to a corporate reorganization or an amalgamation that results in a Change of Control of DCE.

(ix) Outside Projects in which EnerMark participates will be the subject of a separate Joint Venture Agreement between DCE and EnerMark, which shall contain terms substantially the same as the terms of this Agreement, with appropriate modifications, and excluding Article 7.

(d) **Put and Call Options**

(i) In the event that:

(A) EnerMark elects not to pay its proportionate share of any expenditure on the SAGD Area, EnerMark shall have the option to dispose and assign of all of its Joint Venture Interest as the same may be subject to any and all liens, charges and security interests granted pursuant to the Talisman EnerMark Debenture (as defined in section 3.1) of the Purchase and Sale Agreement (the "SAGD Assigned Interests") to DCE in exchange for Common Shares of DCE and DCE shall (1) accept such disposition and assignment to it of the Assigned Interests on an as is where is basis; (2) utilize its best efforts to obtain from all relevant third parties a release in favour of EnerMark of all of EnerMark's obligations under and pursuant to the Talisman EnerMark Debenture; (3) do all things necessary to enter into arrangements with Talisman Energy Inc. ("Talisman") that are satisfactory to Talisman whereby Talisman will acquire, contemporaneous with the completion of such disposition, a first charge and security interest from DCE in and to the interests being conveyed, and (4) indemnify and save EnerMark harmless of and from any loss, liability, claim, damage, cost or expense (including without limitation; reasonable legal fees and disbursements) suffered or incurred by EnerMark as a result of or in connection with any claims or demands made or action taken by any other party as a result of or in connection with the failure of DCE to satisfy and fulfill EnerMark's obligations under the Talisman EnerMark Debenture; or

(B) EnerMark elects not to pay its proportionate share of any expenditure on the Mining Area, EnerMark shall have the option to dispose and assign of its interest in the Mining Area and its other Joint Venture Interest associated exclusively with the Mining Area as the same may be subject to a proportion of any and all liens, charges and security interests granted pursuant to the Talisman EnerMark Debenture (as defined in section 3.1) of the Purchase and Sale Agreement (the "Mining Area Assigned Interests") to DCE in exchange for Common Shares of DCE and DCE shall (1) accept such disposition and assignment to it of such interests on an as is where is basis, and (2) indemnify and save EnerMark harmless of and from any loss, liability, claim, damage, cost or expense (including without limitation; reasonable legal fees and disbursements) suffered or incurred by EnerMark as a result of or in connection with any claims or demands made or action taken by any other party as a result of or in connection with the failure of DCE to satisfy and fulfill EnerMark's obligation under the assigned portion of the Talisman EnerMark Debenture,

(such option herein called the "EnerMark Put Option"); provided that, the EnerMark Put Option shall not apply until payments made by EnerMark under subsection 7.5(a) equal or exceed the Commitment Amount.

(ii) In the event that:

(A) EnerMark elects not to, or fails to, pay its proportionate share of one or more expenditures totaling $10,000,000 (net to EnerMark) on the SAGD Area, DCE shall have the option to acquire and assign all of EnerMark's Joint Venture Interest as the same may be subject to any and all liens, charges and security interests granted pursuant to the Talisman EnerMark Debenture as defined in section 3.1 of the Purchase and Sale Agreement (the "Assigned Interests") to DCE in exchange for Common Shares of DCE and DCE shall (1) accept such disposition and assignment to it of the Assigned Interests on an as is where is basis; (2) utilize its best efforts to obtain from all relevant third parties a release in favour of EnerMark of all of EnerMark's obligations under and pursuant to the Talisman EnerMark Debenture; (3) do all things necessary to enter into arrangements with Talisman Energy Inc. ("Talisman") that are satisfactory to Talisman whereby Talisman will acquire, contemporaneous with the completion of such disposition, a first charge and security interest from DCE in and to the interests being conveyed, and (4) indemnify and save EnerMark harmless of and from any loss, liability, claim, damage, cost or expense (including without limitation; reasonable legal fees and disbursements) suffered or incurred by EnerMark as a result of or in connection with any claims or demands made or action taken by any other party as a result of or in connection with the failure of DCE to satisfy and fulfill EnerMark's obligations under the Talisman EnerMark Debenture; or

(B) EnerMark elects not to, or fails to, pay its proportionate share of one or more expenditures totaling $10,000,000 (net to EnerMark) on the Mining Area, DCE shall have the option to acquire and assign EnerMark's interest in the Mining Area and EnerMark's other Joint Venture Interests associated exclusively with the Mining Area as the same may be subject to a proportion of any and all liens, charges and security interests granted pursuant to the Talisman EnerMark Debenture (as defined in section 3.1) of the Purchase and Sale Agreement (the "Mining Area Assigned Interests") to DCE in exchange for Common Shares of DCE and DCE shall (1) accept such disposition and assignment to it of such interests on an as is where is basis, and (2) indemnify and save EnerMark harmless of and from any loss, liability, claim, damage, cost or expense (including without limitation; reasonable legal fees and disbursements) suffered or incurred by EnerMark as a result of or in connection with any claims or demands made or action taken by any other party as a result of or in connection with the failure of DCE to satisfy and fulfill EnerMark's obligation under the assigned portion of the Talisman EnerMark Debenture,

(such option herein called the "DCE Call Option"); provided that, the DCE Call Option shall not apply until payments made by EnerMark under subsection 7.5(a) equal or exceed the Commitment Amount.

(iii) Any disposition by EnerMark under the EnerMark Put Option and any acquisition by Deer Creek under the Deer Creek Call Option may, at the option of EnerMark, be carried out on a tax deferred basis utilizing Section 85(1) or a similar provision of the *Income Tax Act* (Canada). For greater certainty, DCE will agree to the amounts so elected by EnerMark under Section 85(1) or similar provision of the *Income Tax Act* (Canada). Further, the amounts so elected by EnerMark shall not impact the valuation of those assets at that time.

(iv) The EnerMark Put Option and the DCE Call Option (in this section referred to as the "Option") may be exercised only by the Party desiring to exercise the Option giving written notice to the other Party that the Option is being exercised.

(v) The number of Common Shares of DCE to be issued in exchange for the Joint Venture Interests being disposed of by EnerMark (such Joint Venture Interests referred to in this section as the "EnerMark Interest") and acquired by DCE shall be determined as follows:

(A) DCE and EnerMark shall engage a mutually acceptable, qualified, independent expert to act as valuator on behalf of both parties;

(B) the valuator shall be guided by the generally accepted definition of fair market value, namely, "the highest price available in an open and unrestricted market between informed and prudent parties acting at arm's length and under no compulsion to act expressed in terms of money or money's worth";

(C) the valuator will initially determine a value for the Enermark Interest by first determining the value of:

(1) 100% of the Joint Venture Interests, in the case of a disposition under subsection 7.2(d)(ii)(B); or

(2) 100% of the Mining Area and the Joint Venture Interests associated exclusively with the Mining Area, in the case of a disposition under subsection 7.2(d)(ii)(B);

and the value so determined shall be apportioned to DCE and EnerMark proportionate to their respective interests in such assets;

(D) when determining the value of the Enermark Interest above, the valuator will focus on an after-tax valuation, but without giving effect to any notional liquidation and distribution, having regard to future general and administrative costs fairly attributable to such assets and specifically in the case of a disposition of EnerMark's interest in the Mining Area and its Joint Venture Interests associated with the Mining Area the valuator shall allocate liability under the Talisman EnerMark Debenture between the Mining Area and SAGD Area in the same proportion as to their respective values;

(E) following apportionment of values under subsection (3), the valuator will determine a value of DCE's equity on a per share basis. When determining such value the valuator will start with the same after tax asset value, but without giving effect to any notional liquidation and distribution, (after apportionment) determined in subsection 3 and will then adjust (add) for additional assets owned by DCE and (subtract) for liabilities (contingent or otherwise and including future general and administrative expenses not otherwise accounted for in the valuation of the EnerMark Interest) to which the DCE assets are burdened. For greater certainty tax pools within DCE could either increase or decrease equity value depending upon their level, composition and availability relative to the full basis applied in the initial asset valuation;

(F) there shall be no adjustment in the price of DCE common shares to reflect the fact that such common shares do not form part of a control block interest;

(G) in the event that DCE and EnerMark are not able to reach agreement regarding the value of DCE equity, the analysis would be subject to arbitration.

(e) **Segregation of Projects**

If prior to the conclusion of Stage 1 of the Joint Venture, the activities of the Joint Venture have resulted in a SAGD project producing 20,000 barrels of petroleum substances per day (or more), the Parties will meet and in good faith attempt to agree upon that area of the Lands which it is reasonable to allocate to a commercial SAGD project (in this subsection called the "Stage 1 Commercial

SAGD Project") with reserves sufficient to produce an estimated 30,000 barrels of petroleum substances per day and having an estimated life of 30 years. Non-Participating Expenditures prior to the date that the Stage 1 Commercial SAGD Project is delineated may be recovered either from production from the Stage 1 Commercial SAGD Project or from other areas of the Lands, however, after the date that the Stage 1 Commercial SAGD Project is delineated:

(i) if a Non-Participating Expenditure arises in relation to the Stage 1 Commercial SAGD Project, the Recovery Amount may only be recovered out of production from the Stage 1 Commercial SAGD Project; or

(ii) if the Non-Participating Expenditure arises in relation to the SAGD Area outside the Stage 1 Commercial SAGD Project, the Recovery Amount may only be recovered out of production from the SAGD Area outside the Stage 1 Commercial SAGD Project.

(f) **Assignment of Joint Venture Interest**

If EnerMark sells all of its Joint Venture Interest during Stage 1 then, subject to the provisions of this Agreement and the Operating Procedure regarding assignment, the buyer will become a Party to this Agreement. If EnerMark sells less than all of its Joint Venture Interests during Stage 1, then, notwithstanding any provisions of this Agreement or the Operating Procedure to the contrary, the buyer will not become a party to this Agreement or the Operating Procedure during Stage 1. If EnerMark sells all of its Joint Venture Interests during Stage 1, and DCE objects to the buyer's nominee under section 7.2(a)(i) being a member nominee under section 7.2(a)(i) being a member of DCE's Board of Directors, then the buyer shall not be obligated to contribute to G&A under subsection 7.2(b) or be eligible to participate in Outside Projects under subsection 7.2(c).

7.3 Stage 2 of the Joint Venture

(a) Stage 2 of the Joint Venture will be deemed to have commenced on the earlier of:

(i) January 1, 2008;

(ii) the date that there is a Change of Control of DCE; and

(iii) the date that DCE is replaced as Operator under section 202(a)(i) of the Operating Procedure.

7.4 Special Terms Applicable during Stage 2

During Stage 2 it is anticipated that substantially the same terms as in Stage 1 will govern the Joint Venture with the following modifications:

(a) **Operatorship and Terms**

DCE shall continue to be operator of the Joint Venture. It is anticipated that the Parties will enter into an operating agreement governing each commercial project on the Lands containing operatorship, voting, disposition and other provisions mutually acceptable to DCE and EnerMark. Such agreement shall conform with industry standard practice taking into account the respective working interests of the Parties and any other participants in the commercial project. Until such an operating agreement is entered into, the Operating Procedure shall apply. The Parties shall proceed diligently and in a timely manner in the preparation of such operating agreements. EnerMark shall not be obligated to pay its proportionate share of G & A during Stage 2 but will pay overhead charges under the Accounting Procedure.

(b) **No EnerMark Representation on DCE Board of Directors**

EnerMark shall not be entitled to have its representative nominated for election to the DCE Board of Directors and EnerMark's nominee will resign from DCE's Board of Directors if requested by DCE.

(c) **No EnerMark Put Option or DCE Call Option**

EnerMark will not have an EnerMark Put Option and DCE will not have a DCE Call Option.

(d) **Segregation of Projects**

The Parties anticipate that at the conclusion of Stage 1 of the Joint Venture, the activities of the Joint Venture will have defined that area of the Lands (in this subsection called the "First Commercial Project") which will be developed as a commercial steam assisted gravity drainage ("SAGD") project with reserves sufficient to produce an estimated 30,000 barrels of petroleum substances per day and having an estimated life of 30 years. At the end of Stage 1 of the Joint Venture, the Parties will meet and in good faith attempt to agree upon that area of the Lands which it is reasonable to allocate to the First Commercial Project having regard to the foregoing parameters, unless this has already occurred under section 7.2(e). Non-Participating Expenditures prior to the date that the First Commercial Project is delineated may be recovered either from production from the First Commercial Project or from other areas of the Lands, however, after the date that the First Commercial Project is delineated:

(i) if a Non-Participating Expenditure arises in relation to the First Commercial Project, the Recovery Amount may only be recovered out of production from the First Commercial Project; or

(ii) if the Non-Participating Expenditure arises in relation to the SAGD Area outside the First Commercial Project, the Recovery Amount may only be recovered out of production from the SAGD Area outside the First Commercial Project.

As the activities of the Joint Venture identify further commercial projects with similar parameters to the First Commercial Project, the parties shall similarly meet and in good faith attempt to agree upon that area of the Lands which it is reasonable to allocate to such each successive commercial project. Following delineation, those areas shall be subject to Non-Participating Expenditure and Recovery Amount provisions similar to those set out in this subsection 7.4(d).

(e) **No Participation in Outside Projects**

EnerMark will not have the right to participate in the acquisition of Outside Projects.

(f) **Assignment of Fractional Joint Venture Interest**

The restrictions set out in section 7.2(f) on a purchaser of a portion of a Party's Joint Venture Interest becoming a party to this Agreement and the Operating Procedure shall not apply.

7.5 **EnerMark's Contributions to Joint Venture Expenses**

(a) **Contributions up to Commitment Amount**

(i) EnerMark shall be obligated to reimburse DCE for its proportionate share of DCE G & A as provided in subsection 7.2(b) and to contribute its proportionate share of the expenses of the Joint Venture, all in accordance with the terms of this Agreement and the Operating Procedure, until the sum of DCE G & A for which EnerMark has reimbursed DCE and the proportionate share of Joint Venture expenses paid by EnerMark is $11,300,000 ("Commitment Amount").

(ii) Until payments made by EnerMark as contemplated by subsection 7.5(a)(i) equal the Commitment Amount, DCE will provide EnerMark with AFE's for Joint Venture expenditures; provided that, such AFE's will be for informational purposes only and the limitations on the Operator's authority set out in section 301(b) of the Operating Procedure shall not apply.

(iii) After payments made by EnerMark as contemplated by subsection 7.5(a)(i) equal the Commitment Amount, EnerMark shall continue to be obligated to reimburse DCE for its proportionate share of G & A during Stage 1 as provided in section 7.2(b).

(b) **Contributions in excess of Commitment Amount**

(i) After payments made by EnerMark contemplated by subsection 7.5(a)(i) are equal to or exceed the Commitment Amount, DCE shall provide EnerMark with AFE's for Joint Venture expenditures in accordance with the AFE Procedure set out in the Operating Procedure. If EnerMark does not, or elects not to, contribute to any expenditure ("Non-Participating Expenditure") proposed by AFE, the following provisions shall apply:

(A) If the Non-Participating Expenditure relates to the SAGD Area, then, subject to subsection 7.2(d)(i)(A), 7.2(e) and 7.4(d), DCE shall be entitled to recover from EnerMark's share of proceeds from the sale of production from the SAGD Area net of all costs for the joint account, (without duplication of any G & A to which EnerMark has contributed under subsection 7.2(b)) an amount equal to 300% ("Recovery Amount") of the EnerMark's proportionate share of the Non-Participating Expenditure.

(B) If the Non-Participating Expenditure relates to the Mining Area, then, subject to subsection 7.2(d)(i)(B), DCE shall be entitled to recover from EnerMark's share of proceeds from the sale of production from the Mining Area of the Lands only, net of all costs for the joint account (without duplication of any G & A to which EnerMark has contributed under subsection 7.2(b)) in relation to the Mining Area, an amount equal to 300% ("Recovery Amount") of the EnerMark's proportionate share of the Non-Participating Expenditure.

(C) In the event that the area of the Lands to which the Non-Participating Expenditure Relates is abandoned prior to the Recovery Amount being received by DCE, DCE shall be entitled to recover the balance of the Recovery Amount from the net salvage value of the materials and equipment recoverable from that portion of the Lands, as if such amount were proceeds from production therefrom.

(ii) If the interest of EnerMark is encumbered by an encumbrance not borne for the joint account which falls within the exception in Clause 802 of the Operating Procedure and DCE is required to make payments with respect to such additional encumbrance, an amount equal to 150% of the amounts so paid shall be added to the costs paid by DCE for purposes of calculating when DCE has received the Recovery Amount.

(iii) Notwithstanding anything to the contrary contained in this subsection 7.5(b), no cash payments, incentives, grants, credits, waivers, exemptions, abatements or other benefits received by (or available to) DCE pursuant to the Regulations (as defined in the Operating Procedure) with respect to Non-Participating Expenditures shall be taken into account when calculating whether DCE has received the Recovery Amount, provided that, this shall not entitle DCE to include in calculation of the Recovery Amount, any amount which is not actually paid by DCE.

7.6 Special Provisions Related to the Mining Area

The following provisions shall relate to the Mining Area only.

(a) **Sale of Mining Area**

If either DCE or EnerMark (the party receiving the Mine Purchase Offer, as hereinafter defined, herein called the "Receiving Party") receives a *bona fide* offer in writing ("Mine Purchase Offer") from a Person with whom the Receiving Party deals at arm's length the ("Proposed Buyer") to purchase all or any part of the Receiving Party's interest in the Mining Area, and the Receiving Party is prepared to accept the Mine Purchase Offer, the Receiving Party shall not accept the Mine Purchase Offer unless the Proposed Buyer has made, or the Receiving Party shall have first caused the Proposed Buyer to make, an offer in writing (a "Take Along Offer") to the other Party to purchase all or, as the case may be, a part of the other Party's interest in the Mining Area on terms and conditions identical to the terms and conditions of the Mine Purchase Offer, adjusted to reflect the Party's relative working interest. It is the intent of the foregoing provision that if the Mine Purchase Offer relates only to a part of the Receiving Party's interest, the interest sought to be acquired under the Mine Purchase Offer shall bear the same proportion to the interest sought to be acquired by the Take Along Offer as the Receiving Party's interest in the Mining Area bears to the Other party's interest in the Mining Area. Upon delivery by the Proposed Buyer of the Take Along Offer to the other Party, the Receiving Party may, accept the Mine Purchase Offer and sell its interest in the Mining Area substantially in accordance with the terms and conditions thereof. Article XXIV of the Operating Procedure shall apply to a disposition under this subsection 7.6(a).

(b) **No Independent Operations**

Except as set out in section 202(a) of the Operating Procedure, EnerMark will not have the right to replace DCE as Operator of the Mining Area. EnerMark will not have the right to initiate operations in the Mining Area unless it is Operator of the Mining Area.

7.7 Special Provisions Related to the SAGD Area

The following provisions shall relate to the SAGD Area only.

(a) **Limitation of EnerMark's Right to Propose Operations**

Except as set out in subsection 7.7(b), EnerMark will not have the right to initiate operations on the SAGD Area. Except as set out in subsection 7.7(b) and section 202(a) of the Operating Procedure, EnerMark will not have the right to replace DCE as Operator of the SAGD Area.

(b) **EnerMark's Right to Propose Operations and Become Operator in Certain Events**

(i) During Stage 1 or Stage 2 of the Joint Venture, EnerMark will have the right to propose a SAGD project on the SAGD Area by giving notice (an "Operation Notice") of same to DCE in the following cases:

(A) at any time, provided that:

(1) the proposed project has first received all necessary regulatory approval; and

(2) no other operations are then being conducted on the SAGD Area; or

(B) if DCE fails to make application on or before May 1, 2004 for regulatory approval of a SAGD project on the Lands having a minimum estimated production of 30,000 barrels of petroleum substances per day and having an estimated life of 30 years; or

(C) if, within six months of receiving the regulatory approval referred to in subsection 7.7(b)(iv)(B), DCE does not diligently proceed with the approved project and EnerMark gives DCE notice of such failure and within six months of receiving such notice DCE does not remedy the failure; or

(D) if DCE is replaced as Operator under section 202(a) of the Operating Procedure;

provided that, in any such case, the maximum size of a SAGD project proposed by EnerMark shall be a project having an estimated production of 10,000 barrels of petroleum substances per day and having an estimated life of 30 years.

(ii) If EnerMark is entitled to and does give an Operation Notice, the Parties will meet and in good faith attempt to agree upon that portion of the SAGD Area which it is reasonable to allocate to the proposed project (the "EnerMark Operated Project") having regard to the parameters set out in subsection 7.7(b)(i). EnerMark will become operator of the EnerMark Operated Project and DCE will remain as operator of the remainder of the Lands. As operator, EnerMark will have all of the power and authority of an Operator under the Operating Procedure to conduct operations on the EnerMark Operated Project.

(iii) Any AFE for operations on the EnerMark Operated Project shall be subject to a 120 day approval period.

(iv) If DCE does not participate in an expenditure on the EnerMark Operated Project, or defaults in payment of expenditures under an approved AFE (in either case called a "DCE Non-Participating Expenditure") for operations on the EnerMark Operated Project, then:

(A) subject to subsection 7.7(b)(iv)(B), DCE will be subject to a 300% penalty on the DCE Non-Participating Expenditure, which penalty may only be recovered from production from the EnerMark Operated Project; and

(B) if the DCE Non-Participating Expenditure relates to a project for which an Operation Notice was given during Stage 1 and was not given in the circumstances described in subsection 7.7(b)(i)(A) or 7.7(b)(i)(B), then DCE will have the right for a period of six months from the date that the EnerMark Operated Project comes on-stream to pay the DCE Non-Participating Expenditures, in which case no penalty shall apply.

(v) In the event that the area of the Lands to which the Non-Participating Expenditure Relates is abandoned prior to the Recovery Amount being received by EnerMark, EnerMark shall be entitled to recover the balance of the Recovery Amount from the net salvage value of the materials and equipment recoverable from that portion of the Lands, as if such amount were proceeds from production therefrom.

(vi) If the interest of DCE is encumbered by an encumbrance not borne for the joint account which falls within the exception in Clause 802 of the Operating Procedure and EnerMark is required to make payments with respect to such additional encumbrance, an amount equal to 150% of the amounts so paid shall be added to the costs paid by EnerMark for purposes of calculating when EnerMark has received the Recovery Amount.

(vii) Notwithstanding anything to the contrary contained in this subsection 7.7(b), no cash payments, incentives, grants, credits, waivers, exemptions, abatements or other benefits received by (or available to) EnerMark pursuant to the Regulations (as defined in the Operating Procedure) with respect to Non-Participating Expenditures shall be taken into account when calculating whether EnerMark has received the Recovery Amount, provided that, this shall not entitle EnerMark to include in calculation of the Recovery Amount, any amount which is not actually paid by EnerMark.

(viii) DCE covenants and agrees with EnerMark that it will use reasonable commercial efforts to ensure that the application referred to in subsection

7.7(b)(i)(B) is complete when filed and thereafter to obtain approval for the application.

(c) **Participation in Contracts**

The Parties shall use reasonable commercial efforts to ensure that the other Party has the opportunity to participate in any contracts or other business arrangements entered into with third parties for the development or exploitation of the Lands or for the transportation, processing or marketing of petroleum substances produced from the Lands.

(d) **Development Plan and Changes**

The Parties plan to develop the Lands on a project by project basis, the first project being a SAGD project designed to produce 2000 bbl/d. After the completion of the 2000 bbl/d project, subject to technical, commercial, regulatory and market impacts, expansion to 10,000 bbl/d is planned as the next most commercially reasonable step. An expansion to less than 10,000 bbl/d will require the consent of EnerMark, such consent not to be unreasonably withheld. The Parties acknowledge that following completion of the 10,000 bbl/d expansion there will be a further expansion to 30,000 bbl/d.

(e) **Future**

The provisions of this section 7.7 may be replaced and superseded by future agreements relating to the Lands or other Joint Venture Interests.

ARTICLE 8
MEDIATION

8.1 Notwithstanding anything contained in this Agreement to the contrary, if a dispute arises between the Parties relating to this Agreement, the Parties agree to use the following procedure as a condition precedent to either party invoking arbitration as hereinafter provided:

(a) a meeting shall be held promptly between the Parties, attended by individuals with appropriate authority regarding the dispute, to attempt in good faith to negotiate a resolution of the dispute;

(b) if, within 30 days after such meeting, the Parties have not succeeded in negotiating a resolution of the dispute, they agree to submit the dispute to non-binding mediation and to bear equally the costs of such mediation;

(c) the Parties will jointly appoint a mutually acceptable mediator, provided that notwithstanding anything contained in the remaining provisions of this paragraph to the contrary, if the Parties have not agreed on the appointment of a mutually acceptable mediator within 60 days after the date of the meeting referred to in subsection 8.1(a), then either Party may refer the dispute to arbitration as hereinafter provided;

(d) the Parties agree to participate in good faith in the mediation and negotiations related thereto for a period of 30 days; and

(e) if the Parties are not successful in resolving the dispute through mediation then the Parties agree to refer the dispute to arbitration as hereinafter provided.

ARTICLE 9
ARBITRATION

9.1 Disputes to be Arbitrated

Subject to Article 8, if any disagreement or dispute arises in respect of this Agreement, then such disagreement or dispute shall be referred to arbitration, and it is agreed that such reference to arbitration and the making of an award in respect thereof shall be a condition precedent to the bringing of any action or proceeding and no cause of action shall arise before the making of such award.

9.2 Notice of Arbitration

Either Party may initiate arbitration by notice of intention to arbitrate given to the other Party in writing stating the difference or dispute to be arbitrated and, upon the giving of such notice, the difference or dispute so stated shall be deemed to be referred for arbitration and final settlement under the provisions of *The Arbitration Act* of Alberta.

9.3 Number of Arbitrators

The arbitrator shall be a single qualified arbitrator satisfactory to both Parties. In the event that the Parties, within thirty (30) days of the giving of the arbitration notice, are unable to agree on the selection of such arbitrator, each Party shall appoint an arbitrator, and such arbitrators shall appoint a third arbitrator who shall be chairman. The decision of the single arbitrator or of the majority of the three (3) arbitrators, as the case may be, shall be final and binding upon each of the Parties hereto. In the event that the three (3) arbitrators are unable to arrive at a simple majority award or decision, the award or decision of the chairman shall be final and binding. The cost of the arbitration shall be apportioned between the Parties as the single arbitrator or the three (3) arbitrators, as the case may be, may decide.

ARTICLE 10
GENERAL

10.1 Severability

Any term, condition or provision of this Agreement which is deemed to be, void, prohibited or unenforceable shall be severable herefrom without in any way invalidating the remaining terms, conditions and provisions hereof.

10.2 Enforcement of Remedies

If at any time any party shall be in default of any of its covenants or agreements contained in or arising out of this Agreement, any remedy which may be available to any other party by virtue of any provision contained in this Agreement and as a consequence of such default shall be in addition to and not by way of substitution for any statutory or common law remedy which may also be available and all such remedies may be enforced either successively or concurrently.

10.3 Non-Waiver

Neither the granting of any time or other indulgence to any party hereto nor the failure of any party to insist upon the strict performance of any covenant, term, or condition of this Agreement or to enforce its rights hereunder shall be construed as a waiver of its rights or remedies hereunder and the same shall continue in full force and effect.

10.4 Written Waiver

Except as otherwise provided herein, only a written waiver by a party hereto of any breach (whether actual or anticipated) of any of the terms, conditions, representations and warranties contained herein, shall be effective or binding on that party. Any waiver so given shall extend only to the particular breach so waived, and shall not limit or affect any rights for any other or future breach.

10.5 Further Assurances

Each party hereto will promptly and duly execute and deliver to each remaining party such further documents and assurances and take such further action as such remaining party may from time to time reasonably request in order to more effectively carry out the intent and purpose of this Agreement and to establish and protect the rights and remedies created or intended to be created hereby.

10.6 Notices

Any notice or acceptance required or permitted to be given under the terms of this Agreement or the Operating Procedure shall be given in the manner and shall be deemed to have been received at the time set out in the Operating Procedure. The addresses of the Parties of service of notices are:

(a) to Deer Creek Energy Limited at:

450, 550 – 6th Avenue S.W.
Calgary, AB T2P 0S2

Attention: President
Fax No. (403) 264-3700

with a copy to:

Parlee McLaws LLP
Barristers & Solicitors
3400 Petro-Canada Centre
150-6th Avenue S.W.
Calgary, Alberta T2P 3Y7

Attention: James D. Thomson
Fax No. (403) 294-7021

(b) and to Enerplus Resources Fund

The Dome Tower
Suite 3000, 333 - 7th Ave. S.W.
Calgary, Alberta T2P 2Z1

Attention: Land Manager
Fax No. (403) 269-4020

10.7 Alteration of this Agreement

No change or modification to this Agreement shall be valid unless it shall be in writing and signed by all parties hereto.

10.8 Governing Law

This Agreement shall be construed and enforced in accordance with, and the rights of the parties hereto shall be governed by, the laws of the Province of Alberta. Each of the Parties hereto hereby irrevocably attorns to the jurisdiction of the courts in the Province of Alberta.

10.9 Time

Time shall be of the essence of this Agreement.

10.10 Entire Agreement

This Agreement constitutes the entire agreement between the parties and there are no statements, representations, warranties, undertakings or agreements, written or oral, express or implied, between the parties hereto except as herein set forth.

10.11 Enurement

This Agreement and everything herein contained shall enure to the benefit of and be binding upon the parties together with their successors and permitted assigns.

10.12 Execution in Counterpart

This Agreement may be executed in two or more counterparts, each of which shall be deemed an original and all of which together shall constitute one and the same instrument. It shall not be necessary that any single counterpart hereof be executed by all parties to this Agreement so long as at least one counterpart is executed by each such party. For the purposes of this Agreement any Person who has acknowledged in writing that he has signed a counterpart of this Agreement shall be conclusively deemed to have executed same.

10.13 Assignment

This Agreement may not be assigned without complying with Article XXIV of the Operating Procedure, modified as necessary to make it applicable to an assignment of an interest in this Agreement rather than a working interest.

10.14 Delivery by Facsimile

This Agreement and any other agreement, document or instrument required or permitted hereby shall be deemed to be validly executed and delivered by a party when a copy thereof has been executed by that party and transmitted by facsimile to each of the remaining parties. A party delivering this Agreement or any such other agreement, document or instrument by facsimile as aforesaid covenants to promptly deliver to each of the remaining parties an originally executed copy of thereof by ordinary mail or by courier.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the 1st day of July, 2002.

DEER CREEK ENERGY LIMITED

Per: (Signed) *"Glen C. Schmidt"*

ENERMARK INC.

Per: (Signed) *"Gordon J. Kerr"*

SCHEDULE "1.1(n)"

THE LANDS

SCHEDULE 1.1(n) to Joint Venture Agreement dated July 1, 2002

The Lands

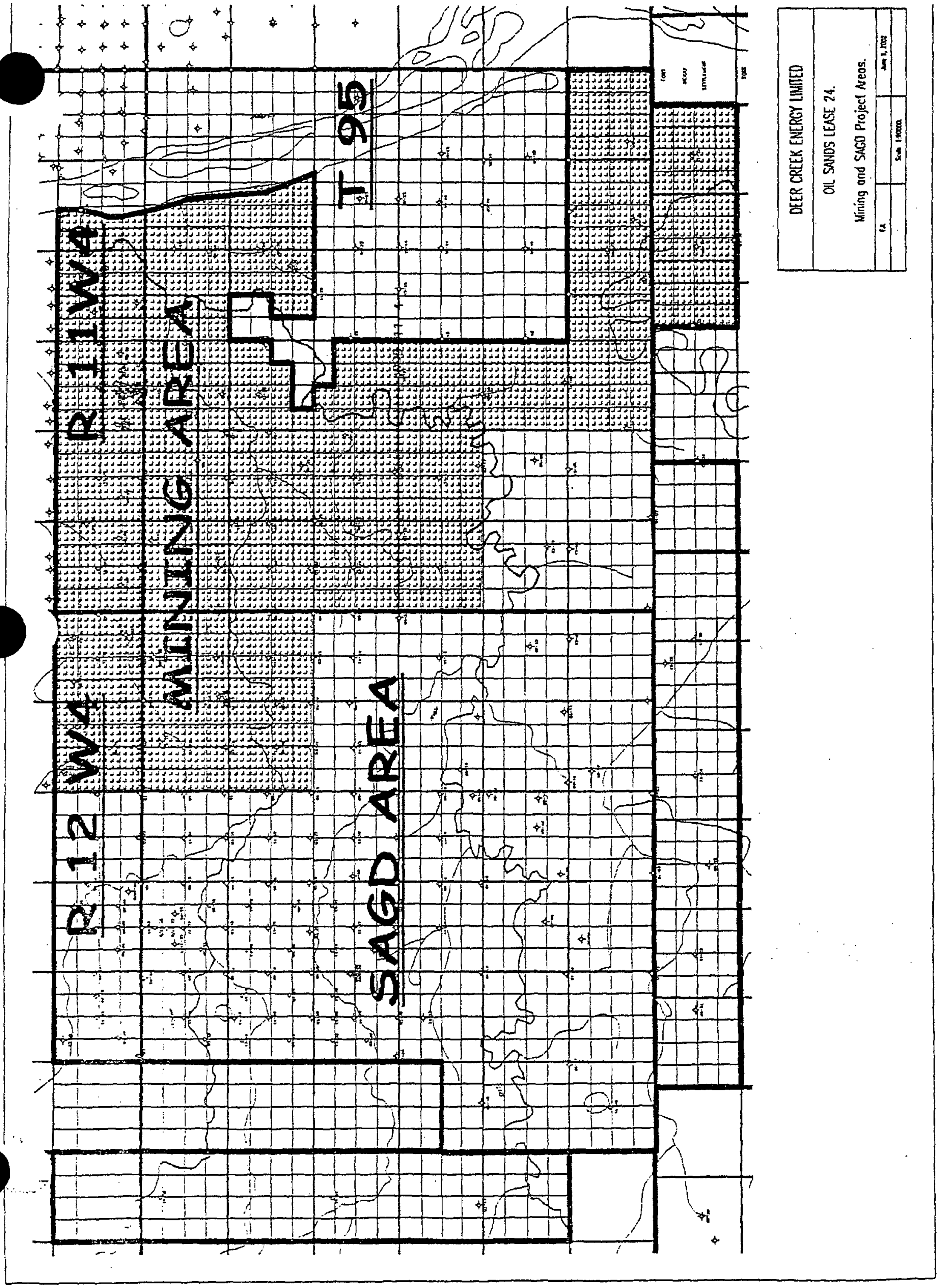
Lands:	Leases:	Vendor's Interest:	Encumbrances:
Twp 95 Rge 10 W4M: That portion of the North West quarter of Section 6 and the West half of Section 7 lying to the West of the left bank of the Athabasca River and what would be if so surveyed pursuant to The Surveys Act, a portion of the South West quarter of said Section 6 lying to the West of the left bank of the said River; Twp 94 Rge 11 W4M: Section 31, the East half of Section 33 and Section 34 and what would be if so surveyed pursuant to The Surveys Act, Section 35 and the West half of Section 36 and that portion of the East half of Section 36 lying to the West of the left bank of the Athabasca River; Twp 95 Rge 11 W4M: The North half of section 1, Sections 2 to 9 inclusive, the South East quarter of Section 12, Sections 16 to 20 inclusive, the South half, the North West quarter and Legal Subdivisions 9 and 10 of Section 21, the West half of Section 26, the East half and Legal Subdivisions 3 and 6 of Section 27, the North half and Legal Subdivisions 4 to 7 inclusive of Section 28 and Sections 29 to 34 inclusive and what would be if so surveyed pursuant to The Surveys Act, the south half of Section 1 and those portions of the East half of Section 26 and Section 35 lying to the West of the left bank of the Athabasca River; Twp 96 Rge 11 W4M: Sections 3 to 6 inclusive and that portion of the West half of Section 2 lying to the West of the left bank of the Athabasca River;	Alberta Crown Oil Sands Lease No. 7280060T24	16%	Crown Royalty

Twp 94 Rge 12 W4M: Sections 31 to 36 inclusive; Twp 95 Rge 12 W4M: Sections 1 to 17 inclusive, the South half of Section 18, Sections 20 to 29 inclusive and Sections 32 to 36 inclusive; Twp 96 Rge 12 W4M: Sections 1 to 5 inclusive; and All statutory road allowances and what would be statutory road allowances if the lands were surveyed pursuant to The Surveys Act, lying within and immediately to the South and West of the above described general area. Oil Sands in the Wabiskaw-McMurray Zone Twp 95 Rge 13 W4M: Sections 12, 13, 24, 25, 36; Twp 96 Rge 13 W4M: Section 1 Oil Sands below the top of the Viking Formation to the base of the Woodbend Group	Alberta Crown Oil Sands Permit No. 7099110070	16%	Crown Royalty

SCHEDULE "1.1(o)"

MAP

Schedule 1.1(o) to Joint Venture Agreement dated July 1, 2002



SCHEDULE "1.1(q)"

OPERATING PROCEDURE

{K:\cdox\0059524\000018\CT028475.DOC;17}

SCHEDULE 1.1(q) to Joint Venture Agreement dated July 1, 2002

OPERATING PROCEDURE

CANADIAN ASSOCIATION OF PETROLEUM LANDMEN

1990

INDEX

OPERATING PROCEDURE

Attached to and forming part of the Agreement dated the day of A.D. ~~19~~ XX 2002

BETWEEN/AMONG:

DEER CREEK ENERGY LIMITED

and

ENERMARK INC.

ARTICLE I

INTERPRETATION

101 DEFINITIONS – In this Operating Procedure, the following words and phrases shall have the following respective meanings, namely:

(a) "abandonment" means the proper plugging and abandoning of a well in compliance with the Regulations and the restoration of the well site to the satisfaction of any governmental body having jurisdiction with respect thereto and to the reasonable satisfaction of the owner or occupier of the surface.

(b) "Accounting Procedure" means the schedule entitled Accounting Procedure attached hereto and made a part of this Operating Procedure.

(c) "Affiliate" means, with respect to the relationship between corporations, that one of them is controlled by the other or that both of them are controlled by the same person, corporation or body politic; and for this purpose a corporation shall be deemed to be controlled by those persons, corporations or bodies politic who own or effectively control, other than by way of security only, sufficient voting shares of the corporation (whether directly through the ownership of shares of the corporation or indirectly through the ownership of shares of another corporation which owns shares of the corporation) to elect the majority of its board of directors, provided that a partnership which is a party and which is comprised solely of corporations which are Affiliates, as described above, shall be deemed to be an Affiliate of each such corporation and its other Affiliates.

(d) "Agreement" means the agreement to which this Operating Procedure is attached and made a part.

(e) "Authority for Expenditure" or "AFE" means a written statement of an operation proposed to be conducted pursuant to this Operating Procedure, which statement shall include:

(i) the type, purpose and location of such operation, in sufficient detail to enable a party to understand the nature, scope and sequence of such operation, the proposed time frame over which such operation will be conducted ~~and, if such operation is the drilling or deepening of a well, the projected total depth thereof, the proposed surface coordinates of the well and, if they will differ materially from the surface coordinates of the well, the proposed bottomhole coordinates therefor~~; and

(ii) the proposing party's estimate of the anticipated costs of such operation, which estimate shall be in sufficient detail to enable a party to identify, in summary form, the anticipated costs of the various identifiable segments of such operation, including, if applicable, those costs which relate to drilling, completing and equipping a well.

(f) ~~"casing point" means that point in time when a well has been drilled to total depth, the authorized logs and tests have been run and a decision must be made by the Joint Operators whether to set production casing and attempt to complete the well.~~

~~(g) 'commercial quantities' means, with respect to a well, the anticipated output of petroleum substances from~~ that well which would reasonably warrant drilling another well in the same area to the formation indicated to be productive by that well, having regard to anticipated drilling costs, completion costs, equipping costs and operating costs, the kind and quality of petroleum substances indicated, the anticipated availability of facilities for treating and processing such petroleum substances and the anticipated cost of such services, the anticipated availability of markets for such petroleum substances, the anticipated availability of transportation service for the delivery of such production to market and the anticipated cost of such service, the royalties and other burdens payable for the joint account with respect thereto, the probable life of the well and the anticipated price to be received for the petroleum ~~substances as and when sold.~~

(h) 'completion' means the installation in, on, or with respect to a well of all such production casing, tubing and wellhead equipment and all such other equipment and material necessary for the permanent preparation of the well for the taking of petroleum substances therefrom up to and including the outlet valve on the wellhead and includes, as necessary, the perforating, stimulating, treating, fracing and swabbing of the well and the conduct of such production tests with respect to such well as are reasonably required to establish the initial producibility of the well.

(i) 'completion costs' means the costs of completing a well.

~~(j) 'development well' means a well, insofar as the geological zones penetrated in the drilling thereof (or~~ proposed to be penetrated, as provided in the AFE therefor or the operation notice relating thereto) are stratigraphically above the base of the deepest geological zone in which an existing well within 3.2 kilometres thereof (as measured from the coordinates where the other well penetrated, and the proposed well is anticipated to penetrate, the top of such geological zone) is or has been capable of production of petroleum substances in commercial quantities, provided that only geological zones and individual petroleum substances included in the joint lands in ~~the spacing unit for such proposed well shall be considered when making such determination.~~

(k) 'drilling costs' means all moneys expended (exclusive of completion costs and equipping costs) with respect to the drilling of a well, including, without restricting the generality of the foregoing, the cost of obtaining surface access to and for the site of the well, the preparation of the site of such well, the construction of such roadways as are reasonably necessary to gain access to the site of the well, the installation of all surface and intermediate casing respecting the well, the logging, coring and testing of the well and, in the event the well is not completed, but is abandoned, the cost of such abandonment.

(l) 'equipping' means the installation of such equipment as is required to produce petroleum substances from a completed well, including, without restricting the generality of the foregoing, a pump (or other artificial lift equipment), the installation of the flow lines and production tankage serving the well and, if necessary, a heater, dehydrator or other wellsite facility for the initial treatment of petroleum substances produced from the well to prepare such production for transportation to market, but specifically excludes any such equipment, installation or facility that is (or is intended to be) a production facility.

(m) 'equipping costs' means the costs of equipping a well.

~~(n) 'exploratory well' means a well, insofar as it is not a development well.~~

(o) 'for the joint account' means for the benefit, interest, ownership, risk, cost, expense and obligation of the parties in proportion to their respective working interests.

(p) 'joint lands' means those lands and interests therein which have been made subject hereto by the Agreement, or so much thereof which remains subject hereto and, except where the context otherwise requires, shall include the petroleum substances within, upon or under those lands and interests, insofar as those lands and interests are subject to the title documents.

(q) 'joint operation' means an operation conducted hereunder for the joint account.

(r) 'Joint-Operator' means a party having a working interest in the joint lands, including the Operator if it has a working interest in the joint lands.

(s) 'market price' means the price at which petroleum substances are to be sold pursuant to Article VI where a party does not take its share of petroleum substances in kind and separately dispose of the same, which price is not unreasonable, having regard to market conditions applicable to similar production in arm's length transactions at the time of such disposition, including, without restricting the generality of the foregoing, such factors as the volumes available, the kind and quality of petroleum substances to be sold, the effective date of the sale, the term of the sale agreement, the point of sale of the petroleum substances and the type of transportation service available for the delivery of the petroleum substances to be sold.

(t) 'operating costs' means all moneys expended (exclusive of drilling costs, completion costs and equipping costs) to operate a well for the recovery of petroleum substances, as more particularly set forth in the Accounting Procedure and, where applicable, all moneys expended to operate a production facility hereunder.

(u) 'Operator' means the party appointed by the Joint-Operators to conduct operations hereunder for the joint account, ~~except as provided in Clause 1004.~~

(v) 'party' means a person, corporation, partnership or body politic bound by this Operating Procedure.

(w) 'participating interest' means the percentage share of the costs of an operation conducted hereunder (or any respective segment thereof) which a party has agreed to pay or is required to pay pursuant to this Operating Procedure.

~~(x) 'paying quantities' means:~~

> ~~(i) in the case of a well which has been drilled, but not completed and equipped: the anticipated output~~ from the well of that quantity of petroleum substances which would reasonably warrant incurring the completion costs and equipping costs of the well, considering the anticipated completion costs, equipping costs and operating costs associated therewith, the kind and quality of petroleum substances indicated, the anticipated availability of facilities for treating and processing such petroleum substances and the anticipated cost of such services, the anticipated availability of markets for such petroleum substances, the anticipated availability of transportation service for the delivery of such production to market and the anticipated cost of such service, the royalties and other burdens payable for the joint account with respect to such production, the probable life of the well and the anticipated price to be received for the petroleum substances produced therefrom as and when sold; ~~or~~
>
> ~~(ii) in the case of a well completed for the taking of production: the output from the well of that quantity~~ of petroleum substances which ~~would reasonably warrant the taking~~ of production from the well, ~~considering the same factors as in paragraph (i) of this Subclause, except completion costs.~~

(y) 'petroleum substances' means petroleum, natural gas and every other mineral or substance, or any of them, in which an interest in or the right to explore for is granted or acquired under the title documents.

(z) 'production facility' means, subject to Article XIII and Clauses ~~1021, 1022 and~~ 1408, any facility serving (or intended to serve) more than one (1) well (including, without restricting the generality of the foregoing, any battery, separator, compressor station, gas processing plant, gathering system, pipeline, production storage facility or warehouse), which is:

> (i) constructed or installed for the joint account;
>
> (ii) owned exclusively by the parties in accordance with their respective working interests;
>
> (iii) initially intended to be utilized exclusively with respect to the production, treatment, storage or transmission of petroleum substances;
>
> ~~(iv) not used for fractionation of petroleum substances, sulphur extraction or separation of liquids by refrigeration;~~ and
>
> (v) not subject to a separate agreement governing the construction, ownership and operation of such facility;

and includes all real and personal property of every kind, nature and description directly associated therewith, excluding petroleum substances, the joint lands and the Operator's owned or leased equipment.

(aa) 'proportionate share' means, with respect to a party, a percentage share equal to that party's working interest.

(bb) 'Regulations' means all statutes, laws, rules, orders and regulations in effect from time to time and made by governments or governmental boards or agencies having jurisdiction over the joint lands and over the operations to be conducted thereon.

~~(cc) 'spacing unit' means:~~

~~(i) with respect to a well which has not been completed for the production of petroleum substances the area allocated by the Regulations for the drilling of that well, provided that in the absence of such allocation or a specific designation in the Agreement, the spacing unit for the well shall be deemed to be the quarter-section, unit or similar geographical area which includes the bottomhole co-ordinates of the well; and~~

~~(ii) in every other case: the area allocated to the well pursuant to the Regulations for the purpose of producing petroleum substances in each zone from which such petroleum substances are to be produced.~~

~~(dd) 'spud' means, with respect to a well, that a drilling rig of adequate capacity to drill that well to the total depth projected in the AFE therefor is rigged up on location and that a drilling bit has penetrated the surface therefrom.~~

(ee) 'title documents' means the documents of title by virtue of which the parties are entitled to drill for, win, take or remove petroleum substances underlying the joint lands, and all renewals, extensions or continuations thereof or further documents of title issued pursuant thereto.

(ff) 'working interest' means the percentage of undivided interest held by a party in a production facility or the joint lands, or the respective zones, portions, parcels or parts thereof, which percentage is as provided in the Agreement or is as modified subsequently pursuant to the provisions hereof.

102 HEADINGS – Article headings and any other headings or captions or indices hereto shall not be used in any way in construing or interpreting any provision hereof.

103 REFERENCES – Unless otherwise expressly stated:

(a) the references 'hereunder', 'herein' and 'hereof' refer to the provisions of this Operating Procedure, and references to Articles, Clauses, Subclauses or paragraphs herein refer to Articles, Clauses, Subclauses or paragraphs of this Operating Procedure;

(b) whenever the singular or masculine or neuter is used in this Operating Procedure, the same shall be construed as meaning plural or feminine or body politic or corporate or vice versa, as the context so requires; and

(c) any reference to days herein is a reference to calendar days, and where the phrase 'within' or 'at least' is used with reference to a specific number of days herein, the day of receipt of the relevant notice or the day of the relevant event, as the case may be, shall be excluded in determining the relevant time period. However, in the event the time for doing any act expires on a Saturday, Sunday or statutory holiday in either the Province of Alberta or Canada, the time for doing such act shall be extended to the next normal business day, except as prescribed in the Accounting Procedure with respect to the payment of billings.

104 OPTIONAL AND ALTERNATE PROVISIONS – Where alternate or optional provisions are provided for herein and the parties have failed to designate which alternate shall apply or whether a respective optional provision shall be included, the first alternate provision in each such case shall apply as if the parties had designated the same, and the remaining optional provision shall be deemed not to form a part hereof.

105 DERIVATIVES – Where a term is defined herein, a derivative of that term shall have a corresponding meaning unless the context otherwise requires.

106 USE OF CANADIAN FUNDS – All references to 'dollars' or '$' herein shall mean lawful currency of Canada, and all payments and receipts shall be made and recorded in lawful currency of Canada.

107 CONFLICTS – If any provision contained in the Agreement conflicts with a provision herein, the provision in the Agreement shall prevail, and if a provision herein conflicts with a provision in an exhibit or schedule attached hereto, the provision herein shall prevail. In the event of a conflict between any provision in the Agreement or this Operating Procedure and the Regulations or the title documents, the Regulations or the title documents, as the case may be, shall govern, except that: (i) the working interests shall prevail if there is a difference between the working interests and the registered interests in the title documents; and (ii) the allocation of responsibility for losses as provided herein (including, without restricting the generality of the foregoing, Article IV hereof) shall govern the relationship of the parties. If there is a conflict as provided above, the Agreement or this Operating Procedure, as the case may be, shall be modified accordingly to the extent necessary to resolve such conflict, and, as so modified, shall continue in full force and effect.

ARTICLE II

APPOINTMENT AND REPLACEMENT OF OPERATOR

201 ASSUMPTION OF DUTIES OF OPERATOR – *The Operator named in the Agreement, or any succeeding Operator* appointed hereunder, shall assume the duties and obligations of the Operator hereunder and shall have all the rights of the Operator hereunder.

202 REPLACEMENT OF OPERATOR –

(a) The Operator shall be replaced immediately and another Operator appointed forthwith pursuant to Clause 206 upon notice to such effect being served by any party to the other parties if:

(i) the Operator becomes bankrupt or insolvent, commits or suffers any act of bankruptcy or insolvency, is placed in receivership, seeks debtor relief protection under applicable legislation (including, without restricting the generality of the foregoing, the Bankruptcy Act of Canada and the Companies' Creditors Arrangement Act of Canada) ~~or permits any judgement to be registered against its working interest,~~ and without restricting the generality of the foregoing, an Operator shall be deemed insolvent for the purposes of this Clause if it is unable to pay its debts as they fall due in the usual course of business or if it does not have sufficient assets to satisfy its cumulative liabilities in full; or

~~(ii) the Operator assigns or purports or attempts to assign its general powers and responsibilities of supervision and management as Operator hereunder.~~

(b) The Operator shall be replaced and another Operator appointed pursuant to Clause 206 if:

~~(i) the Joint-Operators agree, by the affirmative vote, by notice to the other parties, of two (2) or more~~ *Joint-Operators representing a majority of the working interests, to replace the Operator*, provided that a single Joint-Operator holding more than a ~~sixty-six percent~~ (66%) working interest in the joint lands shall have the right, by notice to the other parties, to replace the Operator and to become Operator at the time prescribed by Subclause 206(d), unless it would then be subject to replacement ~~pursuant to paragraph 202(a)(i); or~~

(ii) the Operator defaults in its duties or obligations or any of them hereunder and, within thirty (30) days after written notice from a majority in working interest of the Joint-Operators, excluding the Operator, specifying the default and requiring the Operator to remedy the same, it does not commence to rectify the default and thereafter diligently continue to remedy the default.

~~203 CHALLENGE OF OPERATOR – At any time after an Operator has been Operator for at least two (2) years, any Joint-~~ Operator, other than the Operator, may give notice ("the challenge notice") to the other parties ~~that it is~~ ready, able and willing to conduct operations for the joint account on more favourable ~~terms and~~ conditions. The challenge notice shall contain sufficient detail to enable the receiving parties ~~to evaluate~~ the nature of the challenge notice and to measure the effect the revised terms and ~~conditions~~ would have on joint operations. The Operator shall; within sixty (60) days after receipt of the ~~challenge notice, advise the Joint-Operators either that:~~

~~(a) it is prepared to operate on the terms and conditions set out in the challenge notice, whereupon it shall forthwith proceed to do so; or~~

~~(b) it is not prepared to operate on the terms and conditions set out in the challenge notice and that it will resign as Operator effective not later than ninety (90) days following the sixty (60) day period provided above.~~

~~Failure by the Operator to advise the Joint-Operators of its election within such sixty (60) day period shall be deemed to be~~ an election by the Operator to resign. If the Operator resigns, a new Operator shall be appointed pursuant ~~to Clause~~ 206, whereupon such new Operator shall operate on the terms and conditions set out in the challenge notice. If no other Joint-Operator is prepared to act as Operator on the terms and conditions set out in the challenge notice, the Joint-Operator giving the challenge notice shall become the new Operator and shall thereafter conduct operations pursuant to the undertakings made by it in the challenge notice. Any costs in excess of those set out in the challenge notice shall be for the new Operator's sole account. Notwithstanding ~~Clause~~ 204, the new Operator shall not resign from the position of Operator until it has acted as Operator ~~for a period~~ of at least two (2) years. A Joint-Operator may not issue a challenge notice or become Operator ~~pursuant~~ thereto if, at the time of issuing the challenge notice or the time it would become Operator pursuant ~~thereto, it would be subject to replacement as Operator pursuant to Subclause 202(a) if it were Operator at that time.~~

204 RESIGNATION OF OPERATOR – Subject to Subclause 202(a) and Clauses 203 and 205, the Operator may resign as Operator on giving each of the Joint-Operators ninety (90) days' notice of its intention to do so.

~~205 MODIFICATION OF TERMS AND CONDITIONS BY OPERATOR – At any time after an Operator has been the Operator for a continuous period of two (2) years, it may give notice ("the Operator's notice") to the other parties of the revised terms and conditions on which it is prepared to continue to conduct joint operations. Within sixty (60) days of receipt of the Operator's notice, each Joint-Operator shall advise the Operator whether it agrees to the Operator continuing as Operator and conducting joint operations on the terms and conditions contained in the Operator's notice, provided that failure by a Joint-Operator to respond within such period shall be deemed to be agreement by that party to the terms and conditions in the Operator's notice. If any Joint-Operator does not so agree, it shall give notice ("counter proposal") to the other parties of the terms and conditions upon which it would conduct joint operations. Any such counter proposal shall be deemed to be a challenge of Operator and shall be subject to all of the terms and conditions of Clause 203, as though such counter proposal was "the challenge notice" provided therein, except that in determining the merits of the counter proposal, it shall be compared to the terms and conditions contained in the Operator's notice, rather than to the existing operating terms and conditions.~~

206 APPOINTMENT OF NEW OPERATOR –

(a) If an Operator resigns or is to be replaced, a successor Operator shall be appointed by the affirmative vote (by notice to the other parties) of two (2) or more parties representing a majority of the working interests in the joint lands, provided that a single Joint-Operator holding more than a sixty-six percent (66%) working interest in the joint lands shall have the right, by notice to the other parties, to become the Operator hereunder, unless it would then be subject to replacement pursuant to paragraph 202(a)(i). If there are only two (2) Joint-Operators and the Operator that resigned or is to be replaced is one of the Joint-Operators, the other Joint-Operator shall have the right to become the Operator.

(b) No party shall be appointed as Operator hereunder unless it has given its written consent to the appointment. However, if the parties fail to appoint a successor Operator or if any appointed Operator fails to carry out its duties hereunder, the party having the greatest working interest shall act as Operator pro tem, with the right, should a similar situation re-occur after a new Operator has been appointed, to require the party having the next greatest working interest to act as Operator pro tem and so on as the occasion demands.

(c) No provision of this Article shall be construed to re-appoint as next-succeeding Operator an Operator who had been replaced under Clause 202, except with the unanimous consent of the parties.

(d) Except as provided in Subclause 202(a), every replacement of Operator shall take effect at eight o'clock in the morning (0800 hours) on the first (1st) day of the calendar month following the determination to replace the Operator pursuant to Subclause 202(b) or such other date as may be prescribed pursuant to Clause 203 or 204, as the case may be, notwithstanding anything contained herein.

207 TRANSFER OF PROPERTY ON CHANGE OF OPERATOR – At the effective date of the resignation or replacement of an Operator as provided in this Article II, the Operator being replaced shall deliver to the successor Operator possession of:

(a) the wells being drilled or operated by the Operator hereunder, ~~except any wells in respect of which the succeeding Operator is not entitled to information, which shall be operated by a party determined pursuant to Clause 1004 until the successor Operator becomes entitled to such information;~~

(b) all production facilities, other facilities and funds held for the joint account, together with all production, if any, which has not been delivered in kind;

(c) copies of books of account and records kept for the joint account or pertaining to wells delivered hereunder; and

(d) all documents, agreements and other papers relating to property transferred hereunder.

Upon compliance with such obligation, the outgoing Operator shall be released and discharged from, and the successor Operator shall assume, all duties and obligations of the Operator, except those unsatisfied duties and obligations of the outgoing Operator which had accrued prior to the effective date of the change of Operator, for which the outgoing Operator shall continue to remain liable.

208 AUDIT OF ACCOUNTS ON CHANGE OF OPERATOR – Within ninety (90) days after the successor Operator commences to act as Operator, the parties shall cause an audit to be made of the books of account and records kept for the joint account and may cause an inventory of controllable material to be taken. The cost of the audit and inventory shall be a charge for the joint account.

209 ASSIGNMENT OF OPERATORSHIP – In the event the Operator wishes its assignee to replace it as Operator after having disposed of all or a portion of its working interest in the joint lands and any production facilities to such assignee pursuant to Article XXIV, such assignee shall have the right to become Operator if it is an Affiliate of the Operator or, if it is not an Affiliate of the Operator, if the parties agree that it shall become Operator pursuant to Clause 206. Should an assignee which is an Affiliate of the Operator become the Operator pursuant to this Clause, the two (2) year time periods described in Clauses 203 and 205 shall be calculated as if the assignment had not occurred and the audit prescribed pursuant to Clause 208 shall not be required.

ARTICLE III

FUNCTION AND DUTIES OF OPERATOR

301 CONTROL AND MANAGEMENT OF OPERATIONS –

(a) The Operator shall consult with the Joint-Operators from time to time with respect to decisions to be made for the exploration, development and operation of the joint lands and the construction, installation and operation of any production facilities, and the Operator shall keep the Joint-Operators informed with respect to operations planned or conducted for the joint account. Subject to the provisions hereof, the Operator is hereby delegated the management of the exploration, development and operation of the joint lands and the construction, installation and operation of any production facilities for the joint account on behalf of the Joint-Operators.

(b) The Operator shall be entitled to make or commit to such expenditures for the joint account as it considers necessary and prudent in order to conduct a good and workmanlike operation on the joint lands for the joint account. However, the Operator shall not make or commit to an expenditure for the joint account for any single operation, the total estimated cost of which is in excess of twenty-five thousand ($25 000) dollars, without an approved Authority for Expenditure from the Joint-Operators, unless the expenditure is reasonably considered by the Operator to be necessary by reason of an event endangering life or property or is required by the Regulations and failure to make such expenditure could result in the prosecution of the Operator thereunder. If the Operator is required to make such an expenditure, it shall promptly advise the Joint-Operators of the nature of such event or requirement and the expenditure anticipated to be associated therewith.

(c) Approval of an Authority for Expenditure by a party shall constitute that party's approval of all expenditures necessary to conduct the operation described therein, subject to the provisions of Article IX. However, if the Operator incurs or expects to incur expenditures with respect to a joint operation which would exceed by more than ten percent (10%) the total amount estimated in the AFE therefor, the Operator thereupon shall, for informational purposes only, forthwith advise the Joint-Operators of such overexpenditure, the Operator's explanation therefor and the Operator's revised estimate of the cost of such operation. The Operator thereafter shall provide estimates of current and cumulative costs incurred for the joint account with respect to such operation. Such estimates shall be provided on a daily basis where practical, but in any event at intervals of not greater than ten (10) days until the operation is completed.

302 OPERATOR AS JOINT-OPERATOR – The Operator shall have all of the rights and obligations of a Joint-Operator with respect to its working interest.

303 INDEPENDENT STATUS OF OPERATOR – The Operator is an independent contractor in its operations hereunder. The Operator shall supply or cause to be supplied all material, labor and services necessary for the exploration, development and operation of the joint lands and the operation of any production facilities for the joint account. The Operator shall determine the number of employees respecting its operations, their selection, their hours of labour and their compensation. All employees and contractors used in its operations hereunder shall be the employees and contractors of the Operator.

304 PROPER PRACTICES IN OPERATIONS – The Operator shall conduct all joint operations diligently, in a good and workmanlike manner, in accordance with good oilfield practice and the Regulations.

305 BOOKS, RECORDS AND ACCOUNTS – The Operator shall, with respect to all joint operations, keep and maintain true and correct books, records and accounts with respect to the development and progress made, drilling done, the conduct of other operations, the production of petroleum substances and the disposition thereof in the manner prescribed herein and in the Accounting Procedure. The Operator shall, upon request of a Joint-Operator, make available in Alberta and there permit each Joint-Operator during normal business hours to inspect such books, records and accounts and to make extracts or copies therefrom and thereof, and to audit the Operator's books, records and accounts as provided in the Accounting Procedure. ~~However, a Joint-Operator shall not have the rights granted under this Clause with respect to a well while not entitled to information with respect to that well.~~

306 PROTECTION FROM LIENS – The Operator shall pay, or cause to be paid, as and when they become due and payable all accounts of contractors and claims for wages and salaries for services rendered or performed and for materials supplied with respect to the joint lands, any joint operations and any production facilities. The Operator shall keep the joint lands and any production facilities free from liens and encumbrances resulting therefrom, unless there be a bona fide dispute with respect thereto.

307 JOINT-OPERATOR'S RIGHTS OF ACCESS – Except as otherwise provided herein, the Operator shall permit each Joint-Operator or its duly authorized representative, at that Joint-Operator's sole risk, cost and expense, full and free access at all reasonable times to inspect and observe all production facilities and all joint operations being conducted upon the joint lands and to the records on location of current operations being conducted thereon.

308 SURFACE RIGHTS – The Operator shall acquire and maintain for the joint account all necessary surface rights respecting joint operations.

309 MAINTENANCE OF TITLE DOCUMENTS –

(a) Except as otherwise provided herein or in the Agreement, the Operator shall, on behalf of the parties and for the joint account, comply with all the terms and conditions of the title documents including: (i) the payment of rentals; (ii) the payment of any encumbrances agreed to be borne for the joint account; and (iii) the performance of all things necessary to maintain the title documents in good standing and in full force and effect. However, nothing in this Clause shall be construed to require or permit the Operator to drill a well or conduct any joint operation without the approval of the Joint-Operators, if their approval of an Authority of Expenditure with respect thereto is required pursuant to Clause 301.

(b) The Operator shall consult with the parties in a timely manner with respect to any applications it proposes to make under the Regulations to maintain any of the title documents in good standing, including, without restricting the generality of the foregoing, continuation and grouping applications and any other material decisions which are required to be made to maintain any of the title documents in good standing. The Operator shall provide the parties in a timely manner with copies of material correspondence pertaining to the maintenance of the title documents.

(c) If the joint lands are subject to a particular title document whereby the parties may select some (but not all) of such joint lands for the joint account in a successor title document as a result of work or operations which have been conducted (in this Clause called a "lease selection"), the following shall apply to the lease selection:

(i) the parties having a working interest in such title document shall consult, at least ten (10) days prior to the date upon which the lease selection is required, to attempt to agree on the lease selection; and

(ii) insofar as the parties are unable to agree on the joint lands to be included in the lease selection, the Operator shall determine the required number of minimum size geographic units prescribed by the Regulations with respect to a lease selection ("selection units") to complete the lease selection. This number shall be multiplied by each party's working interest, to determine the number of selection units which each party may select to complete the lease selection, with rounding of such number up or down to the nearest whole integer in the event such calculation would entitle a party to a selection of a partial selection unit. Each party shall be entitled to select for inclusion in leases, on a selection unit by selection unit basis, that number of selection units determined by such calculation, with the order of such selections to be determined by lot.

Following the conclusion of the lease selection process, the Operator shall submit the application for leases on behalf of the parties in such manner and at such time as are prescribed by the Regulations.

(d) If the joint lands are subject to a particular title document pursuant to which the parties may make a lease selection, a party may, at any time not earlier than one (1) year before the latest date such lease selection may be made pursuant to that title document, require the parties to select, for the purposes of Clause 1010 only, the lands which will be retained for the joint account in the manner prescribed in the Agreement or Subclause (c) of this Clause, as the case may be. The parties thereupon shall make such lease selection within ten (10) days of the receipt of such notice, as if such lease selection was required at such time. Unless otherwise agreed by the parties, such lease selection shall be binding on the parties for the purposes of determining whether a well is a title preserving well or portions of the lands are preserved lands, as those terms are defined in Clause 1010.

310 PRODUCTION STATEMENTS AND REPORTS – The Operator shall provide each Joint-Operator, before the twenty-fifth (25th) day of each month, with a statement showing production, inventories, sales and deliveries in kind to the parties of petroleum substances during the preceding month. The Operator shall also make all reports relating to joint operations

as required by the Regulations and shall, upon request of a Joint-Operator, provide it with a copy of each such report filed by the Operator with any governmental agency.

311 INSURANCE – The Operator shall comply with the requirements of all Unemployment Insurance, Workers' Compensation and Occupational Health and Safety legislation and all similar Regulations with respect to workers employed in joint operations. Without in any way limiting the obligations or liabilities of the Operator, the Operator shall also comply with the provisions of ALTERNATE __A__ below (Specify A or B: the ALTERNATE not specified is deemed to be deleted from this Operating Procedure):

ALTERNATE - A:

The Operator shall, prior to the commencement of joint operations, hold or cause to be held with a reputable insurance company or companies, and thereafter maintain or cause to be maintained for the joint account and benefit of the parties and their respective Affiliates, directors, officers, servants, consultants, agents and employees, the insurance hereinafter set forth and any other insurance which is specifically required to comply with the Regulations. The insurance required pursuant to this Subclause shall apply to each separate claim and shall be as follows:

(i) Automobile Liability Insurance covering all motor vehicles or snowcraft and all terrain vehicles, owned or non-owned, operated or licenced by the Operator and used in joint operations (insofar only as they are used in joint operations), with an inclusive bodily injury, death and property damage limit of one million dollars ($1 000 000) per accident;

(ii) Comprehensive General Liability Insurance with an inclusive bodily injury, death, and property damage limit of one million dollars ($1 000 000) per occurrence, and, without restricting the generality of the provisions of this paragraph, such coverage shall include, but not be limited to, Employer's, Employer's Contingent Liability, Contractual Liability, Contractor's Protective Liability, Products and Completed Operations Liability; and

(iii) Aircraft Liability Insurance covering all aircraft, owned or non-owned, operated or licenced by the Operator and used in joint operations (insofar only as they are used in joint operations), with an inclusive bodily injury, death and property damage limit of five million dollars ($5 000 000) per occurrence.

- OR -

ALTERNATE - B:

The Operator shall, prior to the commencement of joint operations, hold or cause to be held with a reputable insurance company or companies, and thereafter maintain or cause to be maintained for the joint account and benefit of the parties and their respective Affiliates, directors, officers, servants, consultants, agents and employees, only that insurance as is specifically required to comply with the Regulations. It is the intention of the parties that, except as provided in the previous sentence and in Article IV, the cost of any accident, loss or any claim of or liability to third parties or to each other for bodily injury, death or property damage arising out of any operation conducted hereunder shall be borne individually by the parties participating in the operation, proportionate to their respective participating interests in the operation.

The following conditions shall be applicable to the ALTERNATE which is specified:

(a) The amount of the deductible specified for each accident or occurrence in any insurance policy maintained for the joint account shall not exceed the amount set forth in Clause 301 without the prior approval of the Joint-Operators.

(b) In the event that the policies which the Operator is required to obtain or maintain for the joint account are, in the Operator's reasonable opinion, unavailable or available only at an unreasonable cost, the Operator shall promptly notify the other Joint-Operators, in order that the parties may redetermine the policies which shall be held for the joint account. Subject to the provisions of this Clause, policies obtained for the joint account pursuant to this Clause may contain terms, conditions or exclusions affecting or limiting the risks covered thereby or the circumstances under which the insurer may be required to indemnify or compensate the parties thereunder, provided that such terms, conditions or exclusions are, in the Operator's reasonable opinion, the best available from the marketplace on reasonable terms and ordinary or appropriate. However, the Operator shall obtain the prior consent of the parties with respect to any such change which is made after the relevant policy or policy renewal has been acquired for the joint account.

(c) If the Operator makes any payments with respect to any losses, damages, claims or liabilities arising out of joint operations which are covered by insurance policies maintained for the joint account hereunder with the approval of the insurers thereof or if the Operator makes any payments authorized hereunder with respect to any other losses, damages, claims or liabilities arising out of such operations, such payments shall be a charge for the joint account. However, the Operator shall diligently attempt to process its claims under such policies with respect to such losses, damages, claims or liabilities, and shall promptly credit the joint account the amount it ultimately recovers under such policies. Insofar as such charge is one which is not to be borne for the joint account pursuant to Article IV, the Operator shall adjust the accounts of the parties accordingly at such time as it is determined that the charge is not to be borne for the joint account.

(d) The Operator shall use reasonable efforts to ensure that each insurance policy maintained for the joint account pursuant to this Clause includes: a provision that coverage is primary to any other coverage carried by the parties (other than coverage maintained by a party to reduce its exposure to a deductible), a provision that such policy shall survive the default or bankruptcy of the insured for claims arising out of an event before such default or bankruptcy and a provision that the insurer shall provide the Operator with sixty (60) days' written notice of cancellation of such policy.

(e) Each party shall be responsible for insuring its own interest in the joint lands and any production facilities with respect to physical damage to property, loss of income, Operator's Extra Expense, Pollution Liability and any insurance other than that referred to in the Alternate specified in this Clause. Each party shall ensure that each policy maintained by it for its own account hereunder shall contain waivers of all rights, by subrogation or otherwise, against the other parties and their respective Affiliates, directors, officers, servants, consultants, agents and employees.

(f) The Operator shall provide each Joint-Operator with written notice of damages or losses incurred hereunder as soon as practicable after the damage or loss has been discovered. The Operator shall provide the Joint-Operators with such assistance and materials as is required to substantiate such damages or losses for the purposes of the Joint-Operators' insurance coverages.

(g) The Operator shall, with respect to joint operations, use every reasonable effort to have its contractors and sub-contractors:

(i) comply with Unemployment Insurance, Workers' Compensation and Occupational Health and Safety legislation and all other similar Regulations applicable to workers employed by them; and

(ii) carry such insurance in such amounts as the Operator deems necessary, provided that such insurance policies shall include waivers of all rights, by subrogation or otherwise, against the parties and their respective Affiliates, directors, officers, servants, consultants, agents and employees.

312 TAXES – Except as otherwise provided herein or in the Agreement, the Operator shall initially pay, for the joint account, all taxes with respect to property held for the joint account, provided that nothing herein contained shall require or permit the Operator to pay for the joint account income taxes, mineral taxes, or any other taxes, assessments or levies based on reserves, on a unit of production or on the value thereof unless required to do so by the Regulations. The Operator shall promptly provide each applicable Joint-Operator with copies of all tax notices or assessments received by it respecting property held for the joint account and for which payment is not the responsibility of the Operator.

ARTICLE IV

INDEMNITY AND LIABILITY OF OPERATOR

401 LIMIT OF LEGAL RESPONSIBILITY – Notwithstanding Clauses 303 and 304, the Operator, its Affiliates, directors, officers, servants, consultants, agents and employees shall not be liable to the other Joint-Operators, or any of them, for any loss, expense, injury, death or damage, whether contractual or tortious, suffered or incurred by the Joint-Operators resulting from or in any way attributable to or arising out of any act or omission, whether negligent or otherwise, of the Operator or its Affiliates, directors, officers, servants, consultants, agents, contractors or employees in conducting or carrying out joint operations, except:

(a) when and to the extent that such loss, expense, injury, death or damage relates to a risk against which the Operator is required to carry insurance for the joint account, as provided in Clause 311, and is within the limits of such required insurance (insofar as such limits exceed the deductible applicable thereto), provided that if the Operator had maintained the required insurance covering such loss, expense, injury, death or damage, the Operator shall be released from the responsibility and indemnity otherwise imposed by this Clause to the extent that the insurer thereunder is financially unable to pay all or any portion of a valid claim with respect to such loss, expense, injury, death or damage or such insurer is determined by a court of competent jurisdiction not to be required to make payment with respect to such loss, expense, injury, death or damage under such policy of insurance; and

(b) when and to the extent that such loss, expense, injury, death or damage is a direct result of, or is directly attributable to, the gross negligence or wilful misconduct of the Operator or its Affiliates, directors, officers, servants, consultants, agents, contractors or employees, provided that an act or omission of the Operator or its Affiliates, directors, officers, servants, consultants, agents, contractors or employees shall be deemed not to be gross negligence or wilful misconduct, insofar as such act or omission was done or was omitted to be done in accordance with the instructions of or with the concurrence of the Joint-Operators.

To the extent that the conditions in Subclauses (a) or (b) of this Clause apply (but subject to the exceptions provided therein), the Operator shall be solely liable for such loss, expense, injury, death or damage and, in addition, shall indemnify and save harmless each other Joint-Operator and its Affiliates, directors, officers, servants, consultants, agents and employees from and against the same and also from and against all actions, causes of action, suits, claims and demands by any person or persons whomsoever in respect of any such loss, expense, injury, death or damage, and any costs and expenses relating thereto. However, in no event shall the responsibility of the Operator prescribed by this Clause extend to losses suffered by the Joint-Operators respecting the loss or delay of production from the joint lands, including, without restricting the generality of the foregoing, loss of profits or other consequential or indirect losses applicable to such loss or delay of production.

402 INDEMNIFICATION OF OPERATOR – Except as otherwise provided in Clause 401, the Joint-Operators hereby indemnify and save harmless the Operator, its Affiliates, directors, officers, servants, consultants, agents and employees from and against any and all actions, causes of action, suits, claims, demands, costs, losses and expenses resulting from loss, injury, death or damage respecting any person, which may be brought against or incurred or suffered by the Operator, its Affiliates, directors, officers, servants, consultants, agents or employees or which the Operator, its Affiliates, directors, officers, servants, consultants, agents or employees may sustain, pay or incur by reason of, or which may be attributable to or arise out of, any act or omission of the Operator or its Affiliates, directors, officers, servants, consultants, agents, contractors or employees in conducting joint operations. All such liabilities shall be for the joint account and shall be borne by the Joint-Operators in the proportions of their respective working interests.

ARTICLE V

COSTS AND EXPENSES

501 ACCOUNTING PROCEDURE AS BASIS – The Accounting Procedure shall be the basis for all charges and credits for the joint account, except to the extent that the Accounting Procedure may be in conflict with the provisions herein or in the Agreement. The accounting and financial records maintained by the Operator with respect to the operations conducted by it hereunder shall be maintained separately from those kept by it with respect to operations which are not conducted hereunder, in accordance with established industry accounting practice.

and the Agreement

502 OPERATOR TO PAY AND RECOVER FROM PARTIES – Subject to the provisions of Clause 503, the Operator shall initially advance and pay all costs and expenses incurred for the joint account. The Operator shall charge to each Joint-Operator its proportionate share of such costs and expenses, and each respective Joint-Operator shall pay the same to the Operator within thirty (30) days after receipt of the Operator's statement thereof.

503 ADVANCE OF COSTS –

~~(a) Upon approval of an Authority for Expenditure by a Joint-Operator, the Operator may, by notice, require that~~ individual Joint-Operator to secure payment of its proportionate share of all costs to be incurred ~~for the joint~~ account pursuant to such AFE in a manner satisfactory to the Operator. If the payment ~~is to be~~ secured by an irrevocable standby letter of credit, it shall be established in favour of ~~the Operator~~ by that Joint-Operator with a Canadian chartered bank with respect to that Joint-~~Operator's~~ proportionate share of the costs and expenses which are anticipated to be incurred ~~pursuant to~~ such AFE. In the event a letter of credit is so established, the Operator may draw on the ~~letter of credit~~ in the same manner and at the same time intervals as provided with respect to amounts ~~to be paid by that Joint-Operator pursuant to such AFE.~~

(b) The Operator may, by notice to the Joint-Operators, require each Joint-Operator to advance its proportionate share of all costs to be incurred for the joint account, subject to Subclause (a) of this Clause. If the Operator so elects to cash call the Joint-Operators, it shall, not earlier than thirty (30) days prior to the first (1st) day of a calendar month, submit to each Joint-Operator an itemized written estimate of the costs which are expected to be paid by the Operator for the joint account hereunder in that calendar month, together with a request for payment by each Joint-Operator of its proportionate share thereof, insofar as such amount is not secured by Subclause (a) of this Clause. A Joint-Operator shall pay its share of such cash call to the Operator (or otherwise secure payment thereof as provided in Subclause (a) above) on or before the twentieth (20th) day after its receipt of such estimate or by the fifteenth (15th) day of the calendar month to which such estimate relates, whichever is the later.

(c) The Operator shall adjust each monthly billing to reflect advances received from a Joint-Operator hereunder. Costs in excess of the advances requested hereunder shall be billed and paid by the Joint-Operators pursuant to the Accounting Procedure. Amounts advanced by the Joint-Operators in excess of actual costs shall be refunded by the Operator with the related billing for the month in which the advance was paid. Any such excess amounts not refunded shall, at the option of each Joint-Operator, bear interest (payable by the Operator for the account of that Joint-Operator) on the same basis as is provided in paragraph 505(b)(i).

504 FORECAST OF OPERATIONS – The Operator shall, from time to time at the request of a Joint-Operator, provide the Joint-Operators with a written forecast outlining all operations which it proposes to conduct for the joint account during the forecast period (which shall be not less than three (3) months and not more than twelve (12) months), together with the estimated costs thereof. Such forecasts are for informational purposes only and shall not commit the parties to make the expenditures described therein.

505 OPERATOR'S LIEN –

(a) Effective from the date of the Agreement, the Operator shall have a lien and charge, which is first and prior to any other lien, charge, mortgage or other security interest, with respect to the interest of each Joint-Operator in the joint lands, the wells and equipment thereon, the petroleum substances produced therefrom and any production facilities, to secure payment of such Joint-Operator's proportionate share of the costs and expenses incurred by the Operator for the joint account.

(b) If a Joint-Operator fails to pay or advance any of the costs or expenses incurred for the joint account which are to be paid or advanced by it within the time period prescribed by the Accounting Procedure or Clause 502 or 503, as the case may be, the Operator may, without limiting the Operator's other rights as contained in this Operating Procedure or otherwise held at law or in equity:

(i) charge such Joint-Operator compound interest, as computed monthly, with respect to such unpaid amount from the day such payment is due until the day it is paid, at the rate of two percent (2%) per annum higher than the rate designated as the prevailing prime rate for Canadian commercial loans by the principal Canadian chartered bank used by the Operator, regardless of whether the Operator has notified such party in advance of its intention to charge interest with respect to such unpaid amount;

(ii) withhold from such Joint-Operator any further information and privileges with respect to operations conducted hereunder, which information and privileges shall be conveyed or restored, as the case may be, to such Joint-Operator upon such default being fully rectified;

(iii) set-off against the amount unpaid by such defaulting Joint-Operator, any sums due or accruing to such Joint-Operator from the Operator pursuant to this Operating Procedure or any other agreement between the Operator and such Joint-Operator, whether executed before or after the effective date of the Agreement;

(iv) maintain an action or actions for such unpaid amounts and interest thereon on a continuing basis as such amounts are payable, but not paid by such defaulting Joint-Operator, as if the obligation to pay such amounts and the interest thereon were liquidated demands due and payable on the relevant date such amounts were due to be paid, without any right or resort of such Joint-Operator to set-off or counter-claim;

(v) treat the default as an immediate and automatic assignment to the Operator of the proceeds of the sale of such Joint-Operator's share of petroleum substances produced hereunder. Service of a copy of this Operating Procedure upon a purchaser of such petroleum substances from such Joint-Operator, together with written notice from the Operator, shall constitute a written irrevocable direction by the Joint-Operator to any such purchaser to pay to the Operator the proceeds from any such sale up to the amount owed to the Operator by such Joint-Operator hereunder (including any accrued interest with respect thereto), and such purchaser is authorized by such Joint-Operator to rely upon the statement of the Operator as to the amount so owed to it by such Joint-Operator; and

(vi) enforce the lien referred to in Subclause (a) of this Clause by taking possession of or using free of charge all or any part of the interest of the defaulting Joint-Operator in the joint lands, in all or any part of the production therefrom and equipment thereon or in any production facilities and all rights, powers and privileges of such Joint-Operator in connection with such interest until such default is fully rectified. Notwithstanding the provisions of Clauses 601 and 2401, the Operator may sell and dispose of any interest, production, equipment or production facility of which it has so taken possession, either in whole or in part or in separate parcels, at public auction or by private tender at a time and on whatever terms it shall arrange, having first given at least ten (10) days' prior written notice to such Joint-Operator of the time and place of the sale, provided that the Operator may only sell such interest, production, equipment or production facility to such person or persons for such price and on such conditions as the Operator determines are reasonable, having due regard, inter alia, to the possible recovery of funds for such Joint-Operator in excess of the amount owed by it hereunder. Such sale or other realization shall be without prejudice to the Operator's claim for deficiency and shall be free from any right of redemption on the part of such Joint-Operator (which right is hereby waived and released), and such Joint-Operator also waives all formalities prescribed by custom or by law with respect to such sale or other realization. The proceeds of the sale shall be first applied by the Operator in payment of any amount required to be paid by the defaulting Joint-Operator and not paid by it hereunder (including any accrued interest with respect thereto), and any balance remaining shall be paid to the defaulting Joint Operator after deducting reasonable costs of the sale. Any sale made as aforesaid shall be a perpetual bar both at law and in equity against the defaulting Joint-Operator and its assigns and against all other persons claiming an interest in such property or any portion thereof sold as aforesaid by, from, through or under the defaulting Joint-Operator or its assigns.

However, the Operator may not exercise the rights granted in paragraphs (iii) - (vi) of this Subclause with respect to such default until at least thirty (30) days following the issuance of a notice to such Joint-Operator specifying such default and requiring the same to remedied.

(c) The obligation to pay interest at the rate specified in Subclause (b) with respect to a default is to apply until such default is rectified and shall not merge into a judgement for principal and interest, or either of them. The parties waive the application of any Regulations to the contrary, insofar as such waiver is permitted by the Regulations.

(d) Books and records kept by the Operator for the joint account shall constitute prima facie proof of the existence of any financial default hereunder, subject, however, to the rights of inspection and audit provided for elsewhere in this Operating Procedure.

(e) If the Operator is the party which defaults in paying its share of any cost or expense incurred for the joint account, the other parties may appoint a party as representative ad hoc of those parties, pending the appointment of a new Operator pursuant to Article II. Such party thereupon shall be entitled to exercise any of the rights and remedies otherwise available to the Operator pursuant to this Operating Procedure, mutatis mutandis, in order to rectify such default.

506 REIMBURSEMENT OF OPERATOR – If the Operator has not received full payment of a Joint-Operator's share of the costs and expenses of joint operations within three (3) months following the date the payment was due, each other Joint-Operator, upon being billed therefor by the Operator, shall contribute a fraction of the unpaid amount, excluding interest thereon, which fraction shall have:

(i) as its numerator – the working interest of such Joint-Operator; and

(ii) as its denominator – the aggregate working interests of all parties except the defaulting Joint-Operator.

Thereupon, each such contributor shall be proportionately subrogated to the Operator's rights pursuant to Clause 505 and to the interest thereafter payable thereunder on the unrecovered portion of its contribution.

507 COMMINGLING OF FUNDS – The Operator may commingle with its own funds the moneys which it receives from or for the account of the Joint-Operators pursuant to this Operating Procedure. Notwithstanding that moneys of a Joint-Operator have been commingled with the Operator's funds, the moneys of a Joint-Operator advanced or paid to the Operator, whether for the conduct of operations hereunder or as proceeds from the sale of production under this Operating Procedure, shall be deemed to be trust moneys, and shall be applied only to their intended use and shall in no way be deemed to be funds belonging to the Operator, other than in its capacity as the Joint-Operators' trustee.

ARTICLE VI

OWNERSHIP AND DISPOSITION OF PRODUCTION

601 EACH PARTY TO OWN AND TAKE ITS SHARE – Each party shall own its proportionate share of the petroleum substances produced from wells operated for the joint account. The Operator shall measure and deliver into the possession of each party, as and when produced at the first point of measurement, the proportionate share of petroleum substances owned by that party, exclusive of production which has been unavoidably lost and production which may be used by the Operator in producing operations respecting the joint lands. Each party shall, at its own expense, have the right to take in kind and separately dispose of its proportionate share of such production, provided that it gives the Operator six months notice of its intention to do so. Each Joint-Operator shall provide the Operator with such information respecting such Joint-Operator's arrangements for the disposition of its share of production as the Operator may reasonably require to fulfil its obligations hereunder.

602 PARTIES NOT TAKING IN KIND –

(a) Notwithstanding Clause 601, to the extent that a Joint-Operator does not take in kind and separately dispose of its share of production hereunder or advises the Operator that it will not be fulfilling that obligation, the Operator shall have the authority, but not the obligation, to dispose of such portion of the non-taking party's share of production, as the agent of the non-taking party, pursuant to any of the following options:

(i) the Operator may sell such production at the same price which the Operator receives from a third party under an arm's length sale contract for its own share of production, and account to the non-taking party for the proceeds of the sale applicable to the production sold on its behalf, less all direct processing and transportation expenses pertaining thereto and the applicable marketing fee prescribed by Clause 604; or

(ii) the Operator may sell such production at a market price to a third party in an arm's length transaction, and account to the non-taking party for the proceeds of the sale, less all direct processing and transportation expenses pertaining to such production and the applicable marketing fee prescribed by Clause 604; or

(iii) the Operator may purchase such production for the Operator's own account (or the account of an Affiliate) at a market price.

Insofar as the Operator disposes of all or a portion of a non-taking party's share of production pursuant to this Subclause, the Operator shall advise that party of the option pursuant to which the Operator disposed of that party's production within one (1) month of the commencement of that disposition.

(b) The Operator may not purchase production pursuant to paragraph (a)(iii) of this Clause under any arrangement which has a term exceeding one (1) month, unless such arrangement is terminable at any time on not greater than one (1) month's notice by the non-taking party to the Operator without an early termination penalty or other cost. If, pursuant to paragraph (a)(i) or (ii) of this Clause, the Operator proposes to enter into a sales contract which either has a term greater than one (1) month or is not so terminable at any time on notice of one (1) month or less, the following shall apply:

(i) the Operator shall notify the non-taking party of such intention and provide it with a summary of the terms of the proposed contract in sufficient detail to enable the non-taking party to determine whether it wishes that portion of its share of production not being taken in kind and separately disposed of by it sold pursuant to the proposed contract;

(ii) the non-taking party shall notify the Operator within ten (10) days of the receipt of the Operator's notice whether it consents to having such production sold under such contract, provided that failure of the non-taking party to notify the Operator of its position within such period shall be deemed to be the consent of the non-taking party to the sale of such production pursuant to such contract;

(iii) if the non-taking party consents to having such production sold under such contract pursuant to the preceding paragraph, the Operator shall sell such production under such contract. If the non-taking party does not consent to having such production sold pursuant to such contract pursuant to the preceding paragraph, the non-taking party shall state in its notice whether it intends to commence taking such production in kind and separately disposing of the same, and, if so, it shall promptly supply the Operator with the information required by it pursuant to Clause 601; and

(iv) If the non-taking party does not consent to having such production sold under such contract pursuant to this Subclause and does not proceed to take such production in kind and separately dispose of the same, the Operator may dispose of such production pursuant to Subclause (a) of this Clause.

No contract described in this Subclause, however, shall have a term exceeding one (1) year ~~without the consent of the non-taking party, unless that contract may be terminated by the Operator at any time on not greater than one (1) year's notice to the applicable purchaser.~~

(c) If a non-taking party proposes to commence to exercise its right to take in kind and separately dispose of its share of production hereunder, it shall give notice of such intention to the Operator and shall promptly supply the Operator with the information required by it pursuant to Clause 601. Such notice shall be effective either at the end of the term of any sale agreement pursuant to which such production is being sold by the Operator or at the date such agreement is terminated, if terminable by the Operator at an earlier date. However, such notice shall not be effective with respect to an agreement which is terminable by the Operator, unless the Operator has received such notice at least fifteen (15) days prior to any specified date upon which the Operator is required to serve notice to the applicable purchaser to terminate such agreement.

603 OPERATOR NOT TAKING IN KIND – To the extent that the Operator either is the party who does not take in kind and separately dispose of its proportionate share of production or the Operator does not intend to dispose of production not being taken in kind by another Joint-Operator pursuant to Clause 602, the Operator shall advise the other Joint-Operators, in a timely manner, of the information required by them to exercise their rights pursuant to this Clause 603. In such event, the Joint-Operators, or any one or more of them, shall have the same rights and obligations, mutatis mutandis, with respect to such share of production as the Operator has with respect to a Joint-Operator's share of production under Clause 602. Insofar as the provisions of this Clause are applicable and the Operator requires instructions respecting production and marketing to give effect to this Clause and, if applicable, Clause 602, the Operator shall follow the instructions which are given by the parties marketing production on behalf of the Operator and, if applicable, any other party hereunder. Two or more Joint-Operators exercising their rights under this Clause shall do so in proportion to their working interests, and shall attempt to coordinate their plans for the disposition of such production in such a manner that the instructions to be provided to the Operator with respect to such production shall be consistent. For so long as the Operator continues to be a non-taking party, it shall advise the other parties periodically when and how it proposes to take in kind and separately dispose of its share of production pursuant to Clause 601. If the Operator commences to take its share of production in kind and separately dispose of the same, the Operator thereupon shall have the right to sell a non-taking party's share of production pursuant to Clause 601 following the termination of any contract entered into on behalf of such non-taking party in accordance with Clauses 602 and 603.

~~604 MARKETING FEE – To the extent that a party fails to take in kind and dispose of all or a portion of its share of~~ production and such production is disposed of either by the Operator pursuant to ~~paragraph 602(a)(i)~~ or (ii) or by another Joint-Operator pursuant to Clause 603, other than ~~by way of a transaction~~ described in paragraph 602(a)(iii), the party so marketing such production ~~shall be entitled~~ to charge the non-taking party the marketing fee in ALTERNATE ____ below ~~(Specify A or B), namely:~~

~~ALTERNATE A:~~

~~The party so marketing such production on behalf of a non-taking party may charge that party a marketing fee equal to 2.5% of the sale price of such production, calculated at the wellhead.~~

~~– OR –~~

~~ALTERNATE B:~~

~~The party so marketing such production on behalf of a non-taking party may charge that party a marketing fee which is either a percentage of the sale price of such production, calculated at the wellhead, or a specified fee, being (specify one option for each item):~~

~~(a) in the case of petroleum, _______ % or $ _______ /m³;~~

~~(b) in the case of natural gas, _______ % or $ _______ /10³m³;~~

~~(c) in the case of natural gas liquids and substances other than petroleum and natural gas (but not including sulphur), _______ % or $ _______ /m³; and~~

~~(d) in the case of sulphur, _______ % or $ _______ /t.~~

605 PAYMENT OF LESSOR'S ROYALTY – Each party shall pay or cause to be paid the Lessor's royalty and all other payments required pursuant to the title documents which are attributable to its proportionate share of the production of petroleum substances hereunder. However, the party disposing of a non-taking party's share of production pursuant to Clause 602 or 603 may pay the royalty attributable to that share of petroleum substances directly to the Lessor on behalf of the non-taking party, in which case the amount so paid shall be deducted from amounts owing to the non-taking party pursuant to Clause 606.

606 DISTRIBUTION OF PROCEEDS – *Subject to the foregoing provisions of this Article*, a party that disposes of another party's share of production pursuant to Clause 602 or 603 shall forthwith pay the proceeds of such sale, less all direct processing and transportation expenses pertaining to such production (if known at such time) and any applicable marketing fee prescribed by Clause 604, to the party on whose behalf such production was sold, and shall include with such payment a statement showing the manner in which the amount was calculated. If the disposing party does not pay such amount within ten (10) days following its receipt or, if not previously deducted from the proceeds of such sale hereunder, the non-taking party does not pay the direct processing and transportation expenses applicable to such production within thirty (30) days of being invoiced therefor by the disposing party, the provisions of Subclause 505(b) shall apply, mutatis mutandis, between the non-taking party and the disposing party with respect to such outstanding amounts. Proceeds of sale of a party's share of production pursuant to Clause 602 or 603 and the applicable marketing fee prescribed by Clause 604 shall be determined by reference to the volume of production taken by each party in a month.

607 AUDIT BY NON-TAKING PARTY – To the extent only that a party sells all or a portion of the share of production of a party which does not take in kind and separately dispose of the same hereunder, the audit provisions of the Accounting Procedure shall apply, mutatis mutandis, with respect to such sale between the party who sold such production and the party on whose behalf such production was sold, provided that the party who sold such production shall not be required to provide the auditors with access to any contract described in paragraph 602(a)(i).

608 DISPOSING PARTY TO BE INDEMNIFIED – In the event a party does not take in kind and separately dispose of its share of production and another party disposes of such production on behalf of the non-taking party pursuant to this Article, the non-taking party shall indemnify the disposing party with respect to any injury, loss or damage which the disposing party may suffer with respect to such sale by virtue of defects in the non-taking party's title to such production.

ARTICLE VII

OPERATOR'S DUTIES RE CONDUCTING JOINT OPERATIONS

701 PRE-COMMENCEMENT REQUIREMENTS – If the Operator proposes to conduct a joint operation, the following conditions shall apply:

(a) The Operator shall submit an Authority for Expenditure for such operation to each Joint-Operator for its approval, *if required* by Clause 301. ~~Such Authority for Expenditure shall be void unless it has been approved by all of the Joint-Operators within forty-five (45) days of being submitted to them by the Operator. The Operator shall promptly advise the Joint-Operators whether such Authority for Expenditure has been approved by all of the Joint-Operators.~~

~~(b) An Authority for Expenditure which was approved by the parties shall be void if the operation to which it relates is not commenced within the later of one hundred and twenty (120) days following the date the Authority for Expenditure was submitted to the other parties by the Operator or forty-five (45) days following the anticipated date of commencement specified therein with respect to such operation, as the case may be, provided that in no event shall such operation be commenced later than one hundred and eighty (180) days following the submission of such Authority for Expenditure to the parties by the Operator.~~

~~(c) Submission or approval of an Authority for Expenditure shall not preclude any party from giving an operation notice under Clause 1002 with respect to the operation proposed in the AFE. However, approval of the Authority for Expenditure by all parties before expiration of the response period provided in Clause 1002 with respect to that operation notice shall nullify such operation notice.~~

~~(d) If the operation is the drilling of a well for the joint account, the Operator shall submit to each Joint-Operator at least forty-eight (48) hours prior to the commencement of the well:~~

~~(i) written notice of intention to spud such well;~~

~~(ii) a copy of the plan of each well location survey, the application for the well licence and, when available, a copy of the well licence; and~~

~~(iii) a copy of the proposed program of drilling, coring, logging, testing and casing the well, and, subject~~ to Article IX, a Joint-Operator shall be ~~deemed to have approved~~ the program, unless it notifies the ~~Operator to the contrary within seven (7) days of receipt of such program.~~

702 DRILLING INFORMATION AND PRIVILEGES OF JOINT-OPERATORS – ~~During the drilling of a well for the joint account,~~ the Operator shall provide to each Joint-Operator:

~~(a) immediate notice of the spud date of the well;~~

~~(b) the surface elevation of the well;~~

~~(c) daily drilling and geological reports;~~

(d) access to the Operator's set of samples of the cuttings of formations penetrated and a complete sample description, or, if specifically requested by a Joint-Operator, a complete set of samples of the cuttings of the formations penetrated for its own retention;

(e) access to all cores taken and copies of any core analysis conducted for the joint account;

~~(f) immediate advice of any porous zones with showings of petroleum substances encountered and the proposed tests, if any, to be run on those porous zones;~~

~~(g) a reasonable opportunity for each Joint-Operator to have a representative present to witness and observe any tests conducted pursuant to Subclause (f) of this Clause;~~

(h) access to each well, including derrick floor privileges as set forth in Clause 307; and

(i) estimates of current and cumulative costs incurred for the joint account.

703 LOGGING AND TESTING INFORMATION TO JOINT-OPERATORS – Upon a well being drilled for the joint account reaching total depth (or during the drilling of the well, if any such operations are to be conducted prior to the well reaching its projected total depth), the Operator shall:

(a) test it in accordance with the approved program;

~~(b) make such further tests as are warranted in the circumstances, of any porous zones with showings of~~ petroleum substances encountered or ~~indicated by any survey and provide~~ each Joint-Operator with a reasonable ~~opportunity to have a representative present to witness and observe any such tests;~~

(c) take representative mud samples and drillstem test fluid samples in order to obtain accurate resistivity, mud filtrate and formation water readings and supply each Joint-Operator with the information pertaining thereto in a timely manner;

(d) supply each Joint-Operator, in a timely manner, with copies of the drillstem test and service report on each drillstem test run, including copies of pressure charts; and

~~(e) run all log surveys agreed upon among the Joint-Operators, supply each Joint-Operator, in a timely manner,~~ with copies of each log so run and ~~provide each Joint-Operator with a~~ reasonable opportunity to have a ~~representative present to witness and observe any such surveys.~~

704 WELL COMPLETION AND PRODUCTION INFORMATION TO JOINT-OPERATORS – ~~During any completion operation conducted for the joint account,~~ the Operator shall:

(a) complete the well in accordance with the approved program and supply each Joint-Operator with current reports on all completion activities which, without restricting the generality of the foregoing, shall include:

(i) a summary of the casing program;

(ii) the location and density of perforations;

(iii) details of formation treatment and stimulation;

(iv) results of back pressure tests;

(v) daily completion reports; and

(vi) estimates of current and cumulative costs incurred for the joint account; and

(b) promptly provide each Joint-Operator with all relevant information pertaining to any formation tests and production tests conducted on the well ~~and daily advice as to the nature, rate and amount of petroleum substances and other fluids produced from the well.~~

705 WELL INFORMATION SUBSEQUENT TO COMPLETION - Subsequent to the completion of any well completed for the joint account, the Operator shall supply to each Joint-Operator:

(a) copies of any directional, temperature, caliper or other well surveys conducted for the joint account;

(b) copies of any petroleum, natural gas, water or other substance analyses made with respect to the well, provided that if the Operator does not make analyses of water and petroleum substances, representative samples of water and petroleum substances (other than natural gas) recovered from each test shall be supplied;

(c) a complete summary of the drilling and completion of the well;

(d) written notice of the commencement of production of any of the petroleum substances from the well; and

(e) initial production rates and the nature, kind, and quality of petroleum substances and any other substances produced from the well.

706 DATA SUPPLIED IN ACCORDANCE WITH ESTABLISHED STANDARDS - The Operator shall supply all data to be provided to the Joint-Operators hereunder in accordance with established industry standards.

707 ADDITIONAL TESTING BY LESS THAN ALL JOINT-OPERATORS - After giving written notice to each of the other Joint-Operators of its intention to do so, any Joint-Operator may, at its sole risk and expense (including rig costs), conduct such other or additional tests of its choosing in a well to which it is entitled to have access hereunder, unless the Operator advises such Joint-Operator that, in the Operator's opinion, the hole is not in satisfactory condition for that purpose. Subject always to Article IX and Clauses 1017 and 1801, the Joint-Operator so conducting any such tests shall retain all rights thereto and shall not be required to make the results thereof available to any other Joint-Operator pursuant to this Operating Procedure.

~~708 APPLICATION OF ARTICLE VII WHEN OPERATION CONDUCTED BY LESS THAN ALL PARTIES - If an operation hereunder is not conducted for the joint account, the provisions of this Article VII shall apply, mutatis mutandis, among those parties participating therein.~~

ARTICLE VIII

ENCUMBRANCES

801 RESPONSIBILITY FOR ADDITIONAL ENCUMBRANCES - If the working interest of a party is or becomes encumbered by any royalty, overriding royalty, production payment or other charge of a similar nature, other than the royalties payable to the grantor of the title documents and any charge to be borne for the joint account pursuant to either the Agreement or the agreement of the parties, such party shall be solely responsible for such additional encumbrance. In the event of any surrender, forfeiture or production penalty provided for in this Operating Procedure, such surrendered, forfeited or affected interest shall be freed of any such additional encumbrance caused, suffered or created by or through such party (or its predecessor in interest) at the sole cost and expense of such party, and such party shall indemnify the other parties for any losses they may suffer as a result of the failure of such party to fulfill the obligation to remove such additional encumbrance.

802 EXCEPTION TO CLAUSE 801 - Notwithstanding the preceding Clause (but subject to the provisions of the Agreement), the obligation to remove an additional encumbrance and to indemnify the other parties with respect thereto shall not apply, insofar as such additional encumbrance is created pursuant to the provisions of the Agreement or is specifically acknowledged therein to be a charge applicable to a party's working interest which shall continue to apply to such working interest following the application of the surrender, forfeiture or production penalty provisions hereof to such working interest.

ARTICLE IX

CASING POINT ELECTION

901 AGREEMENT TO DRILL NOT AUTHORITY TO COMPLETE - Agreement by the parties to drill or deepen a well for the joint account shall not be deemed to include agreement by any Joint-Operator to participate in the setting of production casing, the attempted completion of the well or any completion program set forth in the Authority for Expenditure submitted pursuant to Subclause 701(a).

902 ELECTION BY JOINT-OPERATORS RE CASING AND COMPLETION -

(a) The Operator shall immediately notify the Joint-Operators when a well being drilled for the joint account has been drilled to the authorized total depth and the logs and tests conducted pursuant to Article VII have been run. The Operator shall also notify the Joint-Operators at such time of the Operator's proposed program for completing the well and forthwith provide an AFE therefor.

(b) Subject to Subclause 1002(c), each Joint-Operator shall have a period of twenty-four (24) hours after both the logs and results of the tests in which it participated and the Operator's proposed completion program respecting the well have been made available to it, to inform the Operator whether it wishes to participate in the setting of production casing and a completion attempt. Failure to reply to the notice from the Operator within such period shall be deemed to be an election by a party to participate in such completion attempt. If a party which elects to participate in the completion attempt fails to object to the Operator's proposed completion program by notice to the Joint-Operators within such period, that party shall be deemed to concur with that program. If the Operator proposes to alter the proposed completion program materially as a result of a party's objection to the Operator's proposed program, the Operator shall immediately notify all parties, and each party shall have the right for twelve (12) hours following the receipt of such notice to re-elect to participate in such completion attempt. Notwithstanding the foregoing portion of this Subclause, if Alternate 903A applies and a party's objection to the Operator's proposed completion program is that such party wishes to limit its participation in such operation to the setting of production casing and the suspension of the well, that party may so limit its participation in such operation. In such event, the cost recovery prescribed by Alternate 903A with respect to such party's limited participation shall apply only to that *portion of the costs of such completion attempt not assumed by such party, if one or more of the other parties* proceed to conduct such completion attempt at such time.

(c) If one or more Joint-Operators elect to participate in the completion attempt, the participating parties shall proceed to run production casing and attempt to complete the well for the taking of petroleum substances. If none of the Joint-Operators elect to participate in the completion attempt, the Operator shall abandon the well.

(d) Notwithstanding the foregoing Subclauses of this Clause and Clause 903, in the event the Operator's proposed program pursuant to this Clause is the setting of production casing in the well and the suspension of the well, so that the well may be re-entered at some unspecified later date for the conduct of an unspecified completion program, the approval of a Joint-Operator to participate in such program shall not constitute the approval of that Joint-Operator to participate in the attempted completion of such well at such time as it may be conducted, and Clause [illegible] shall apply to such subsequent re-entry and completion attempt.

903 LESS THAN ALL PARTIES PARTICIPATE - If one or more, but not all, of the parties elect to set production casing and attempt to complete the well and the well is completed for the taking of petroleum substances in paying quantities, ALTERNATE ______ below (Specify A or B) shall apply, namely:

ALTERNATE - A:

The setting of production casing and the completion attempt shall be considered an independent operation under the provisions of Article X (including the provisions of Clause 1009 if the well is abandoned before the penalty in Clause 1007 is recovered), as if the independent operation were with respect to a development well or an exploratory well, as the case may be, provided that the drilling costs of the well shall not be considered when calculating the amount recoverable pursuant to paragraph 1007(a)(iv).

- OR -

ALTERNATE B:

Each party not participating in the setting of production casing and the completion attempt shall assign to the parties that paid such non-participating party's share of such costs, all of the assignor's interest in the spacing unit of the well, insofar only as it relates to the zone in which the well is so completed, subject to Clause 1015. The assignees shall forthwith pay to the assignors the latter's share of the estimated salvage value of the material and equipment placed in or on the well prior to commencement of the completion attempt.

904 ABANDONMENT OF WELL - If one or more, but not all, of the parties elect to set production casing and attempt to complete the well pursuant to Clause 903 and the participating parties in such completion attempt then propose to abandon the well within six (6) months of the expiry of the twenty-four (24) hour period provided in Clause 902, they shall so notify the non-participating parties. Such abandonment shall be for the joint account, except that:

(a) the participating parties in the completion attempt shall bear all extra costs of the abandonment incurred by reason of the completion attempt; and

(b) income received by the participating parties from the sale of petroleum substances produced from the well within such six (6) month period and any amounts received from the sale of salvable material and equipment shall firstly be applied to abate costs incurred by those parties in the completion attempt, and the excess, if any, shall be a credit for the joint account.

If the well is not abandoned within such six (6) month period, the participating parties in the setting of production casing and, if applicable, the completion attempt shall be solely responsible for the costs of abandoning the well, subject, if applicable, to the *reacquisition of participation in the well by a non-participating* party pursuant to Clause 1007 or 1008, *as* the case may be.

905 PROVISIONS OF ARTICLE X TO APPLY - The provisions of Article X shall apply, mutatis mutandis, to operations conducted pursuant to this Article by one or more, but not all, of the parties, except to the extent that those provisions would conflict with those contained in this Article IX.

ARTICLE X

INDEPENDENT OPERATIONS

1001 DEFINITIONS - In this Article, the following words and phrases shall have the following respective meanings, namely:

(a) 'independent operation' means an operation to be conducted hereunder by less than all of the parties.

(b) 'non-participating party' means a party which does not participate in an independent operation.

(c) 'operation notice' means a notice of intention to conduct an independent operation.

(d) 'participating party' means a party which participates in an independent operation.

(e) 'proposing party' means the party or parties which issue an operation notice.

(f) 'receiving party' means a party which receives an operation notice.

1002 PROPOSAL OF INDEPENDENT OPERATION -

(a) The parties normally shall consult with respect to decisions to be made for the exploration, development and operation of the joint lands. Whether or not such consultation has occurred or has been requested, a party may at any time become a proposing party and give to the other parties an operation notice for an operation on or with respect to the *joint lands* or the construction or installation of a production facility, including therein or therewith:

(i) the nature of the operation;

(ii) the proposed location of the operation;

(iii) the anticipated time of commencement and estimated duration of the operation;

~~(iv) the classification, if applicable, of the operation as a development well or exploratory well and the application of Clause 1010 thereto, if any; and~~

~~(v) an Authority for Expenditure, provided that an Authority for Expenditure otherwise submitted hereunder~~ shall not in itself be construed as an operation notice unless it is specifically part of an operation ~~notice served pursuant to this Article X.~~

~~(b) A receiving party shall be deemed to have elected not to participate in the operation proposed in an~~ operation notice unless, within thirty (30) days after receipt of such operation notice, that receiving party has given notice to the proposing party that it elects to participate in the operation. However, if the operation notice states that the operation is to be conducted for the purpose of evaluating lands specified therein which either have been offered for public tender by a governmental authority or which it is known will be so offered within sixty (60) days after receipt of the operation notice, such thirty (30) day period shall be reduced to fifteen (15) days, provided that no operation shall be considered as being conducted for such evaluation if none of the lands proposed to be evaluated are within 1.6 kilometres of the location of the proposed well. Notwithstanding the foregoing portion of this Subclause, if the operation notice pertains to a proposed deepening, plugging back, whipstocking, re-entry and completion of a suspended well, recompletion or reworking pursuant to Clause 1008, the drilling or service rig to be used in such operation is then at the location thereof and the operation notice states that such rig is so located, such thirty (30) or fifteen (15) day response period shall be reduced to forty-eight (48) hours, during which period all incremental expenses accruing as a consequence of the issuance of such operation notice, including, without restricting the generality of the foregoing, standby time, shall be for the account of the proposing party and, if ~~conducted, the other participating parties.~~

~~(c) The participating parties shall have the right to participate in the independent operation in the proportions~~ that their respective working interests bear one to the other, and a participating party which does not elect to limit its participation in such operation shall be deemed to have elected to participate to the extent of its working interest, increased by its proportionate share of the unassumed percentage of participation respecting such operation. A proposing party, in the operation notice, and a receiving party, in its response thereto, may elect to participate in the independent operation only to the extent of its working interest or only to the extent of its working interest increased by its proportionate share of the unassumed percentage of participation respecting such operation, with a limitation as to the maximum amount of such increased participation such party is prepared to accept. If there remains an unassumed percentage of participation respecting such operation following those elections, the proposing party shall be deemed to have withdrawn the operation notice, unless the participating parties otherwise agree to assume such unassumed percentage of participation within five (5) days of the completion of such process if the response period applicable to the operation notice is greater than forty-eight (48) hours and within twelve (12) hours of the completion of such process if the response period applicable to the operation notice is forty-eight (48) hours ~~or less.~~

~~(d) Once the applicable response period prescribed by Subclause (b) above has expired or upon receipt of the~~ responses of all of the receiving parties to the operation notice, whichever first occurs, the proposing party shall forthwith give notice to the parties specifying how the costs, risks and benefits of the operation will be shared ~~hereunder.~~

~~(e) A party may become a proposing party with respect to more than one operation at any given time, and may~~ serve as many operation notices as it so wishes and proceed to conduct operations pursuant thereto. However, no single operation notice shall relate to more than one well, and the receiving parties shall not be required to respond to an operation notice pertaining to a well unless and until each operation notice previously served by that proposing party respecting a well located within 3.2 kilometres of the proposed well has expired, been withdrawn or the operation proposed thereunder has been completed and the information therefrom has been provided to the receiving parties, to the extent required by Clauses 1018 and 1019. If a party serves more than one (1) operation notice at one time, it shall, subject to the foregoing provisions of this Subclause, state the order in which the operation notices are deemed to be received by the receiving parties, provided that if it fails to specify the order, the operation ~~notices shall be deemed to be received in accordance with Clause 2201.~~

~~1003 TIME FOR COMMENCING THE OPERATION - The proposing party may begin the operation without waiting for the~~ applicable response period prescribed by Clause 1002 to lapse, provided that the proposing party shall not be obligated to supply any information with respect thereto to a receiving party until such time as it elects to participate in such operation. However, the proposing party shall not commence the operation more than ninety (90) days after the operation notice is deemed to be received by the receiving parties, unless the operation is the construction or installation of a production facility, in which case the operation shall not be commenced more than one hundred and fifty (150) days following such receipt. In the event the operation is not commenced within the applicable period, such operation notice thereupon shall be void, unless and to the extent that the receiving parties consent to the delay of the commencement of the operation. If the operation notice lapses in such manner, the proposing party may serve a new operation notice for the operation within or ~~after the expiration of such period.~~

1004 OPERATOR FOR INDEPENDENT OPERATIONS - Notwithstanding anything to the contrary contained in this Operating Procedure, the proposing party shall be the Operator with respect to any operation proposed as an independent operation, unless the parties otherwise agree or the proposing party would be disqualified from serving as Operator pursuant to Subclause 202(a). If the Operator is a participating party, but not the proposing party, with respect to a well proposed as an independent operation, the Operator shall succeed the proposing party as Operator with respect to such operation at the completion of such operation or, if agreed by the proposing party and the Operator, at the completion of a particular phase of the operation.

1005 SEPARATE ELECTION WHERE WELL STATUS DIVIDED -

(a) If the proposed independent operation is the drilling of a well which would be in part a development well and in part an exploratory well, the proposing party shall identify the respective portions of the well in the operation notice. The proposing party shall also estimate the costs separately for each portion of the well in the operation notice. For the purposes of such allocation of costs, the costs of the development well shall only be those costs which would be anticipated to be incurred if the well were being drilled and, if applicable, completed as a development well only, and all additional costs anticipated to be incurred as a consequence of the well also being drilled as an exploratory well (including, without restricting the generality of the foregoing, the utilization of any special equipment or casing to enable the well to be drilled to such depth) shall be allocated to that portion of the well which will be an exploratory well.

(b) Each receiving party electing to participate in a well described in the preceding Subclause shall elect to participate to the extent only that it is a development well or to the extent that it is both a development well and an exploratory well. However, a party which elects to participate in such well without specifying the extent of its participation shall be deemed to have elected to participate in the entire well.

(c) If the participation in the well varies between the well as a development well and the well as an exploratory well, the following shall apply:

(i) If the well is capable of producing petroleum substances in paying quantities from at least one (1) zone in each of the development well and the exploratory well portions of the well and such petroleum substances can be produced simultaneously from all such zones through the well, the Operator for the participating parties in the deepest producing zone shall operate the well. It shall apportion the operating costs of the well to each zone on an equitable basis, and deliver to the Operator for the participating parties in each productive zone the total share of production from such zone. Each such Operator shall account for such production to the respective participating parties in accordance with Clause 1007, as if a separate operation had been conducted with respect to each producing zone.

(ii) Notwithstanding anything to the contrary contained in paragraph (i) of this Subclause, if the well is capable of producing petroleum substances in paying quantities from at least one (1) zone in each of the development well and the exploratory well portions of the well, but such petroleum substances cannot be produced simultaneously from all such zones through the well, the participating parties in the exploratory well portion of the well shall have the pre-emptive right to complete the exploratory well portion of the well. However, if those participating parties exercise such pre-emptive right, they shall promptly reimburse the participating parties in the development well portion of the well all costs incurred by them in drilling and, if applicable, completing the well as a development well. Thereafter, the well shall be deemed to be a single operation, ab initio, involving the drilling of an exploratory well only and conducted by the participating parties in the exploratory well portion of the well pursuant to this Article X. However, for the purposes of the application of Clause 1007 between the participating parties in the exploratory well portion of the well and the participating parties in the development well portion of the well, the costs so reimbursed to the latter shall be deemed to be operating costs and included as a charge under paragraph 1007(a)(ii), and the amount prescribed by paragraph 1007(a)(iv) with respect to those parties shall exclude the costs of drilling and, if applicable, completing the well as a development well.

1006 ABANDONMENT OF INDEPENDENT WELL - If an independent operation is the drilling of a well and the well is not capable of production of petroleum substances in paying quantities, the participating parties shall abandon the well in a timely manner.

1007 PENALTY WHERE INDEPENDENT WELL RESULTS IN PRODUCTION - If an independent operation proposed in an operation notice is the drilling of a well, the following shall apply with respect thereto:

(a) If such well is completed for the production of petroleum substances from one or more zones, the

~~participating parties shall be entitled to retain possession of the well and all production from such zones through the well until the gross proceeds (calculated at the wellhead) from the sale of such production equals the aggregate of:~~

~~(i) one hundred percent (100%) of the Lessor's royalty and any overriding royalties or other~~ encumbrances thereon which otherwise would have been borne for the joint account which are paid ~~with respect to such production, subject to Subclause 1007(b)~~;

~~(ii) one hundred percent (100%) of the operating costs applicable to the well;~~

~~(iii) two hundred percent (200%) of the equipping costs of the well; and~~

~~(iv) a multiple of the drilling costs and completion costs of the well as a development well or an~~ exploratory well, as the case may be, being _____% with respect to a development well and _____% with respect to an exploratory well, provided that if such well was in part a development well and in part an exploratory well and such well was completed for production only as an exploratory well, all of the drilling costs and completion costs of such well shall be deemed to have been incurred solely with respect to an exploratory well, except that, subject to paragraph 1005(c)(ii), the costs of drilling and, if applicable, attempting to complete the well as a development well shall be excluded for the purposes only of determining the amount prescribed by this paragraph with respect to a party ~~which was only a participating party with respect to the development well portion of the well.~~

~~The Operator for the participating parties shall notify the non-participating parties upon recovery of the proceeds~~ prescribed by paragraphs (i) to (iv) of this Subclause not later than thirty (30) days following such recovery. Subject to Subclause 1021(b), each non-participating party shall have thirty (30) days following receipt of such notice within which to elect to accept or refuse participation in the well, the applicable zones and the production therefrom, provided that failure of a non-participating party to make an election within such period shall be deemed to be an election to accept such participation to the extent of its working interest in the spacing unit of the well. Subject to Clause 1015, if a non-participating party refuses participation as above provided, it shall be deemed to have forfeited its right of participation in and to the well and to the spacing unit of the well, insofar only as it relates to the applicable zones and the production therefrom, to the participating parties therein. If a non-participating party elects to accept participation in the well, the applicable zones and the production therefrom as above provided, its participation shall be equal to its working interest, and shall be effective as of the time when the gross proceeds of production from the well equalled the aggregate of the amounts prescribed by paragraphs (i), (ii), (iii) and (iv) of this Subclause, whereupon the accounts of the parties shall be adjusted accordingly. Thereafter, the well shall be held for the account of the parties then participating therein, and shall be operated by the Operator if it is one of the parties so participating, or an Operator appointed pursuant to Clause 1004 if the Operator has elected to forfeit ~~its interest in the well.~~

~~(b) Notwithstanding the preceding Subclause, in the event the working interest of one or more of the parties is~~ encumbered by an encumbrance not borne for the joint account which falls within the exception in Clause 802, the ~~following shall apply to such additional encumbrance for the purposes of the calculation in Paragraph 1007(a)(i)~~:

~~(i) if a participating party's working interest is encumbered by such an additional encumbrance, amounts~~ paid by that participating party with respect to the application of such additional encumbrance to the production from the relevant well shall not be included in paragraph 1007(a)(i), subject to ~~paragraph (ii) of this Subclause; and~~

~~(ii) if a non-participating party's working interest is encumbered by such an additional encumbrance, the~~ participating parties shall make the required payments with respect to the application of such additional encumbrance to the production from the relevant well. As between only that non-participating party and those participating parties receiving the assignment of the production attributable to that non-participating party's working interest pursuant to this Clause, one hundred and fifty percent (150%) of the amounts so paid on behalf of that non-participating party shall be ~~included in paragraph (a)(i).~~

~~(c) Throughout the period that the participating parties are retaining production from a well pursuant to Subclause~~ (a) of this Clause, the proceeds from such production shall be applied on a current basis and in order, to ~~paragraphs (i), (ii), (iii) and (iv) of that Subclause.~~

~~(d) If any cash contributions are received by the participating parties pursuant to Clause 1202 with respect to~~ the release of information respecting a well drilled as an independent operation, the contribution shall be credited ~~to paragraph (a)(iv) of this Clause to reduce the cost thereof for the calculation of the penalty relating thereto.~~

~~(e) Notwithstanding anything to the contrary contained in this Article, no cash payments, incentives, grants,~~ credits, waivers, exemptions, abatements or other benefits received by (or available to) the participating parties pursuant to the Regulations with respect to an independent operation shall be taken into account when calculating any of the items set forth in paragraphs (a)(i) to (iv) inclusive of this Clause, provided that this Subclause shall not entitle the participating parties to include in the amounts to be recovered under paragraph 1007(a)(i) any amount ~~which is not paid by the participating parties.~~

~~1008 INDEPENDENT DEEPENING, PLUGGING BACK, WHIPSTOCKING, RE-ENTRY AND COMPLETION, RECOMPLETION, REWORKING OR EQUIPPING –~~

~~(a) No operation notice for a deepening, plugging back, whipstocking, recompletion or reworking operation may~~ be given with respect to a well producing or capable of producing petroleum substances in paying quantities. No operation notice may be given for a deepening of a well below its authorized total depth if one or more parties propose to attempt to complete the well at or above that depth pursuant to Article IX, unless and until either those parties no longer propose to attempt such completion or such completion has been conducted without resulting in ~~the production of petroleum substances in paying quantities.~~

~~(b) A non-participating party with respect to a well may not propose any operation in the well unless and until (and only to the extent that) it has regained the right to share in production from the well.~~

~~(c) If an independent operation is a deepening, plugging back, whipstocking, re-entry and completion of a~~ suspended well, recompletion, reworking or equipping operation which results in the production of petroleum substances in paying quantities from one or more zones, the provisions of Subclauses 1007 (a), (b), (c), (d) and (e) shall apply, *mutatis mutandis*, to such formations, the production therefrom, the operation and the recovery of costs of the operation (including the penalty provided therein), to the extent that such operation and production relates ~~to the well as a development well or an exploratory well, as the case may be.~~

~~(d) If an independent operation is a deepening, plugging back, whipstocking, re-entry and completion of a~~ suspended well, recompletion, reworking or equipping operation and within six (6) months of receipt of the operation notice by the receiving parties, the participating parties elect to terminate the operation or propose to abandon the well, they shall so notify the non-participating parties. Effective as of the date of issuance of that notice, the participating parties shall be deemed to have returned the well and the zones to the parties that held participating interests therein at the time such operation was proposed, and all further operations with respect thereto, including abandonment, shall, subject to Clause 904, be deemed to be proposed for the account of the parties then holding ~~participating interests therein, except that:~~

~~(i) the salvable materials and equipment placed in and on the well by the participating parties shall be salvaged by and for the account of the participating parties; and~~

~~(ii) the participating parties shall bear all extra costs of abandonment incurred by reason of the operation.~~

~~If the participating parties do not propose termination of the operation or abandonment of the well within such six~~ (6) month period, they shall forthwith thereafter pay to each non-participating party, its proportionate share of the net salvage value of the materials and equipment located in and on the well at the time the operation notice was received by the non-participating parties. The amounts so paid to those non-participating parties shall be deemed to be operating costs and included as a charge under paragraph 1007(a)(ii). Thereafter, a non-participating party shall have no legal responsibility with respect to the well, including the abandonment thereof, unless and until (and ~~only to the extent that) it has resumed participation in the well and the production therefrom.~~

~~1009 WHERE WELL ABANDONED BEFORE PENALTY RECOVERED –~~

~~(a) If an independent operation is the drilling of a well and the well is to be abandoned before the gross~~ proceeds of production therefrom equal the aggregate of the amounts prescribed by paragraphs 1007(a)(i) to (iv) inclusive, the participating parties shall abandon the well, record as a credit to the well the net salvage value of the materials and equipment recoverable from the well, as if such amount were proceeds from production, and report that credit in the monthly statement provided for in Clause 1013. If the gross proceeds from production from the well then exceed the aggregate of paragraphs 1007(a)(i) to (iv) inclusive, the excess amount shall be a credit for ~~the joint account.~~

~~(b) Subject to Subclause (d) of Clause 1008, if an independent operation is the deepening, plugging back,~~ whipstocking, re-entry and completion, recompletion, reworking or equipping of a well pursuant to Clause 1008 and the well is to be abandoned before the gross proceeds of production received therefrom by the participating parties after commencement of the operation equal the aggregate of the costs and penalties to be recovered by the ~~participating parties pursuant to Subclause 1008(c), the participating parties shall abandon the well, record as a credit~~

to the well the net salvage value of the materials and equipment recoverable from the well, as if such amount were proceeds from production, and report that credit in the monthly statement provided for in Clause 1013. If the gross proceeds of production from the well then exceed the aggregate of the amounts chargeable to the well pursuant to Clause 1006, the excess amount shall be a credit for the joint account.

1010 EXCEPTION TO CLAUSE 1007 WHERE WELL PRESERVES TITLE

(a) In this Clause, the following terms shall have the meanings hereby assigned to them, namely:

(i) 'common preserved lands' means that portion of the preserved lands with respect to which a subsequent title preserving well would have been a title preserving well had the title preserving well not been drilled, completed or recompleted.

(ii) 'preserved lands' means any joint lands which would have been forfeited pursuant to a particular title document had a title preserving well not been drilled, completed or recompleted at the time and in the manner prescribed herein, subject to the designation of preserved lands pursuant to Subclause 306(d).

(iii) 'subsequent title preserving well' means a well which is drilled, completed or recompleted hereunder at such time and in such manner that such well would have been a title preserving well with respect to all or a portion of the preserved lands had the title preserving well not been drilled, completed or recompleted.

(iv) 'title preserving well' means a well which is drilled, completed or recompleted hereunder, where the failure to conduct such operation would result in the forfeiture of all or a portion of the joint lands contained in a title document and such operation is to be commenced not earlier than _____ days prior to the date such forfeiture would occur pursuant to such title document.

(b) Notwithstanding Clauses 903, 1007 and 1008, a non-participating party with respect to a title preserving well shall forfeit:

(i) upon completion of such operation, one hundred percent (100%) of its working interest in such well and the spacing unit for such well to the participating parties in the title preserving well, insofar only as such spacing unit pertains to the preserved lands; and

(ii) at the date the preserved lands otherwise would have been forfeited pursuant to the relevant title document, one hundred percent (100%) of its remaining working interest in the balance of the applicable preserved lands to the participating parties in the title preserving well, subject to Subclauses (c) and (d) of this Clause.

(c) The following shall apply with respect to a subsequent title preserving well:

(i) a non-participating party with respect to the title preserving well which participates in the subsequent title preserving well shall not forfeit its working interest in any common preserved lands pursuant to paragraph (b)(ii) of this Clause;

(ii) a non-participating party with respect to the title preserving well which is also a non-participating party with respect to the subsequent title preserving well shall, if the subsequent title preserving well is *located on a spacing unit of preserved lands, forfeit one hundred percent (100%) of its working* interest in the subsequent title preserving well and the common preserved lands included in the spacing unit for such well to the participating parties in the subsequent title preserving well, rather than to the participating parties in such title preserving well pursuant to paragraph (b)(ii) or Subclause (d) of this Clause; and

(iii) a participating party in the title preserving well which is a non-participating party with respect to the subsequent title preserving well shall be subject to the production penalty prescribed by Clause 903, 1007 or 1008 with respect to the subsequent title preserving well and the spacing unit for such well, provided that if the subsequent title preserving well preserves lands in addition to those preserved by the title preserving well, that party shall be subject to the forfeiture of one hundred percent (100%) of its working interest in such additional preserved lands pursuant to paragraph (b)(ii) of this Clause.

(d) Subject at all times to paragraphs (b)(i), (c)(i) and (c)(ii) of this Clause, the working interest to be forfeited by a party in any common preserved lands shall be allocated equally to the title preserving well and the applicable subsequent title preserving well, to be then apportioned among the respective participating parties pursuant to Clause 1016.

(e) In the event of a dispute as to the classification of a well as a title preserving well or the determination of either the preserved lands or the common preserved lands, a party may, by notice to the other parties, refer the matter to arbitration under the provisions of the Arbitration Act or Ordinance of the province, state or territory where the joint lands are situated not later than forty-five (45) days after the date at which the preserved lands otherwise would have been forfeited pursuant to the applicable title document. The parties to such dispute thereupon shall diligently attempt to complete such arbitration in a timely manner.

1011 INDEPENDENT GEOLOGICAL OR GEOPHYSICAL OPERATION - Nothing in this Operating Procedure shall be interpreted to preclude a party from conducting a geological or geophysical operation on or with respect to the joint lands for its own account, provided that such operation shall not interfere with other joint operations. The parties not participating in such operation shall not be entitled to any information or data with respect thereto, unless such operation was the subject of an operation notice. In such event, any non-participating party may, prior to the end of the calendar year following the calendar year in which such operation was completed, pay to the participating parties two hundred percent (200%) of what its share of the cost of such operation would have been had the operation been conducted for the joint account. If a non-participating party makes that payment, it shall be entitled to a copy of all basic data obtained from the operation for its own use, but it shall not obtain any trading rights respecting that data or any interpretations of such data made by or for the participating parties, or any of them. The types and formats of data supplied to a non-participating party hereunder shall be consistent with established industry practice in data sales.

1012 USE OF BATTERY AND OTHER EQUIPMENT FOR INDEPENDENT WELL - To the extent that capacity is available with respect to production facilities operated for the joint account, the participating parties in an independent operation shall be permitted to make use of and to share them in the same manner as if the operation had been conducted for the joint account, provided that a reasonable allocation of operating costs is made with respect to such sharing of such production facilities. However, to the extent that such production facilities are not adequate to accommodate both the independent operation and wells operated for the joint account, the latter shall have priority with respect to the utilization of such production facilities.

1013 ACCOUNTS AND AUDIT DURING PENALTY RECOVERY

(a) Subject to Clauses 205 and 1018, the Operator for an independent operation shall supply all parties with a monthly statement showing the status of the recovery of costs and penalties pursuant to this Article during the period of recovery of such costs and penalties. The provisions of the Accounting Procedure relating to the audit of accounts shall apply, mutatis mutandis, to the audit of accounts with respect to such recovery of costs and penalties by the participating parties.

(b) If it is determined that the recovery of the costs and penalties prescribed by this Article with respect to an independent operation has occurred and that the participating parties either have not issued the non-participating parties notice of such recovery or have issued the notice to the non-participating parties later than thirty (30) days following such recovery, each non-participating party shall have the right to elect, within thirty (30) days following receipt of such notice or the discovery by it that such notice had not been issued, to obtain participation in such operation in the manner provided in this Article, effective as of the date of such recovery. The accounts of the parties shall retroactively be adjusted accordingly if one or more of the non-participating parties elect to obtain participation in the well. If a non-participating party retroactively obtains participation in such operation and amounts are owing to the non-participating party as a result of such election, the non-participating party may charge the participating parties which assumed its share of costs of such operation interest on the amount so owing on the same basis as is provided in paragraph 505(b)(i).

1014 PARTICIPANT'S RIGHTS AND DUTIES RE INDEPENDENT OPERATIONS - Subject to the provisions of this Article, the provisions of this Operating Procedure relating to the rights, duties and obligations of the Operator and the Joint-Operators (including the provisions of Article IX) shall apply, mutatis mutandis, among the participating parties with respect to the conduct of the independent operation and, if applicable, to the operation of any well during the prescribed recovery of costs and penalties with respect thereto.

1015 REVERSION OF ZONE UPON ABANDONMENT - If a geological zone or the right to production therefrom was (or is to be) assigned to the participating parties by the non-participating parties as a result of an independent operation respecting a well and such well is subsequently abandoned in such zone, each non-participating party shall reacquire the interest so assigned (or to be assigned) by it with respect to such zone, effective at the completion of such abandonment, provided that in no event shall the non-participating parties assume any responsibility for the costs or risks associated with such abandonment. However, nothing in this Clause shall apply to any assignment of a working interest by a non-participating party pursuant to Clause 1010.

~~1016 BENEFITS AND BURDENS TO BE SHARED - Any resultant assignment of production or forfeiture of any interest in~~ the joint lands by a non-participating party pursuant to this Article shall be allocated among ~~the participating~~ parties in the proportions in which those parties have borne that share of the ~~cost of the independent~~ operation which would have been applicable to the non-participating party ~~had the operation~~ been conducted for the joint account. Except as provided in the preceding sentence, ~~the benefits and~~ burdens relating to an independent operation shall be shared by the participating parties ~~in the proportions of their participating interests therein.~~

~~1017 INDEMNIFICATION OF NON-PARTICIPATING PARTIES - The participating parties in an independent operation shall:~~

~~(a) be liable to the non-participating parties with respect thereto for any losses, costs, damages and expenses whatsoever (whether contractual or tortious) which those non-participating parties suffer, sustain, pay or incur; and~~

~~(b) in addition, indemnify and hold harmless those non-participating parties and their Affiliates, directors, officers,~~ servants, consultants, agents and employees against all actions, causes of action, ~~proceedings,~~ claims, demands, losses, costs, damages and expenses whatsoever ~~which may be~~ brought against or suffered by those non-participating parties, their ~~Affiliates, directors,~~ officers, servants, consultants, agents and employees or which they ~~may sustain, pay or incur;~~

~~insofar as they are a direct result of or directly attributable to any act or omission (whether negligent or otherwise) of the~~ participating parties or their Affiliates, directors, ~~officers, servants, consultants, agents,~~ employees, independent contractors, ~~licensees or invitees with respect to such independent operation.~~

~~1018 NON-PARTICIPATING PARTY DENIED INFORMATION - If an independent operation is the drilling of a well or is conducted on a well which has been drilled, the following shall apply with respect thereto:~~

~~(a) if the independent operation is the drilling of a well, a non-participating party shall not be entitled to access~~ to the wellsite or any information with respect to the well, including ~~monthly statements and~~ audit privileges as provided in Clause 1013, until ~~the earlier of the date it~~ becomes a participating party or ninety (90) days after the ~~date of the release of the drilling rig used to drill the well; or~~

~~(b) if the independent operation is conducted on a well which has been drilled, a non-participating party shall~~ not be entitled to access to the wellsite or any information with ~~respect such operation,~~ including monthly statements and audit privileges as ~~provided in Clause 1013,~~ until the earlier of the date it becomes a participating party or one ~~hundred and twenty (120) days after the date the operation notice is deemed to be received by it.~~

~~Once a non-participating party is entitled to access to the wellsite and such information, such party shall be provided with~~ the rights and information to which it is entitled in a timely manner. ~~However, if a non-participating~~ party is required to make an assignment of such well ~~pursuant to Clause 1010~~ with respect to such independent operation, such party shall not be ~~entitled to access to the wellsite or any information with respect to the well pursuant to this Operating Procedure at any time.~~

~~1019 NO JOINT OPERATIONS UNTIL INFORMATION RELEASED - If the participating parties are temporarily withholding~~ well information from a non-participating party pursuant to Clause 1018, ~~no participating party~~ shall propose or conduct any operation pertaining to a well on ~~the joint lands within~~ 3.2 kilometres of such well (except regular production and maintenance ~~operations on producing wells) until it has released such information to the non-participating party.~~

~~1020 POOLING OR UNITIZATION PRIOR TO RECOVERY - If an independent operation is the drilling of a well (or is~~ conducted with respect to a well which has been drilled) to which the forfeiture in Clause 1010 ~~does not~~ apply, the participating parties may include the well and its spacing unit in a pooling agreement or ~~unit with~~ the consent of the non-participating parties, which consent shall not be unreasonably withheld. ~~If the well~~ and the spacing unit are included in a pooling agreement or unit, the participating parties shall ~~retain the~~ production allocated to the spacing unit until they have recovered all costs and penalties to which ~~they are entitled~~ pursuant to this Article X. The credits and debits accruing to the participating parties under a ~~pooling or~~ unit agreement with respect to any adjustment of investment for well costs paid and equipment ~~supplied by~~ them shall be allocated to the payout account of the well by the participating parties in accordance ~~with the principles in Clauses 1007 and 1008, and shall be recorded in the monthly statement referred to in Clause 1013.~~

~~1021 NON-PARTICIPATION IN INSTALLATION OF PRODUCTION FACILITY - The parties normally shall consult with~~ respect to the construction, acquisition or installation of production facilities and attempt ~~to negotiate~~ either an individual agreement respecting the construction, acquisition or installation of ~~a production~~ facility or the fee to be charged to a party which wishes to utilize such production facility ~~but does~~ not wish to participate in such construction, acquisition or installation. Whether or not ~~such consultation~~ has occurred or been requested, a party may at any time become a proposing party and ~~give to the other parties an operation notice respecting a production facility.~~

~~A party which receives an operation notice respecting the construction, acquisition or installation of a production facility shall,~~

pursuant to Clause 1002, elect: to participate in such proposed operation; not to participate in such operation, but to take in kind, before the inlet of such proposed production facility, its share of any petroleum substances which would otherwise utilize such production facility for production, processing, treatment, storage or transmission; or not to participate in such operation and to incur a penalty with respect to such operation on the basis provided in this Clause. Failure of a party to make an election with respect to such operation notice within the period prescribed by Clause 1002 shall be deemed to be an election by such party not to participate in such operation and to take in kind, before the inlet of such proposed production facility, its share of any petroleum substances which would otherwise utilize such production facility.

If a production facility is constructed, acquired or installed as an independent operation, the following shall apply between the participating parties and those non-participating parties which did not elect to take in kind, before the inlet of such production facility, their share of petroleum substances which otherwise would utilize such production facility:

(a) If the wells on the joint lands to which such operation pertains are held for the joint account, the participating parties shall be entitled to retain possession of the production facility and all production from such wells which would utilize such production facility (and a non-participating party's share of any other hydrocarbon substances as that party and the participating parties may otherwise agree), excluding any such production owned or attributable to any party which has elected not to participate in such operation, but to take in kind such share of such production at the inlet of such production facility, until the gross proceeds (calculated at the wellhead) from the sale of such production equals the aggregate of:

(i) one hundred percent (100%) of the Lessor's royalty and any overriding royalties or other encumbrances thereon which otherwise would have been borne for the joint account which are paid with respect to such production, subject to Subclause (c) of this Clause;

(ii) one hundred percent (100%) of the operating costs incurred with respect to such production facility and its utilization for the production, processing, treatment, storage or transmission of petroleum substances; and

(iii) two hundred percent (200%) of the cost of the acquisition, construction and installation of such production facility.

The Operator for the participating parties shall notify those non-participating parties subject to the penalty upon recovery of the proceeds prescribed by paragraphs (i), (ii) and (iii) of this Subclause (a), not later than thirty (30) days following such recovery. Each such non-participating party shall have thirty (30) days following receipt of such notice within which to elect to accept or refuse participation in the production facility, provided that failure of such a non-participating party to make an election within such period shall be deemed to be an election to accept participation in such production facility. If such a non-participating party refuses participation as above provided, it thereby shall be deemed to have forfeited its right of participation in and to the production facility, and may thereafter only use such production facility with respect to its share of production from the joint lands for such fee as may be agreed from time to time with the parties which own such production facility, and failing agreement, in accordance with Subclause (d) of this Clause. If such a non-participating party elects to accept participation in the production facility, its participation in the production facility shall be equal to its working interest, and shall be effective as of the time the proceeds prescribed by paragraphs (i), (ii) and (iii) above have been recovered, whereupon the accounts of the participating parties and those non-participating parties so acquiring an interest in the production facility shall be adjusted accordingly. Thereafter, the production facility shall be held for the account of the parties participating therein, and shall be operated under the provisions of this Operating Procedure by the Operator if it is one of the parties so participating or by an Operator appointed pursuant to Clause 1004 if the Operator does not have a working interest in the production facility.

(b) Insofar as Clause 1007 applies to a well to which such operation pertains prior to the recovery of the amounts prescribed by Subclause 1007(a), Subclause (a) of this Clause shall apply immediately following the recovery of the amounts prescribed by Subclause 1007(a), such that a non-participating party with respect to the well may not resume participation in such well until the recovery of the additional amounts prescribed by Subclause (a) of this Clause.

(c) Except to the extent modified in this Clause, Subclauses 1007(b), (c), (d) and (e) shall apply, mutatis mutandis, to this Clause.

(d) To the extent that a party which elected to take in kind, before the inlet of such production facility, its share of petroleum substances which would otherwise utilize such production facility, does not take such petroleum substances in kind, the parties owning such production facility may, on behalf of such party, produce, process, treat, store or transmit that share of petroleum substances so delivered to such production facility. In such event (but subject always to any individual agreement negotiated by the parties owning such production facility and such other party respecting the utilization of such production facility), the parties owning such production facility shall, in addition

~~to any marketing fee applicable pursuant to Article VI, be entitled to charge such other party a fee sufficient to cover~~ the cost of producing, processing, treating, storing or transmitting, as the case may be, such other party's share of petroleum substances so utilizing such production facility, which fee shall also include a reasonable rate of return ~~on capital investment in accordance with the principles in Clause 1404.~~

~~1022 NON-PARTICIPATION IN EXPANSION OF PRODUCTION FACILITY - Subject to Clause 1408, the provisions of Clause 1021 shall apply, mutatis mutandis, to an expansion of or an addition to an existing production facility, except that:~~

~~(a) Participation in such operation shall be limited to those parties holding a working interest in such production facility at the time such operation is proposed;~~

~~(b) A party holding a working interest in a production facility which receives an operation notice respecting such~~ operation shall elect either to participate in such operation or to be subject to the recovery of the costs associated ~~with such operation on the basis provided in Subclause 1021(a);~~

~~(c) A party holding a working interest in a production facility which is a non-participating party with respect to~~ such operation shall acquire its working interest in the portion of the production facility resulting from such operation ~~following the recovery of costs prescribed in Clause 1021; and~~

~~(d) If such operation is to be conducted prior to the recovery of costs prescribed by Subclause 1021(a) with~~ respect to the construction or installation of such production facility, the costs of such operation shall be added to the costs to be recovered pursuant to that Subclause with respect to those non-participating parties subject to such cost recovery, provided that the proceeds of production to be applied against such costs shall be applied firstly to the penalty prescribed by Clause 1021 with respect to the construction, acquisition or installation of such production ~~facility.~~

ARTICLE XI

SURRENDER AND QUIT CLAIM OF JOINT LANDS

1101 INITIATION OF SURRENDER PROPOSAL AND QUIT CLAIM OF INTERESTS -

(a) Not later than sixty (60) days before a rental date or other obligation date with respect to the joint lands affected (except an obligation to pay royalty or a drilling obligation not being enforced under the title documents), a party who proposes that some or all of the joint lands be surrendered to the grantor under the applicable title documents shall give notice to such effect to the other parties, subject to Subclause (b) of this Clause. Not later than thirty (30) days before the next ensuing rental date or other obligation date under the respective title documents included in the surrender notice, the parties receiving the notice shall each give notice to all other parties stating whether or not they wish to join in the proposed surrender. Failure to respond to such notice shall be deemed to be an election not to join in the surrender. Any party giving notice of the proposed surrender or giving notice of its intention to join in the proposed surrender may, by notice to the other parties, revoke its notice of intention to surrender at any time up to, but not later than, thirty (30) days before the next ensuing rental date or other obligation date under the respective title documents.

(b) Notwithstanding the preceding Subclause, the joint lands proposed for surrender must be of such dimensions that the grantor of the title documents to which such lands are subject would be obligated to accept the surrender pursuant to the title documents, and a party may not propose the surrender of a portion of the joint lands while an obligation exists with respect to such lands which cannot be avoided by the surrender or quit claim of those lands to the grantor of the title documents to which they are subject.

1102 SURRENDER BY ALL PARTIES - ~~Subject always to the provisions of Articles IX and X,~~ if all parties join in a surrender under Clause 1101, the Operator shall proceed forthwith to salvage for the joint account all salvable material, equipment upon the lands to be surrendered, and, if applicable, any production facilities serving solely wells located upon the lands to be surrendered. The parties shall promptly execute and deliver to the Operator all documents necessary to effect the surrender, which documentation shall be prepared by the Operator. The Operator shall thereafter deliver all such documents to the grantor of the applicable title documents in order to effect the surrender properly.

1103 SURRENDER BY LESS THAN ALL PARTIES - If less than all parties join in the surrender, the parties not joining in the surrender shall (unless the Operator is one of them) promptly appoint an Operator pro tem for the parties retaining the applicable lands and interests. Such Operator shall be responsible for taking the necessary steps to ensure payment of rentals or the meeting of any other obligation to maintain such lands and interests in good standing for the benefit of the retaining parties.

1104 ASSIGNMENT OF SURRENDERED INTEREST –

(a) Effective as of 2400 hours on the day before the rental or other obligation referred to in Clause 1101 is required to be paid or met with respect to a title document included in the surrender notice, the parties which elected to surrender shall assign all of their interest in the joint lands and interests which were the subject of the proposed surrender notice to the retaining parties, in proportion to the retaining parties' working interests in the joint lands or in such proportions as the retaining parties may otherwise agree. Within thirty (30) days after receipt of the assignment, the parties shall determine, in accordance with the Accounting Procedure, the assignors' pre-surrender working interest share of the net salvage value of the recoverable material and equipment on the lands so assigned less the assignors' pre-surrender working interest share of the estimated cost of abandoning each well on the lands so assigned. The accounts of the parties shall be adjusted accordingly within thirty (30) days of such determination, and the provisions of Subclause 505(b) shall apply, mutatis mutandis, in the event the parties have not adjusted their accounts by such time.

(b) Upon the assignment described in the preceding Subclause, a party which so assigned its interest with respect to the applicable portion of the joint lands shall be released from all obligations thereafter accruing with respect to such lands. Such release shall not apply to any obligation which had accrued, and any environmental damage which had occurred, with respect to those lands or production facilities prior to such assignment, provided that such obligation shall not extend to the obligation to abandon any well on such lands.

1105 RETAINING PARTIES TO MEET OBLIGATIONS – In accepting the interests of the surrendering parties, the retaining parties shall be deemed to have covenanted to satisfy the obligation which prompted the surrender proposal if: (i) the obligation could have been avoided had all parties joined in the proposed surrender; and (ii) failure to satisfy the obligation would prejudice the title of the parties in any other portion of the joint lands. However, this covenant shall not require the retaining parties to conduct any operation on or with respect to such surrendered lands in order to maintain them in good standing.

1106 FAILURE TO SURRENDER AS AGREED – Where all of the parties have agreed to effect surrender pursuant to this Article (and whether or not some or all of them have taken any action by way of release or assignment pursuant to an intention to join in the surrender), the lands and interests which are the subject of the surrender notice shall be deemed to be held for the joint account until the surrender has been irrevocably effected, including the termination of any right to reinstate any title document, so that all of the parties shall receive or have the right to participate in any benefits which might accrue during the period before the surrender is irrevocably effected. If, however, any party to whom any interest is conveyed or released for the purpose of effecting the surrender does not duly proceed with the surrender and thereby causes any further obligation to arise, that party shall be solely responsible for meeting the obligation and shall indemnify the other parties for any losses they may suffer with respect thereto.

ARTICLE XII

~~ABANDONMENT OF WELLS~~

~~1201 PROCEDURE FOR ABANDONMENT – If a party proposes to abandon a well on the joint lands (except at casing~~ point, when Article IX shall apply), it shall give notice of the proposed abandonment to the other parties. Within thirty (30) days of receipt of the notice, each of the other parties shall elect, by notice to the other parties, whether it wishes to take over the well. Failure by a party to respond to such notice shall be deemed to an election by that party to take over, or participate in the takeover, of the well. Subject to Clauses 1015 and 1202, the parties taking over the well shall be entitled to an assignment, without consideration or warranty, of the abandoning parties' working interests in the well and in the spacing unit of the well, insofar as it relates to the producing zone of the well. All such assignments shall be proportionate to the non-abandoning parties' respective working interests each to the other prior to any such takeover or assignment, unless the non-abandoning parties agree to a different allocation of the assigned working interests. If all parties elect to join in the ~~abandonment, the well shall be abandoned for the joint account.~~

~~1202 ASSIGNMENT OF EQUIPMENT AND SURFACE RIGHTS – If less than all parties elect to abandon a well under~~ Clause 1201, the abandoning parties shall, without warranty, promptly transfer to the other parties the materials and equipment serving solely the well. Within thirty (30) days of such transfer, the parties shall determine, in accordance with the Accounting Procedure, the abandoning parties' working interest share of the net salvage value of such materials and equipment, less the abandoning parties' working interest share of the estimated cost of abandoning the well. The accounts of the parties shall be adjusted accordingly within thirty (30) days of such determination, and the provisions of Subclause 505(b) shall apply, mutatis mutandis, in the event the parties have not adjusted their accounts by such time. The abandoning parties shall also transfer to the other parties, without warranty or consideration, the surface rights appurtenant to the well. The parties receiving the assignment thereupon shall be responsible for all obligations accruing with respect to such well following such takeover, ~~subject to Clause 1203.~~

~~1203 REVERSION OF ZONES UPON SUBSEQUENT ABANDONMENT – If the parties that took over a well subsequently~~ cease to maintain the well as a producer of petroleum substances from a zone which was ~~assigned to~~ them pursuant to Clause 1202, each of those parties shall re-assign to the applicable assignor ~~all of the~~ interest assigned to it by the assignor in that zone. Such interest thereupon shall be vested ~~again in the~~ assignor and included in the joint lands. However, nothing in this Clause shall be construed to ~~affect the~~ ownership of the well and the materials and equipment appurtenant thereto, as determined ~~pursuant to~~ Clauses 1201 and 1202, and the responsibility for the abandonment of the well, which shall be ~~retained by the parties that took over the well.~~

ARTICLE XIII

OPERATION OF LANDS SEGREGATED FROM JOINT LANDS

1301 OPERATING PROCEDURE TO APPLY – Where by reason of the operation of any provision hereof any portion of the joint lands ceases to be owned by the parties in the same percentages of interest as their working interests or ceases to be owned by all of the parties, the parties acquiring the different percentages of interest in such lands shall thereafter hold the same as if they are parties to a separate Operating Procedure, the terms of which are identical to the terms hereof, having regard only to the different ownership and percentages of ownership interest in those lands, and such portion of the joint lands shall cease to be 'joint lands' hereunder. The parties holding working interests in the lands which cease to be joint lands under this Clause shall appoint one of them to be the initial Operator under the separate Operating Procedure, in accordance with the provisions of Article II thereof. This Clause shall apply, mutatis mutandis, to a production facility.

ARTICLE XIV

OPERATION OF JOINT PRODUCTION FACILITIES

1401 OWNERSHIP OF PRODUCTION FACILITIES – ~~Subject to Clauses 1021 and 1022~~, each Joint-Operator owns an undivided interest equal to its working interest in each production facility.

1402 COMMITMENT TO DELIVER – Each Joint-Operator shall, ~~subject to Clauses 1021 and 1022~~, utilize each production facility to produce, process, treat, store or transmit, as the case may be, its share of the petroleum substances produced from the joint lands.

1403 USE OF PRODUCTION FACILITIES – Each production facility shall be used primarily for the production, processing, treatment, storage or transmission, as the case may be, of petroleum substances produced from the joint lands. If surplus capacity in any production facility is available at any time, any Joint-Operator may use all or a portion of such surplus capacity to produce, process, treat, store or transmit, as the case may be, other hydrocarbon substances which are produced from lands other than the joint lands (in this Article called 'outside substances') and are owned by it, provided that:

(a) such outside substances are at all times and in all ways (including the manner and timing of the production and delivery thereof to such production facility) compatible with the design, nature and operation of such production facility and the petroleum substances produced from the joint lands (including the manner and timing of the production and delivery thereof to such production facility); and

(b) the production, processing, treatment, storage or transmission, as the case may be, of petroleum substances produced from the joint lands shall at all times take precedence respecting the use of such production facility, and to the extent that all or a portion of such surplus capacity is required for such purpose, the delivery of such outside substances shall be curtailed or shall cease, as required.

In the event that there is competition for surplus capacity, such surplus capacity shall be prorated to the Joint-Operators desiring to use the same, based on the percentage that each such Joint-Operator's interest in the production facility to which such surplus capacity relates, bears to the total combined interest in such production facility of all of the Joint-Operators seeking to utilize such surplus capacity. If a Joint-Operator is eligible to use more surplus capacity than such Joint-Operator desires to utilize pursuant to such calculation, such Joint-Operator shall be allocated only the desired capacity, whereupon such capacity shall be subtracted from the total surplus capacity available. The remaining surplus capacity shall then be prorated in such manner to the other Joint-Operators desiring to use the same, until all of the surplus capacity has been allocated.

The J[illegible]rs normally shall consult with respect to the construction, acqu[illegible]nstallation of production facilities [illegible]nt to negotiate either an individual agreement respecting the co[illegible] acquisition, installation or expans[illegible] a production facility. Whether or not such consultation has occurred or [illegible] requested, and whether or not an agreement has been reached, the Operator may at any time issue an AFE for any of the foregoing operations and if an individual agreement has not been reached, the provisions of this Article XIV shall apply.

1404 THIRD PARTY CUSTOM USAGE – A production facility may only be utilized with respect to the production, processing, treatment, storage or transmission of outside substances owned by a third party with the approval of all of the Joint-Operators having an interest in such production facility. Any such arrangement to allow a third party to utilize a production facility shall be entered into by the Operator on behalf of all of the Joint-Operators having an interest in such production facility, on terms and conditions similar to those outlined in Clause 1403. All third party outside substances so produced, processed, treated, stored or transmitted shall be subject to a fee as agreed upon by such Joint-Operators. Such fee shall be composed of:

(a) a capital recovery component, so as to provide the Joint-Operators with a reasonable rate of return on their capital investment; and

(b) an operating cost component, which shall be calculated and assessed in accordance with the provisions of Clause 1405 on the same basis that the Joint-Operators bear and pay operating costs with respect to the applicable production facility.

The capital recovery component of all fees received from a third party under any such arrangement shall be allocated to and distributed among the Joint-Operators in accordance with their interests in such production facility. The operating cost component of any such fees shall be applied against the operating costs for the production facility.

1405 ALLOCATION OF COSTS – Each Joint-Operator shall reimburse the Operator for a portion of the operating costs incurred with respect to any production facility. This reimbursement shall either be in that proportion which the volume of petroleum substances and outside substances delivered to such production facility by or on behalf of such Joint-Operator bears to the total volume of all petroleum substances and outside substances delivered to such production facility or on such other basis as the Operator, with the approval of the parties pursuant to the Accounting Procedure, may determine is appropriate. Notwithstanding the foregoing sentence, to the extent that there is a significant variation in the composition of the various streams of petroleum substances and outside substances being delivered to such production facility, the Operator shall advise the other Joint-Operators, who shall meet with the Operator to attempt to determine an equitable method of allocating the operating costs incurred with respect to such production facility. Subject to Clauses 1021 and 1022, each Joint-Operator having an interest in a production facility shall bear a share of the capital costs subsequently incurred respecting such production facility, equal to its interest in such production facility. Notwithstanding anything to the contrary contained herein, the Operator shall be entitled to deny any outside substances entry into any production facility, if the Operator, in its sole discretion, believes that the cost to process, treat, store or transport such outside substances, as the case may be, would be significantly higher than the average cost to process, treat, store or transport the petroleum substances.

1406 ALLOCATION OF PRODUCTS – Subject to Clauses 1021 and 1022, each Joint-Operator shall be entitled to and allocated a share of any products produced from the processing or treatment of petroleum substances or outside substances at any production facility, when produced from such production facility, in that proportion which the volume of petroleum substances and outside substances delivered to such production facility by or on behalf of such Joint-Operator bears to the total volume of all petroleum substances and outside substances delivered to such production facility. Notwithstanding the foregoing sentence, if there is a significant variation in the composition of the various streams of petroleum substances and outside substances being delivered to such production facility at any time, the Operator shall advise the other Joint-Operators, who shall meet with the Operator to attempt to determine an equitable method of allocating the products produced from such production facility.

1407 ALLOCATION OF LOSSES AND SHRINKAGE – The Operator shall have the right to flare any petroleum substances, outside substances or any product obtained from the processing or treatment thereof, at any time and from time to time, at its sole discretion, in the event of an emergency or operational problem. With respect to any production facility, each Joint-Operator utilizing such production facility shall bear a share of any losses or gains actually incurred with respect to petroleum substances, outside substances or any products obtained from the processing or treatment thereof, due to evaporation, leakage, spills, flaring, handling, measurement or use as facility fuel, in that proportion which the volume of petroleum substances and outside substances delivered to such production facility by or on behalf of such Joint-Operator bears to the total volume of all petroleum substances and outside substances delivered to such production facility. Notwithstanding the foregoing sentence, if the Operator is able to identify the actual owner of any such gain or loss, such owner shall bear such loss or share such gain in proportion to its ownership thereof.

1408 EXPANSION OF PRODUCTION FACILITIES – If any proposed expansion of or addition to a production facility would result in such production facility no longer being used primarily for the production, processing, treatment, storage or transmission, as the case may be, of petroleum substances produced from the joint lands, such proposal shall not be subject to the provisions hereof. Upon the commencement of any construction relating to such proposal, such production facility shall cease to be a production facility and shall no longer be subject to the provisions hereof, provided that nothing contained herein shall affect the application of such provisions to the period during which such facility had been held as a production facility hereunder.

1409 REFERENCE TO ARBITRATION – If there is a dispute between or among the parties with respect to: (i) the approval of a facility usage fee for a production facility pursuant to either Clause 1021 or 1404; (ii) the allocation of operating costs pursuant to Clause 1405; or (iii) the allocation of products utilizing a production facility, a party may, by notice to the other parties, cause the matter to be referred to arbitration under the provisions of the Arbitration Act or Ordinance of the province, state or territory where the production facility is located.

ARTICLE XV

RELATIONSHIP OF PARTIES

1501 PARTIES TENANTS IN COMMON – The rights, duties, obligations and liabilities of the parties hereunder shall be separate and not joint or collective, nor joint and several, it being the express purpose and intention of the parties that their interests in the joint lands and in the wells, equipment, production facilities and property thereon held for the joint account shall be held as tenants in common, subject to the modification of the incidents thereof that are provided in this Operating Procedure. Nothing contained herein shall be construed as creating a partnership, joint venture or association of any kind or as imposing upon any party, any partnership duty, obligation or liability to any other party.

ARTICLE XVI

FORCE MAJEURE

1601 DEFINITION OF FORCE MAJEURE – For the purposes of this Article, "force majeure" means an occurrence beyond the reasonable control of the party claiming suspension of an obligation hereunder, which has not been caused by such party's negligence and which such party was unable to prevent or provide against by the exercise of reasonable diligence at a reasonable cost and includes, without limiting the generality of the foregoing, an act of God, war, revolution, insurrection, blockage, riot, strike, a lockout or other industrial disturbance, fire, lightning, unusually severe weather, storms, floods, explosion, accident, shortage of labour or materials or government restraint, action, delay or inaction.

1602 SUSPENSION OF OBLIGATIONS DUE TO FORCE MAJEURE – If any party is prevented by force majeure from fulfilling any obligation hereunder, the obligations of the party, insofar only as its obligations are affected by the force majeure, shall be suspended while the force majeure continues to prevent the performance of such obligation and for that time thereafter as that party may reasonably require to commence to fulfill such obligation. A party prevented from fulfilling any obligation by force majeure shall promptly give the other parties notice of the force majeure and the affected obligations, including reasonably full particulars in respect thereof.

1603 OBLIGATION TO REMEDY – The party claiming suspension of an obligation as aforesaid shall promptly remedy the cause and effect of the applicable force majeure, insofar as it is reasonably able so to do, and such party shall promptly give the other parties notice when the force majeure ceases to prevent the performance of the applicable obligation. However, the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of such party, notwithstanding Clause 1601, and that party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly the force majeure thereby constituted.

1604 EXCEPTION FOR LACK OF FINANCES – Notwithstanding anything contained in this Article, lack of finances shall not be considered a force majeure, nor shall any force majeure suspend any obligation for the payment of money due hereunder.

ARTICLE XVII

INCENTIVES

1701 INCENTIVES TO BE SHARED – Any drilling or other well incentives, geophysical incentive credits or grouping rights which accrue collectively to the parties under the Regulations with respect to any operation conducted on the joint lands shall be shared by the parties which participate in such operation, in proportion to their participating interests therein.

ARTICLE XVIII

CONFIDENTIAL INFORMATION

1801 CONFIDENTIALITY REQUIREMENT - Each party entitled to information obtained hereunder or pursuant to the Agreement may use such information for its sole benefit. However, the parties shall take such measures with respect to operations and internal security as are appropriate in the circumstances to keep confidential from third persons all such information, except information which the parties have expressly agreed among themselves to release and information disclosed by a party:

(a) when and to the extent required by the Regulations and securities laws applicable to such party, provided that such party shall invoke any confidentiality protection permitted by such Regulations and securities laws;

(b) to an Affiliate, provided that such party shall be deemed to have required such Affiliate to maintain the confidential status of the disclosed information in accordance with this Article XVIII, that such Affiliate shall be deemed to have accepted such obligation and that such party shall be liable for any loss suffered by the parties, or any of them, because of the failure of such Affiliate to maintain such information confidential;

(c) to a third person to which such party has been permitted to assign a portion of its interest hereunder, provided that a binding covenant is obtained from such third person prior to disclosure which provides, inter alia, that none of such information shall be disclosed by it to any other third person;

(d) to the technical, financial or other professional consultants of such party which require such information to provide their services to such party or to a bank or other financial institution from which such party is attempting to obtain financing, provided that a binding covenant is obtained from such consultant or financier, as the case may be, prior to such disclosure, which provides, inter alia, that none of such information shall be disclosed by it to any other third person or used for any purposes other than advising such party or providing financing to such party, as the case may be; and

(e) as and when required to any recognized association within the petroleum industry, of which such party is a member, that engages in the exchange of factual information relating to the type of operations conducted pursuant to this Agreement, unless and to the extent that the information pertains to a well drilled hereunder which a party had requested to be given tight hole status, provided that such party shall invoke any confidentiality protection permitted by such association with respect to such disclosed information.

However, the confidentiality obligation in this Clause shall not extend to information to the extent it is in the public domain, provided that specific items of information shall not be considered to be in the public domain merely because more general information is in the public domain.

1802 DISCLOSURE OF INFORMATION FOR CONSIDERATION - Notwithstanding Clause 1801, a party which proposes to disclose information obtained hereunder or pursuant to the Agreement for cash, in exchange for other information or for other consideration shall notify each other party having a proprietary interest in such information of the details of such proposed transaction. Within fifteen (15) days following receipt of such notice, each of those parties shall, by notice, advise the party which proposes to make such disclosure whether it approves of such disclosure on the terms specified in such notice, provided that failure of a party to respond within such period shall be deemed to be the approval of such party to the disclosure of such information on such terms. Unless the party which proposes to disclose such information obtains such approvals from all of those other parties, the proposed disclosure of such information shall be prohibited. In the event such approvals are obtained, the consideration to be received for such disclosure shall be shared by the applicable parties in the proportions of their proprietary interests in such information.

1803 CONFIDENTIALITY REQUIREMENT TO CONTINUE - Notwithstanding the foregoing provisions of this Article, any party which otherwise ceases to be bound by the provisions of this Operating Procedure shall nevertheless remain bound by the provisions of this Article with respect to information obtained hereunder or pursuant to the Agreement until and to the extent that such information is in the public domain.

ARTICLE XIX

DELINQUENT PARTY

1901 CLASSIFICATION AS DELINQUENT PARTY – If a party changes its address and does not provide the other parties with notice of its changed address for service and subsequently cannot readily be located, or if any party becomes inactive or is struck off the corporate register or otherwise consistently refuses or neglects to answer communications addressed to it at its address for service, the Operator may send notice, by registered mail to that party at its last address for service hereunder, advising such party that it shall thereafter be considered a delinquent party within the meaning of this Article.

1902 EFFECT OF CLASSIFICATION AS DELINQUENT PARTY – From the fifteenth (15th) day after the Operator has forwarded the notice described in Clause 1901, the delinquent party shall thereafter:

(a) not be entitled to any further notices or communications from the Operator or any other party with respect to any matter hereunder, including information from operations;

(b) be deemed to have elected not to participate in any operation thereafter proposed to be conducted for the joint account; and

(c) be deemed to have elected to join, proportionate to its working interest, with the Operator in the joint lands affected, in all farmouts, assignments, surrenders and abandonments proposed and effected hereunder by the Operator for its own account, and any such dispositions effected by the Operator, or by any of the parties at the direction of the Operator, shall be binding on the delinquent party.

However, the proceeds of the sale of the delinquent party's share of petroleum substances and any other funds accruing to the working interest of the delinquent party shall be retained in trust by the Operator for the account and benefit of the delinquent party, after deducting the delinquent party's proportionate share of operating costs and all other relevant costs and expenses incurred for the joint account and any marketing fee applicable to the delinquent party's share of such petroleum substances pursuant to Article VI.

1903 RESTORATION OF STATUS – If a delinquent party subsequently communicates with the Operator, pays all amounts owing by it hereunder, satisfies all of its other obligations hereunder and undertakes in writing to comply from that time with the provisions of this Operating Procedure, such party's rights and obligations hereunder shall be restored to it, provided that such party shall be deemed to have ratified all actions taken pursuant to this Article, including, without restricting the generality of the foregoing, any elections or transactions made on its behalf pursuant to Clause 1902.

1904 LIEN NOT AFFECTED – Nothing in this Article shall derogate from the enforcement of the lien of the Operator and the other parties pursuant to Clauses 505 and 506.

ARTICLE XX

WAIVER

2001 WAIVER MUST BE IN WRITING – No waiver by any party of any breach (whether actual or anticipated) of any of the covenants, provisos, conditions, restrictions or stipulations herein contained shall take effect or be binding upon that party unless the same is expressed in writing under the authority of that party. Any waiver so given shall extend only to the particular breach so waived and shall not limit or affect any rights with respect to any other or future breach.

ARTICLE XXI

FURTHER ASSURANCES

2101 PARTIES TO SUPPLY – Each party shall from time to time and at all times do all such further acts and execute and deliver all further deeds and documents as may be reasonably required in order fully to perform and carry out the terms of this Operating Procedure.

ARTICLE XXII

NOTICE

2201 SERVICE OF NOTICE – Whether or not so stipulated herein, all notices, communications and statements (herein called "notices") required or permitted hereunder shall be in writing, subject to the provisions of this Clause. Any notice to be given hereunder shall be deemed to be served properly if served in any of the following modes:

(a) personally, by delivering the notice to the party on whom it is to be served at that party's address for service. Personally served notices shall be deemed received by the addressee when actually delivered as aforesaid, if such delivery is during normal business hours, on any day other than a Saturday, Sunday or statutory holiday. If a notice is not delivered during the addressee's normal business hours, such notice shall be deemed to have been received by such party at the commencement of the day next following the date of delivery, other than a Saturday, Sunday or statutory holiday; or

(b) by telecopier or telex (or by any other like method by which a written and recorded message may be sent) directed to the party on whom it is to be served at that party's address for service. A notice so served shall be deemed received by the respective addressees thereof: (i) when actually received by them, if received within the normal business hours on any day other than a Saturday, Sunday or statutory holiday; or (ii) at the commencement of the next ensuing business day following transmission thereof if such notice is not received during such normal business hours; or

(c) by mailing it first class (air mail if to or from a location outside of Canada) registered post, postage prepaid, directed to the party on whom it is to be served at that party's address for service. Notices so served shall be deemed to be received by the addressees at noon, local time, on the earlier of the actual date of receipt or the fourth (4th) day (excluding Saturdays, Sundays and statutory holidays) following the mailing thereof. However, if postal service is interrupted or operating with unusual or imminent delay, notice shall not be served by such means during such interruption or period of delay.

However, where this Operating Procedure provides for a notice period of forty-eight (48) hours or less, the applicable notice shall be given in accordance with Subclause (a) or (b) of this Clause, provided that notices of twenty-four (24) hours or less under Article IX may be made by telephone and shall be deemed to be received at the conclusion of the conversation if: the telephone conversation is between representatives of the parties who are specifically authorized to accept such notice; such representatives are officially on duty at the time of such conversation; and such telephone conversation and notice are then confirmed pursuant to Subclause (a) or (b) of this Clause.

2202 ADDRESSES FOR NOTICES – The address for service of notices hereunder of each of the parties shall be ~~as follows:~~ the addresses set out in the Agreement.

2203 RIGHT TO CHANGE ADDRESS – Any party may change its address for service by notice to the other parties, and such changed address for service thereafter shall be effective for all purposes of this Operating Procedure.

ARTICLE XXIII

NO PARTITION

2301 WAIVER OF PARTITION OR SALE – No party shall exercise any right to apply for any partition of the joint lands or any production facility or sale thereof in lieu of partition.

ARTICLE XXIV

DISPOSITION OF INTERESTS

2401 RIGHT TO ASSIGN, SELL OR DISPOSE – Other than as required and allowed one party to another elsewhere in this Operating Procedure and subject to Clause 2402, a party shall not dispose of any of its working interest, whether by assignment, sale, trade, lease, sublease, farmout or otherwise, without first complying with the provisions of ALTERNATE __A__ below (Specify A or B):

ALTERNATE - A:

The party wishing to make the disposition shall, by notice, advise the other parties of its intention to make the disposition, including in such notice a description of the working interest proposed to be disposed and the identity of the proposed assignee, and request their written consent to such disposition, which consent shall not be unreasonably withheld. Failure of a party to reply to the request for consent within twenty (20) days of its receipt shall be deemed to be the consent of such party to such disposition. It shall be reasonable for a party to withhold its consent to a disposition hereunder if it reasonably believes that the disposition would be likely to have a material adverse effect on it, its working interest or operations to be conducted hereunder, including, without limiting the generality of all or any part of the foregoing, a reasonable belief that the proposed assignee does not have the financial capability to meet prospective obligations arising out of this Operating Procedure.

ALTERNATE - B:

(a) The party wishing to make the disposition (in this Article called "the disposing party") shall, by notice, advise each other party (in this Article called an "offeree") of its intention to make the disposition, including in such notice a description of the working interest proposed to be disposed, the identity of the proposed assignee, the price or other consideration for which the disposing party is prepared to make such disposition, the proposed effective date and closing date of the transaction and any other information respecting the transaction which the disposing party reasonably believes would be material to the exercise of the offerees' rights hereunder (such notice in this Article called "the disposition notice").

(b) In the event the consideration described in the disposition notice cannot be matched in kind and the disposition notice does not include the disposing party's bona fide estimate of the value, in cash, of such consideration, an offeree may, within seven (7) days of the receipt by the offerees of the disposition notice, request the disposing party to provide such estimate to the offerees, whereupon the disposing party shall provide such estimate in a timely manner and the election period provided herein to the offerees shall be suspended until such estimate is received by the offerees.

(c) In the event of a dispute as to the reasonableness of an estimate of the cash value of the consideration described in the disposition notice or provided pursuant to Subclause (b), as the case may be, the matter shall be referred to arbitration under the provisions of the Arbitration Act or Ordinance of the province, state or territory where the joint lands are situated within seven (7) days of the receipt of such estimate. The disposing party and the applicable offeree shall thereupon diligently attempt to complete such arbitration in a timely manner. The equivalent cash consideration determined in such arbitration shall thereupon be deemed to be the sale price for the working interest described in the disposition notice.

(d) Within the later of: i) thirty (30) days from the receipt of the disposition notice, as modified by any suspension pursuant to Subclause (b) of this Alternate B; or ii), if applicable, fifteen (15) days from receipt of notice of the arbitrated value determined pursuant to the preceding Subclause, an offeree may give notice to the disposing party that it elects to purchase the working interest described in the disposition notice for the applicable price (in this Article called a "notice of acceptance"). A notice of acceptance shall create a binding contractual obligation upon the disposing party to sell, and upon an offeree giving a notice of acceptance to purchase, for the applicable price, all of the working interest included in such disposition notice on the terms and conditions set forth in the disposition notice. However, if more than one offeree gives a notice of acceptance, each such offeree shall purchase the working interest to which such notice of acceptance pertains in the proportion its working interest bears to the total working interest of such offerees.

(e) In the event that the working interest described in the disposition notice is not disposed of to one or more of the offerees pursuant to the preceding Subclause, the disposition to the proposed assignee shall be subject to the consent of the offerees. Such consent shall not be unreasonably withheld, and it shall be reasonable for an offeree to withhold its consent to the disposition if it reasonably believes that the disposition would be likely to have a material adverse effect on it, its working interest or operations to be conducted hereunder, including, without limiting the generality of all or any part of the foregoing, a reasonable belief that the proposed assignee does not have the financial capability to meet prospective obligations arising out of this Operating Procedure. However, an offeree shall be deemed to have consented to the disposition to the proposed assignee, unless, within the time period prescribed in Subclause (d), the offeree advises the other parties, by notice, that it is not prepared to consent to such disposition.

(f) If the working interest described in the disposition notice is not disposed of to one or more of the offerees pursuant to Subclause (d), the disposing party may, subject to obtaining the consents prescribed by the preceding Subclause, dispose of such working interest at any time within one hundred and fifty (150) days from the issuance of such disposition notice, provided that such disposition is not on terms that are more favourable to such purchaser than those offered in the disposition notice.

(g) Following a disposition herein or one hundred and fifty (150) days following the issuance of a disposition notice from which a disposition did not result, as the case may be, the provisions of this Alternate shall once again apply to the working interest described in the disposition notice.

2402 EXCEPTIONS TO CLAUSE 2401 – Clause 2401 shall not apply in the following instances, namely:

(a) An assignment made by way of security for the assignor's present or future indebtedness, or liabilities (whether contingent, direct or indirect and whether financial or otherwise), the issuance of the bonds or debentures of a corporation, or the performance of the obligations of the assignor as a guarantor under a guarantee, provided that in the event the security is enforced by sale or foreclosure, Clause 2401 shall apply.

(b) A disposition to an Affiliate of the assignor, or in consequence of a merger or amalgamation of the assignor with another corporation or pursuant to an assignment, sale or disposition made by a party of its entire working interest to a corporation in return for shares in that corporation or to a registered partnership in return for an interest in that partnership.

(c) A disposition made by the assignor of all, or substantially all, or of an undivided interest in all or substantially all, of its petroleum and natural gas rights in the province, state or territory where the joint lands are situated, and for the purposes of this Subclause, "substantially all" means a percentage of ninety percent (90%) or more of the net hectares held by such party in that province, state or territory.

(d) A disposition by a party in which the net hectares being disposed of by that party in the joint lands represent less than five percent (5%) of the total net hectares being disposed of by that party pursuant to that disposition.

However, a party making such a disposition pursuant to Subclause (b), (c) or (d) of this Clause shall advise the other parties of such disposition in a timely manner.

2403 MULTIPLE ASSIGNMENT NOT TO INCREASE COSTS – If any assignment of working interest is made to multiple assignees so as to increase the expenses or duties of the Operator, the Operator may require the assignees (and the assignor if it retains a working interest) to appoint one of their number as representing all of them for the purposes of this Operating Procedure, unless arrangements satisfactory to the Operator are made to compensate the Operator for the increased expenses or duties.

2404 RECOGNITION UPON ASSIGNMENT – Other than as required and allowed one party to another elsewhere in this Operating Procedure, a party which proposes that an assignment of a working interest, or a corresponding interest in the Agreement and this Operating Procedure, shall be effective against the parties who are not parties to the assignment (in this Clause called the "other parties") shall first comply with the provisions of ALTERNATE __A__ below (Specify A or B):

ALTERNATE - A:

The assignment of a working interest or a corresponding interest in the Agreement and this Operating Procedure shall only be effective against the other parties if:

(i) notice of the assignment has been served on each of the other parties in accordance with Clause 2401, if applicable; and

(ii) the assignor and assignee have entered into an agreement with the other parties, which is acceptable to the other parties, to ensure the assumption of and compliance with the obligations of the assignor by the assignee with respect to the interest assigned to the assignee.

- OR -

ALTERNATE - B:

The assignment of a working interest or a corresponding interest in the Agreement and this Operating Procedure shall only be effective against the other parties if:

(i) notice of the assignment has been served on each of the other parties in accordance with Clause 2401, if applicable; and

(ii) the assignor and the assignee have entered into an agreement with the other parties, to ensure the assumption of and compliance with the obligations of the assignor by the assignee with respect to the interest assigned to the assignee, provided that the other parties shall be deemed to have executed that agreement, unless, within ninety (90) days of the receipt of that agreement, one (1) or more of the other parties have advised the parties, by notice, that they are not prepared to execute that agreement and the reasonable objections they have to that agreement.

The assignor shall forthwith give notice to the parties respecting the status of that agreement upon the earliest of: execution of that agreement by the other parties; the receipt of notices of one or more of the other parties that they are not prepared to execute that agreement; or the expiry of such ninety (90) day period, as the case may be.

The following conditions shall be applicable to the ALTERNATE which is specified:

(a) Subject to Subclause (b) of this Clause, if an assignment is effected in the manner prescribed in this Clause, the assignment shall be effective against the other parties at the time specified in the agreement provided to the other parties pursuant to the Alternate specified in this Clause.

(b) Until the agreement provided to the other parties pursuant to the Alternate specified in this Clause has been executed, or, if applicable, deemed to have been executed by the other parties, the assignor shall continue to remain liable to the other parties for performance of the obligations applicable to the assigned interest under the Agreement and this Operating Procedure. The other parties may also rely on the assignor as being trustee for and authorized agent of the assignee in all matters relating to the assigned interest during such period.

(c) This Clause 2404 shall in no event operate to affect or impede an assignment described in Subclause 2402(a).

ARTICLE XXV

LITIGATION

2501 CONDUCT OF LITIGATION – Litigation with respect to the title documents, the joint lands or any joint operation shall be conducted for the joint account on behalf of all parties, unless and to the extent that such litigation is among the parties. Each party shall notify the other parties of any process served upon it, or of any process it intends to serve, in any action involving the title documents, the joint lands or any joint operation. The parties then shall decide whether an action for the joint account shall be handled by the solicitors of the parties or by joint counsel mutually selected by the parties. However, nothing contained in this Clause shall preclude a party from also acting on its own (and at its own expense) if, in its opinion, it considers such action advisable or necessary to protect its particular interest hereunder, provided that a party so acting on its own behalf shall not pursue a course of action contrary to litigation then being conducted for the joint account.

ARTICLE XXVI

PERPETUITIES

2601 LIMITATION ON RIGHT OF ACQUISITION – Notwithstanding anything to the contrary contained herein, the right of any party to acquire any interest in the joint lands hereunder shall not extend beyond the period prescribed by the applicable perpetutities Regulations or, in the absence of such Regulations, twenty-one (21) years after the lifetime of the last survivor of the lawful descendants now living of Her Majesty Queen Elizabeth II.

ARTICLE XXVII

UNITED STATES TAXES

2701 UNITED STATES TAXES – If for purposes of the United States Internal Revenue Code of 1986, as amended, ("the Code") this Operating Procedure or the relationship established thereby constitutes a partnership as defined in Section 761(a) of the Code, each of the parties who are entitled under such Section to elect, hereby elects to have such partnership excluded from the application of Subchapter K of Chapter 1 of Subtitle A of the Code, or such portion thereof as the Secretary of the Treasury of the United States, or his delegate, shall permit by election to be excluded therefrom. The Operator is authorized to execute such election on behalf of the parties who are entitled to make such election and to file the election with the proper United States government office or agency. The Operator is further authorized and directed to execute and file such additional and further evidence of such election as may be required, all at the expense solely of those parties subject to the Code. However, if the Operator is not subject to the Code with respect to the joint lands, the obligations of the Operator under this Clause shall be fulfilled by the party who is subject to the said Code with respect to the joint lands and who, among those parties subject to the Code, holds the greatest working interest.

ARTICLE XXVIII

MISCELLANEOUS

2801 SUPERSEDES PREVIOUS AGREEMENTS – Except for the Agreement (other than to the extent that the Agreement by its terms becomes ineffective when this Operating Procedure is made effective), this Operating Procedure supersedes all other agreements, documents, writings and verbal understandings among the parties relating to the joint lands and any production facilities, and expresses all of the terms and conditions agreed upon by the parties with respect to the joint lands and any production facilities.

2802 TIME OF ESSENCE – Time shall be of the essence in this Operating Procedure.

2803 NO AMENDMENT EXCEPT IN WRITING – Except as otherwise provided in this Operating Procedure, no amendment or variation of the provisions of this Operating Procedure shall be binding upon any party unless and until it is evidenced in writing executed by the parties.

2804 BINDS SUCCESSORS AND ASSIGNS – Subject to the provisions of Article XXIV, this Operating Procedure shall enure to the benefit of and shall bind the parties, their respective successors and assigns and the heirs, executors, administrators and assigns of natural persons who are or become parties.

2805 LAWS OF JURISDICTION TO APPLY – This Operating Procedure shall for all purposes be construed and interpreted according to the laws of the jurisdiction within which the joint lands are situated and the laws of Canada applicable therein. The courts having jurisdiction with respect to matters relating to this Operating Procedure shall be the courts of that jurisdiction.

2806 USE OF NAME – Each party agrees that it will not use, suffer or permit to be used, directly or indirectly, the name of any other party for the purpose of, or in connection with, the financing, in whole or in part, of any operation hereunder, in connection with the offering for sale of shares of stock or any other securities or for the formation or promotion of any business enterprise, without, in each instance, first obtaining the written consent of that other party.

2807 WAIVER OF RELIEF – The parties acknowledge that any default, forfeiture or assignment provisions contained in this Operating Procedure are, in view of the risks inherent in the exploration for petroleum substances, reasonable and equitable. Each party waives any and all rights which it may have at law, in equity or by the Regulations, against default, forfeiture or penalty if such provisions are invoked.

ARTICLE XXIX

TERM

2901 TO CONTINUE DURING ANY JOINT OWNERSHIP – Subject to Clause 1803, this Operating Procedure shall terminate when no portion of the joint lands and no production facility is owned jointly by two or more parties or at that later date upon which, joint ownership continuing, all title documents have terminated, all wells on the joint lands have been abandoned, all equipment relating thereto salvaged and a final settlement of accounts has been made among the parties, provided that those provisions relating to audit, liability, indemnity, disposal and salvage of material and enforcement on default shall survive for six (6) years thereafter.

EXHIBIT "__"

Attached to and a part of ____

____

____

____

RATES, ELECTIONS AND MODIFICATIONS TO THE 1996 PETROLEUM ACCOUNTANTS SOCIETY OF CANADA (PASC) ACCOUNTING PROCEDURE AND EXPLANATORY TEXT

When using this model care should be taken to ensure consistency and avoid conflicts with the body of the Agreement (which takes precedence).

Some general areas which should be checked are:

- References to the parties and approval process should be consistent with the Agreement. The model refers to approval by the Owners, but the Agreement may refer to an Operating Committee.

- Clauses 110, 111, and 112 in the model may be covered in the Agreement, in which case they should be changed to refer to the appropriate clause in the Agreement. (These accounting matters are best covered in the accounting procedure with reference to the Agreement.)

101. Rates and Elections

The following clauses of the Accounting Procedure are modified to include the indicated election, alternate, option or value:

105. **Operating Fund:** ___10___%

110. **Approvals:** ~~Clause~~XXXXXX; from ___Two (2)___; ___Seventy-Five___ percent (___75___%)

112. **Expenditure Limitations:**
(a) excess of ___One Hundred Thousand___ dollars ($___100,000___)
(c) excess of ___One Hundred Thousand___ dollars ($___100,000___)

202. **Employee Benefits:**
(b) exceed ___Twenty___ percent (___20___%)

213. **Camp and Housing:**
(b) shall ___X___/shall not ________

216. **Warehouse Handling:**
___Five___ percent (___5___%)

221. Allocation Options:

CLAUSE	OPTIONS FOR CHARGING JOINT ACCOUNT			
	Fixed $/ Month			
	Subject to 302 (e)	Not subject to 302 (e)	Percentage of Direct Cost	Other (Specify) (Well/m3)
204	--	--		--
207(c)	--	--		--
212	--	--		--
213(a)	--	--		--
214	--	--		--

302. Overhead Rates:

(a) Exploration Project __________ percent (______%)

OR

(1) Five percent (5 %); Fifty Thousand 50,000 dollars ($50,000)
(2) Three percent (3 %); 100,000 dollars ($100,000)
(3) One percent (1 %)

(b) ~~Drilling Well~~ XXXXXXXXX ~~percent~~ XXXXXXXX ~~%~~ Each Drilling Project

OR

(1) Five percent (5 %); Fifty Thousand dollars ($50,000)
(2) Three percent (3 %); One Hundred Thousand dollars ($100,000)
(3) One percent (1 %)

(c) Initial Construction __________ percent (______%)

OR

(1) Five percent (5 %); Fifty Thousand dollars ($50,000)
(2) Three percent (3 %); One Hundred Thousand dollars ($100,000)
(3) One percent (1 %)

(d) Construction Project __________ percent (______%)

OR

(1) Five percent (5 %); Fifty Thousand dollars ($50,000)
(2) Three percent (3 %); One Hundred Thousand dollars ($100,000)
(3) One percent (1 %)

(e) Operation and Maintenance: (1)

(1) Fifteen percent (15 %) of cost; and/or
(2) One Hundred and Fifty dollars ($ 150.00) per producer or injector
(3) __________ dollars ($ __________)

Subclause 302(e)(2) and 302(e)(3) hereof shall x /shall not ______

406. Dispositions: One Hundred Thousand dollars($ 100,000)

(1) Up to a defined well count, then a flat rate to be mutually agreed by all parties.

PASC
PASC ACCOUNTING PROCEDURE

Recommended by the Petroleum Accountants Society of Canada

EXHIBIT " "

Attached to and a part of ____
____
____

ARTICLE I - GENERAL PROVISIONS

101. *Definitions*

In this Accounting Procedure the following words and phrases shall have the following respective meanings, namely:

(a) "Administrative Services" means support services such as accounting, purchasing, clerical, secretarial, and administrative whether On-Site or not.

(b) "Affiliate" means, with respect to the relationship between corporations, that one of them is controlled by the other or that both of them are controlled by the same person, corporation or body politic; and for this purpose a corporation shall be deemed to be controlled by those persons, corporations or bodies politic who own or effectively control, other than by way of security only, sufficient voting shares of the corporation (whether directly through the ownership of shares of the corporation or indirectly through the ownership of shares of another corporation which owns shares of the corporation) to elect the majority of its board of directors, provided that a partnership which is a party and which is comprised solely of corporations which are Affiliates, as described above, shall be deemed to be an Affiliate of each such corporation and its other Affiliates.

(c) "Agreement" means the Agreement to which this Accounting Procedure is attached.

(d) "Alliance" means a contractual arrangement whereby a third party provides services to the Operator and which involves the sharing of employees and/or office spaces.

(e) "Completion" means the installation in, on, or with respect to a well of all such production casing, tubing and wellhead equipment and all such other equipment and material necessary for the permanent preparation of the well for the taking of petroleum substances therefrom up to and including the outlet valve on the wellhead and includes, as necessary, the perforating, stimulating, treating, fracturing and swabbing of the well and the conduct of such production tests with respect to such well as are reasonably required to establish the initial production of the well.

(f) "Construction Project" means construction, abandonment and reclamation of facilities or installation activity undertaken for the Joint Account, including each subsequent addition thereto or alteration thereof and Equipping wells but does not include Drilling. For purposes of Clause 302 of this Accounting Procedure, each addition or alteration hereunder will be considered as a separate Construction Project except that multiple projects of a similar nature being constructed under a single program will be consolidated as a single Construction Project. Replacement of Material in kind should be considered Operations and Maintenance unless the Owners agree otherwise.

(g) "Controllable Material" means Material which at the time is so classified in the Controllable Material Price Catalogue as most recently recommended by the Petroleum Accountants Society of Canada.

(h) "Drilling" means all activities with respect to the drilling of a well, including surface access and the construction of roads to and from the site of the well, preparation of the site of the well, the installation of all surface and intermediate casing respecting the well, logging, coring, capping, deepening, abandoning, reclaiming, plugging back, sidetracking, re-drilling, production testing of a well or the converting of a well to a source, injection, observation or producing well and including stratigraphic tests, and includes Completion but does not include Equipping, routine clean-out and pump or rod pulling operations which are Operations and Maintenance. Without limiting the generality of the foregoing this also includes environmental or socioeconomic studies required by governmental authorities as a prerequisite to the issuance of approval for the drilling of such well.

(i) "Equipping" means the installation of such equipment as is required to produce petroleum substances from a completed well, including, without restricting the generality of the foregoing, a pump (or other artificial lift equipment), the installation of the flow lines and production tankage serving the well and, if necessary, a heater, dehydrator or other wellsite facility for the initial treatment of petroleum substances produced from the well to prepare such production for transportation to market, but specifically excludes any such equipment, installation, or facility that is (or is intended to be) a production facility.

(j) "Exploration" means geological, geophysical and geochemical examinations and other investigations relating to geology, and any related environmental studies, other than Drilling, for the purpose of defining field limits or defining development well locations, conducted pursuant to the terms of the Agreement.

(k) "Initial Construction" means construction conducted to place the Joint Property on stream to the date of initial operations.

(l) "Joint Account" means the account showing, in Canadian funds, the charges paid and credits received as a result of Joint Operations and which are to be shared by the Owners in accordance with the terms of the Agreement.

(m) "Joint Operations" means Exploration, Drilling, Completion, Equipping, Construction Projects, and Operations and Maintenance activities conducted pursuant to the terms of the Agreement.

(n) "Joint Property" means all property subject to the Agreement.

(o) "Material" means equipment or supplies acquired for use in the conduct of Joint Operations, which shall be classified as follows:

(1) Condition "A" means that which is new;
(2) Condition "B" means that which has been used but is suitable for its original function without reconditioning;
(3) Condition "C" means that which has been used and would be suitable for its original function after reconditioning or that which cannot be reconditioned for, but has a limited service in, its original function;
(4) Condition "D" means that which is not suitable for its original function but is usable for another function;
(5) Condition "E" means that which is junk.

(p) "New Price" means the current price of Condition"A" Material at the nearest reputable supply store where such Material is available or at the nearest receiving point to which such Material could be delivered, whichever is closer to the Joint Property. Tubular goods fifty and eight tenths millimetres (50.8 mm) or two inches (2 inches) in diameter and over shall be priced on a carload basis. Costs of special services to tubular goods, including transportation for that service, shall be included when determining the New Price. Any cash discount that may be allowed by a dealer shall not be deducted in determining the New Price.

(q) "Non-Operator" means an Owner or a Party to the Agreement other than the Operator.

(r) "Operations and Maintenance" means activities and Material required to directly operate, repair, and maintain wells and facilities on the Joint Property.

(s) "Operator" means the Owner or Party designated pursuant to the Agreement to conduct Joint Operations.

(t) "On-Site" means within the legal boundaries of the Joint Property or in the Production Office or in the general vicinity of the Joint Property when in direct conduct of Joint Operations.

(u) "Owner" or "Party" means a person, partnership, corporation or other entity who is bound by the Agreement.

(v) "Production Engineering" means facilities and operations engineering support for Operations and Maintenance. This includes the following activities:

(1) facilities engineering which includes evaluation, optimization, testing, and if required, modifications to wellsite facilities, pipelines, production satellites, oil treating facilities, gas treating facilities, production storage and custody transfer facilities, gas and natural gas liquid injection facilities, produced water handling and injection facilities, fresh water supply and handling facilities, gas compression facilities, controls and data acquisition, loss prevention, utilities, corrosion control and classification, environmental protection, quality control and assurance, operational problem resolution and process optimization and maintenance planning.

(2) operations engineering which includes preparation of expense recompletion programs, remedial workover and stimulation programs (acidizing, fracturing, slick line and wireline programs, coiled tubing, snubbing, nitrogen and carbon dioxide programs); preparation of well control and safety programs; design and optimization of artificial lift systems (dynamometer and fluid level analysis, well bore gradient and interpretation, water analysis, pressure, volume, temperature data, open and cased hole logs, absolute open flow data and the like required to evaluate well performance and workover candidate); and optimization of downhole completion assemblies excluding reservoir performance optimization but including tubing force analysis and packer design, wellhead design, sand control equipment and procedures, downhole equipment for quality assurance and quality control as well as metallurgical design for critical service, selection of workover candidate to rectify mechanical problems, design and implementation of field bottom hole pressure survey and interpretation of pressure data, and interpretation of data required for optimization of downhole completion assemblies.

(w) "Production Office" means an office or a portion of an office, the primary function of which is to directly serve the daily Operations and Maintenance.

(x) "Professional Consulting Services" means the services of a professional individual or firm employed to provide professional advice for the benefit of Joint Operations.

(y) "Supervision" means the supervision of employees and/or contract labour directly employed On-Site in the conduct of Joint Operations.

(z) "Technical Services" means the services providing specific engineering, geological or other professional skills such as, but not limited to those performed by engineers, geologists, geophysicists, technologists, environmentalists, safety specialists, and surface landmen required to handle specific operating conditions and problems for the benefit of Joint Operations which are not Production Engineering or Administrative Services.

(aa) "Warehouse" means a building, pipe yard and/or storage point where idle equipment is stored.

102. *Statement and Billings*

The Operator shall bill each Non-Operator on or before the last day of each month for its proportionate share of the Joint Account for the preceding month. Such bills shall be accompanied by statements which identify the authority for expenditure, lease or facility, and all charges and credits, summarized in accordance with the Joint Interest Billing Exchange Chart of Accounts as most recently recommended by the Petroleum Accountants Society of Canada classifications, as a minimum.

In the event that production revenue settlement statements are submitted by the Operator, sufficient volumetric, pricing, and revenue information by product, production month and year shall be provided to enable each Non-Operator to correctly calculate and record its income and pay its obligations attached thereto.

103. *Payments by Non-Operators*

Unless otherwise provided in the Agreement, each Non-Operator shall pay all bills as rendered pursuant to Clause 102 of this Accounting Procedure within thirty (30) days of receipt thereof. When the due date falls on a weekend or a statutory holiday, the payment will be due on the preceding business day.

104. *Capital Advances*

Unless otherwise provided in the Agreement, the Operator may require each Non-Operator to advance its proportionate share of the estimated costs to be paid in the succeeding month for approved capital projects for Joint Operations. If the Operator so elects, it shall, not earlier than thirty (30) days prior to the first day of each month, submit to each Non-Operator a reasonably detailed estimate of the costs proposed to be paid for the Joint Account in that month, with a request for payment by each Non-Operator of its proportionate share thereof. Each Non-Operator shall pay the Operator its proportionate share of the costs so estimated on or before the fifteenth (15th) day of the month for which the advance is requested or twenty (20) days after receipt of such estimate, whichever is later.

The Operator shall adjust each monthly billing to reflect advances received from the Non-Operator. Expenditures in excess of the advances shall be billed to and paid by each Non-Operator pursuant to Clause 103 of this Accounting Procedure. Amounts advanced by each Non-Operator in excess of actual costs shall be refunded by the Operator with the related billing for the month in which the advance was paid. Any such excess amounts not refunded will, at each Non-Operator's option, bear interest, payable by the Operator for the account of each Non-Operator, at the rate specified pursuant to Clause 106 of this Accounting Procedure from the day the billing is rendered pursuant to Clause 102 of this Accounting Procedure.

105. *Operating Fund*

Unless otherwise provided in the Agreement, the Operator may require each Non-Operator to advance for an operating fund its proportionate share of ________ percent (_____%) of an approved forecast of expenditures for Operations and Maintenance for a year. The amount of this operating fund shall be increased or decreased annually in accordance with the current year's approved forecast of expenditures for Operations and Maintenance. This adjustment shall be done within ninety (90) days after the end of the previous year or when the current year's forecast is approved, whichever is later. Each Non-Operator shall remit such advance thirty (30) days after receipt of request for payment. After the establishment of the operating fund, each Non-Operator shall remit its share of actual costs in accordance with each month's billing, thus maintaining the operating fund intact.

106. *Unpaid Accounts*

Unless otherwise provided for in the Agreement, if payment of any bills or requests for advances is not made within the time stipulated in this Accounting Procedure, the unpaid amount may, at the Operator's option, bear interest payable by the Non-Operator and compounded monthly, for the account of the Operator at the rate of two percent (2%) per annum higher than the average prime rate charged by the principal Canadian Chartered bank used by the Operator, regardless of whether the Operator has notified such Non-Operator in advance of its intention to charge interest with respect to such unpaid amount, for the period in which such interest is payable.

107. *Adjustment and Right to Protest/Question Bills*

(a) A Non-Operator shall not withhold payment of any portion of a bill presented by the Operator due to protest or question related to such a bill unless there is a significant item under dispute and the Operator agrees to the Non-Operator withholding payment for the disputed item. Questions by the Non-Operator related to bills shall be responded to by the Operator within fourteen (14) days of receipt of the Non-Operator's query. In the event the Operator agrees that the questioned charges require adjustment, such adjustment shall be made by the Operator within thirty (30) days after such agreement to the adjustment. Notwithstanding the foregoing provisions, the Operator shall not unreasonably deny the Non-Operator's request to withhold payment for significant disputed charges which require adjustment and for which written notice has been received.

(b) Subject to Subclause 107(c) hereof, payment of any bills or requests for advances shall not prejudice the right of the Non-Operator to protest or question the correctness thereof; provided however, all bills and statements rendered to the Non-Operator during any calendar year shall be presumed to be true and correct after the later of twenty-six (26) months following the end of such calendar year or any approved extensions pursuant to Subclause 108(b) of this Accounting Procedure, unless before the end of the said twenty-six (26) months the Non-Operator takes written exception thereto and makes claim on the Operator for an adjustment.

(c) If within the period referred to in Subclause 107(b) hereof, the Non-Operator or the Operator establishes that an error in the books, accounts and records relating to Joint Operations existing in the said period also existed previous to the period, the Operator shall make the required adjustments retroactively either to the inception of the error or in a manner as approved by the Owners. The provisions of this Subclause are neither intended to extend the Non-Operator's audit rights to access books and records beyond the twenty-four (24) month audit limitation pursuant to Subclause 108(a) of this Accounting Procedure; nor is it intended that the Non-Operator request such an adjustment without being able to adequately support the request. The adjustments shall be subject to the Non-Operator's right to audit.

(d) The provisions of this Clause shall not prevent adjustments resulting from physical inventory of Controllable Material pursuant to Article V of this Accounting Procedure.

108. *Audits*

(a) The Operator's books, accounts, and records relating to Joint Operations for a calendar year may be audited within twenty-four (24) months next following the end of the calendar year. In the event of a payout situation, the twenty-four (24) month period for expenditures commences with receipt of any payout statement. Where two or more Non-Operators desire to conduct an audit, they shall make every reasonable effort to conduct an audit by a joint committee which shall be appointed by the Non-Operators. The Non-Operators shall select a chairman and set the rates of remuneration and expenses, and provided that approvals are obtained from a Majority Interest of the Non-Operators, the costs of such audit shall be borne by all Owners, excluding the Operator and its Affiliates. For purposes of this Subclause, a "Majority Interest" means two (2) or more Non-Operators having interests totalling more than fifty percent (50%) of the remaining interest in the Joint Property after the exclusion of the interests of the Operator and its Affiliates. Nothing, however, shall prevent a Non-Operator from conducting an audit at its sole cost, provided notification has been given to the Operator and other Non-Operators. Each audit shall be conducted so as to cause a minimum of inconvenience to the Operator.

(b) Any claims of discrepancies disclosed by such audit shall be made in writing to the Operator by the chairman of the audit committee within two (2) months of the completion of the field work unless the Operator has consented to a reasonable time extension, which consent shall not be unreasonably withheld.

(c) The Operator shall respond in writing to any claims of discrepancies within six (6) months of receipt of such claims. If the Operator is unable to respond to the claims during the said six (6) month period, an adjustment to the Joint Account for the full amount of the unanswered queries shall be processed unless a request for a time extension supported by a clear work plan and a definite date for resolution is submitted and agreed upon, which approval shall not be unreasonably withheld. If the Operator does not agree with the claim, then the Operator shall include with its response a detailed and relevant explanation. If the Operator agrees with a claim, then adjustment shall be made by the Operator within thirty (30) days of such agreement. Evidence of such adjustment shall accompany the Operator's response. If adjustment cannot be made within a thirty (30) day period, the response shall include an explanation and an anticipated date for adjustment.

(d) The status of all claims of discrepancies issued by the audit committee shall be reported to the Owners within twelve (12) months of the date the claims were issued. Claims reported as unresolved shall be submitted forthwith by the Operator to the Owners for resolution in accordance with the provisions of the Agreement for resolution of disputes. All necessary adjustments resulting from the Owners' resolution shall be reported by the Operator to the audit committee and adjustments processed within thirty (30) days of the date of resolution.

(e) With approval by the Owners, the cost of audits of contract services shall be for the Joint Account. To the extent that the Operator performs and charges the Joint Account for such audits, it is agreed that the Operator's auditor's working papers and findings will be available for inspection and inquiry by the Non-Operators.

109. *Control of Assets*

(a) The Operator shall maintain records of Controllable Material to identify potential loss or underutilization of Controllable Material, and to provide adequate control and tracking of Controllable Material movements.

(b) The Operator shall maintain records of all Controllable Material stored at joint stock locations.

110. *Approvals*

Where approval by the Owners is required in this Accounting Procedure, approval by the Owners pursuant to Clause ____ of the Agreement shall be binding on all the Owners. In the absence of provisions in the Agreement, approval shall be obtained by the Operator in writing from __________ or more Owners having interests in the Joint Property totalling ______ percent (____%) or more. Each Owner shall, by notice, cast its vote with the Operator fifteen (15) days from receipt of request for approval and an Owner who does not vote on any matter shall be deemed conclusively to have voted affirmatively.

111. *Rates and Limitations*

All rates and limitations set forth in this Accounting Procedure may be amended from time to time pursuant to Clause 110 of this Accounting Procedure.

112. *Expenditure Limitations*

Unless otherwise specified in the Agreement, the Operator shall make or incur the following expenditures for the Joint Account in addition to operating expenditures allowed by an approved forecast, without approval by the Owners:

(a) Expenditures including capital expenditures for any single undertaking, the total estimated cost of which is not in excess of ______________ dollars ($______).

(b) Expenditures which the Operator deems necessary in emergencies to protect lives or property, but if the Operator makes any such expenditure in excess of the limit specified pursuant to Subclause 112(a) hereof, it shall promptly advise the Owners.

(c) Expenditures for full settlement of each damage claim resulting or arising from Joint Operations not in excess of ____________ dollars ($________).

(d) Expenditures which it deems necessary to remedy a violation of an environmental regulation or law, but if the Operator makes any such expenditures in excess of the limit specified pursuant to Subclause 112(a) hereof, it shall promptly advise the Owners.

113. *Value Added Tax*

For refundable value added, goods and services or sales taxes, the Operator is authorized to make all elections and file all forms or documents required to administer such taxes on behalf of the Joint Account, including any documents which are required to deem all purchases of goods and services to be purchases of the Operator, and all recoveries to be recoveries of the Operator.

114. *Interpretation*

The Explanatory Text for the 1996 PASC Accounting Procedure (Explanatory Text) forms part of and is incorporated into the 1996 PASC Accounting Procedure (Accounting Procedure) and shall assist in the interpretation of the Accounting Procedure. In the event of a conflict between the provisions of the Explanatory Text and the Accounting Procedure, the Accounting Procedure shall prevail.

ARTICLE II - DIRECT CHARGES

The Operator shall charge the Joint Account with the cost of the following items:

201. *Labour*

(a)(1) Salaries and wages of the Operator's employees located On-Site in the conduct of Joint Operations, including Supervision, Technical Services, or Production Engineering but excluding Administrative Services.

(2) Salaries and wages of the Operator's employees engaged in On-Site Administrative Services in support of Joint Operations, with approval by the Owners.

(3) Salaries and wages of the Operator's employees working in a contractor's or supplier's main or field offices and travelling to contractor's offices or suppliers' plants for inspection and expediting of design and Materials during Initial Construction and subsequent additions or alterations to the Joint Property.

(4) Salaries and wages of the Operator's employees chargeable pursuant to Subclause 201(a)(1) hereof, receiving familiarization training On-Site prior to startup of production facilities.

(5) Salaries and wages of the Operator's employees engaged in Technical Services who are either temporarily or permanently assigned to and directly employed off-site of the Joint Property with approval by the Owners.

(6) Salaries and wages of the Operator's employees engaged in Production Engineering located off-site in direct support of Joint Operations.

(b) Charges for employees chargeable pursuant to Subclause 201(a) hereof, shall be limited to that portion of the salaries and wages attributable to and actually devoted to Joint Operations and supported by approved time sheets or an equitable allocation. Charges for off-site work shall be supported by a time sheet detailing work performed.

(c) Salaries and wages of the Operator's employees who are chargeable pursuant to Subclause 201(a) hereof, and are working through secondment or otherwise part of an Alliance shall be charged at actual cost.

(d) Earned or compensatory time off relating to the above wage or salary categories.

(e) Holiday, vacation, sickness, and disability benefits and other customary allowances paid to employees whose salaries and wages are for the Joint Account. Costs pursuant to this Subclause, may be charged by a percentage assessment on the amount of salaries and wages chargeable to the Joint Account. The rate shall be based on the Operator's cost experience from either the preceding year's actual cost experience or the current year's cost.

(f) For the purpose of charging the cost of the Operator's employees engaged in Technical Services pursuant to Clause 201 hereof, the Operator may use a per diem rate based on actual cost.

202. *Employee Benefits*

Employee benefits based on a percentage assessment applied to the amount of salaries and wages charged to the Joint Account. The percentage assessment shall be based on the Operator's actual cost experience, from either the preceding year's actual cost experience or the current year's cost. Such rates shall exclude the Operator's cost of administering such plans. In determining actual cost experience, any dividends or refunds received which are applicable to insurance or annuity policies shall be used to reduce the cost of such policies.

(a) Compulsory - Payments made by the Operator pursuant to assessments imposed by government authority such as Unemployment Insurance, Workers Compensation, Canada Pension, or other payments of like nature that are applicable to the Operator's salaries and wages charged to the Joint Account.

(b) Non-Compulsory - Established benefit plans which are made available to all employees on a regular basis. Such benefit plans may include employees' group life insurance, hospitalization, medical, dental, company pension, retirement (excluding early retirement and severance incentives), stock purchase, savings, bonus, and other benefit plans of a like nature. The cost of such plans may be borne entirely by the Operator or jointly by the Operator and the employees; however, only the Operator's share of these costs is chargeable to the Joint Account. The Operator shall charge the actual cost of such plans but not to exceed _________ percent (_____%) of the cost of labour charged pursuant to Clause 201 of this Accounting Procedure calculated on an annualized basis.

Bonuses given to selected employees and other special benefits available only to executives, certain employees, or groups on a selective basis shall be excluded from the employee benefits calculation and shall not be chargeable to the Joint Account.

203. *Travel and Moving*

(a) Personnel transfers and personal expenses for the required initial staffing of the Joint Property, required staff increases, and subsequent replacements where such replacements are beyond the control of the Operator. Such costs shall include transportation of employee, spouse, and dependents, and their personal and household effects, and all other relocation costs in accordance with the Operator's normal reimbursement policy. Personnel transfers for normal staff rotation, corporate reorganization, and training assignments shall not be charged to the Joint Account.

(b) Travel and personal expenses to and from and within the Joint Property as well as to and from other locations other than the Joint Property on behalf of Joint Operations for those employees whose salaries and wages are chargeable to the Joint Account.

204. *Automotive*

The Operator's owned or leased automotive equipment used in Joint Operations, including depreciation and interest on the depreciated investment pursuant to Subclause 207(e) or 207(f) of this Accounting Procedure. Costs shall be charged on a kilometre, hourly, or other equitable basis based on the Operator's cost experience, or as otherwise agreed by the Owners, pursuant to Clause 221 of this Accounting Procedure.

205. *Engineering and/or Design*

(a) Engineering and/or design work for Drilling, Completion, Equipping and Construction Projects which have had prior approval by the Owners with engineering and/or design costs clearly identified separate from other costs on the approval document, or engineering and/or design work within the Operator's authority pursuant to Clause 112 of this Accounting Procedure, whether provided by the Operator's employees or contract services as follows:

(1) For work provided by the Operator's employees at cost, which shall mean salaries chargeable pursuant to Subclause 201(a), 201(b) and 201 (c) of this Accounting Procedure, benefits and travel expenses only, plus the cost of computerized equipment used in the engineering and/or design application at rates calculated pursuant to Subclauses 207(e) or 207(f) of this Accounting Procedure.

(2) For work provided by contract services, at the invoiced cost paid by the Operator.

(3) On a basis other than at cost, provided that such basis is clearly identified and explained on the cost estimate submitted for approval by the Owners.

(b) The total amount charged pursuant to Subclause 205(a) hereof shall not exceed the following limits unless otherwise approved by the Owners:

(1) For projects requiring approval by the Owners pursuant to Subclause 112(a) of this Accounting Procedure, the amount stated for engineering and/or design in the approved project estimate plus two thousand dollars ($2,000) or ten percent (10%), whichever is greater.

(2) For projects within the Operator's approval authority pursuant to Subclause 112(a) of this Accounting Procedure, ten percent (10%) of the total project costs.

206. *Material*

Material purchased or furnished by the Operator for use in Joint Operations pursuant to Article IV of this Accounting Procedure.

207. *Services*

(a) Services, equipment and utilities required for Joint Operations incurred pursuant to contracts entered into by the Operator, as follows:

(1) Equipment and utilities provided On-Site.

(2) Technical Services and Production Engineering performed On-Site and related off-site services specifically related to work performed On-Site.

(3) Production Engineering provided off-site.

(4) Technical Services performed off-site, except those pursuant to Subclause 207(a)(2) hereof, only with approval by the Owners.

(5) Professional Consulting Services with approval by the Owners.

(6) Chart integration services.

(7) Charges for any services provided pursuant to this Subclause 207(a) through an Alliance shall not include any charges for the Operator's own seconded employees, nor any administrative or overhead charges on the Operator's employees.

(b) Use of the Operator's or its Affiliates' owned or leased facilities and equipment required for Joint Operations, as follows:

(1) Chart integration performed by the Operator. The Operator's charges shall not exceed commercial rates.

(2) Use of the Operator's or its Affiliates' laboratory facilities for the performance of testing and analysis required for Joint Operations at rates based on usage and actual costs. The rates used for laboratory services performed by the Operator and Affiliates shall not exceed those currently available from outside service laboratories unless approved by the Owners.

(3) Use of the Operator's or its Affiliates' owned or leased facilities and equipment other than that pursuant to Subclauses 207(b)(1) or 207(b)(2) hereof. The Operator's charges shall be pursuant to Subclauses 207(e) or 207(f) hereof.

(c) Maintaining and operating a Production Office. When additional operations or activities are served by the Production Office, the cost of maintaining and operating the Production Office shall be allocated among all operations or activities served, on an equitable basis or as otherwise agreed to by the Owners, pursuant to Clause 221 of this Accounting Procedure. Costs of other offices only with approval by the Owners.

(d) Maintaining and operating an On-Site warehouse that is part of the Joint Property. When additional operations or activities are served by the On-Site warehouse, the cost of maintaining and operating the On-Site warehouse shall be allocated among all operations or activities served, on an equitable basis or as otherwise agreed to by the Owners pursuant to Clause 216 of this Accounting Procedure.

(e) The Operator's charges pursuant to Subclauses 207(b)(3), 207(c) or 207(d), hereof may include actual operating costs, depreciation and interest on the depreciated investment. The annual interest rate on investment shall not exceed the prime bank rate of the principal Canadian Chartered bank used by the Operator plus one percent (1%), determined at the beginning of each calendar year.

(f) In lieu of the calculation of charges provided for in Subclause 207(e) hereof, the Operator's charges pursuant to Subclause 207(b)(3) hereof may be at commercial rates available in the immediate area, less twenty percent (20%).

208. *Damages and Losses*

Repair or replacement of Joint Property made necessary by, but not limited to, damages or losses incurred by fire, flood, storm, theft, accident, or any other cause for which the Operator is not liable. The Operator shall notify each Non-Operator in writing of damages or losses incurred as soon as practicable after the damage or loss has been discovered. Proceeds arising from a claim with respect to damages or losses from any insurance carried by the Operator for the Joint Account shall be credited to the Joint Account when received by the Operator. .

209. *Surface and Subsurface Rights*

(a) Acquisition or renewal of surface rights and periodic rentals and related legal services for title work.

(b) Acquisition of subsurface rights and related bonus costs, lease, license or permit deposits, rentals, renewal or extension fees, royalties, and other similar payments required to maintain the interest of the Owners in the Joint Property.

210. *Taxes*

All taxes paid by the Operator for the Joint Account. Taxes shall not include income taxes or taxes of a similar nature.

211. *Insurance*

(a) Premiums paid for insurance as required by the Agreement to be carried for Joint Operations.

(b) Any deductible or uninsured loss under any policy of insurance required to be carried by the Operator for Joint Operations.

(c) That portion of any claim in excess of limits of insurance coverage required to be carried by the Operator for Joint Operations.

212. *Communication*

(a) Communication equipment including microwave facilities, cellular telephones, mobile radios, walkie-talkies, satellite dishes, ancillary equipment, and tie-lines directly serving the Joint Property and outgoing communication charges incurred by the Operator directly from the Joint Property. Rental or ownership and any other related costs of operating transmitter/receiver equipment in vehicles, or Production Offices, either as a direct charge, or when operations in addition to the Joint Property are served by this equipment, allocated among all such operations on an equitable basis, or as otherwise agreed to by the Owners, pursuant to Clause 221 of this Accounting Procedure.

(b) Other communication services and data transmission services other than those pursuant to Clause 214 of this Accounting Procedure, as approved by the Owners.

213. *Camp and Housing*

(a) Camp
Operation and maintenance of all necessary camp facilities for, and boarding of, employees whose salaries and wages are for the Joint Account provided that the charges for the Operator's owned or leased facilities shall be

commensurate with the costs of ownership, leasing and operation thereof, including depreciation and interest on depreciated investment, less any revenue therefrom. The annual interest rate on investment shall not exceed the prime bank rate of the principal bank in Canada used by the Operator plus one percent (1%) determined at the beginning of each year. When operations in addition to Joint Operations are served by these facilities, the charge for such facilities shall be apportioned among all such operations on an equitable basis, or as otherwise agreed to by the Owners, pursuant to Clause 221 of this Accounting Procedure.

(b) Housing
The cost of housing On-Site employees employed directly in the conduct of Joint Operations shall ________/shall not ________ be chargeable. The charge to the Joint Account shall not exceed rental rates of moderate accommodation in the area and shall be reduced by actual or deemed rental revenues. This charge may be calculated using the cost of ownership, leasing and operation thereof, including depreciation and interest on the depreciated value less any revenue therefrom, pursuant to Subclause 213(a) hereof.

214. *Computerized Measurement and Control*

(a) Automated measurement, field and facilities data capture and/or control systems owned or leased by the Operator, including employee costs for maintenance and operation of the control system and related computer facilities serving Joint Operations. Such costs shall be allocated to each operation and application served on an equitable basis, or as otherwise agreed to by the Owners, pursuant to Clause 221 of this Accounting Procedure.

(b) On-Site and off-site computer usage other than that pursuant to Subclause 214(a) hereof and Clause 205 of this Accounting Procedure, as approved by the Owners.

215. *Ecological and Environmental*

(a) Ecological and environmental requirements resulting from operation of the Joint Property, whether statutory, regulatory, or pursuant to industry association recommendations or the Operator's documented corporate policy relating to the ecology or environment resulting from operation of the Joint Property.

(b) All costs other than those specified in Subclause 215(a) hereof require approval by the Owners.

216. *Warehouse Handling*

A warehouse handling fee for Material delivered from the Operator's Warehouse or an Alliance's Warehouse, if such Material is not currently or normally stored at the Joint Property Warehouse, on a percentage assessment basis of __________ percent (______%) of the cost of such Material.

For the purposes of this Clause, the cost of Material shall be determined pursuant to Clause 402 of this Accounting Procedure.

217. *Recruitment, Training, and Safety*

(a) Recruitment, induction and training for initial staffing, expansion of the Joint Property and replacement of employees resulting from circumstances beyond the control of the Operator.

(b) Training the Operator's employees chargeable pursuant to Subclause 201(a)(1) of this Accounting Procedure with respect to operational, environmental and safety matters for the primary benefit of Joint Operations, including off-site technical training courses for new On-Site equipment or processes. Developmental technical training or personal development or management courses, such as team building, performance coaching, or interpersonal skills shall not be charged to the Joint Account.

(c) Safety articles such as, but not limited to, safety clothing, safety boots, safety glasses, and safety kits required in the operation of the Joint Property, as required by government regulations, industry association recommendations, or the Operator's documented corporate policy for the Operator's employees chargeable pursuant to Subclause 201(a)(1) of this Accounting Procedure.

(d) Safety awards and dinners, the primary function of which is the recognition and promotion of safety practices and concepts in the operation of the Joint Property for employees and contract labor chargeable pursuant to Subclauses 201(a)(1), 207(a) and 207(b) of this Accounting Procedure. Costs of safety dinners shall be limited to food and meeting room only. The cost of safety awards shall be reasonable.

(e) Preparing, implementing, and maintaining site-specific emergency procedures and safety manuals required for direct support of the Joint Property.

218. *Litigation and Claims*

Subject to the provisions of the Agreement, handling, investigating and settling litigation, discharging of liens, payment of judgements, and settlement of claims incurred by the Operator, whether through its own personnel or through third parties, in or resulting from Joint Operations. Charges for services of the Operator's legal staff or fees or expenses of outside legal counsel shall be subject to prior approval by the Owners.

219. *Abandonment and Reclamation*

(a) Abandonment and reclamation of the Joint Property, including those costs required under statutory regulations to restore the location to its natural state.

(b) Upon abandonment and reclamation of the Joint Property, all payments made by the Operator for termination, early retirement, severance, or other similar type settlements made to the Operator's field employees engaged in Operations and Maintenance and chargeable pursuant to Subclause 201(a)(1) of this Accounting Procedure who cannot reasonably be relocated within the Operator's other operations. Each employee's settlement costs shall be charged to the Joint Account in proportion to that employee's service at the Joint Property compared to that employee's total service with the Operator or Operator's predecessor, unless otherwise agreed to by the Owners. Where more than one property is abandoned, such settlement costs must be equitably allocated among them.

220. *Other Costs*

Any other expenditure for which provision is not otherwise made within the Agreement nor this Accounting Procedure and is incurred by the Operator in the conduct of Joint Operations with the approval by the Owners.

221. *Allocation Options*

Notwithstanding anything to the contrary contained in this Article II, when operations in addition to the Joint Property are served, the Operator shall use an equitable allocation of the actual costs as the basis for charges to the Joint Account, except for the following fixed or percentage allocations which shall be in lieu of actual cost allocations.

CLAUSE	COST	OPTIONS FOR CHARGING JOINT ACCOUNT			
		Fixed $/ Month			
		Subject to 302 (e)	Not subject to 302 (e)	Percentage of Direct Cost	Other (Specify) (Well /mcf/BBL)
204	Automotive				
207(c)	Production Office				
212	Communications				
213(a)	Camp				
214	Measurement and Controls				

ARTICLE III - OVERHEAD

301. *General*

Notwithstanding anything to the contrary contained in this Article III, it is specifically understood that any cash payments, incentives, grants, credits, waivers, exemptions, abatements, or other benefits received by or available to the Operator from any governmental source pursuant to regulations with respect to Joint Operations and for the Joint Account, shall not be taken into account when calculating any of the items pursuant to Clause 302 of this Accounting Procedure.

In this Article III:

(a) "Cost" means total expenditures pursuant to Article II of this Accounting Procedure, excluding those expenses pursuant to Subclause 209(b) and Clause 218 of this Accounting Procedure, and salvage credits for Material retired, the value of injected substances purchased for enhanced recovery, custom processing revenues and charges and any additional exclusions as approved by the Owners.

(b) "Overhead" means all costs to the Operator other than those costs pursuant to Article II of this Accounting Procedure.

(c) "Producing Well" means a well for the Joint Account that in a calendar month:

(1) is equipped for and is capable of producing crude oil; or

(2) is connected to a permanent gas sales outlet, source or injection system; or

(3) is used as a disposal well;

provided that: a well that is Drilling during the entire month or is permanently shut-in and awaiting abandonment shall not be considered a Producing Well; a well completed in more than one zone for segregated production shall be considered a separate Producing Well for each such zone; an injection, source or disposal well shall be active during at least one day of the month; and a temporarily shut-in oil or gas well shall not be charged for Overhead longer than three (3) consecutive months after being shut-in.

302. *Overhead Rates*

The Operator shall charge the Joint Account for Overhead at the following rates:

(a) For each Exploration project ____________ percent (___%) of Cost.

OR

(1) _________ percent (___%) of the first _______ dollars ($_____) of Cost plus
(2) _________ percent (___%) of the next _______ dollars ($_____) of Cost plus
(3) _________ percent (___%) of Cost exceeding the sum of (1) and (2)

(b) For the Drilling of a well ____________ percent (___%) of Cost.

OR

(1) _________ percent (___%) of the first _______ dollars ($_____) of Cost plus
(2) _________ percent (___%) of the next _______ dollars ($_____) of Cost plus
(3) _________ percent (___%) of Cost exceeding the sum of (1) and (2)

(c) For Initial Construction _________ percent (______%) of Cost.

OR

(1) ________ percent (___%) of the first _______ dollars ($_____) of Cost plus
(2) ________ percent (___%) of the next _______ dollars ($_____) of Cost plus
(3) ________ percent (____%) of Cost exceeding the sum of (1) and (2)

(d) For each subsequent Construction Project ___________percent (___%) of Cost.

OR

(1) ________ percent (____%) of the first _______ dollars ($____) of Cost plus
(2) ________ percent (____%) of the next _______ dollars ($____) of Cost plus
(3) ________ percent (____%) of Cost exceeding the sum of (1) and (2)

(e) For Operations and Maintenance:

(1) ________ percent (____%) of Cost; and/or
(2) _______ dollars ($____) per Producing Well per month; or
(3) A flat rate of _____________ dollars ($____________) per month.

The rates in Subclauses 302(e)(2) and 302(e)(3) hereof shall ________/shall not ________ be adjusted as of the first day of July each year following the year in which the Agreement became effective. The adjustment will be computed by multiplying the rate currently in use by the percentage increase or decrease in the average weekly wages and salaries of the Canadian Petroleum and Natural Gas Industry for the last calendar year compared with the calendar year next preceding such last calendar year as reported by Statistics Canada. The adjusted rates shall be the rates currently in use, plus or minus the computed adjustment rounded to the nearest dollar. Notwithstanding the provisions hereof, these rates may be adjusted from time to time upon approval by the Owners pursuant to Clause 110 of this Accounting Procedure.

ARTICLE IV - PRICING OF JOINT MATERIAL PURCHASES, TRANSFERS, AND DISPOSITIONS

The Operator shall make proper and timely charges and credits for all Material movements affecting the Joint Operations.

401. *Purchases*

(a) Material purchased shall be charged at the price paid by the Operator including duty and/or sales tax thereon and after deduction of all discounts and rebates received. Where Material is found to be defective or is returned to vendor for any other reasons, credit shall be passed to the Joint Account when adjustment has been received by the Operator.

(b) The Operator shall, whenever practical, purchase Material for delivery to the Joint Property; provided that only such Material as may be required for the conduct of Joint Operations shall be purchased and transported to the Joint Property.

402. *Material Movements*

Material movements to and from the Joint Property (for disposals see Clause 406 of this Accounting Procedure) shall be priced on the following basis, unless otherwise approved by the Owners. When the use of the Material is temporary and the reduced value as provided is not justified, then such material shall be valued on a basis commensurate with its usage on the Joint Property.

(a) New Material (Condition A):
Condition A Material at the New Price.

(b) Good used Material (Condition B):
(1) Condition B Material at seventy-five percent (75%) of New Price, or
(2) Fair market value.

(c) Material requiring conditioning (Condition C):
(1) Condition C Material at fifty percent (50%) of New Price, or
(2) Fair market value.

(d) Other used Material (Conditions D and E):
(1) Condition D Material (damaged) at fair market value.
(2) Condition E Material at salvage value.

Fair market value is deemed to be the selling price that would result when a buyer and a seller agree upon the price of an item giving due consideration for like goods in the marketplace at the time of sale and considering applicable expenses to inspect, repair, refurbish, dismantle and/or move such equipment or Material. Fair market value shall be based on the selling price or replacement cost of the equipment as obtained from current supplier published prices, current Controllable Material Price Catalogue as most recently recommended by the Petroleum Accountants Society of Canada, or as a quotation from a supplier. For audit purposes, documentation must be available to support the use of fair market value.

403. *Transportation of Material*

The Operator may, for transporting Material, charge the cost of transportation to or from the Joint Property provided that the charge for transporting Material furnished by the Operator shall not exceed the estimated costs of transporting such Material from the closer of the nearest reputable supply store or railway receiving point. Transportation costs incurred in transferring Material from the Joint Property to other operations where a change of ownership occurs shall not be charged to the Joint Account except with approval by the Owners.

404. *Warranty of Material Furnished by the Operator*

There shall be no obligation on the part of the Operator to warrant Material beyond the dealer's or manufacturer's warranty.

405. *Premium Prices*

Whenever the specifically required Material is not readily obtainable at published or listed prices because of national emergencies, strikes, or other unusual causes over which the Operator has no control, the Operator may charge the Joint Account for the required Material at the Operator's actual cost incurred in providing such Material, in making it suitable for use, and in moving it to the Joint Property.

406. *Dispositions*

The Operator shall make timely disposition of idle and/or surplus Material, either through sale to the Non-Operators or sale to other parties. The Operator may purchase, but shall be under no obligation to purchase, the interest of the Non-Operator's surplus Material. All sales of Material, regardless of Condition, the proceeds from disposition of which is greater than ___________ dollars ($_______) shall be subject to approval by the Owners. All other disposals of Material shall be at the discretion of the Operator excepting sale to the Operator or its affiliates. Exceptions shall be priced pursuant to Clause 402 of this Accounting Procedure unless prior approval by the Owners is obtained.

ARTICLE V - INVENTORIES

501. *Inventories*

(a) Inventories of Controllable Material shall be taken by the Operator as approved by the Owners.

(b) The Operator shall conduct an inventory of stock maintained in a warehouse which is part of Joint Operations on an annual basis or as otherwise approved by the Owners.

PASC
PASC ACCOUNTING PROCEDURE
EXPLANATORY TEXT

Recommended by the Petroleum Accountants Society of Canada

ADDENDUM " "

Attached to and a part of Exhibit " " of ______________________________

____

____

Table I is a quick reference guide which classifies categories of expense as Overhead or directly chargeable with or without approval by the Owners.

ARTICLE I

101. *Definitions*

Definitions are only required for terms not already defined in the Agreement. The terms Month, Day, and Year are not used as defined terms in the Accounting Procedure but may be defined in the Agreement or addressed by a general provision.

(a) Administrative Services
The intent of including this definition is to make sure that the parties to the Agreement are aware that the Operator receives compensation for these services through the collection of Overhead pursuant to Clause 301. It is at the Operator's discretion whether these services are performed On-Site or not. It is also the intention that any items not specifically covered by Article II of this Accounting Procedure or approved as a stand-alone item would fall under Administrative Services. These items would then require approval pursuant to Clause 220 to be charged to the Joint Account. The services listed in the definition are only examples of the types of services which are included under this Clause and the intent is not to limit the services to those listed in the definition.

(b) Affiliates
No comments are necessary.

(c) Agreement
No comments are necessary.

(d) Alliance
Some operators in the industry have established arm's-length contractual arrangements with third party contractors in which the Operator's employee is in the contractor's office (or vice-versa). For example, the Operator may have an engineering alliance in which an engineering firm provides most of the engineering for specific projects, however the Operator may have some employees located in the contractor's office. Cost savings occur because the Operator does not have to carry a large staff for special projects. The engineering firm, by having alliances with other companies, is able to provide a flexible workforce.

(e) Completion
The Overhead associated with Completion should be considered as part of the initial Drilling costs only if the physical completion operations commence within twelve (12) months following the date of rig release from drilling operations. Completion operations commenced after this time period should be considered a separate project.

(f) Construction Project
No comments are necessary.

(g) Controllable Material
No comments are necessary.

(h) Drilling
Subsequent to the initial Drilling and Completion of a well, a rig and crew is often used to carry out a variety of downhole work which may be considered Drilling or Operations and Maintenance. This distinction is difficult to predetermine as it is somewhat dependant on the magnitude of the work involved. The following is a list of activities which generally require a rig and crew but which are typical of Operations and Maintenance activities.

(1) Sucker rod repairs and/or replacement (with the same quality/type of rod);

(2) Pulling of bottom hole pump for repairs;

(3) Tubing and bottom hole equipment repairs and/or partial replacement (with the same quality/type);

(4) Hot oiling or wireline work for downhole dewaxing;

(5) Wireline work to switch sliding sleeves, bottom hole chokes, etc.;

(6) Solvent, acid washes, or scale removal required to remove well bore restrictions;

(7) Bailing and swabbing;

(8) Maintenance and replacement of downhole sand control material and equipment including well bore clean out of existing zone.

Abandonment operations undertaken after a well has produced for any period of time beyond the initial test production period should be considered a separate Drilling project for Overhead purposes. The Overhead associated with abandoning an unproductive well should be considered as part of the initial Drilling costs only if the physical abandonment operations commence within twelve (12) months following the date of rig release from Drilling operations. Abandonment operations commenced after this time period should be considered a separate project.

(i) <u>Equipping</u>

For purposes of this definition a "production facility" shall mean any facility serving (or intended to serve) more than one (1) well (including, without restricting the generality of the foregoing, any battery, separator, compressor station, gas processing plant, gathering system, pipeline, production storage facility or warehouse), which is:

(1) constructed or installed for the joint account;

(2) owned exclusively by the parties in accordance with their respective working interests;

(3) initially intended to be utilized exclusively with respect to the production, treatment, storage or transmission of petroleum substances;

(4) not used for fractionation of petroleum substances, sulphur extraction or separation of liquids by refrigeration; and

(5) not subject to a separate agreement governing the construction, ownership and operation of such facility;

and includes all real and personal property of every kind, nature and description directly associated therewith, excluding petroleum substances, the joint lands and the Operator's owned or leased equipment

(j) <u>Exploration</u>

No comments are necessary.

(k) Initial Construction
No comments are necessary.

(l) Joint Account
No comments are necessary.

(m) Joint Operations
No comments are necessary.

(n) Joint Property
No comments are necessary.

(o) Material
No comments are necessary.

(p) New Price
No comments are necessary.

(q) Non-Operator
No comments are necessary.

(r) Operations and Maintenance
No comments are necessary.

(s) Operator
No comments are necessary.

(t) On-Site
On-Site refers not only to the legal area of the Joint lands and facilities included in the Joint Property, but the whole area of routine operations as follows:

(1) Field employees who operate the wells and facilities are considered On-Site while they are in the Production Office where they are based. When a central Production Office serves several properties, the field operators from all the properties are deemed to be On-Site while performing their duties in the office. Field employees, supervisors, and employees providing Technical Services are considered On-Site while travelling back and forth from the wells and facilities and the Production Office.

(2) The routine operation of the fields and facilities does require some travel outside of the immediate boundaries of the Joint Property or the Production Office. Examples include emergency evacuation or notification of residents in the area, investigation of odour problems, or

meetings with other operators within a complex (such as a field operator meeting the gas plant operator on an operating problem). In the case of meetings, the On-Site test is that the employee is on call and able to respond promptly to any problem or requirement within the Joint Operation.

(u) Owner or Party
No comments are necessary.

(v) Production Engineering
The following provides a list of engineering activities and tasks, which, if within the Operator's authority or specifically approved and performed in direct support of Operations and Maintenance, should be charged directly to the Joint Account. Any undertaking by the Operator's employees for the benefit of the Joint Account performing Production Engineering activities are chargeable pursuant to Clauses 201 or 207 regardless of their title, level or location.

Any work which is directed towards longer term operations such as work normally performed by geologists, petro-physicists and reservoir engineers falls within the provisions of Engineering and Design pursuant to Clause 205. This also applies to work resulting in a capital or expense AFE which should be charged to such AFE following approval by the Owners.

For clarity, the tasks which are chargeable as Production Engineering activities have been segregated into facilities and operations engineering as follows:

(A) Facilities Engineering

Evaluation, optimization, testing and if required, modification of the following:

(1) Wellsite facilities (heaters, dehydrators, measurement devices, and other similar equipment)

(2) Pipelines (production, injection, and other similar pipelines)

(3) Production satellites (headers, pig facilities, test systems, group separation, measurement, pumping, and other similar equipment)

(4) Oil treating facilities (gas separation, dewatering, desanding)

(5) Gas treating (dehydration, sweetening, liquids extraction, fractionation, sulphur production)

(6) Products storage and custody transfer (oil, C5+, LPG, sulphur, gas)

(7) Produced water handling and injection (compatibility testing, storage, oil removal, treating, filtration, pumping)

(8) Gas and natural gas liquid injection facilities and associated well bores.

(9) Fresh water supply and handling (dams, wells, storage, filtration, treating, pumping)

(10) Gas compression (reciprocating, centrifugal, rotary vane, etc., including drivers)

(11) Controls and data acquisition (pneumatic, PLC [program logic control], SCADA [supervisory control and data acquisition], DCS [distributed control system], and other similar operations)

(12) Loss prevention (PSV's [pressure safety valves], ESD [emergency shut down], block and bleed, gas detection, fire detection and control, and other similar operations)

(13) Utilities (electrical, compressed air, cooling and potable water, sewer and drain, flares, steam generation and distribution)

(14) Corrosion control and de-gasification (chemicals, materials selection, and other similar operations)

(15) Environmental protection (site specific compliance monitoring and control, permit renewal applications, and other similar operations)

(16) Quality control/assurance (standards for fabricating and maintaining, shop inspections, and other similar operations)

(17) Operational problem resolution and process optimization (including simulations)

(18) Maintenance planning (turnaround scheduling, inspections, and other similar operations)

<u>(B) Operations Engineering</u>

(1) Preparation of expensed recompletion programs, remedial workover and stimulation programs including:

(a) Acidizing, fracturing, remedial cementing, and other similar operations

(b) Slick line and wireline programs

(c) Coiled tubing, snubbing, nitrogen, and CO_2 programs

(2) Preparation of well control and safety programs.

(3) Design and optimization of artificial lift systems including:

(a) Dynamometer and fluid level analyses

(b) Well bore gradient and interpretation of IPR (inflow performance relationship), water analysis, PVT (pressure volume temperature) data, open and cased hole logs, AOF (absolute open flow) data, etc., as required to evaluate well performance and workover candidate selection.

(4) Optimization, excluding reservoir performance, of downhole completion assemblies (packers, nipples, sleeves, SSV's [subsurface safety valves], expansion joints, and other similar equipment). This includes:

(a) Tubing force analysis and packer design.

(b) Wellhead design.

(c) Sand control equipment and procedures.

(d) Downhole equipment QA/QC (quality assurance/quality control) and metallurgical design for critical service.

(e) Selection of workover candidates to rectify mechanical problems.

(f) Design and implementation of field bottom hole pressure surveys and interpretation of pressure data.

(g) Interpretation of data required for optimization of downhole completion assemblies.

(w) <u>Production Office</u>
The intent of this definition is to not be restrictive as to the physical locations of such offices, but rather to define the functions served by these offices.

The Production Office is the office or portion of offices where the field employees and supervisors chargeable pursuant to Subclause 201(a)(1) report external reporting requirements. Companies who are not transmitting their billings electronically via the current Electronic Data Interchange Joint Interest Billings Exchange System (EDI/JIBE) adopted by the Canadian Petroleum Industry still need to comply with the classification standards set out in the PASC/JIBE Chart of Accounts.

The statement/billing should reconcile to any advances made.

If the Operator handles production revenue for the Joint Account, it is recommended that sufficient information relating to each Owner's sales be provided so the Non-Operators are able to calculate and pay obligations such as overriding royalties that are not normally handled by the Operator and to accurately record all revenue transactions.

103. *Payments by Non-Operators*

No comments are necessary.

104. *Capital Advances*

It is suggested that where the Non-Operator is cash called for amounts in excess of what could reasonably be expected to be a cash paid charge to the Joint Account for a particular month:

(i) the Operator should be asked for an explanation, and if applicable;
(ii) the Non-Operator and Operator negotiate the amount of the advance.

In any event, payment of the advance must be made by the original due date.

105. *Operating Fund*

The Operator normally advances funds through its accounts payable system to finance an operation and submits a billing to the Non-Operator for the recovery of such funds. Operating advances are allowed, based on an approved forecast, to provide working capital for the normal operating expenditures. Operating advances may be made for net billings but the Operator must adjust the amount of the advance to reflect the reduced timing difference between invoice payment and the billing to the Joint Account. The operating advance must not place the Operator in a more favourable financial position relative to the Non-Operator.

When a company disposes of its share (% Ownership) of the Joint Property during the year, that company should adjust the sales value of its ownership to include any operating advance delivered to the Operator (see PASC "Acquisitions, Dispositions and Trader's Checklist" dated February 23, 1993). Hence, the Operator would remit the operating advance at the end of the year to the new Owner.

If the head document does not have provisions for approvals then approval of the forecast would be pursuant to Clause 110. The "forecast of expenditures" referred to in the Accounting Procedure may differ from any operational forecasts required pursuant to the Agreement.

106. *Unpaid Accounts*

Remittances should be made promptly by the Non-Operator in accordance with the terms of the Agreement. If such remittances are not made on a timely basis, interest should accrue monthly on the unpaid balance at the stipulated rate. The use of the wording "regardless ...." removes the need for written notice to be given before interest can begin to be calculated. The remedies are premised on the fact that a default did exist. Not paying an invoice is a default, but querying the validity of a charge is not a default and remedies are covered in Clause 107.

To encourage the enforcement of this provision, it is recommended that the Operator place a notation on his billings that the interest provision will be applied.

When the total monthly billing to a particular Non-Operator's account reflects a credit balance, the Operator's payment should accompany the billing to settle the account, except where inventory and/or ownership adjustments are involved. In these instances the Operator may effect distribution after collection of sufficient funds from the Non-Operators.

107. *Adjustment and Right to Protest/Question Bills*

The problems and resulting cost of accounting for adjusted payments is very significant; therefore, it is essential that the joint billing be paid as rendered unless agreement to the contrary is reached between the Operator and the Non-Operator.

The monthly Joint Account billing must be paid as rendered by the Operator, unless there is an agreement to short pay for items, such as incorrect working interest (division of interest) or unapproved expenditures. These two examples are not intended to limit the Non-Operator's rights to question doubtful charges, but are valid guidelines for short payment.

If any item on the Operator's statement is questionable, a request for an adjustment or an explanation of the item in question should be directed immediately to the Operator. All significant queries must be in writing with appropriate supporting documentation. A request by the Non-Operator for an adjustment or explanation is not considered an audit request by the Non-Operator and shall not change the normal two-year formal audit limitation.

Subclause 107(c) recognizes the situations where either the Operator or the Non-Operator discovers that an error existed in the Joint Account for periods prior to the twenty-six month protest/questioning period described in Subclause 107(b). Recognizing that joint ventures are supposed to be a co-operative effort and that no Owner should either gain or lose from inadvertent errors, it is recommended that such errors be corrected back to the origin of the error. If the necessary records and information are not available for all prior periods, the parties should then negotiate the adjustment. The provisions of this Subclause are not intended to extend the Non-Operators' auditors' rights to access books and records beyond the twenty-four month audit limitation. Nor is it intended that a Non-Operator request such an adjustment without being able to adequately support the request. Supporting evidence must come from the current period and provide reasonable cause to support the argument that the situation existed in prior periods. The right to audit these types of adjustments is restricted to the support and backup for the adjustment(s) only.

108. *Audits*

Reference should be made to the PASC Joint Venture Audit Committee Bulletin No. 6, "Joint Venture Audit Protocol Guide." All audits of the Operator should be conducted in accordance with this bulletin.

It is recommended that the audit notification be issued at least three months prior to the commencement of the audit. A provision is included for the approval of audit costs by Non-Operators to be determined by a majority interest of the Non-Operators. Such vote would normally be accomplished by means of a mail ballot initiated by the Non-Operator wishing to conduct the audit. The Operator is not normally required to share in the cost of audits conducted by the Non-Operator.

The recommended time period for submission of audit claims or queries by the Non-Operator is within two months following completion of the audit field work at the Operator's office unless the Operator has consented to a reasonable time extension. The last day of field work is normally a date appearing on the mail ballot and/or the audit confirmation letter. The intent of the two month provision is to ensure queries are issued in a timely manner and to clearly establish that the definition of "field work" does not normally extend beyond the scheduled time at the Operator's premises. Audit queries should be sufficiently descriptive and contain the necessary backup to support the claim.

The intent of the six month time limitation from the date of filing for the Operator to answer the Non-Operator's audit claims is to prevent the Operator from ignoring such claims. The six month limitation is viewed as a maximum time for response except in extenuating circumstances. A response to an audit claim should be sufficiently descriptive and contain the necessary support and backup for adjustments processed or claims denied.

The intent of the provision for issuing the final audit report within twelve months of issuing claims of discrepancies is to promote timely reporting to the Non-Operator and to encourage the parties to settle such matters expeditiously.

If the agreement provides for an operating or management committee, this is the recommended vehicle to resolve audit matters. If no such committee exists, it is recommended the parties meet and negotiate a resolution. The agreement may also contain other provisions for settling disputes.

The intent is that for pay-out situations the audit is to be done within 24 months of receipt of any statement. By sending timely statements the Operator avoids audits that go back many years and the Non-Operator is getting timely data. The auditing provisions related to payout wells, net profits interests, and carried interests are governed by the applicable agreements. For a discussion of this topic, please refer to PASC Joint Interest Research Committee Bulletin No. 2.

109. *Control of Assets*

(a) The objective of this clause is to ensure that the Operator is effectively controlling and utilizing Material for the benefit of Joint Operations. The Operator should utilize whatever records or methods are necessary to properly process movements to and from the Joint Account.

(b) Records of Controllable and non-controllable Material shall be maintained by the Operator for the joint stock locations.

110. *Approvals*

This provision provides a basis for approvals of charges to the Joint Account in those instances where there are no approval provisions in the Agreement. (See preamble.)

111. *Rates and Limitations*

No comments are necessary. (See preamble.)

during the year, an allocation of the performance pay for the additional employees to reflect the number of months the new positions have been in place, or to reflect the number of months the discontinued positions were in place, may be required.

Actual costs may be charged on an as-paid, actual basis, or by a percentage assessment basis. The method used by the Operator to charge such payments to the Joint Account should be reasonable and clearly documented This allows the Operator to avoid extremely detailed accounting at the property level.

Following is an explanation of direct labour chargeable to the Joint Account:

(a)(1) Salaries and wages of the Operator's employees directly engaged in Joint Operations, Supervision, Technical Services, or Production Engineering who are On-Site (see definitions) handling day-to-day operations and problems. This includes travel time to or from the Joint Property in the conduct of Joint Operations.

Salaries of the Operator's employees engaged in Technical Services are chargeable pursuant to Clause 205 for capital project work within the Operator's approval authority.

Salaries and wages of the Operator's employees engaged in Administrative Services located On-Site are covered by Overhead and therefore not chargeable to the Joint Account except as provided for in Subclause 201 (a)(2).

(2) This Subclause provides flexibility for the Operator of a facility to request approval to direct charge specified On-Site Administrative costs, such as receptionist or secretarial services, which are excluded as an automatic charge pursuant to Subclause 201(a)(1), in situations where there is a benefit to all Owners to provide such services On-Site. In large plant facilities provision of such services can be cost effective as without such support technical and operating personnel may have to divert their attention to administrative details. It is expected that the mail ballot will detail the positions to be charged and provide the rationale for charging the Joint Account.

(3) Salaries and wages of the Operator's personnel chargeable pursuant to Subclause 201 (a)(1) working in a contractor's or supplier's main or field office and travelling to and from those offices while in the conduct of Joint Operations. These are normally employees providing Production Engineering or Technical Services whose primary function is to handle specific operating conditions or problems directly related to Joint Operations and may include visitations to suppliers and vendors, Material inspections, etc.

(4) Salaries and wages of the Operator's employees chargeable pursuant to Subclause 201(a)(1) while such employees are receiving familiarization training On-Site prior to initial start-up of operations.

(5) Salaries and wages of the Operator's employees providing Technical Services who are directly involved in the capital project work of Drilling, Completion, Equipping, and Construction Projects and have had prior approval by the Owners.

(6) Salaries and wages of the Operator's employees regardless of titles, level or location engaged in Production Engineering to provide site-specific support for the day to day Operations and Maintenance of the Joint Property. These employees perform the tasks outlined in this Explanatory Text for Production Engineering.

(b) Time sheets or some other appropriate written instrument must document and support time spent and work done on any particular job while in the conduct of Joint Operations and the charge should be based upon such time shown. In some instances, however, certain employees such as supervisors may directly service a number of properties, and it may not be practical nor equitable to use "time" alone as a basis for the charge. In these instances a fair and equitable allocation may be the only cost effective method of charging time. The allocation must be supported by time sheets or some other appropriate written documentation indicating that the employee was working on the various properties.

(c) This subclause is set out separately to make it clear that the salaries of the Operator's employees who are part of an Alliance working for the Joint Account are chargeable at actual cost (salaries plus benefits) and should not be charged as part of the Alliance firm's billing for labour (at its charge-out rates). Similarly all office and overhead costs associated with the Operator's employees are not chargeable to the Joint Account. (See Subclause 207(a)). If the Alliance firm is affiliated with the Operator the transaction should be treated as non arm's-length. The actual cost of the Operator's employees working in the Alliance will include salary only. Benefits are also chargeable pursuant to Clause 202.

(d) Earned or compensatory time off relating to the above categories. Such costs are charged on an actual cost basis to the Operator and thus the rate used to charge to the Joint Account must reflect not only the "earned" time off but also the actual time off taken.

(e) The Operator's cost of holiday, vacation, sickness, and disability benefits, and other customary allowances paid to employees whose salaries and wages are

(b) Non-Compulsory - Employee benefits may be generally defined as the types of plans enumerated in this Subclause and other established plans, such as medical insurance for employees and dependants, accident and disability insurance which provides for the welfare of the Operator's employees, their families or beneficiaries, and which are made available to all employees of the Operator on an equitable basis.

Established plans are those made available to ALL employees on a REGULAR basis. Such plans may be established in accordance with and subject to collective bargaining agreements. Charges should be made to the Joint Account for benefit plans expense by "percentages assessment" on the amount of the salaries and wages.

The following types of costs (but not limited to) which are beneficial primarily to the Operator should be excluded from the employee benefit calculations:

- industrial nurse or doctor
- service awards
- employees' credit union
- company magazines and periodicals
- social functions
- dinners and seminars in preparation for retirements
- fitness programs and facilities
- mortgage assistance
- business travel plan
- group legal plans
- bus passes
- travel assistance
- parking
- tax protection on taxable benefits
- educational assistance

Christmas or other bonuses given to selected employees and other special benefits available only to executives, certain employees, or groups on a selective basis are to be excluded from the employee benefits calculations and cannot be directly charged to the Joint Account under any circumstances. These costs are intended to be part of Overhead.

There are considerable variations in the actual cost of benefit plans in various companies in the industry. Some of the factors causing these variations are number of employees, average age of employees, types of plans established, methods of funding (contributory or non-contributory, trustee or insured), and collective bargaining agreement requirements.

Since these wide variations exist, a percentage limitation may be established. The Operator should determine annually whether his costs equal or exceed the stipulated percentage of labour before continuing to make charges at that rate. The "percentage assessment" rate is applicable to the Operator's labour costs which are chargeable to the Joint Account but not applicable to Overhead charges or contract labour.

203. *Travel and Moving*

Travel and reimbursable personal expenses of those employees serving the Joint Property should be charged equitably and consistently with wages and salaries as provided in the labour clause. Transfers for normal staff rotation, corporate reorganization and training assignments are considered to be for the primary benefit of the Operator and therefore not chargeable to the Joint Account.

Personal expenses must be in accordance with the Operator's normal documented reimbursement policy and may include such costs as real estate fee and commissions, closing costs, compensation for loss on sale of home, legal fees, and carpeting and drapery expenses.

As there are no overall industry standards for reimbursement policy, the Non-Operators should understand the Operator's policy at the time of negotiating the Agreement.

204. *Automotive*

No comments are necessary.

205. *Engineering and/or Design*

(a) All engineering and/or design work in support of capital and operational projects, including studies, whether provided by the Operator's employees or contract services, must be charged at cost.

For capital or expense projects which require approval by the Owners, the engineering and/or design costs estimate must be shown separately on an approval document and must meet the following requirements:

(1) Approved detailed time sheets describing the work and location of the Operator's employees.

(2) Charges for engineering and/or design provided by contract services must be supported by invoices clearly showing the work, location, rates, etc. and must be duly approved by the Operator's authorized representatives.

(3) Examples of work being charged at rates other than the Operator's costs may be where the costs are based on a percentage of the total project or a flat rate. The basis of charging must be fully explained when requesting approval by the Owners. The Owners should also negotiate whether the percentage or flat rate is inclusive of benefits or whether there are to be specific exclusions.

Capital and expense projects within the Operator's approval authority must also meet the above requirements.

For expense projects that are wholly engineering in nature such as field development or feasibility studies, the engineering costs are chargeable to the Joint Account only with the approval by the Owners.

(b) (1) The intent of this Subclause 205(b)(1) is to allow a maximum variance between the estimated engineering and/or design costs shown on the AFE and the actual costs charged. Costs for engineering and/or design which exceed the maximum variance require additional approval by the Owners even though the total AFE may not be overexpended.

(2) The intent of this Subclause 205(b)(2) is to limit the amount of engineering and/or design charges to a project which is within the Operator's authority, to ten percent of the total cost of the project.

206. *Material*

For complete reference see Article IV.

207. *Services*

(a) The Operator may recover the cost of third party contract services pertaining to Joint Operations. This includes custom processing charges if on behalf of the Joint Account. The Agreement may contain a dollar limitation governing the requirement of obtaining the Non-Operator's approval before the Operator enters into certain types of third party contracts on behalf of Joint Operations. Contracts should provide for the auditing of the contractor's records in cases where payment for work is based on reimbursable time and/or materials. Provisions relating to the audit are detailed in accordance with Subclause 108(d).

If the Operator has entered into a long-term contract for services, such as drilling rigs, service rigs, etc., the Joint Account should not be charged for any resulting standby charges, unless timing, rig availability, or other factors are critical to Joint Operations.

Contracted services normally considered overhead shall not be charged to the Joint Account.

(1) No comments are necessary.

(2) Technical Services means services related to the mechanical, electrical, chemical, geological and/or geophysical technologies as defined in Clause 101. This Subclause 207(a)(2) allows direct charging of all Technical Services provided On-Site, and some limited off-site work which is specifically and directly in support of the work done On-Site. An example would be time spent by a contracted geologist in his office completing a report on a well site visit. Only the actual Technical Services are chargeable. Any contracted services, which if performed by the Operator would be considered overhead, are not chargeable.

(3) Contracted Production Engineering Services may be direct charged whether On-Site (pursuant to Subclause 207(a)(2)) or off-site. An extensive listing of examples of chargeable Production Engineering work is provided in this guide pursuant to Subclause 101(v).

(4) No off-site Technical Services may be charged without approval, by the Owners other than those covered pursuant to Subclause 207(a)(2) above.

(5) Only true Professional Consulting Services require approval by the Owners, not ordinary contract services. Professional consultants are accredited by professional associations, and may perform as consultants or contractors. Professional Consulting Services provide the Operator with reports giving advice, as described in Clause 101(x). The very same firm or professional may also be contracted to perform Engineering and Design work pursuant to Clause 205 or Technical Services pursuant to Clause 207 in which case they are working under the direction of the Operator doing work which could be done by the Operator's employees. Also, many private individuals in the business of doing technical, administrative or accounting work on contract, like to refer to themselves as "consultants", although this usage does not fall under the definition of Professional Consulting Services. If a consultant's report has been charged to the Joint Account, it must be made available to the Owners.

(6) No comments are necessary.

(7) If the Operator has entered into an Alliance, only costs related to the non-employees of the Operator are chargeable pursuant to this Subclause 207(a)(7). The salaries of the Operator's employees' who are physically on the site at the office of the Alliance firm are chargeable pursuant to the provisions of the labour clause (see Clause 201). Any overhead costs associated with the Operator's employees being in the offices of the Alliance firm are not chargeable and are solely for the Operator's account since these are administrative in nature and are recovered through the Operator's overhead recovery. Contracted services normally considered overhead shall not be charged to the Joint Account.

(d) The cost of operating and maintaining an On-Site warehouse that is part of the Joint Property should be charged to the Joint Account.

(e) The intent is that the Operator should recover its costs of ownership but there should be no profit. The cost is calculated by including depreciation and interest on the depreciated investment as established but the total charge shall not exceed prevailing commercial rates. If there are no available commercial rates in the situation, then the limitation does not apply.

(f) The provision of allowing for use of 80% of commercial rates is meant to reduce the administration burden on the Operator of calculating the charge as provided for in Subclause 207(e), when commercial rates are readily available in the area. If such rates are not available, then this alternative does not apply.

208. *Damages and Losses*

The Agreement generally provides that the costs incurred for repairs or replacement of the Joint Property because of damage or loss shall be borne by the Joint Account. Damage or loss to the Joint Property for any cause is recognized as a Joint Account cost except to the extent of exceptions identified in the Agreement.

As soon as practicable, the Operator should notify the Non-Operators in writing of the damage or loss giving the time, cause, extent, and the estimated charge to the Joint Account. The Operator should also give immediate notice to the insurance carrier, if the property is covered by insurance, and protect the property from further damage.

If any equipment is destroyed or removed from the Joint Property, the Operator should furnish the Non-Operators enough information to enable them to make proper entries to their investment records.

209. *Surface and Subsurface Rights*

(a) Surface rights including all surface lease rentals and land necessary for installations and rights-of-way acquired for Joint Operations such as gathering lines, compressors, plants, wellsites, battery sites, flowlines, and roads. The term may vary depending on the particular lease but usually annual rental payments are required.

(b) Petroleum & Natural Gas (P&NG) Lease Rentals and royalties paid by the Operator for the Joint Account.

210. *Taxes*

No comments are necessary.

211. *Insurance*

The types and amounts of insurance agreed upon by the Owners are usually included in another schedule of the Agreement. Note that Worker's Compensation and Unemployment Insurance are chargeable pursuant to Clause 202.

212. *Communication*

For ease of administration and auditing, only outgoing communication costs from the Joint Property may be charged to the Joint Account. Incoming calls are deemed to be administrative in nature and are thus considered Overhead.

Equitable allocation of costs is site specific and dependent on the nature of the operation and duties of people On-Site. If any basis other than 50/50 (outgoing versus incoming calls) is used, the allocation procedure should be fully documented and available for audit.

Ancillary equipment could include computers dedicated to the phone system but would exclude any communication costs that have been corporately allocated.

213. *Camp and Housing*

(a) Camp
It is the intent of this Subclause to provide camp facilities for employees in remote areas chargeable to the Joint Account. Facilities that are used for more than one operation must be charged out in an equitable manner.

(b) Housing
It is the intent of this Subclause to allow the Joint Operation to pay for the cost of subsidizing housing in remote areas which require this incentive to attract and maintain a qualified workforce. The cost of maintaining the housing less the actual or deemed rent charged is chargeable to the Joint Account, if agreed to, and must be charged based on the activity of the resident of the house. Thus, if a house is vacant, it cannot be charged and if the employee works on a number of different projects, these costs must be shared equitably.

214. *Computerized Measurement and Control*

(a) Computerized measurement and control is the direct use of computers in assisting with oil and gas data gathering, surveillance, automation, and supervisory control. In the event the computer equipment serves other purposes, it is recommended that the Operator get prior approval by the Owners of the allocation process in order to ease the administration and audit efforts.

(b) Computer systems (i.e., personal computers and mainframes) that are not used for measurement and control are not chargeable to the Joint Account unless prior approval by the Owners has been obtained. Examples are material maintenance, material transfers, service work order systems, gas plant allocations, invoice payment, electronic mail, expense statements, revenue accounting, etc. This exclusion extends to the systems personnel, hardware, software (i.e., local area networks - LAN's) as well as peripheral devices that may be required.

215. *Ecological and Environmental*

(a) The Operator must operate in compliance with government regulations. A code of environmental conduct published by an industry association such as Canadian Association of Petroleum Producers (CAPP), Small Explorers and Producers Association of Canada (SEPAC), or other organization may be adhered to and the costs should be borne by the Owners. If the Operator has a documented corporate environmental performance policy that goes beyond government agencies or industry association standards, it should be followed for all operations and the costs should be borne by all the Owners. The Owners are entitled to review the environmental policies that the Operator is using.

(b) Costs of related studies or discretionary ecological and environmental activities require approval by the Owners.

216. *Warehouse Handling*

The intent is to permit the Operator to recover that portion of the cost of his Warehouse operation pertaining to movement of material to the Joint Property, through use of a "percentage assessment." The percentage assessment, when initially established, should reflect the Operator's Warehouse and handling procedure to ensure that the Joint Property is charged only its proportionate share of actual costs. The rates used may be adjusted to account for changes in the Operator's warehouse handling operation. For example, the rate should take into consideration no cost Warehouse or no-cost storage space obtained from a supplier or contractor, or storage of supplies by a contractor for the Operator in the Operator's Warehouse facility or whether the Operator is incurring an inventory holding cost or providing the personnel to expedite.

Wherever possible Material should be sent directly from a vendor to the Joint Property and not processed through the Operator's Warehouse or other temporary storage locations to collect fees for the purpose of creating a profit centre. This warehouse service should add value to the process of obtaining goods for the Joint Property. If Material is returned to the Operator's Warehouse and the Joint Account is credited for the value of the Material, any warehouse handling charge, from the original transfer, associated with the returned goods should not be credited to the Joint Account.

217. *Recruitment, Training and Safety*

(a) The Operator is expected to provide fully trained personnel for the operation of the Joint Property. The training required for rotating employees or growth assignments shall be at the Operator's sole expense. Recruitment costs include advertising and travel for interviews but exclude human resources department costs which are administrative in nature and thus recovered through Overhead.

(b) No comments are necessary.

(c) No comments are necessary.

(d) The costs of safety awards and safety dinners should be reasonable. Safety dinners should be PRIMARILY for the purpose of maintaining employee knowledge and commitment to safety programs and practices in field and plant operations. This term is not meant to include routine social events at which safety is a minor element. The cost of liquor or extra costs incurred because of the serving of liquor, such as transportation for employees, are not chargeable. It should be noted the purpose of a reasonable amount for safety awards and safety dinners (not meetings for other purposes) is in recognition of the increased focus on safety, and the resulting benefits to the Joint Account (i.e., reduced Workers Compensation Board (W.C.B.) costs, reduced absences, etc.) Extravagant awards such as expensive clothing or trips are not considered "reasonable" and therefore not chargeable to the Joint Account.

(e) General emergency manuals that are NOT site specific are not chargeable.

218. *Litigation and Claims*

Legal costs and expenses incurred in handling, investigating, and settling litigation, or claims arising by reason of Joint Operations or necessary to protect or recover the Joint Property including court costs, costs of investigating or procuring evidence, and amounts paid in settlement or satisfaction of any litigation or claim should be recognized as Joint Account costs.

With the exception of legal services for title work, no charge shall be made for the services of the Operator's legal staff working in the Operator's major administrative

(c) each Construction project
(d) each subsequent Construction project
(e) Operations and Maintenance

Overhead - Fixed Rate Base

In addition to percentage rates, a fixed rate option for Operations and Maintenance, either on a well count or flat monthly fee basis, allows for flexibility in negotiations. Application of this rate to wells is provided by the definition of Producing Wells outlined in this option. Basic guidelines for temporarily shut-in oil and gas wells are that such wells should be:

(a) Capable of producing or retained in a shut-in status for future use,

(b) Mechanically equipped so they may be returned to production with reasonable equipment additions or changes,

(c) In such a condition that they can be returned to a producing status without performing a major repair or recompletion job,

(d) Shut-in for three months or less.

A negotiating option has also been included to provide for annual adjustment of the fixed rate to enable the Operator to administer rate revisions due to changes in industry wage costs. This is to eliminate the necessity to formally negotiate and execute frequent minor rate changes. The source of the amount of change will be Statistics Canada data and is calculated and published by PASC prior to July 1 each year.

It should be noted that when this Accounting Procedure is used as an exhibit to an existing agreement, this option clause should be changed by deleting the reference to "the Agreement" and replacing it with a reference to "this Accounting Procedure."

It should further be noted that in the event of a catastrophe the Owners may choose to negotiate a separate Overhead rate for those costs.

ARTICLE IV

401. *Purchases*

It is understood that the Operator will purchase Material only for immediate needs and accumulation of surplus Material should be avoided. The Operator should

TABLE 1
1996 PASC ACCOUNTING PROCEDURE SUMMARY GRID

Activity in Support of Joint Operations	Clause	Covered by Overhead	Direct Charge	Chargeable with Owner Approval	Comments
Abandonment & Reclamation	219(a)		X		
Severance Allowance	219(b)		X		Field employees only in proportion to time on Joint Property
Early Retirement	219(b)		X		
Automotive	204		X		Rates equitable basis
Compulsory Benefits	202(a)				Actual or percentage assessment
Worker's Compensation			X		
Unemployment Insurance			X		
Canada/Quebec Pension Plan			X		
Non-Compulsory Benefits	202(b)				% limitation
Available to ALL employees including			X		
Life Insurance			X		
Medical/dental/etc. insurance			X		
Company pension/retirement plans			X		
Savings plans			X		
Stock purchase			X		
Bonus			X		
NOT available to ALL employees	202(b)				NOT Chargeable
Bonuses to select employees		X			
Stock plans		X			
Management incentives		X			
Selective benefits		X			See list in Explanatory Text
Early retirement payments		X			Not Joint Account except as
Severance allowance		X			noted in Clause 219(b)
Camp	213(a)		X		Equitable allocation
Housing	213(b)	X	X		Election
Communication	212				
Equipment ownership/rental			X		Equitable basis
Outgoing calls			X		50/50 split suggested
Incoming calls		X			in place of other split
Other				X	
Computerized Measurement and control	214(a)				
Production/facilities data capture including employee costs			X		Equitable basis
Non measurement & control computer usage	214(b)			X	

TABLE 1
1996 PASC ACCOUNTING PROCEDURE SUMMARY GRID

Activity in Support of Joint Operations	Clause	Covered by Overhead	Direct Charge	Chargeable with Owner Approval	Comments
Contract services for Operations	207(a)		X		
Contract Technical Services	207(a)				
on-site and related off-site			X		
other off-site				X	
Contract Production Engineering-	207(a)				If duties listed in Explanatory
on-site or off-site			X		Text
Contract Professional Consulting	207(a)			X	
Operator's Laboratories	207(b)		X		Third party maximum or
Operator Owned Equipment	207(b)		X		formula applies.
Chart integration	207(a)		X		Commercial maximum
Utilities on-site	207(a)		X		
Contract Services Audit	108(e)			X	
Damages and Losses	208		X		Notice required
Insurance proceeds (credit)			X		
Ecological and Environmental	215(a)				
Statutory			X		
Regulatory			X		
Industry association recommendations			X		
Compliance with documented corporate policy			X		
Corporate policy development		X			
Other	215(b)			X	
Facilities Use					
Laboratory	207(b)		X		Commercial Maximum
Chart Integration	207(b)		X		Commercial Maximum
Other owned or leased equipment	207(b)		X		Clause 207(e) & (f) limiter on formula
Production Office	207(c)		X		Equitable basis and Clause 207(e) &
Offices other than Production Office	207(c)			X	(f) limiter on formula
GST	113				Subject to Election
Insurance Premiums	211(a)		X		
Employers Liability			X		
Automotive			X		
General Liability			X		
Insurance deductible	211(b)		X		
Uninsured loss			X		
Claims in excess of limit	211(c)		X		
Inventories Expense	504		X		
Special Inventories	505				Not for Joint Account.
Construction Inventories	506		X		

TABLE 1
1996 PASC ACCOUNTING PROCEDURE SUMMARY GRID

Activity in Support of Joint Operations	Clause	Covered by Overhead	Direct Charge	Chargeable with Owner Approval	Comments
Labour - Admin. (On-Site or Off-Site)	201 or				If separate approval has been
Supervision of administrative functions	201(a)(2)	X			obtained under Clause 201
Contracts administration (field)	or 207			X	(a)(2) for major facilities these
File administration		X			costs may be direct charges.
Systems administration		X			Except as per Clause 214
Budgets and budgeting administration		X			
Production data recording admin.		X			Except as per Clause 214
Human Resources support		X			
Travel and air administration		X			
Recruitment administration		X			
Compensation and payroll admin.		X			
Incentive programs admin.		X			
Insurance and property tax admin.		X			
Office services admin.		X			
Clerical		X			
Vehicles and vehicles admin.		X			
Drilling, Completions, Equipping, Construction admin.		X			
Major out of the ordinary Construction Project admin. done On-Site				X	
Daily plant balance admin. - On-Site			X		
Purchasing		X			
Warehouse Co-ordination			X		
Labour - Completion	201				See Clause 205 for conditions
Program design	or			X	Subject to Approved Compl. AFE
Wellsite supervision	207			X	Subject to Approved Compl. AFE
Personnel Administration		X			HR activities
Labour - Construction Project	201				See Clause 205 for conditions
Engineering & design	or			X	Owner approval required for
In contractors main or field office	207				projects above Clause 112
while in conduct of Joint Operations			X		expenditure limit
Preparing budgets		X			
Feasibility studies - wholly engineering				X	
Procurement and disposal		X			Administrative function
Labour - Drilling	201				See Clause 205 for conditions
Program design	or			X	Owner approved Drilling AFE
Wellsite supervision	207			X	Owner approved Drilling AFE
Personnel administration		X			HR activities
Labour - Equipping	201				See Clause 205 for conditions
Program design	or			X	Owner approved Equipping AFE
Wellsite supervision	207			X	Owner approved Equipping AFE
Personnel Administration		X			HR activities

TABLE 1

1996 PASC ACCOUNTING PROCEDURE SUMMARY GRID

Activity in Support of Joint Operations	Clause	Covered by Overhead	Direct Charge	Chargeable with Owner Approval	Comments
Labour - Operations & Maintenance	201				
Daily wells/facility operations	or				
On-Site of Joint Property	207		X		
Repair & maintaining wells & facilities			X		
Scheduling of production maintenance and turn-arounds including safe-work permits			X		
In contractor's main or field office while in conduct of Joint Operations			X		
Budget, AFE, Mail Ballot preparation		X			
Projects above Cl. 112 approval limit				X	
On site familiarization prior to start-up			X		
Labour-Other Technical Services	201				
Landman On-Site in conduct of Joint	or				
Operations	207		X		
Geologist/Geophysicist working on capital projects				X	
Technologist On-Site conducting studies & analysis in direct support of Operation & Maintenance & Production Eng. within approval limit			X		
Landman working off-site		X			
Technologist on routine government reporting		X			
Geological/Geophysical studies				X	
Technical Services for projects within expenditure limit and On-Site			X		
Technical Services - Off-Site				X	
Labour - Production Engineering	201				On or Off-site within the approval limit
Workovers	or		X		
Facility optimization	207		X		
Downhole equipment optimization			X		
Well control & safety programs			X		
Optimization of artificial lift systems			X		
Budget preparation		X			
Projects above Clause 112 expenditure limit				X	Include engineering cost on AFE
Supervision of Production Engineering					
On-Site			X		
Off-Site		X			
Field development study - wholly engineering				X	
On-site familiarization prior to start up			X		

TABLE 1
1996 PASC ACCOUNTING PROCEDURE SUMMARY GRID

Activity in Support of Joint Operations	Clause	Covered by Overhead	Direct Charge	Chargeable with Owner Approval	Comments
Recruitment, training and safety	217 (a)				
Initial staffing recruitment/induction			X		
Expansion recruitment			X		
Circumstances beyond Operator's control			X		
Training	217(b)				
Initial staffing (familiarization training)			X		
Operations, environmental, safety			X		
Off-site technical for new equipment			X		
General technical, reservoir, process		X			
Personal development		X			
Supervisory practices, team building		X			
Quality improvement		X			
Interpersonal skills		X			
Performance coaching		X			
Safety articles required by regulations or corporate policy	217(c)		X		
Safety dinners (meal & room only)	217(d)		X		
Dinners which are not mainly safety	217(d)	X			
Safety dinners (alcohol & transport)	217(d)	X			
Site specific safety manuals	217(e)		X		
General safety manuals	217(e)	X			
Surface and sub-surface rights acquisition	209		X		While On-Site
Surface and sub-surface rights renewals			X		While On-Site
Periodic rental payments			X		As required to maintain Joint Prop.
Mineral lease payments			X		As required to maintain Joint Prop.
Land administrative functions		X			Administrative function
Related legal title work			X		
Taxes - property	210(a)		X		
Income Taxes					Not for Joint Account
Travel and moving	203(a)				To the Joint Property
Initial staffing			X		
Staff increase			X		
Replacement beyond Operator's control			X		
Staff rotation		X			
Corporate reorganization		X			
Training assignments		X			
Travel on behalf of Joint Operations	203(b)		X		
Warehouse handling fee	216		X		
Operating joint owned warehouse	207(d)		X		Allocated equitably

EXHIBIT "__"

Attached to and a part of ______________________________

____

____

____

RATES, ELECTIONS AND MODIFICATIONS TO THE 1996 PETROLEUM ACCOUNTANTS SOCIETY OF CANADA (PASC) ACCOUNTING PROCEDURE AND EXPLANATORY TEXT

When using this model care should be taken to ensure consistency and avoid conflicts with the body of the Agreement (which takes precedence).

Some general areas which should be checked are:

- References to the parties and approval process should be consistent with the Agreement. The model refers to approval by the Owners, but the Agreement may refer to an Operating Committee.

- Clauses 110, 111, and 112 in the model may be covered in the Agreement, in which case they should be changed to refer to the appropriate clause in the Agreement. (These accounting matters are best covered in the accounting procedure with reference to the Agreement.)

101. Rates and Elections

The following clauses of the Accounting Procedure are modified to include the indicated election, alternate, option or value:

105. **Operating Fund:** __10__ %

110. **Approvals:** ~~Clause~~XXXXXX; from __Two (2)__; __Seventy-Five__ percent (__75__ %)

112. **Expenditure Limitations:**
(a) excess of __One Hundred Thousand__ dollars ($__100,000__)
(c) excess of __One Hundred Thousand__ dollars ($__100,000__)

202. **Employee Benefits:**
(b) exceed __Twenty__ percent (__20__ %)

213. **Camp and Housing:**
(b) shall __X__/shall not ____

216. **Warehouse Handling:**
__Five__ percent (__5__ %)

DEBENTURE

THIS DEBENTURE is issued as of December 1, 1999 by **Deer Creek Energy Limited**, a corporation subsisting under the laws of Alberta, and having an office at Calgary, Alberta (the "**Corporation**").

1. PROMISE TO PAY: PRINCIPAL AND INTEREST

1.1 Principal

The Corporation, for value received, hereby acknowledges itself indebted and promises to pay to or to the order of Talisman Energy Inc. (who and whose successors and assigns as holders of this Debenture are herein called the "**Holder**"), the principal amount of TWENTY ONE MILLION DOLLARS ($21,000,000) (the "**Principal Amount**") at the office of the Holder at Suite 2400, 855 Second Street S.W., Calgary, Alberta T2P 4J9, or at such other place as the Holder may designate from time to time by notice in writing to the Corporation, and in the following manner (or at such earlier time as the principal moneys hereby secured may become payable in accordance with the terms hereof):

(a) SIX MILLION DOLLARS ($6,000,000) plus the Interest Amount on the date as set forth in the Sale Agreement;

(b) SEVEN MILLION DOLLARS ($7,000,000) plus the Interest Amount on the date as set forth in the Sale Agreement; and

(c) EIGHT MILLION DOLLARS ($8,000,000) plus the Interest Amount on the date as set forth in the Sale Agreement.

1.2 Interest

The Corporation shall pay to the Holder at the same place interest on the Principal Amount at a rate per annum equal to the Prime Rate from time to time. Such interest shall accrue monthly in arrears on the first Banking Day of each month in respect of the immediately preceding calendar month and the actual number of days elapsed. Interest shall not be compounded. Such interest shall be calculated after as well as before default and judgment with interest on overdue interest at the same rate. When payment of the Principal Amount or a portion thereof becomes payable hereunder, all accrued and unpaid interest relating to such amount shall also be payable on the date for payment of the Principal Amount.

2. DEFINITIONS AND INTERPRETATION

2.1 Definitions

In this Debenture, the following terms shall have the meanings set forth below (unless the context requires otherwise):

"Applicable Laws" means, in relation to any Person, transaction or event:

(a) all applicable provisions of laws, statutes, rules and regulations from time to time in effect of any Governmental/Judicial Body; and

(b) all judgments, orders, awards, decrees, official directives, writs and injunctions in effect of any Governmental/Judicial Body in an action, proceeding or matter in which the Person is a party or by which it or its property is bound or having application to the transaction or event;

"Cash Collateral Account" means an interest-bearing account with the Holder and from which the Corporation has no withdrawal rights or privileges until repayment in full of the Secured Obligations except in respect of any requirement to apply funds to the Secured Obligations;

"Cdn. Dollars", "Cdn. $" and "$" mean lawful money of Canada for the payment of public and private debts;

"Charge" means the Security Interests created or expressed to be created or required to be created by the Corporation pursuant to Section 3.1 or any other provision of this Debenture;

"Event of Default" has the meaning attributed thereto in Section 8.1;

"Governmental/Judicial Body" means:

(a) any government, parliament or legislature or any regulatory or administrative authority, agency, commission, tribunal or board of any government and any other law, regulation or rule making entity having or purporting to have jurisdiction in the relevant circumstances, or any Person acting or purporting to act under the authority of any of the foregoing; and

(b) any judicial, administrative or arbitral court, authority, tribunal or commission having jurisdiction in the relevant circumstances;

"Hydrocarbons" means petroleum, natural gas and any other solid, liquid or gaseous hydrocarbons (whether consisting of a single element or of two or more elements in chemical combination or uncombined), and any other substances (whether a hydrocarbon or not) produced in association therewith, including oil-bearing shale, tar sands, oil sands as defined in the *Mines and Minerals Act* (Alberta), as amended, crude oil, petroleum, helium, sulphur and hydrogen sulphide, and any of the foregoing;

"Hydrocarbon Right" means any leasehold, license, permit, reservation, working, royalty, profit, carried, fee, mineral or other interest, estate or right in or in respect of any Hydrocarbons;

"<u>Insolvency Event</u>" means an event whereby the Corporation becomes insolvent, makes any assignment in bankruptcy or makes any other general assignment for the benefit of creditors, makes any proposal under the *Bankruptcy and Insolvency Act* (Canada) or any comparable law, seeks relief under the *Companies' Creditors Arrangement Act* (Canada), the *Winding Up Act* (Canada) or any other bankruptcy, insolvency or analogous law, is adjudged bankrupt, files a petition or proposal to take advantage of any act of insolvency, becomes subject to the appointment of a trustee, receiver, receiver and manager, interim receiver, custodian, sequestrator or other person with similar powers of itself or of all or any substantial portion of its assets, which appointment is not diligently and in good faith defended by the Corporation with reasonable likelihood of success, or files a petition or otherwise commences any proceeding seeking any reorganization, arrangement, composition or similar relief under any applicable bankruptcy, insolvency, moratorium, reorganization or other similar law affecting creditor's rights or becomes subject to the filing of such a petition or the commencement of such proceeding which is not diligently and in good faith defended by the Corporation with reasonable likelihood of success, or if proceedings are commenced for the dissolution, liquidation or winding-up of the Corporation or for the suspension of the operations of the Corporation;

"<u>Interest Amount</u>" has the meaning ascribed thereto in the Sale Agreement;

"<u>Lease</u>" means Athabasca Oil Sands Lease 24 registered as Alberta Crown Lease No. 7280060T24;

"<u>Mortgaged Property</u>" means the property, assets and undertaking of the Corporation which are subject to the Charge and shall be deemed to refer to any part or parts thereof as the context may require;

"<u>Operating Equipment</u>" means all surface and subsurface machinery, apparatus, equipment, field facilities and other property and assets of whatsoever nature and kind, including oil wells, gas wells, water wells, disposal wells, injection wells, casing, tubing, rods, pumps and pumping equipment, Christmas trees and other wellhead equipment, separators, flow lines, pipelines, tanks, treaters, heaters, plants and systems to gather, treat and/or compress Hydrocarbons, plants and systems to treat, dispose of or inject water or other substances, power plants, poles, lines, transformers, starters, controllers, machine shops, tools, spare parts and spare equipment, telephone, radio and other communication equipment, racks and storage facilities and leases, licences, permits and agreements related thereto;

"<u>Permitted Dispositions</u>" means:

(a) dispositions of inventory, including Hydrocarbons, in the ordinary course of the Corporation's business;

(b) dispositions of tangible equipment which has become worn out, unserviceable, obsolete, unsuitable or unnecessary in the conduct of its business;

(c) any abandonment, surrender or similar disposition where desirable in accordance with good oil and gas industry practice in the ordinary course of its business as presently conducted;

(d) dispositions which are Permitted Encumbrances;

(e) a disposition by the Corporation of an interest or other participation in the Mortgaged Property of less than 20% provided that following any such disposition the Corporation continues to retain an interest in the Mortgaged Property of not less than 50%; and in such case the Corporation shall not be released of its obligations hereunder in any manner;

~~(f) a disposition by the Corporation of an interest in the Mortgaged Property~~ to a third party acceptable to the Holder, ~~provided~~ that such third party assumes the related obligations ~~hereunder~~ and under the Sale Agreement in a manner satisfactory to the Holder; and in such a case the Corporation ~~shall be entitled to a release to the extent of such a disposition;~~

(g) dispositions made with the prior consent in writing of the Holder, such consent not to be unreasonably withheld;

"Permitted Encumbrances" has the meaning ascribed thereto in the Sale Agreement and shall also include Permitted Royalties and security granted pursuant to a Permitted Financing;

"Permitted Financing" means a financing entered into by the Corporation to facilitate the development and production from the Scheduled Lands and Scheduled Interests, the security for which may cover the Mortgaged Property described in Section 3.1(b) and Sections 3.1(a)(iii) and (iv) and proceeds relating thereto and a second charge on the Mortgaged Property described in Sections 3.1(a)(i), (ii), (v) and (vi) and proceeds relating thereto; provided that in connection with such financing, the lender (or a trustee or other representative of the lender) enters into an agreement with the Holder in the form attached as Schedule B;

"Permitted Royalties" means royalties granted to third parties on market terms and in the ordinary course of business in respect of the participation of such third parties in the development and production from the Scheduled Lands and Scheduled Interests provided that (i) in the event of realization under the Debenture such royalties shall be subject to the priority of the Charge, and (ii) pursuant to the terms of any such royalties they shall terminate and be of no further effect upon exercise by the Holder of the option pursuant to Section 2.7 of the Sale Agreement;

"Person" means an individual, a partnership, a corporation, a trust, an unincorporated organization, a joint venture, an association, a government or any department or agency thereof, and the heirs, executors, administrators or other legal representatives of an individual, and words importing persons have a similar meaning;

"PPSA" means the *Personal Property Security Act* (Alberta);

"Prime Rate" has the meaning ascribed thereto in the Sale Agreement;

"Principal Amount" means the principal amount payable pursuant to Section 1.1 hereof, or so much thereof as remains from time to time unpaid;

"Receiver" means any receiver or receivers of the Mortgaged Property appointed by the Holder pursuant to this Debenture or by a court having jurisdiction and such term shall be deemed to refer to a receiver or receiver-manager;

"Sale Agreement" means the Sale Agreement between Talisman Energy Inc. and Deer Creek Energy Limited relating to the Lease dated as of March 1, 1998;

"Scheduled Interests" means the interests of the Corporation as identified in Schedule A in respect of the Scheduled Lands;

"Scheduled Lands" means the lands described in Schedule A and any amendments or additions thereto;

"Secured Obligations" means all indebtedness, liabilities and obligations of the Corporation under this Debenture, including, without limitation, payment of the Principal Amount, interest thereon and interest on overdue interest, payment of all other amounts required to be paid by the Corporation hereunder, and compliance by the Corporation with all other covenants, indemnities, terms, conditions, agreements and other requirements herein contained; provided that: (a) in the case of an Event of Default under section 8.1(a) the Secured Obligations shall only include those amounts that were then due and unpaid without acceleration of further amounts due; and (b) in the case of Events of Default under Sections 8.1(b),(c), (e) and (g) the Secured Obligations shall refer to the next future payment then contemplated pursuant to Section 1.1 hereof; and

"Security Interest" means any mortgage, charge, pledge, lien, hypothec, encumbrance, assignment by way of security, lease, conditional sale or title retention agreement or other security interest, howsoever created or arising, whether absolute or contingent, fixed or floating, legal or equitable, perfected or otherwise, and any other interest in property or assets that secures payment or performance of an obligation, but does not include a right of set-off unless such right is created for the purposes of securing the repayment of borrowed money.

2.2 Interpretation

(a) Unless otherwise specified, all dollar references are references to dollars of the lawful currency of Canada for the payment of public and private debts.

(b) In this Debenture, words importing the singular number include the plural and vice-versa and words importing gender include masculine, feminine and neuter.

(c) The division of this Debenture into Sections and paragraphs and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation hereof.

(d) The terms "this Debenture", "hereof", "herein", "hereunder" and similar expressions refer, unless otherwise stated, to this Debenture taken as a whole and not to any particular Article, Section, paragraph, and include any agreement or instrument in writing which amends or is supplementary to this Debenture.

(e) Unless otherwise specified, all references to "Section" are references to a section, subsection or paragraph of this Debenture.

(f) References herein to a statute include, unless otherwise stated, regulations passed or in force pursuant thereto and any amendments to such statute or to such regulations from time to time, and any legislation or regulations substantially replacing the same or substantially replacing any specific provision to which such reference is made.

2.3 Schedule

The following Schedules are attached hereto and form a part hereof:

Schedule A	-	Scheduled Interests and Scheduled Lands
Schedule B	-	Acknowledgement re: Permitted Financing

3. SECURITY

3.1 **Grant of Security**

As continuing collateral security for the payment, observance and performance by the Corporation of the Secured Obligations, but subject to the exceptions contained in Sections 3.2 and 7.2 the Corporation hereby:

(a) real property: grants, assigns, conveys, mortgages and charges as and by way of a fixed and specific mortgage and charge to and in favour of the Holder, the Scheduled Interests in the Scheduled Lands, and all of the Corporation's present and after-acquired right, title, estate and interest (whether freehold, leasehold, profit à prendre or otherwise, and whether legal or equitable, corporeal or incorporeal) in and to

(i) all Hydrocarbon Rights in or in respect of the Scheduled Lands, to the extent that such Hydrocarbon Rights result from or are derived from the Scheduled Interests;

(ii) all lands now or hereafter pooled, unitized, grouped or otherwise combined for production or other purposes with the Scheduled Lands;

(iii) all buildings, structures, improvements, expansions, erections, works and fixtures now or hereafter brought, built, erected, constructed, placed or otherwise situate on or used directly in connection with the Scheduled Lands (or lands with which the Scheduled Lands are now or hereafter pooled, unitized, grouped or otherwise combined);

(iv) all Operating Equipment characterized as real property or fixtures now or hereafter situate on the Scheduled Lands or used or useful or intended to be used in connection with operations on or relating to the Scheduled Lands (or lands with which the Scheduled Lands are now or hereafter pooled, unitized, grouped or otherwise combined), including with respect to the exploration, development, removal, production, injection, compression, treatment, storage, measuring, gathering or transportation of Hydrocarbons therefrom or allocated thereto;

(v) all present and after-acquired servitudes, leases, licenses, privileges, easements, rights-of-way, rights of entry and other surface rights, governmental or administrative authorizations, licenses, permits and consents and other rights under which the Corporation derives or holds the right to drill for, produce, store, gather, treat, process, ship or transport Hydrocarbons now or hereafter produced from or allocated to the Scheduled Lands (or lands with which the Scheduled Lands are now or hereafter pooled, unitized, grouped or otherwise combined); and

(vi) all Hydrocarbons within, upon or under the Scheduled Lands, (or lands with which the Scheduled Lands are now or hereafter pooled, unitized, grouped or otherwise combined), in place or in storage, or used in operations relating thereto, including Hydrocarbons produced from or allocated to such lands and in storage off the Scheduled Lands, or used as pipeline fill or inventory; and

(b) **personal property**: grants, assigns, conveys, mortgages and creates a continuing security interest to and in favour of the Holder, and the Holder hereby takes a continuing security interest, in all of the Corporation's present and after-acquired personal property relating to, used in connection with, or derived from, the property specified in Section 3.1(a), including all intellectual property rights and proprietary technology, relating to, used in connection with, or derived from the property specified in Section 3.1(a) (including all goods, chattel paper, securities, documents of title, instruments, money and intangibles, as these terms are defined in the PPSA), wherever located; and

(c) proceeds: grants, assigns, mortgages and creates a continuing security interest to and in favour of the Holder, and the Holder hereby takes a continuing security interest in, all proceeds derived directly or indirectly from any dealing with any of the foregoing property (or any dealing with such proceeds), whether or not of the same type, class or kind as the original property, including a right to an insurance payment or any other payment as indemnity or compensation for loss or damage, and payments made in the total or partial discharge of an intangible, chattel paper, an instrument, a security or a mortgage or charge in respect of an interest in land;

it being the intent hereof that the foregoing property of the Corporation shall be subject to the Charge, subject to Sections 3.2. and 7.2.

3.2 Last Day of Term Excluded

Notwithstanding any other provision of this Debenture, the Charge shall not extend or apply to the last day of the term of any lease or agreement therefor, whether oral or written, now held or hereafter acquired by the Corporation but should the Charge become enforceable and the Holder shall have determined to enforce the same, the Corporation shall thereafter stand possessed of such last day and shall hold it in trust to assign the same to any person who may acquire such term or the part thereof hereby mortgaged and charged in the course of any enforcement of the Charge or any realization of the subject matter thereof.

3.3 Attachment

The Corporation acknowledges that the Charge attaches upon the execution of this Debenture (or in the case of any after-acquired property, upon the date of acquisition thereof), that value has been given, and that the Corporation has, or in the case of after-acquired property will have, rights in the relevant Mortgaged Property.

3.4 Further Assurances

(a) The Corporation shall at all times do, execute, acknowledge and deliver or cause to be done, executed, acknowledged and delivered all such further acts, deeds, transfers, Security Interests and assurances which the Holder may reasonably request in order to give effect to the provisions hereof.

(b) The Corporation hereby authorizes the Holder to execute and register such financing statements, financing change statements and other documents as the Holder may deem appropriate to perfect on an ongoing basis and continue the Charge, and to protect and preserve the Charge and the Corporation hereby irrevocably constitutes and appoints any officer from time to time of the Holder the true and lawful attorney of the Corporation, with full power of substitution, to do any of the foregoing in the name of the Corporation whenever and wherever it may be deemed necessary or expedient.

3.5 Effect of Amalgamation

The Corporation acknowledges and agrees that, in the event it amalgamates with any other corporation or corporations, it is the intention of the Corporation and the Holder that the term "Corporation" when used herein shall apply to each of the amalgamating corporations and to the amalgamated corporation, such that the Charge shall secure the indebtedness of each of the amalgamating corporations and the amalgamated corporation to the Holder at the time of amalgamation.

3.6 Ranking of Security

Subject to the Permitted Encumbrances and Section 6.1(b), the Charge shall constitute a first mortgage, charge and security interest over all of the Mortgaged Property; provided that nothing herein shall operate as a subordination, discharge or release of the Charge or require the Holder to execute any subordination, discharge or release in respect of any Permitted Encumbrances. For greater certainty, it is acknowledged that without subordinating the priority of its Charge, the Holder consents to the Corporation making payments in the ordinary course pursuant to royalties which qualify as Permitted Encumbrances.

4. POSSESSION AND USE UNTIL DEFAULT

4.1 Possession

Unless and until an Event of Default shall have occurred and is continuing, the Corporation may, subject to the express terms hereof:

(a) possess, operate, manage, use and enjoy the Mortgaged Property and control the conduct of its business, and take and use the incomes and profits thereof; and

(b) exercise, enjoy and enforce all of its rights and remedies under any agreement subject to the Charge hereof; but nothing herein shall be construed as subordinating the Charge hereof to any other present or future creditor of the Corporation, whether secured or unsecured.

5. REPORTING

5.1 Reporting Requirements

The Corporation shall provide the following to the Holder:

(a) monthly production reports in respect of the Scheduled Lands, together with a statement of cumulative bitumen production, to be provided to the Holder within thirty (30) days of each month end;

(b) copies of all notices and other documents received by the Corporation from time to time in respect of the Lease from the Department of Energy and Natural Resources (Alberta) or any other applicable Governmental/ Judicial Body;

(c) notice of any intended disposition of any interest in the Scheduled Interests, to be provided to the Holder prior to any such disposition;

(d) notice of any occurrence of any condition or event which constitutes an Event of Default or which, after the giving of notice or passage of time, or both, would constitute an Event of Default, to be provided to the Holder immediately upon the occurrence thereof; and

(e) notice prior to the Corporation entering into a Permitted Financing, and notice of any occurrence of any event of default, demand for payment, acceleration, or other realization or enforcement action taken in respect of any Permitted Financing, to be provided to the Holder immediately upon the occurrence thereof.

6. COVENANTS

6.1 Prohibition of Security Interests

(a) The Corporation shall not create, issue, incur, assume or permit to exist or otherwise have outstanding any Security Interest on any of the Mortgaged Property other than Permitted Encumbrances; provided that nothing herein shall be construed as a subordination of the Charge to such Permitted Encumbrances except as provided in subparagraph (b) below.

(b) Notwithstanding anything else contained herein, the Holder agrees to subordinate the Charge to a charge on the Corporation's property described in Section 3.1(b) and Sections 3.1(a)(iii) and (iv) in connection with a Permitted Financing, (provided that the Holder's legal fees and expenses associated therewith shall be for the account of the Corporation).

6.2 Prohibited Dispositions

Except for Permitted Dispositions, the Corporation shall not sell, transfer, assign, abandon, surrender, exchange, lease, sublease, convey or otherwise dispose of any of the Mortgaged Property, or enter into any transaction or series of transactions (including by way of reconstruction, reorganization, consolidation, amalgamation, merger, liquidation or otherwise) which would have that effect or which would otherwise result in such property and assets becoming the property of any other Person, or in the case of an amalgamation, of the continuing corporation resulting therefrom.

6.3 Operations

The Corporation shall use commercially reasonable efforts to pursue operations in respect of the production of Hydrocarbons from the Lease in accordance with sound industry practice and Applicable Laws; and the Corporation shall use commercially reasonable efforts to perform or cause to be performed all obligations under the Lease including payment of all rentals, royalties, taxes or other charges in respect thereof which are necessary to maintain the Lease in good standing in all material respects.

7. EFFECT ON AGREEMENTS

7.1 Holder Not Liable on Corporation's Agreements

Nothing contained in this Debenture shall be construed as rendering the Holder liable, directly or indirectly, for any obligations of the Corporation under any agreements, instruments, permits, leases, licenses or other documents mortgaged, assigned or charged to the Holder pursuant hereto.

7.2 Consents to Assignment

If any lease, agreement, license, permit, intellectual property right or other interest contains a clause which provides in legal effect that either (a) it cannot be encumbered in the manner herein provided, or (b) it cannot be encumbered in the manner herein provided without the consent or approval of the other party thereto or the issuer thereof, then vis-a-vis such party or issuer only, and in respect to such lease, agreement, license, permit or other interest only, the Charge shall not be effective in respect of those cases within item (a), and in respect of those cases within item (b) the effectiveness of the Charge shall be conditional upon such consent or approval having been obtained. The Corporation shall notify the Holder in respect of all such limitations on the granting of security, and shall take all steps reasonably requested by the Holder from time to time to protect the interests of the Holder in any such lease, agreement, license, permit, or other interest, and where a consent or approval is required the Corporation shall use its best efforts to obtain such consent or approval forthwith, and the Charge, while effective as against the Corporation and all other Persons immediately, shall be effective against such other party as soon as the required consent or approval is given, or deemed or required to be given, whichever shall first occur.

7.3 Realization on Agreements

Nothing in Section 7.2 or elsewhere in this Debenture shall be construed as limiting the rights of the Holder or any Receiver to rely upon provisions in any agreement or instrument hereby assigned where such provisions are more favourable to the Holder or a Receiver than those contained herein (notwithstanding any inconsistency herewith), nor as requiring the Holder or any Receiver to comply with any restrictions of the nature referred to in Section 7.2 in connection with any realization on the Mortgaged Property where such compliance is not otherwise required by Applicable Laws relating to realization of security.

8. EVENTS OF DEFAULT

8.1 Events of Default

The following shall constitute <u>Events of Default</u>:

(a) the Corporation fails to pay any principal, interest or any other amount payable pursuant to this Debenture or secured hereby when such amount becomes due or payable;

(b) with the exception of the circumstances described in Paragraph (f) below, the Corporation makes or purports to make a disposition of any interest in Scheduled Lands or the Scheduled Interests which is not a Permitted Disposition;

(c) the Corporation takes any action, or fails to take any action, which results or may reasonably be expected to result in the termination of the Lease, or the Corporation loses its title to, or substantive rights in respect of, the Lease or the Holder otherwise determines, acting reasonably, that the Corporation is in jeopardy of losing its title to, or substantive rights in respect of, the Lease;

(d) written notice from the Holder of the occurrence of an Insolvency Event unless within 120 days thereafter the Corporation has concluded arrangements, satisfactory to the Holder acting reasonably, for the ongoing assumption of the Secured Obligations and the Corporation's obligations under the Lease and during such period all other secured creditors of the Corporation refrain from enforcement proceedings in respect of their security or participation in settlement or reorganization proceedings with the Corporation;

(e) the Corporation fails to perform or breaches, in a material and substantial manner, its obligations pursuant to Section 6.3;

(f) the Corporation enters into, or purports to enter into, a financing which would otherwise qualify as a Permitted Financing, except that the lender (or trustee or other representative of such lender) does not enter into an agreement with the Holder in the form attached as Schedule B

  (i) within 120 days of written notice from the Holder to do so, in the case of any such financing or financings which do not exceed the principal amount of $250,000 individually or $1,000,000 in aggregate, or

  (ii) within 15 days of written notice from the Holder to do so, in the case of any other such financing or financings; and

(g) the occurrence of the declaration of any event of default and the expiry of any related cure period, demand for payment, acceleration, or other realization or enforcement action taken in respect of any Permitted Financing.

9. REMEDIES ON DEFAULT

9.1 Upon the occurrence of an Event of Default, each and every Secured Obligation secured hereby shall immediately become due and payable by the Corporation without further demand, and the Charge hereof shall immediately become enforceable. If the Charge becomes enforceable and the Holder has determined to enforce the same, the Holder may itself (or through an agent), to the fullest extent permitted by Applicable Laws, and a Receiver appointed by the Holder pursuant to Section 9.2 may:

(a) Possession of Mortgaged Property and Power of Entry

take possession of all or any part of the Mortgaged Property at such place or places as it may then be situate, and/or demand by notice in writing to the Corporation that the Corporation assemble and deliver possession of the moveable Mortgaged Property to such place or places as is specified in such demand, whereupon the Corporation shall forthwith do so. The Holder or a Receiver may take such steps as it considers necessary or desirable to obtain possession of the Mortgaged Property to the exclusion of the Corporation and to that end the Corporation agrees that the Holder or Receiver may at any time enter upon lands and premises comprising the Mortgaged Property or where the Mortgaged Property may be found for the purpose of taking possession of and/or removing the Mortgaged Property. In the event that the Holder or Receiver takes possession of the Mortgaged Property, it shall have the right to seize, repossess and maintain the same upon the premises on which the Mortgaged Property may then be situate without removal to other premises, and may dispose of the same from such premises;

(b) Power of Disposition

sell, lease or otherwise dispose of all or any part of the Mortgaged Property either as a whole or in separate parcels, by public auction or private or closed tender or by private contract, with only those notices, if any, as are required by Applicable Laws, and with or without advertising and without any other formality (except as otherwise required by Applicable Laws), and such sale, lease or disposition shall be on such terms and conditions as to title, credit and otherwise and as to upset or reserve bid or price as may seem advantageous to the Holder or Receiver, and the Holder or Receiver shall not be required to accept the highest or any bid or tender at any public sale. If such sale, lease or disposition is made in whole or in part on credit or deferred payment, there need only be applied against the Secured Obligations the actual cash received from time to time. Any payments made pursuant to any credit granted at the time of the disposition shall be applied as provided in Section 9.5 as and when they are received. The Holder may itself purchase or lease any of the Mortgaged Property, unless prohibited from doing so by Applicable Laws. The Holder or Receiver may rescind or vary any contract for the sale, lease or other disposition of the Mortgaged Property and may resell or re-lease without being answerable for any loss occasioned thereby, and may delay any disposition of the Mortgaged Property in whole or in part;

(c) Pay Encumbrances

pay all or any part of any indebtedness of the Corporation secured by a Security Interest against the Mortgaged Property, whether prior to or subordinate to the Charge;

Mortgaged Property. Any such Receiver shall have all of the powers, remedies and rights set forth in Section 9.1, and the powers, remedies and rights of the Holder hereunder, in addition to those possessed by a receiver or receiver-manager, as applicable, pursuant to Applicable Laws unless any of such powers, remedies and rights are expressly limited in the instrument appointing the Receiver or in amendments thereto. The Holder may appoint one or more Receivers hereunder and may remove any such Receiver or Receivers and appoint another or others in his or their stead from time to time. Any Receiver so appointed may be an officer or employee of the Holder. Any Receiver appointed by the Holder need not be appointed, ratified, or supervised in any way by a court, and may be appointed with or without bond or security. The Holder may from time to time fix the remuneration of every such Receiver, and direct the payment thereof out of the Mortgaged Property or the proceeds thereof in priority to payment of the Secured Obligations.

(b) **Receiver's Certificates**

A Receiver appointed pursuant to Section 9.2(a) may, with the consent in writing of the Holder, borrow money for the maintenance, protection or preservation of the Mortgaged Property or for the carrying on of the business or undertaking of the Corporation which relates to the Mortgaged Property, and any Receiver may issue certificates (in this paragraph called "receiver's certificates"), for such amounts as will, in the opinion of the Holder, be sufficient for obtaining upon the security of the Mortgaged Property the amounts from time to time required, and such receiver's certificates may be payable either to order or bearer and may be payable at such time or times as the Holder may consider expedient, and shall bear such interest as shall therein be provided and the Receiver may sell, deposit, pledge or otherwise dispose of the same in such manner as the Holder may consider advisable and may pay such commission on the sale thereof as he may consider reasonable, and the amounts from time to time payable by virtue of such receiver's certificates shall, at the option of the Holder, be entitled to the security of the Charge in priority to the Secured Obligations.

(c) **Indemnity**

To the fullest extent permitted by Applicable Laws, any Receiver appointed pursuant to Section 9.2(a) shall so far as concerns responsibility for its acts be deemed the agent of the Corporation. The Corporation shall indemnify and save harmless the Holder from and against any and all costs, charges, demands, damages, liabilities, claims and actions whatsoever and howsoever suffered or incurred by the Holder as a result of the acts of any such Receiver except for any wilful misconduct or gross negligence on the part of any such Receiver.

(d) **Power of Attorney**

To enable the Holder to exercise the powers granted to it hereunder, the Corporation hereby irrevocably appoints the Holder as its attorney and on its behalf to effect any sale, lease or other disposition of all or any part of the Mortgaged Property, and to execute all instruments and deeds, and do all acts, matters and things that may be necessary or advisable in the name of or on behalf of the Corporation or otherwise. The power of attorney hereby granted shall be effective upon the occurrence of an Event of Default and shall continue throughout the subsistence of any Event of Default. Any deed, lease, agreement or other instrument required to be signed under seal and signed by the Holder under his seal pursuant hereto will have the same effect as if it were signed under the corporate seal of the Corporation. The Holder shall have full power of substitution, and may provide the Receiver with the power to exercise such rights as attorney hereunder, and may at any time revoke any such substitution.

(e) Court-Appointed Receiver

The Holder may, in its sole discretion, either before or after the private appointment of a Receiver hereunder, institute proceedings in any court of competent jurisdiction for the appointment of a Receiver of all or any part of the Mortgaged Property, and in such case the Receiver shall have the powers expressed in the order appointing it, as such order may be varied from time to time.

9.3 Effect of Appointment of Receiver

Upon the Corporation receiving notice from the Holder of the taking of possession of the Mortgaged Property or the appointment of any Receiver, all powers, functions, rights and privileges of each of the directors and officers of the Corporation with respect to the Mortgaged Property shall cease unless specifically continued by the written consent of the Holder.

9.4 Extensions of Time

The Holder may grant renewals, extensions of time and other indulgences, take, release and give up securities, accept compositions, grant releases and discharges, perfect or fail to perfect any securities, release the Mortgaged Property and otherwise deal or fail to deal with the Corporation, guarantors, sureties and others and with the Mortgaged Property and other securities as the Holder may see fit, all without prejudice to the liability of the Corporation to the Holder or the Holder's rights and powers under this Debenture.

9.5 Application of Payments Against Secured Obligations

(a) Any and all payments made in respect of the Secured Obligations from time to time may (notwithstanding any rule of law or equity to the contrary) be applied to such part or parts of the Secured Obligations as the Holder may see fit, and the Holder shall at all times and from time to time have the right to change any appropriation as the Holder may see fit.

(b) The Holder shall be entitled, when in its sole discretion it considers doing so advantageous to it in the course of realizing on the Charge, to retain any proceeds of realization in a Cash Collateral Account, such Cash Collateral Account to be subject to the Charge, and amounts so retained ultimately to be applied (with any accrued interest) to the Secured Obligations.

9.6 **Validity of Sale**

No Person dealing with the Holder or any Receiver shall be concerned to inquire whether the Charge has become enforceable or whether the powers which the Holder or any Receiver is purporting to exercise have become exercisable or whether any money remains due on the security of the Mortgaged Property or as to the necessity or expedience of the stipulations and conditions subject to which any sale, lease or other disposition shall be made or otherwise as to the propriety or regularity of any sale or any other dealing by the Holder with the Mortgaged Property or to see to the application of any moneys paid to the Holder or Receiver. In the absence of fraud on the part of such Person, such dealings shall be deemed to be within the powers hereby conferred and to be valid and effective accordingly.

9.7 **Deficiency**

The Holder's rights and remedies shall be restricted to realization upon the Mortgaged Property and if the proceeds of the realization of the Mortgaged Property are insufficient to repay the Holder all Secured Obligations including all costs and expenses related to such realization, the Corporation shall have no obligation to pay any such deficiency to the Holder.

9.8 **Rights in Addition**

Each and every right, remedy and power conferred by this Section 9 is in supplement of and in addition to and not in substitution for any other right, remedy or power the Holder or any Receiver may have from time to time under this Section 9 or elsewhere in this Debenture or any other agreement or under the Applicable Laws in force at the time of the exercise of such right, remedy or power. The Holder or Receiver may proceed by way of any action, suit, remedy or other proceeding at law or in equity (including, without limitation, specific performance of any covenant and injunctions against violations of any covenant) and no such remedy for the enforcement of the rights of the Holder or Receiver shall be exclusive of or dependent on any other such remedy. Any one or more of such remedies may from time to time be exercised separately or in combination.

9.9 **Limitation of Liability**

(a) Subject to Section 9.9(c), the Holder shall not be liable or accountable for any loss or damage suffered or incurred by the Corporation as a result of:

(i) the failure by the Holder or a Receiver to exercise any rights or remedies provided for herein, or to exercise any rights or remedy in lieu of any other right or remedy; or

(ii) the taking and maintaining of possession by the Holder or a Receiver of the Mortgaged Property pursuant to the terms of this Debenture, or the carrying on of the business of the Corporation as herein provided.

(b) Subject to Section 9.9(c), the Holder shall not be liable, accountable or responsible:

(i) to account as mortgagee in possession or otherwise upon entry into possession as herein provided, other than for actual receipts; or

(ii) to observe or perform, or to see to the observance or performance by the Corporation of any obligations or agreements to which the Corporation is a party or by which it is bound, whether before or during any period when the Holder is in possession hereunder;

and all such obligations are hereby waived by the Corporation.

(c) Notwithstanding anything herein to the contrary, to the extent that any Applicable Law imposes obligations upon or restricts the rights or remedies of the Holder herein provided, and which have not been waived or varied by the Corporation expressly or by implication, or which are by the provisions of such Applicable Law incapable of waiver or variance by the Corporation, the provisions of such Applicable Law shall govern and the affected provisions hereof shall be deemed to be amended to the extent necessary to give effect to such Applicable Law without in any way affecting any other provision herein.

10. SEVERABILITY

If one or more of the provisions of this Debenture or any part of any of them is, or is adjudged to be, invalid, illegal or unenforceable in any respect, the validity, legality and enforceability of the remaining provisions hereof shall not in any way be affected or impaired thereby, and such invalid, illegal or unenforceable provision or part shall be deemed to be severable.

11. IMMEDIATE EFFECT

The Charge shall take effect forthwith upon execution of this Debenture and shall thereupon operate as security for the Secured Obligations, present or future, direct or indirect, absolute or contingent, matured or not, at any time owing by the Corporation to the Holder or remaining unpaid.

12. SECURITY IN ADDITION

The security hereby constituted is not in substitution for any other security for the Secured Obligations or any other agreement between the parties whether or not creating any Security Interest in all or part of the Mortgaged Property whether heretofore or hereafter made, and such security and agreements shall be deemed to be continued and not affected hereby unless expressly provided to the contrary in a writing signed by the Corporation and the Holder. The taking of any action or proceedings or refraining from so doing, or any other dealing with any other security for the Secured Obligations or any part thereof shall not release or affect the Charge and neither the issue of this Debenture nor the taking of any proceedings hereunder for the realization of the security hereby constituted shall release or affect any other security held by the Holder for the repayment of the Secured Obligations.

13. EXPENSES AND INDEMNITIES

13.1 Expenses

The Corporation shall pay to the Holder all out-of-pocket costs and expenses, including without limitation, all legal fees (on a solicitor and his own client basis) and consultants' fees and other expenses incurred by the Holder from time to time in the enforcement, realization and collection of or in respect of this Debenture (including all charges incurred in the obtaining, maintaining possession of and preserving the Mortgaged Property and obtaining any reports or evaluations in respect thereof). All such amounts shall become part of the Secured Obligations, shall be payable by the Corporation on demand, shall bear interest at the rate set forth herein in respect of the Principal Amount calculated from the date incurred by the Holder to the date paid by the Corporation, and such amounts and interest shall be secured by the Charge.

13.2 General Indemnity

The Corporation shall indemnify the Holder against any and all losses, costs, claims, damages, expenses and liabilities (including all legal fees and expenses on a solicitor and his own client basis) of any and every kind which the Holder may sustain or incur as a consequence of a default by the Corporation in the payment of any Secured Obligations, any representation or warranty made herein by the Corporation being incorrect at the time it was made or deemed to have been made, the failure by the Corporation to comply with any of its covenants hereunder, or the occurrence of any Event of Default or other default hereunder. The amount required to be paid by the Corporation hereunder shall become part of the Secured Obligations, shall be payable by the Corporation on demand, shall bear interest at the rate set forth herein in respect of the Principal Amount calculated from the date any indemnified outlay is made by the Holder hereunder to the date paid by the Corporation, and such amounts and interest shall be secured by the Charge.

13.3 Environmental Indemnity

The environmental indemnity within Section 9.2 of the Sale Agreement shall apply to the benefit of the Holder and any Receiver of the Holder and shall also extend to the officers, directors, employees, agents, shareholders and assignees of the Holder and any Receiver of the Holder.

14. NO MERGER

Neither the taking of any judgment nor the exercise of any power of seizure or sale shall operate to extinguish the liability of the Corporation to make payment of, or to satisfy the Secured Obligations nor shall the acceptance of any payment or alternate security constitute or create any novation, and it is further agreed that the taking of a judgment or judgments under any of the covenants herein contained shall not operate as a merger of such covenants.

15. WAIVER AND AMENDMENTS

(a) The Holder may waive any default by the Corporation in the observance or performance of any Secured Obligation; provided, however, that such waiver shall not extend to or be taken in any manner whatsoever to affect any subsequent breach or default or to affect the rights of the Holder resulting therefrom.

(b) No failure on the part of the Holder in exercising any right or remedy under this Debenture shall operate as a waiver thereof, nor shall any single or partial exercise of any such right or remedy preclude any other or further exercise thereof or the exercise of any other right or remedy in law, by statute, equity or otherwise conferred.

(c) No waiver or variation by the Holder of any provision of this Debenture shall be effective unless evidenced by an instrument in writing dated subsequent to the date hereof and executed by the Holder.

16. EFFECTIVE NOTICE

Any demand, notice or other communication hereunder shall be in writing and shall be considered received on the day it is given to an officer of the recipient, or the next business day if the day the notice or other communication is given to an officer at the following addresses:

To the Corporation:

Deer Creek Energy Inc.
Suite 550, Bow Valley Square 4, 250 - 6th Avenue S.W.
Calgary, Alberta
T2P 3H8

Attention: President
Rapifax No.: (403) 264-3700

To the Holder:

Talisman Energy Inc.
Suite 2400, 855 Second Street S.W.
Calgary, Alberta
T2P 4J9

Attention: Land Manager
Rapifax No.: (403) 237-1544

In all cases, receipt of the notice or other communication by the officer of the recipient must be actual receipt to constitute notice under this agreement.

17. DISCHARGE

Once the Corporation has permanently satisfied all of the Secured Obligations (including any liabilities and obligations for which this Debenture may be deposited as collateral security), the Holder shall, at the written request and expense of the Corporation, discharge the Charge, return this Debenture and execute and deliver to the Corporation such deeds or other instruments as shall be required to give effect to such discharge.

18. NO DISCHARGES UNLESS SPECIFICALLY PROVIDED

No postponement or partial release or discharge of the Charge in respect of all or any part of the Mortgaged Property shall in any way operate or be construed so as to release or discharge the security hereby constituted in respect of the Mortgaged Property except as therein specifically provided, or to release or discharge the Corporation from its liability to the Holder to fully pay and satisfy the Secured Obligations.

19. DEBENTURE LOST OR STOLEN

If this Debenture is mutilated, lost, stolen or destroyed, the Corporation shall, upon being furnished with evidence satisfactory to it of such mutilation, loss, theft or destruction, issue and deliver a new Debenture of like date and tenor as the one mutilated, lost, stolen or destroyed, in exchange for, in place of and upon cancellation of the mutilated Debenture, or in lieu of or in substitution for the lost, stolen or destroyed Debenture.

20. GOVERNING LAW

This Debenture shall be governed by and interpreted in accordance with the laws of the Province of Alberta and the laws of Canada applicable therein and shall be treated as an Alberta contract, except to the extent otherwise required by the laws of a jurisdiction in which certain of the Mortgaged Property may be situate. The Corporation irrevocably submits to the non-exclusive jurisdiction of the courts of the Province of Alberta, without prejudice to the rights of the Holder to take proceedings in any other jurisdictions.

21. ASSIGNMENT BY CORPORATION

Except as set forth in paragraph (f) of the definition of Permitted Dispositions in section 2.1, the Corporation shall not and cannot assign the Secured Obligations without the prior written consent of the Holder, which may be arbitrarily withheld. Subject thereto, all the Secured Obligations shall bind the Corporation and its successors and assigns.

22. WAIVER OF PRESENTMENT

Except as provided herein, the Corporation waives presentment of this Debenture for payment, diligence, notice of non-payment, protest and notice of protest.

23. TIME OF ESSENCE

Time is of the essence in this Debenture.

24. COPY RECEIVED

The Corporation acknowledges having received and retained a copy of this executed Debenture. The Corporation waives any right it now has or hereafter may have to receive from the Holder a copy of any financing statement in which the Corporation is named as a debtor.

25. CONFLICT

In the event of conflict between the Debenture and the Sale Agreement, the Sale Agreement shall prevail.

IN WITNESS WHEREOF the Corporation has caused this Debenture to be executed by its duly authorized representative(s).

DEER CREEK ENERGY LIMITED

Per: ______________________ c/s
Name: P. J. JESPERSEN
Title: PRESIDENT

Per: ______________________
Name: Lin Y. Ding
Title: Vice President, Engineering

SCHEDULE B

attached to and made part of a Debenture dated as of December 1, 1999
by Deer Creek Energy Limited in favour of Talisman Energy Inc.

PERMITTED FINANCING LENDER ACKNOWLEDGEMENT

TO: Talisman Energy Inc.

RE: **DEBENTURE ISSUED BY DEER CREEK ENERGY LIMITED ("Deer Creek") IN FAVOUR OF TALISMAN ENERGY INC. ("Talisman") DATED DECEMBER 1, 1999 (the "Debenture")**

Pursuant to the terms of the Debenture it is contemplated that Deer Creek may enter into certain secured financings from time to time in connection with the development of Athabasca Oil Sands Lease 24. In connection with the provision of such financing to Deer Creek the undersigned acknowledges and agrees for the benefit of Talisman as follows:

1. Capitalized terms shall have the meanings ascribed thereto in the Debenture, and the following terms shall have meanings set out below:

   "**Lender Financing**" means the debt financing to be provided by the undersigned to Deer Creek the particulars of which are set out in Appendix A hereto, including any amendment thereto or replacement thereof.

   "**Lender Security**" means all of the security held, or to be taken in the future, by or on behalf of the undersigned in respect of the Lender Financing.

   "**Priority Assets**" means all of Deer Creek's right, title, estate and interest in all of the property and assets more particularly set out in Sections 3.1(a)(i), (ii), (v), and (vi) of the Debenture, including the proceeds thereof.

   "**Priority Asset Proceeds**" means any payment or distribution of assets, whether in cash, property or securities, and whether made by Deer Creek, a trustee in bankruptcy, receiver, manager or other liquidating agency making such payment or distribution, where such payment or distribution is generated from or attributable to the Priority Assets including any realization in respect thereof.

2. The undersigned is providing this acknowledgement and agreement in order to qualify as a Permitted Financing as contemplated in the Debenture.

3. The undersigned acknowledges the priority of the Debenture over the Lender Security insofar as it relates to the Priority Assets. The priority of the Debenture over the Priority Assets, and the rights of Talisman in respect thereof, shall apply notwithstanding:

(a) the time or order of creation, execution, delivery, attachment or perfection of the Debenture or the Lender Security; or the time or order of registration or filing of financing statements, real estate charges or other recording of the Debenture or the Lender Security;

(b) the date or dates of any existing or future obligation to pay arising under, or any loan or any existing or future advance or advances made in respect of, the Debenture or the Lender Financing; and

(c) the date or dates of any defaults by Deer Creek under the Debenture or the Lender Financing, the date of crystallization of any floating charge contained in the Debenture or the Lender Security, or the date of commencement of enforcement proceedings under the Debenture or the Lender Security.

4. The undersigned acknowledges and agrees that upon and during any Event of Default under the Debenture in respect of which the undersigned has received written notice from Talisman, Talisman shall be entitled to payment of the Secured Obligations (to the extent then due pursuant to the terms of the Debenture) in priority to any payments due under the Lender Financing in respect of any distribution of Priority Asset Proceeds.

5. (a) In the event that, notwithstanding paragraph 3 and 4 hereof, any payment or distribution in respect of Priority Asset Proceeds shall be received by the undersigned after the undersigned has received notice from Talisman that an Event of Default has occurred under the Debenture but before all Secured Obligations then due are paid in full then such payment or distribution, to the extent required to pay such Secured Obligations, shall be held in trust for the benefit of, and shall be paid over to Talisman for application to the payment of the Secured Obligations then due.

(b) Subject to the prior payment of all Secured Obligations under the Debenture to the point where Talisman has been paid in full under the Debenture, the undersigned shall be subrogated to the rights of Talisman to receive payments or distributions of assets of Deer Creek to the extent such payments or other assets would have been received by the undersigned but for the provisions of this paragraph 5.

6. Nothing contained in the Lender Financing or Lender Security shall limit or otherwise adversely affect Talisman's right to exercise its option to re-acquire the Scheduled Interests and the Scheduled Lands, including the Hydrocarbon Rights, from Deer Creek free and clear of the Lender Security, and at no cost to Talisman, in the event that Deer Creek does not meet certain production requirements, all as more particularly contemplated in Section 2.7 of the Sale Agreement. In the event that Talisman exercises this option, the undersigned hereby agrees to cooperate with Talisman and to do all things which are reasonably necessary or desirable to give effect thereto.

7. The undersigned will not assign, sell or otherwise transfer all or any of its rights under the Lender Financing or Lender Security to any person without obtaining a concurrent

written acknowledgement from the assignee or transferee in the form hereof for the benefit of Talisman. Any purported assignment, sale or transfer which does not comply herewith shall be null and void.

8. (a) If any covenant or provision herein or any portion thereof is determined to be void, unenforceable or prohibited by the law of any province or the local requirements of any provincial or federal governmental authority such shall not be deemed to affect or impair the validity of any other covenant or provision herein or portion thereof, as the case may be, nor the validity of such covenant or provision or portion thereof, as the case may be, in any other jurisdiction.

(b) This Acknowledgement shall be deemed to have been made and shall be construed in accordance with the laws of the Province of Alberta and the laws of Canada applicable therein and shall be treated in all respects as an Alberta contract. The undersigned hereby irrevocably submits to the jurisdiction of the courts of the Province of Alberta for any action, suit or any other proceeding arising out of or relating to this Acknowledgement and any other agreement or instrument mentioned herein or any of the transactions contemplated hereby.

(c) All notices or other communication required or permitted by this Acknowledgement must be in writing and either delivered by hand or by any form of electronic communication by means of which a written or typed copy is produced by the receiver thereof and is effective on actual receipt unless sent by electronic means in which case it is effective on the business day next following the date of transmission, addressed to the relevant party, as follows:

if to Talisman:

•

if to the undersigned:

•

or the last address or telecopier number of the party concerned, notice of which was given in accordance with this paragraph.

(d) This Acknowledgement and all its provisions shall enure to the benefit of Talisman, its successors and assigns and shall be binding upon the undersigned and its successors and permitted assigns.

This Acknowledgement executed and delivered this ___ day of ___________, 1999.

RECEIVED

2004 NOV 16 P 12: 11

OFFICE OF INTERNATIONAL
CORPORATE FINANCE

AS AT NOVEMBER 15, 2004, NO DOCUMENT HAS BEEN FILED BY DEER CREEK ENERGY LIMITED UNDER THIS TAB