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REGISTRANT'S NAME Harvest Energy Trust and Harvest Operations Corp.

*CURRENT ADDRESS 1900, 330 - 5th Avenue SW
Calgary, Alberta T2P 0L4

**FORMER NAME

**NEW ADDRESS

SEC MAIL PROCESSED MAR 08 2004 WASH., D.C.

PROCESSED MAR 16 2004 THOMSON FINANCIAL

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OICF/BY: EBS

DAT : 3/15/04

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

Attention Business Editors:
Harvest Energy Trust confirms February 17, 2003 cash distribution of $0.20 per unit.

(HTE.UN - TSX)

/NOT FOR DISTRIBUTION TO U.S. NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATES. ANY FAILURE TO COMPLY WITH THIS RESTRICTION MAY CONSTITUTE A VIOLATION OF U.S. SECURITIES LAW./

CALGARY, Jan. 15 /CNW/ - Harvest Energy Trust ("Harvest") (TSX: HTE.UN) announces that a cash distribution of $0.20 per trust unit will be paid on February 17, 2003 to Unitholders of record on January 31, 2003. The trust units of Harvest are expected to commence trading on an ex-distribution basis on January 29, 2003. This distribution amount represents Distributable Cash earned in the month of January 2003.

Harvest Energy Trust is a Calgary based oil and natural gas trust that strives to deliver stable monthly cash distributions to its Unitholders through its strategy of acquiring, enhancing and producing crude oil, natural gas and natural gas liquids. Harvest's assets, comprised of high quality medium and heavy gravity crude oil properties in East Central Alberta, and its hands on operating strategy underpin Harvest's objective to deliver superior economic returns to Unitholders. Harvest's strategy is to retain up to 50% of its Cash Available for Distribution for capital reinvestment in the form of existing property enhancement and new property acquisitions while maintaining a high rate of cash distributions. Harvest currently operates approximately 99% of its production, enabling it to pursue additional asset growth through property optimization and enhancement.

ADVISORY: Certain information regarding Harvest Energy Trust and Harvest Operations Corp. including management's assessment of future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing and transportation such as loss of market, volatility of prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources; as a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

%SEDAR: 00018577E

-0- 01/15/2003

/For further information: please contact either: Jacob Roorda, President, Harvest Energy Trust, 2400, 500 - 4th Avenue S.W., Calgary, AB T2P 2V6, Canada, Telephone: (403) 265-1178, Facsimile: (403) 265-3490, Email address: roorda(at)harvestenergy.ca, TSE Symbol: HTE.UN; David Fisher, Vice President, Finance, Harvest Energy Trust, 2400, 500 - 4th Avenue S.W., Calgary, AB T2P 2V6, Canada, Telephone: (403) 265-1178, Facsimile: (403) 265-3490 Email address: fisher(at)harvestenergy.ca, TSX Symbol: HTE.UN/

(HTE.UN)

CO: Harvest Energy Trust
ST: Alberta
IN: OIL
SU:

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

2

Attention Business Editors:
Harvest Energy Trust announces $15 million equity financing

/NOT FOR DISTRIBUTION TO U.S. NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATES. ANY FAILURE TO COMPLY WITH THIS RESTRICTION MAY CONSTITUTE A VIOLATION OF U.S. SECURITIES LAW/

CALGARY, Jan. 17 /CNW/ - Harvest Energy Trust ("Harvest") (TSX: HTE.UN) announces that it has entered into an underwriting agreement led by FirstEnergy Capital Corp. and including Haywood Securities Inc. to issue 1,000,000 Special Warrants at a price of $10.00 each on a bought deal basis and has granted to the underwriters an option to purchase an additional 500,000 special warrants at a price of $10.00 each. The underwriters may exercise this option at any time up to 48 hours prior to closing. Each special warrant will be exchangeable into one trust unit of Harvest at no additional cost to the holder. This issue is subject to normal regulatory approval and is expected to close on February 4, 2003. Harvest intends to file a prospectus to qualify the distribution of trust units on exercise of the special warrants.

Proceeds of the offering will be used to repay debt and for general working capital purposes.

Harvest Energy Trust is a Calgary based oil and natural gas trust that strives to deliver stable monthly cash distributions to its Unitholders through its strategy of acquiring, enhancing and producing crude oil, natural gas and natural gas liquids. Harvest's assets, comprised of high quality medium and heavy gravity crude oil properties in East Central Alberta, and its hands on operating strategy underpin Harvest's objective to deliver superior economic returns to Unitholders. Harvest's strategy is to retain up to 50% of its Cash Available for Distribution for capital reinvestment in the form of existing property enhancement and new property acquisitions while maintaining a high rate of cash distributions. Harvest currently operates approximately 99% of its production, enabling it to pursue additional asset growth through property optimization and enhancement.

ADVISORY: The Toronto Stock Exchange has neither approved nor disapproved of the information contained herein. Certain information regarding Harvest Energy Trust and Harvest Operations Corp. including management's assessment of future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing and transportation such as loss of market, volatility of prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources; as a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

%SEDAR: 00018577E

-0- 01/17/2003

/For further information: Jacob Roorda, President, Harvest Energy Tr
2400, 500 - 4th Avenue S.W., Calgary, AB T2P 2V6, Canada, Telephone:
(403) 265-1178, Facsimile: (403) 265-3490, Email address:
roorda(at)harvestenergy.ca, TSX Symbol: HTE.
Finance, Harvest Energy Trust, 24
2V6, Canada, Telephone: (403) 26
address: fisher(at)harvestenergy.
(HTE.UN.)

CO: Harvest Energy Trust

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ST: Alberta
IN: OIL
SU: FNC

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CNW 09:00e 17-JAN-03

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MATERIAL CHANGE REPORT

MATERIAL CHANGE REPORT UNDER SECTION 146(1) OF THE SECURITIES ACT

This form is intended as a guideline. A letter or other document may be used if the substantive requirements of this form are complied with. Every report that is filed under section 146(1) of the Securities Act shall be sent to the Executive Director in an envelope marked "Continuous Disclosure".

Where this report is filed on a confidential basis, write at the beginning of the report in block capitals "CONFIDENTIAL -SECTION 146".

1. **Reporting Issuer:**

Harvest Energy Trust ("Harvest")

2. **Date of Material Change:**

January 17, 2003

3. **News Release**

A press release disclosing the details outlined in this Material Change Report was issued by Harvest on January 17, 2003 and disseminated through the facilities of Canada NewsWire and would have been received by the securities commissions where Harvest is a "reporting issuer" and the stock exchanges on which the securities of Harvest are listed and posted for trading in the normal course of its dissemination.

4. **Summary of Material Change:**

Harvest has entered into an agreement with FirstEnergy Capital Corp. and Haywood Securities Inc. (the "Underwriters") to issue 1,000,000 Special Warrants at a price of $10.00 each on a bought deal basis and has also granted to Underwriters an option to purchase an additional 500,000 special warrants at a price of $10.00 each. The Underwriters may exercise this up to 48 hours prior to closing. Each special warrant will be exchangeable into one trust unit of Harvest at no additional cost to the holder.

5. **Full Description of Material Change:**

See attached press release.

6. **Reliance on Section 146(2) of the *Securities Act***

N/A

7. **Omitted Information:**

N/A

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8. **Senior Officer:**

For further information, please contact Jacob Roorda, President, of Harvest Operations Corp. at Harvest Energy Trust, 2400, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6, Telephone (403) 265-1178.

9. **Statement of Senior Officer:**

The foregoing accurately discloses the material change referred to in this report.

DATED this 22nd day of January, 2003, at the City of Calgary, in the Province of Alberta.

HARVEST ENERGY TRUST, by its duly authorized attorney, **HARVEST OPERATIONS CORP.**

Per: *"Jacob Roorda"*
Jacob Roorda
President

cc: The Toronto Stock Exchange

IT IS AN OFFENCE UNDER THE SECURITIES ACT AND THE ALBERTA SECURITIES COMMISSION RULES FOR A PERSON OR COMPANY TO MAKE A STATEMENT IN A DOCUMENT REQUIRED TO BE FILED OR FURNISHED UNDER THE ACT OR THE RULES THAT, AT THE TIME AND IN THE LIGHT OF THE CIRCUMSTANCES UNDER WHICH IT IS MADE, IS A MISREPRESENTATION.

ANY FEE PAYABLE TO THE ALBERTA SECURITIES COMMISSION UNDER THE SECURITIES ACT, THE SECURITIES REGULATION AND THE ALBERTA SECURITIES COMMISSION RULES SHALL BE PAID TO THE ALBERTA SECURITIES COMMISSION IN ACCORDANCE WITH THE REQUIREMENTS OF THE FEE SCHEDULE TO THE SECURITIES REGULATION. ANY FAILURE TO ACCOMPANY A FORM OR APPLICATION WITH THE PRESCRIBED FEE SHALL RESULT IN THE RETURN OF THAT FORM OR APPLICATION.

Harvest Energy Trust

Harvest Energy Trust – News Release
(HTE.UN – TSX)

HARVEST ENERGY TRUST ANNOUNCES $15 MILLION EQUITY FINANCING

JANUARY 17, 2003

Calgary, January 17, 2003 – Harvest Energy Trust ("Harvest") (TSX: HTE.UN) announces that it has entered into an underwriting agreement with FirstEnergy Capital Corp. and Haywood Securities Inc. to issue 1,000,000 Special Warrants at a price of $10.00 each on a bought deal basis and granted to the underwriters an option to purchase an additional 500,000 special warrants at a price of $10.00 each. The underwriters may exercise this up to 48 hours prior to closing. Each special warrant will be exchangeable into one trust unit of Harvest at no additional cost to the holder. This issue is subject to normal regulatory approval and is expected to close on February 6, 2003. Harvest intends to file a prospectus to qualify the distribution of trust units on exercise of the special warrants.

Proceeds of the offering will be used to repay debt and for general working capital purposes.

Harvest Energy Trust is a Calgary based oil and natural gas trust that strives to deliver stable monthly cash distributions to its Unitholders through its strategy of acquiring, enhancing and producing crude oil, natural gas and natural gas liquids. Harvest has successfully acquired high quality medium and heavy gravity crude oil properties in East Central Alberta and will endeavor to deliver superior economic returns to Unitholders. Harvest's strategy is to retain up to 50% of its Cash Available for Distribution for capital reinvestment in the form of existing property enhancement and new property acquisitions while maintaining a high rate of cash distributions. Harvest currently operates approximately 99% of its production, enabling it to pursue additional asset growth through property optimization and enhancement.

For further information, please contact:

Jacob Roorda, President
Harvest Energy Trust
2400, 500 – 4th Avenue S.W.
Calgary, Alberta T2P 2V6
Canada

Telephone: (403) 265-1178
Facsimile: (403) 265-3490
Email address: roorda@harvestenergy.ca
TSX Symbol: HTE.UN

ADVISORY: The Toronto Stock Exchange has neither approved nor disapproved of the information contained herein. Certain information regarding Harvest Energy Trust and Harvest Operations Corp. including management's assessment of future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing and transportation such as loss of market, volatility of prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources; as a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

NOT FOR DISTRIBUTION TO U.S. NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATED. ANY FAILURE TO COMPLY WITH THIS RESTRICTION MAY CONSTITUTE A VIOLATION OF U.S. SECURITIES LAW.

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

Attention Business Editors:
Harvest Energy Trust Announces Closing of Special Warrant Financing

NOT FOR DISTRIBUTION TO U.S. NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATED. ANY FAILURE TO COMPLY WITH THIS RESTRICTION MAY CONSTITUTE A VIOLATION OF U.S. SECURITIES LAW.

(HTE.UN - TSX)

CALGARY, Feb. 4 /CNW/ - Harvest Energy Trust ("Harvest") is pleased to announce the closing of its offering of Special Warrants previously announced on January 17th, 2003. In accordance with the underwriting agreement, Harvest issued 1,500,000 Special Warrants at a price of $10.00 per Special Warrant. Each Special Warrant will be exercisable into one trust unit of Harvest, at no additional cost to the holder subject to adjustment in certain circumstances. Harvest intends to file a prospectus to qualify the distribution of trust units issuable upon the exercise of the Special Warrants. The offering was conducted on a "bought deal" basis by a syndicate led by FirstEnergy Capital Corp. and including Haywood Securities Inc. Certain directors and officers of Harvest participated in the offering by acquiring 180,500 of the Special Warrants.

Proceeds of the offering will be used to repay debt and for general working capital purposes. Harvest currently has 9,462,500 trust units outstanding. After giving effect to the exercise of the Special Warrants into trust units, Harvest will have 10,962,500 trust units outstanding.

Harvest Energy Trust is a Calgary based oil and natural gas trust that strives to deliver stable monthly cash distributions to its Unitholders through its strategy of acquiring, enhancing and producing crude oil, natural gas and natural gas liquids. Harvest's assets, comprised of high quality medium and heavy gravity crude oil properties in East Central Alberta, and its hands on operating strategy underpin Harvest's objective to deliver superior economic returns to Unitholders. Harvest's strategy is to retain up to 50% of its Cash Available for Distribution for capital reinvestment in the form of existing property enhancement and new property acquisitions while maintaining a high rate of cash distributions. Harvest currently operates approximately 99% of its production, enabling it to pursue additional asset growth through property optimization and enhancement.

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%SEDAR: 00018577E

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/For further information: Jacob Roorda, President or David Fisher, Vice President, Finance, Harvest Energy Trust, Telephone: (403) 265-1178. Facsimile: (403) 265-3490, Email addr...

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CO: Harvest Energy Trust
ST: Alberta
IN: OIL

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

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Attention Business Editors:
Harvest Energy Trust Announces Approval of Dividend Reinvestment and Optional Unit Purchase Plan

(HTE.UN - TSX)

NOT FOR DISTRIBUTION TO U.S. NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATED. ANY FAILURE TO COMPLY WITH THIS RESTRICTION MAY CONSTITUTE A VIOLATION OF U.S. SECURITIES LAW.

CALGARY, Feb. 4 /CNW/ - Harvest Energy Trust (the "Trust") announces that it has received all necessary regulatory approvals, effective January 31, 2003, in respect of its distribution reinvestment and optional unit purchase plan (the "DRIP Plan"). Furthermore, the DRIP Plan is available for the January distribution to be paid on February 17, 2003 to Unitholders of record on January 31, 2003.

The DRIP Plan provides eligible Unitholders of trust units the advantage of accumulating additional trust units by reinvesting their cash distributions paid by the Trust. The cash distributions will be reinvested at the discretion of Harvest Operations Corp., either by acquiring trust units at prevailing market rates, or by acquiring trust units issued from treasury at 95% of the Average Market Price (which is the weighted average trading price of trust units on the Toronto Stock Exchange for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days). In addition, participants in the DRIP Plan may also purchase additional trust units by investing optional cash payments to a maximum of $5,000 per month and a minimum of $1,000 per remittance. The price of trust units purchased from treasury with optional cash payments will be 100% of the Average Market Price. No commission, service charges or brokerage fees are payable by participants in connection with trust units acquired under the DRIP Plan.

The DRIP Plan is presently available to Canadian registered holders, other than Unitholders who are resident of Quebec. Residents of the United States may not participate in the DRIP Plan.

Detailed information about the DRIP Plan can be obtained from Valiant Trust Company at No. 510, 550 - 6th Avenue S.W., Calgary, Alberta T2P 0S2 Attention: Debbie Le Blanc, Operations Officer (telephone: (403) 233-2801 or facsimile: (403) 233-2847.

Harvest Energy Trust is a Calgary based oil and natural gas trust that strives to deliver stable monthly cash distributions to its Unitholders through its strategy of acquiring, enhancing and producing crude oil, natural gas and natural gas liquids. Harvest's assets, comprised of high quality medium and heavy gravity crude oil properties in East Central Alberta, and its hands on operating strategy underpin Harvest's objective to deliver superior economic returns to Unitholders. Harvest's strategy is to retain up to 50% of its Cash Available for Distribution for capital reinvestment in the form of existing property enhancement and new property acquisitions while maintaining a high rate of cash distributions. Harvest currently operates approximately 99% of its production, enabling it to pursue additional asset growth through property optimization and enhancement.

ADVISORY: Certain information regarding Harvest Energy Trust and Harvest Operations Corp. including management's assessment of future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing and transportation such as loss of market, volatility of prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources; as a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

%SEDAR: 00018577E

-0- 02/04/2003

/For further information: Jacob Roorda, President, Harvest Energy Trust, Telephone: (403) 265-1178, Facsimile: (403) 265-3490, Email address: information(at)harvestenergy.ca, David Fisher, Vice President, Finance, Harvest Energy Trust, Telephone: (403) 265-1178, Facsimile: (403) 265-3490, Email address: information(at)harvestenergy.ca/

(HTE.UN)

CO: Harvest Energy Trust
ST: Alberta
IN: OIL
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MATERIAL CHANGE REPORT

MATERIAL CHANGE REPORT UNDER SECTION 146(1) OF THE SECURITIES ACT

This form is intended as a guideline. A letter or other document may be used if the substantive requirements of this form are complied with. Every report that is filed under section 146(1) of the Securities Act shall be sent to the Executive Director in an envelope marked "Continuous Disclosure".

Where this report is filed on a confidential basis, write at the beginning of the report in block capitals "CONFIDENTIAL -SECTION 146".

1. **Reporting Issuer:**

   Harvest Energy Trust ("Harvest")

2. **Date of Material Change:**

   February 4, 2003

3. **News Release**

   A press release disclosing the details outlined in this Material Change Report was issued by Harvest on February 4, 2003 and disseminated through the facilities of Canada NewsWire and would have been received by the securities commissions where Harvest is a "reporting issuer" and the stock exchanges on which the securities of Harvest are listed and posted for trading in the normal course of its dissemination.

4. **Summary of Material Change:**

   On February 4, 2003, Harvest announced that it had successfully closed a "bought deal" financing arrangement with a syndicate of underwriters led by FirstEnergy Capital Corp. and Haywood Capital Securities Inc. pursuant to which Harvest issued 1,500,000 Special Warrants on a private placement basis at a price of $10.00 per Special Warrant for aggregate gross proceeds of $15,000,000. Each Special Warrant is exchangeable into one trust unit of Harvest, subject to certain conditions and adjustments, at no additional cost to the holder.

5. **Full Description of Material Change:**

   See attached press release.

6. **Reliance on Section 146(2) of the *Securities Act*:**

   N/A

7. **Omitted Information:**

   N/A

8. **Senior Officer:**

For further information, please contact Jacob Roorda, President, of Harvest Operations Corp. at Harvest Energy Trust, 2400, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6, Telephone (403) 265-1178.

9. **Statement of Senior Officer:**

The foregoing accurately discloses the material change referred to in this report.

DATED this 4th day of February, 2003, at the City of Calgary, in the Province of Alberta.

HARVEST ENERGY TRUST, by its duly authorized attorney, **HARVEST OPERATIONS CORP.**

Per: (signed) "David Fisher"
David Fisher
Vice President, Finance

cc: The Toronto Stock Exchange

IT IS AN OFFENCE UNDER THE SECURITIES ACT AND THE ALBERTA SECURITIES COMMISSION RULES FOR A PERSON OR COMPANY TO MAKE A STATEMENT IN A DOCUMENT REQUIRED TO BE FILED OR FURNISHED UNDER THE ACT OR THE RULES THAT, AT THE TIME AND IN THE LIGHT OF THE CIRCUMSTANCES UNDER WHICH IT IS MADE, IS A MISREPRESENTATION.

ANY FEE PAYABLE TO THE ALBERTA SECURITIES COMMISSION UNDER THE SECURITIES ACT, THE SECURITIES REGULATION AND THE ALBERTA SECURITIES COMMISSION RULES SHALL BE PAID TO THE ALBERTA SECURITIES COMMISSION IN ACCORDANCE WITH THE REQUIREMENTS OF THE FEE SCHEDULE TO THE SECURITIES REGULATION. ANY FAILURE TO ACCOMPANY A FORM OR APPLICATION WITH THE PRESCRIBED FEE SHALL RESULT IN THE RETURN OF THAT FORM OR APPLICATION.

Harvest Energy Trust

Harvest Energy Trust – News Release

(HTE.UN – TSX)

HARVEST ENERGY TRUST ANNOUNCES CLOSING OF SPECIAL WARRANT FINANCING

FEBRUARY 4, 2003

Calgary, February 4, 2003 – Harvest Energy Trust ("Harvest") is pleased to announce the closing of its offering of Special Warrants previously announced on January 17th, 2003. In accordance with the underwriting agreement, Harvest issued 1,500,000 Special Warrants at a price of $10.00 per Special Warrant. Each Special Warrant will be exercisable into one trust unit of Harvest, at no additional cost to the holder subject to adjustment in certain circumstances. Harvest intends to file a prospectus to qualify the distribution of trust units issuable upon the exercise of the Special Warrants. The offering was conducted on a "bought deal" basis by a syndicate led by FirstEnergy Capital Corp. and including Haywood Securities Inc. Certain directors and officers of Harvest participated in the offering by acquiring 180,500 of the Special Warrants.

Proceeds of the offering will be used to repay debt and for general working capital purposes. Harvest currently has 9,462,500 trust units outstanding. After giving effect to the exercise of the Special Warrants into trust units, Harvest will have 10,962,500 trust units outstanding.

Harvest Energy Trust is a Calgary based oil and natural gas trust that strives to deliver stable monthly cash distributions to its Unitholders through its strategy of acquiring, enhancing and producing crude oil, natural gas and natural gas liquids. Harvest's assets, comprised of high quality medium and heavy gravity crude oil properties in East Central Alberta, and its hands on operating strategy underpin Harvest's objective to deliver superior economic returns to Unitholders. Harvest's strategy is to retain up to 50% of its Cash Available for Distribution for capital reinvestment in the form of existing property enhancement and new property acquisitions while maintaining a high rate of cash distributions. Harvest currently operates approximately 99% of its production, enabling it to pursue additional asset growth through property optimization and enhancement.

For further information, please contact either:

Jacob Roorda, President or David Fisher, Vice President, Finance

Harvest Energy Trust
2400, 500 – 4th Avenue S.W.
Calgary, AB T2P 2V6
Canada

Telephone: (403) 265-1178
Facsimile: (403) 265-3490
Email address: information@harvestenergy.ca
TSE Symbol: HTE.UN

ADVISORY: Certain information regarding Harvest Energy Trust and Harvest Operations Corp. including management's assessment of future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and gas exploration, production, marketing and transportation such as loss of market, volatility of prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources; as a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

NOT FOR DISTRIBUTION TO U.S. NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATED. ANY FAILURE TO COMPLY WITH THIS RESTRICTION MAY CONSTITUTE A VIOLATION OF U.S. SECURITIES LAW.

A copy of this preliminary prospectus has l *h Columbia, and*
Ontario but has not yet become final for the *be complete and*
may have to be amended. The securities ma *ties.*

This prospectus constitutes a public offerin *d therein only by*
persons authorized to sell such securities. N *offence to claim*
otherwise. These securities have not been a *gly, except to the*
extent exempt from such registration require *not constitute an*
offer to sell or a solicitation of an offer to bu

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New Issue **February 12, 2003**

PRELIMINARY PROSPECTUS

Harvest Energy Trust

1,500,000 Trust Units issuable

on exercise of 1,500,000 Special Warrants

Harvest Energy Trust (the "**Trust**") is hereby qualifying for distribution 1,500,000 Trust Units of the Trust (the "**Qualified Units**") issuable upon exercise of 1,500,000 issued and outstanding special warrants (the "**Special Warrants**"). The Special Warrants were issued on February 4, 2003 (the "**Closing Date**") pursuant to the Special Warrant Indenture (as defined herein) and sold to purchasers in the provinces of Alberta, British Columbia and Ontario (collectively, the "**Filing Provinces**") on a private placement basis pursuant to prospectus exemptions under applicable securities legislation through FirstEnergy Capital Corp. and Haywood Securities Inc. (collectively, the "**Underwriters**"). The Special Warrants are not available for purchase pursuant to this prospectus. See "Plan of Distribution".

The issue price of $10.00 per Special Warrant was determined by negotiation between Harvest Operations Corp. ("**Harvest**" or the "**Corporation**"), a wholly-owned subsidiary of and manager of the Trust, on behalf of the Trust, and the Underwriters. No commission or fee will be payable to the Underwriters by the Trust in connection with the distribution of the Qualified Units upon the exercise of the Special Warrants.

	Offering Price	Underwriters' Fee (1)	Net Proceeds (2)
Per Special Warrant	$ 10.00	$ 0.50	$ 9.50
Total	$ 15,000,000	$ 750,000	$ 14,250,000

Notes:

(1) The Trust paid a fee of 5% to the Underwriters in connection with the sale of the Special Warrants. No commission or fee is payable to the Underwriters in connection with the distribution of the Qualified Units upon the exercise of the Special Warrants.

(2) Before deducting the expenses in connection with the issuance of the Special Warrants and qualification for distribution of the Qualified Units estimated to be $200,000.

Each Special Warrant entitles the holder to acquire, subject to adjustment, at no additional cost, one Qualified Unit at any time until 5:00 p.m. (Calgary time) on the earlier of: (i) five (5) Business Days (as defined herein) after the Final Receipt Date (as defined herein); and (ii) the first anniversary of the Closing Date (the first of such events to occur is hereinafter referred to as the "**Expiry Time**").

In the event that a Final MRRS decision document (as defined herein) is not obtained by the Trust on or prior to the Qualification Deadline (as defined herein) on behalf of the Canadian securities regulatory authority in each of the Filing Provinces, then each holder of Special Warrants in each of the Filing Provinces on whose behalf a Final MRRS decision document has not been obtained (or, if a Final MRRS decision document has not been obtained on behalf of the Province of Alberta, all holders wherever resident) shall be entitled after the Qualification Deadline to receive on the exercise or deemed exercise of the Special Warrants an additional 0.09 of a Trust Unit for each such Special Warrant so exercised without additional payment. Special Warrants not previously exercised by the holders thereof shall be deemed to be exercised *immediately prior to the Expiry Time without further action on the part of the holder.* The Trust will continue to use its best efforts to obtain a Final MRRS decision document on behalf of the Canadian securities regulatory authority in each Filing Province where a Final MRRS decision document is not obtained on or before the Qualification Deadline until February 4, 2004.

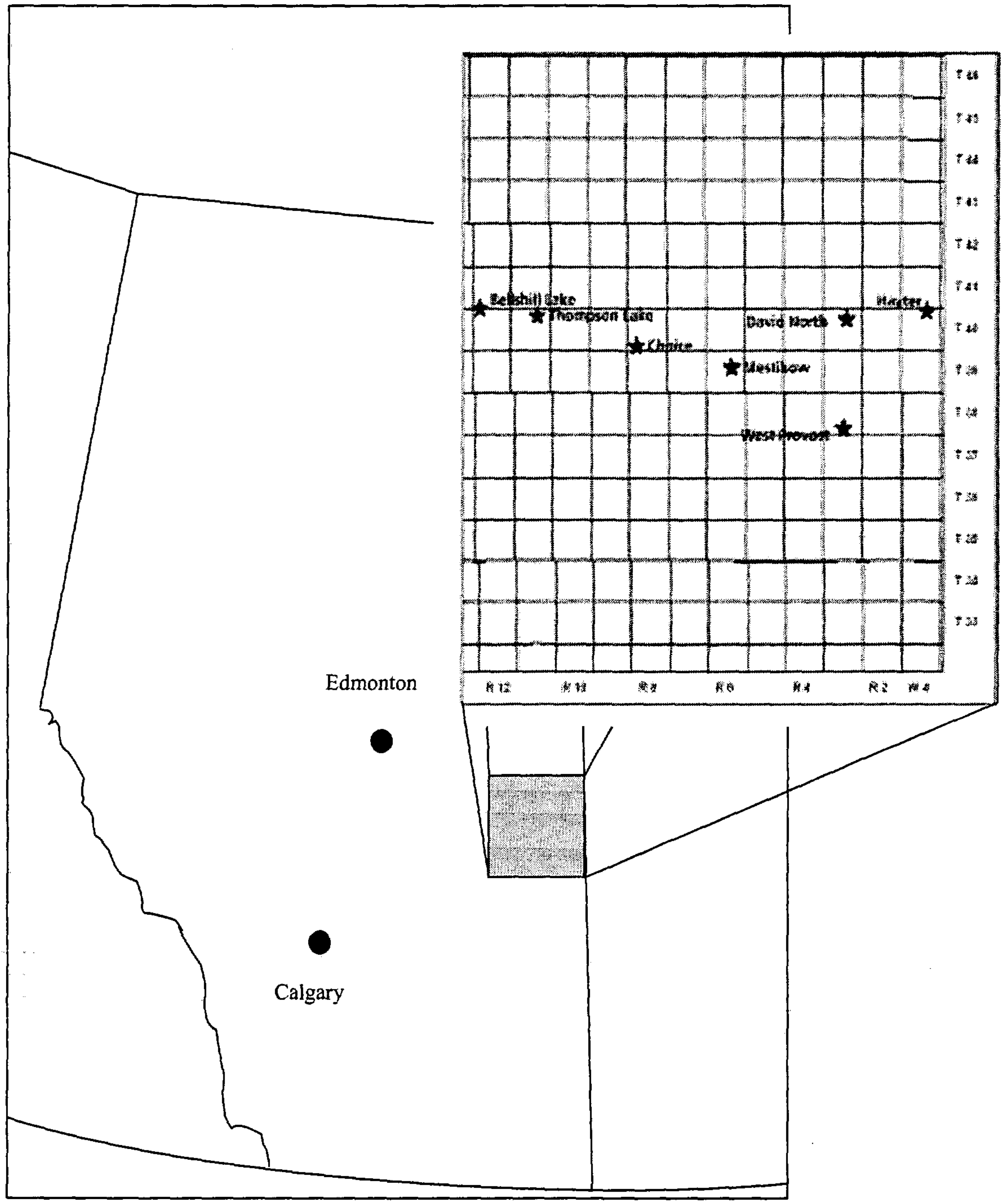
Any Trust Units issued upon the exercise of Special Warrants prior to the Final Receipt Date will be subject to relevant hold periods under applicable securities legislation.

An investment in the Qualified Units is highly speculative due to a number of risks, including: (i) the volatility of oil, natural gas and natural gas product prices; (ii) Trust's and the Corporation's ability to replace reserves by purchasing reserves or otherwise; (iii) depletion and recoverability of reserves and reserves estimates; (iv) environmental concerns; (v) debt service; (vi) changes in legislation; (vii) the nature of oil and natural gas operations; (viii) reliance on the Corporation; (ix) potential conflicts of interest; (x) investment eligibility; (xi) the nature of the Trust Unit form of security; and (xii) fluctuations in interest rates. See "Risk Factors".

The Trust Units are listed and posted for trading on the Toronto Stock Exchange (the "**TSX**") under the trading symbol "HTE". The TSX has conditionally approved the listing of the Qualified Units subject to the Trust fulfilling all of the requirements of such exchange. On January 16, 2003, being the day of negotiation of the issue price of the Special Warrants, the closing price of the Trust Units on the TSX was $10.75. On February 11, 2003, being the last day on which the Trust Units traded prior to the date of this prospectus, the closing price of the Trust Units on the TSX was $10.45. See "Price Range and Trading Volume".

Certificates for the Trust Units will be available for delivery within five (5) Business Days from the date of the exercise or deemed exercise of the Special Warrants. Certain legal matters in connection with this offering will be reviewed on behalf of the Trust and the Corporation by Burnet, Duckworth & Palmer LLP, and on behalf of the Underwriters by Blake, Cassels & Graydon LLP.

PROPERTIES OF THE TRUST



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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

The Trust is hereby providing cautionary statements identifying important factors that could cause the Trust's actual results to differ materially from those projected in forward-looking statements made in this prospectus. Any statements that express or involve discussions as to expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always through use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "estimated", "intends", "plans", "projection" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this prospectus, and particularly in the risk factors set forth herein under "Risk Factors". Because actual results or outcome could differ materially from those expressed in any forward-looking statements of the Trust made by or on behalf of the Trust, investors should not place undue reliance on any such forward-looking statements. Further, any forward-looking statement speaks only as of the date on which such statement is made, and the Trust undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by law including applicable securities laws. New factors emerge from time to time, and it is not possible for management of the Corporation to predict all of such factors and to assess in advance the impact of each such factor on the Trust or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

GLOSSARY OF TERMS

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

"ABCA" means the *Business Corporations Act* (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time.

"Additional Direct Royalties" means a 99% undivided interest in the royalty interests acquired by the Corporation in connection with the Additional Properties Acquisition and sold by the Corporation to the Trust pursuant to a Direct Royalties Sale Agreement.

"Additional Properties" means the oil and natural gas properties and related assets acquired under the terms of the Additional Properties Agreement. See "Additional Properties".

"Additional Properties Acquisition" means the acquisition of the Additional Properties and the Additional Direct Royalties pursuant to the Additional Properties Agreement.

"Additional Properties Acquisition Cost" means the aggregate purchase price paid for the Additional Properties and the Additional Direct Royalties, being approximately $53.2 million, after adjustments. See "Additional Properties" and "Risk Factors".

"Additional Properties Agreement" means the agreement of purchase and sale between the Additional Properties Vendor and the Corporation dated August 1, 2002 for the purchase of the Additional Properties and the Additional Direct Royalties.

"Additional Properties Vendor" means Anadarko Canada Corporation.

"Administration Agreement" means the agreement dated September 27, 2002 between the Trustee and the Corporation pursuant to which the Corporation has agreed to provide certain administrative and advisory services in connection with the Trust. See "Description of the Trust" and "Information Respecting the Corporation".

"AEUB" means the Alberta Energy and Utilities Board.

"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 and for this purpose a corporation shall be deemed to be controlled by the Person who owns or effectively controls, 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 or otherwise) to elect the majority of its board of directors.

"ARTC" means the Alberta Royalty Tax Credit, an Alberta provincial government program under which, in certain circumstances, tax credits may be provided against royalties on oil and natural gas production payable to the Province of Alberta.

"Board of Directors" or **"Harvest Board"** means the board of directors of the Corporation.

"Business Day" means a day, other than a Saturday, Sunday or statutory holiday in the Province of Alberta or any other day on which banks in Calgary, Alberta are not open for business.

"Canadian resource property" has the meaning given to that term in the Tax Act.

"Capital Fund" means the cumulative amount of funds that the Trust retains from the Cash Available For Distribution to finance future acquisitions and development of the Properties less amounts paid in respect of acquisitions and development of the Properties. Capital Fund retentions may range from 0% to 50% of the annual Cash Available For Distribution.

"Caribou" means Caribou Capital Corp.

"Cash Available For Distribution" means, for any particular period, the NPI Income and the Direct Royalties, any interest or other income from Permitted Investments, and ARTC received by the Trust net of Non-Deductible Crown royalties that are reimbursed by the Trust to the Corporation plus dividends on the issued and outstanding securities of the Corporation held by the Trust less direct expenses and liabilities of the Trust including Debt Service Charges, and prior to any retention by the Trust for the Capital Fund. See "Description of the Trust – Cash Available For Distribution".

"Closing Date" means February 4, 2003, being the date on which the Trust issued the Special Warrants.

"Commodity Price and Currency Swaps" means swap, hedging and other arrangements made by the Corporation (including any assumed by the Corporation by contract, operation of law or otherwise), from time to time, in respect of commodity prices or rates of exchange of currencies the purpose of which is to mitigate or eliminate exposure to fluctuations in prices of commodities or rates of exchange of one currency for another which affect Production Costs or revenues attributable to the Properties and includes guarantees, either direct or indirect, by the Corporation of any swap, hedging and other arrangements made by Persons wholly-owned, directly or indirectly, by the Corporation or the Trust provided such Person has guaranteed, directly or indirectly, the Corporation's Commodity Price and Currency Swaps.

"Corporation" means Harvest Operations Corp., a wholly-owned subsidiary of the Trust.

"Credit Facilities" means the credit facilities made available to the Corporation or the Trust from time to time, including, without limitation, the Current Bank Facility. See "Information Respecting the Corporation – Borrowing".

"Current Lender" means a syndicate of lenders with WestLB AG, New York Branch as a lender and as administrative agent for all of the lenders. On the date hereof, WestLB AG, New York Branch is the only such syndicate member.

"Current Bank Facility" means the existing credit facility provided by the Current Lender as more fully described under "Information Respecting the Corporation – Borrowing".

"Debt Service Charges" means all interest and principal repayments and other costs, expenses and disbursements relating to the borrowing of funds by the Trust and/or the Corporation, as applicable. See "Information Respecting the Corporation – Borrowing".

"Deferred Purchase Price Obligation" means the ongoing obligation of the Trust to pay to the Corporation, to the extent of the Trust's available funds, an amount equal to 99% of the cost of, including any amount borrowed to acquire, any Canadian resource property acquired by the Corporation, and the cost of, including any amount borrowed to fund, certain designated capital expenditures in relation to the Properties.

"Direct Royalties" means royalty interests in petroleum and natural gas rights acquired by the Trust from time to time including the Initial Direct Royalties acquired by the Trust from the Corporation pursuant to a Direct Royalties Sale Agreement and the Additional Direct Royalties acquired from the Corporation in connection with the Additional Properties Acquisition.

"Direct Royalties Sale Agreement" means any purchase and sale agreement between the Trust and the Corporation providing for the purchase by the Trust from the Corporation of Direct Royalties including the amended and restated agreement dated September 27, 2002 in respect of the purchase of the Initial Direct Royalties and the agreement dated November 15, 2002 between the Corporation and the Trust in respect of the purchase of the Additional Direct Royalties.

"Distributable Cash" means, for any particular period, the Cash Available For Distribution less any amounts retained by the Trust and deposited into the Capital Fund.

"Economic Life" means, with respect to an oil and natural gas property, the time remaining before production of Petroleum Substances from the property is forecast to be uneconomic under escalating cost and price assumptions.

"Established Reserves" means the sum of 50% of the Probable Reserves and 100% of Proved Reserves.

"Expiry Date" means, the earlier of: (i) five (5) Business Days after the Final Receipt Date; and (ii) the first anniversary of the Closing Date.

"Expiry Time" means 5:00 p.m. (Calgary time) on the Expiry Date.

"Facilities" means natural gas processing plants, natural gas compression facilities, natural gas gathering facilities, crude oil batteries, crude oil pipelines, power generation facilities and similar facilities in which Petroleum Substances are compressed, processed, gathered, transported, treated, measured or stored and which are located near the oil or natural gas wells from which such Petroleum Substances are produced.

"Farmout" means an agreement whereby a third party agrees to pay for the drilling of a well on one or more of the Properties in order to earn an interest therein, with the Corporation retaining a residual interest in such Properties.

"Filing Provinces" means, collectively, the provinces of Alberta, British Columbia and Ontario.

"Final MRRS decision document" means the document issued by the principal regulator under the Mutual Reliance Procedures that evidences that final receipts of the Securities Commission have been issued for the Final Prospectus.

"Final Prospectus" means the final prospectus of the Trust which qualifies the distribution of the Trust Units issuable upon the exercise of the Special Warrants.

"Final Receipt Date" means the latest date on which a Final MRRS decision document for the Final Prospectus is issued by the Alberta Securities Commission, as principal regulator of the Trust under the Mutual Reliance Procedures, on behalf of Canadian securities regulatory authorities in each of the Filing Provinces.

"Future Acquisition Costs" means the acquisition costs relating to any acquisition of Properties after the date of the NPI Agreement.

"General and Administrative Costs" means the aggregate amount representing all expenditures and costs incurred in the management and administration of the Corporation or the Trust reasonably allocable by the Corporation to the Properties including, (a) all reasonable costs and expenses relating to the Corporation and the Trust and paid to third parties by or on behalf of the Corporation or their affiliates; and (b) all reasonable costs and expenses incurred specifically for the Corporation or the Trust relating to the Corporation or the Trust including, auditing, accounting, bookkeeping, rent and other leasehold expenses, legal, land administration, engineering, travel, consulting, telephone, data processing, reporting, executive and management time, salaries, bonuses (including under an executive bonus plan of the Corporation, if any).

"Gross Reserves" means the Corporation's interest, or the interest to be acquired by the Corporation, in reserves before the deduction of royalty interests.

"Initial Direct Royalties" means a 99% undivided interest in the royalty interests acquired by the Corporation in connection with the acquisition of the Initial Properties and sold to the Trust pursuant to a Direct Royalties Sale Agreement.

"Initial Properties" means the properties and assets (other than the Initial Direct Royalties) acquired by the Corporation from the Initial Properties Vendors pursuant to the Sale Agreement. See "Acquisition of The NPI" and "Initial Properties".

"Initial Properties Acquisition Cost" means the aggregate purchase price paid for the Initial Properties and the Initial Direct Royalties after adjustments, being $26.1 million.

"Initial Public Offering" means the initial public offering of 3,750,000 Trust Units at a price of $8.00 per Trust Unit completed on December 5, 2002, resulting in proceeds of $30,000,000, and includes the over-allotment option granted in favour of and exercised by the Underwriters to acquire an additional 562,500 Trust Units at a price of $8.00 per Trust Unit, resulting in proceeds of $4,500,000.

"Initial Properties Vendors" means Devon Canada, a partnership, and Devon ARL Corporation.

"Interest Rate Swaps" means interest rate swap, hedging and other arrangements made by the Corporation (including any assumed by the Corporation by contract, operation of law or otherwise), from time to time, the purpose of which is to mitigate or eliminate exposure to fluctuations in interest rates applicable to the Credit Facilities or other interest rates which affect the production costs under the NPI Agreement and includes guarantees, either direct or indirect, by the Corporation of any interest rate swap, hedging and other arrangements made by Persons wholly-owned, directly or indirectly, by the Corporation or the Trust provided such Person has also guaranteed, directly or indirectly, the Corporation's Interest Rate Swaps.

"Interim Loan" means the loan agreements dated July 10, 2002 and July 30, 2002 between Caribou and the Trust pursuant to which Caribou agreed to advance up to $43 million to the Trust to finance, in part, the purchase of the NPI, the Initial

Direct Royalties and the Additional Direct Royalties from the Corporation, which were repaid in full from the proceeds of the Initial Public Offering. See "Description of the Trust – Interim Loan".

"Management Group" means those directors and officers of the Corporation and their close friends and associates who held the Management Group Debentures. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust" and "Interests of Management and Others in Material Transactions".

"Management Group Debentures" means debentures of 990148 Alberta Ltd. formerly held by the Management Group. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust", and "Interests of Management and Others in Material Transactions".

"McDaniel" means McDaniel & Associates Consultants Ltd., independent oil and natural gas reservoir engineers of Calgary, Alberta.

"McDaniel Report" means the independent engineering evaluation of the reserves associated with the Initial Properties and the Initial Direct Royalties as at August 1, 2002 conducted by McDaniel on behalf of the Corporation and the Additional Properties and the Additional Direct Royalties as at June 1, 2002 conducted by McDaniel on behalf of Anadarko Canada Corporation (which has been mechanically updated to August 1, 2002), based on constant and escalating price and cost assumptions.

"Miscellaneous Interests" means all miscellaneous properties, assets and rights which are related to Petroleum and Natural Gas Rights or Tangibles (other than Petroleum and Natural Gas Rights and Tangibles).

"Mutual Reliance Procedures" means the mutual reliance review system procedures provided under National Policy 43-201, Mutual Reliance Review System for Prospectuses and Annual Information Forms, of the Canadian Securities Administrators.

"Non-Deductible Crown Royalties" means Crown royalties which are: (i) required to be included in taxable income pursuant to Section 12(1)(o) of the Tax Act or any replacement thereof or substitution therefor; or (ii) not permitted to be deducted in computing taxable income pursuant to Section 18(1)(m) of the Tax Act or any replacement thereof or substitution therefor.

"Notes" means the promissory notes issuable by the Corporation in series pursuant to a note indenture to be redeemed in consideration for a portion of the NPI, having a fair market value equal to such principal amount, and being subject to the following terms and conditions:

(a) being unsecured and bearing interest at 6% per annum payable monthly in arrears on the 20th day of the next following month;

(b) being subordinate to all senior indebtedness which includes all indebtedness for borrowed money or owing in respect of property purchases on any default in payment of any such senior indebtedness, and to all trade debt of the Corporation or any subsidiary of the Corporation or the Trust on any creditor proceedings such as bankruptcy, liquidation or insolvency;

(c) being subject to earlier prepayment, being due and payable on the 15th anniversary of the date of issuance;

(d) being an aggregate principal amount not to exceed $500 million, and

(e) being subject to such other standard terms and conditions as would be included in a note indenture for promissory notes of this kind, as may be approved by the Harvest Board.

"NPI" means the net profit interest owing by the Corporation to the Trust pursuant to the NPI Agreement.

"NPI Agreement" means the amended and restated net profit interest agreement regarding the creation and sale of the NPI dated September 27, 2002 between the Corporation and the Trustee as trustee for and on behalf of the Trust.

"NPI Deductions" means, the aggregate of (a): the Corporation's share of all costs and expenses in respect of the operation of the Properties and includes, without limitation, those costs relating to (i) the drilling completion, equipping and re-entry of wells (including injection wells); (ii) the compression, dehydration, gathering, treating, processing and transportation of Production or substances produced from the Properties; (iii) the acquisition of Tangibles (including construction of Facilities); (iv) the payment of royalties and similar burdens other than Non-Deductible Crown Royalties; (v) the acquisition of Miscellaneous Interests; (vi) the sale and marketing of Production; (vii) insurance premiums; (viii) property, municipal, mineral and other taxes; (ix) the abandonment of wells and the decommissioning of Tangibles and Facilities; (x) remediation and reclamation of surface sites and clean-up and monitoring of environmental damage; (xi) drilling, transportation and other contracts or contract settlements not assigned to specific Properties; (xii) income, capital and other taxes of the Corporation reasonably allocable by the Corporation to the Properties; (b) Debt Service Charges incurred by the Corporation and any net loss from Interest Rate Swaps; (c) amounts contributed to the Reclamation Fund or the Reserve Fund; (d) General and Administrative Costs in excess of Residual Revenues; and (e) Future Acquisition Costs; but excluding depreciation, deferred taxes and losses from Commodity Price and Currency Swaps.

"NPI Income" in respect of any period for which the NPI Income is calculated means 99% of production revenues from the Properties less 99% of the amount by which all the NPI Deductions for such period exceeds the aggregate, without duplication, for such period of: (A) acquisition costs associated with an acquisition of certain rights and other interests under the NPI Agreement paid with the proceeds from the sale of Properties; (B) withdrawals from the Reserve Fund or Reclamation Fund to fund payment of the NPI Deductions; and (C) advances made pursuant to the Credit Facilities to fund the payment of the NPI Deductions less those NPI Deductions paid as part of the Deferred Purchase Price Obligation.

"NYMEX" means the New York Mercantile Exchange.

"Offering Documents" means any one or more of a prospectus, information memorandum, private placement memorandum and similar public or private offering documents, including this prospectus, or any understanding, commitment or agreement to issue or offer Trust Units.

"Ordinary Resolution" means a resolution approved at a meeting of Unitholders by more than 50% of the votes cast in respect of the resolution by or on behalf of Unitholders present in person or represented by proxy at the meeting.

"Permitted Investments" means:

(a) loan advances to the Corporation;

(b) interest bearing accounts of certain financial institutions including Canadian chartered banks and the Trustee;

(c) obligations issued or guaranteed by the Government of Canada or any province of Canada or any agency or instrumentality thereof;

(d) term deposits, guaranteed investment certificates of deposit or bankers' acceptances of or guaranteed or accepted by any Canadian chartered bank or other financial institution (including the Trustee and any Affiliate of the Trustee) the short term debt or deposits of which have been rated at least A or the equivalent by Standard & Poor's Corporation or Moody's Investors Service, Inc. or Dominion Bond Rating Service Limited;

(e) commercial paper rated at least A or the equivalent by Dominion Bond Rating Service Limited; and

(f) investments in bodies corporate, partnerships or trusts engaged in the oil and natural gas business;

provided that an investment is not a Permitted Investment if it:

(g) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by Regulation 5000(1) of the Regulations to the Tax Act;

(h) is a "small business security" as that term is used in Part L1 of the Regulations to the Tax Act; or

(i) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

"Person" includes an individual, a body corporate, a trust, a union, a pension fund, a government and a governmental agency.

"Petroleum and Natural Gas Rights" means rights to explore for, drill for, produce, save and market Petroleum Substances, including fee simple interests in Petroleum Substances and interests granted pursuant to instruments commonly known as Crown or freehold petroleum and/or natural gas leases, licenses or permits, but not Direct Royalties.

"Petroleum Substances" means petroleum, natural gas and related hydrocarbons, (including condensate and natural gas liquids) and all other substances (including sulphur and its compounds), whether liquid, solid or gaseous and whether hydrocarbons or not, produced in association therewith.

"Pro Rata Share" means, of any particular amount in respect of a Unitholder at any time, the product obtained by multiplying the number of Trust Units that are owned by that Unitholder at that time by the quotient obtained when the particular amount is divided by the total number of all Trust Units that are issued and outstanding at that time.

"Production" means the produced Petroleum Substances attributed to the Properties.

"Properties" means the working, royalty or other interests of the Corporation in any petroleum and natural gas rights, tangibles and miscellaneous interests, including the Initial Properties, the Additional Properties and any other properties which may be acquired from time to time by the Corporation (excluding the Direct Royalties).

"Proved Reserves", **"Probable Reserves"**, **"Producing Reserves"**, **"Non-Producing Reserves"** and **"Net Reserves"** have the meanings given to those terms under "Initial Properties – Oil and Natural Gas Reserves" and "Additional Properties – Oil and Natural Gas Reserves", as the case may be.

"Qualification Deadline" means 5:00 p.m. (Calgary time) on May 5, 2003.

"Qualified Units" means the Trust Units issuable upon exercise of the Special Warrants and which are being qualified for distribution by the Final Prospectus.

"Reclamation Fund" means the cumulative amount of funds that the Corporation retains from the Properties to fund ongoing environmental obligations net of amounts used to fund the NPI Deductions. See "Description of the Trust – Reclamation Fund".

"Record Date" means December 31 of each year hereafter and the last day of each calendar month or such other date as may be determined from time to time by the Trustee upon the recommendation of the Board of Directors.

"Reserve Fund" means the cumulative amount of production revenues and Residual Revenues entitled to be retained by the Corporation pursuant to the NPI Agreement to provide for payment of production costs which the Corporation estimates will or may become payable in the following six months for which there may not be sufficient production revenues to satisfy such production costs in a timely manner net of amounts used to fund the NPI Deductions. See "Description of the Trust – Reserve Fund".

"Reserve Life Index" means the amount obtained by dividing the quantity of reserves by the annualized 2002 production of Petroleum Substances from those reserves as projected in the McDaniel Report.

"Reserve Value" means, for any petroleum and natural gas property at any time, the present worth of all of the estimated pre-tax net cash flow from the Established Reserves shown in the most recent engineering report relating to such property, discounted at 10% and using escalating price and cost assumptions (a common benchmark in the oil and natural gas industry).

"Residual Revenues" means: (a) the Corporation's share of any and all net revenues received by Corporation attributable in any way to the Properties other than revenues used to calculate the NPI Income or the net proceeds of a disposition of the Petroleum and Natural Gas Rights subject to the NPI and includes, without limitation, net revenues relating to the transportation, processing, gathering and treatment of third party production, the sale of Tangible and Miscellaneous Interests, insurance proceeds, seismic sale or licensing, incentives and rebates in respect of production costs, the net profit or loss relating to Commodity Price and Currency Swaps, take or pay payments, ARTC; and (b) royalty or other similar interests owned by the Corporation other than Direct Royalties less (c) amounts declared as dividends to the shareholders of the Corporation.

"Sale Agreement" means the purchase and sale agreement dated May 28, 2002 and as amended on July 4, 2002 between the Corporation and the Initial Properties Vendors providing for the purchase by the Corporation of the Initial Properties and the Initial Direct Royalties.

"Securities Commission" means, collectively, the applicable securities commissions or similar securities regulatory authorities in the Filing Provinces.

"Special Resolution" means a resolution proposed to be passed as a special resolution at a meeting of Unitholders (including an adjourned meeting) duly convened for the purpose and held in accordance with the provisions of the Trust Indenture at which two or more holders of at least 10% of the aggregate number of Trust Units then outstanding are present in person or by proxy and passed by the affirmative votes of the holders of not less than 66 2/3% of the Trust Units represented at the meeting and voted on a poll upon such resolution.

"Special Warrant Indenture" means the special warrant indenture entered into between the Trust, the Corporation and the Warrant Trustee dated effective as of the Closing Date governing the terms and conditions of the Special Warrants.

"Special Warrants" means the 1,500,000 special warrants of the Trust created and issued pursuant to the Special Warrant Indenture entitling the holders thereof to acquire, subject to adjustment, one Qualified Unit for each Special Warrant.

"Subsequent Investments" means any of the investments that the Trust may make pursuant to the Trust Indenture, which includes:

(a) making payments to the Corporation pursuant to the Deferred Purchase Price Obligations under the NPI Agreement;

(b) acquiring or investing in securities of the Corporation and in the securities of any other entity and borrowing funds or obtaining credit for that purpose; and

(c) paying costs, fees and expenses associated with the foregoing purposes or incidental thereto,

provided that such investments will not be a Subsequent Investment if it:

(d) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by Regulation 5000(1) of the Regulations to the Tax Act;

(e) is a "small business security" as that term is used in Part L1 of the Regulations to the Tax Act; or

(f) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

"TSX" means the Toronto Stock Exchange.

"Tax Act" means the *Income Tax Act* (Canada) and the regulations thereunder.

"Tangibles" means all tangible property, apparatus, plant, equipment, machinery and facilities used or held for use, from time to time, for purposes of producing Petroleum Substances from the Properties or lands pooled or unitized therewith or for storing, measuring, compressing, treating, processing or collecting such Petroleum Substances, including wellheads, wellhead equipment, tanks, pumps, pump jacks, separators, dehydrators, flow lines and Facilities.

"Third Party" means any Person other than the Corporation, the Trust or an Affiliate of the Corporation.

"Trust" means Harvest Energy Trust.

"Trust Debenture" means the debenture issued August 15, 2002 by the Trust in the principal amount of $5 million to 990148 Alberta Ltd. (the "Holder") pursuant to which an aggregate of $5 million was advanced to the Trust to finance, in part, the Trust's obligation pursuant to the Deferred Purchase Price Obligation under the NPI Agreement. The Trust Debenture was settled on closing of the Initial Public Offering with the issuance of 5,000,000 Trust Units. See "Description of the Trust – Trust Debenture", "Capitalization of the Trust" and "Interests of Management and Others in Material Transactions".

"Trust Fund" at any time, shall mean any of the following monies, properties and assets that are at such time held by the Trustee on behalf of the Trust for the purposes of the Trust under the Trust Indenture:

(a) the amount paid to settle the Trust;

(b) all funds realized from the issuance of Trust Units;

(c) any Permitted Investments in which funds may from time to time be invested;

(d) all rights in respect of and income generated under the NPI Agreement, including the NPI;

(e) all rights in respect of and income generated under a Direct Royalties Sale Agreement;

(f) any Subsequent Investment;

(g) any proceeds of disposition of any of the foregoing property including, without limitation, the Direct Royalties; and

(h) all income, interest, profit, gains and accretions and additional assets, rights and benefits of any kind or nature whatsoever arising directly or indirectly from or in connection with or accruing to such foregoing property or such proceeds of disposition.

"Trust Indenture" means the amended and restated trust indenture dated September 27, 2002 between the Trustee and the Corporation as such indenture may be further amended by supplemental indentures from time to time.

"Trust Units" means a trust unit of the Trust created, issued and certified under the Trust Indenture and outstanding and entitled to the benefits thereof.

"Trustee" means Valiant Trust Company, or its successor as trustee of the Trust.

"Undeveloped Lands" means those lands included in the Initial Properties and the Additional Properties which have not shown definite Proved Reserve or Probable Reserve potential as a result of regional development and/or exploration activities as of the effective date of the McDaniel Report.

"Underwriters" means, collectively, FirstEnergy Capital Corp. and Haywood Securities Inc.

"Underwriting Agreement" means the underwriting agreement entered into between the Trust and the Underwriters dated effective February 4, 2003, with respect to the sale of the Special Warrants.

"Unitholders" means the holders from time to time of one or more Trust Units.

"U.S. Securities Act" means the *United States Securities Act of 1933*, as amended.

"Vendor" means the Initial Properties Vendors or the Additional Properties Vendor, as the case may be.

"Warrant Trustee" means Valiant Trust Company, in its capacity as trustee under the Special Warrant Indenture.

"Warrants" means 150,000 warrants to purchase 150,000 Trust Units at $1.00 per Trust Unit issued in connection with the Interim Loan which were exercised by the holder thereof on January 23, 2003. See "Description of the Trust – Warrants", "Capitalization of the Trust" and "Interests of Management and Others in Material Transactions".

"Working Interest" means an undivided interest held by a party in an oil and/or natural gas or mineral lease granted by a Crown or freehold mineral owner, which interest gives the holder the right to "work" the property (lease) to explore for, develop, produce and market the lease substances but does not include, among other things, a royalty, overriding royalty, gross overriding royalty, net profits interest or other interest that entitles the holder thereof to a share of production or proceeds of sale of production without a corresponding right or obligation to "work" the property.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	Barrel	Mcf	thousand cubic feet
Bbls	Barrels	Mmcf	million cubic feet
Mbbls	thousand barrels	Bcf	billion cubic feet
Bbls/d	barrels per day	Mcf/d	thousand cubic feet per day
Mmbbls	million barrels	Mmcf/d	million cubic feet per day
NGLs	natural gas liquids	MMBTU	million British Thermal Units

Other

AECO	EnCana Corporation's natural gas storage facility located at Suffield, Alberta.
BOE	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one Bbl of oil, unless otherwise specified. The conversion factor used to convert natural gas to oil equivalent is not necessarily based upon either energy or price equivalents at this time.
BOE/d	barrels of oil equivalent per day.
MBOE	means thousand barrels of oil equivalent.
OOIP	means original oil in place.
WTI	means West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
MW	megawatts of electricity.

CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

ALL DOLLAR AMOUNTS SET FORTH IN THIS PROSPECTUS ARE IN CANADIAN DOLLARS, EXCEPT WHERE OTHERWISE INDICATED.

PROSPECTUS SUMMARY

The following is a summary of the principal features of this distribution and should be read together with the more detailed information and financial data and statements contained elsewhere in this prospectus. For an explanation of certain terms and abbreviations used in this prospectus, reference is made to the "Glossary of Terms", "Abbreviations" and "Conversions".

The Offering

The Trust: The Trust is a publicly traded oil and natural gas energy trust engaged, through its wholly-owned subsidiary, Harvest, in the exploration for, and the acquisition, development and production of, oil and natural gas reserves primarily in the Province of Alberta. See "Description of the Trust" and "Information Respecting the Corporation".

The Offering: 1,500,000 Qualified Units issuable on the exercise or deemed exercise of 1,500,000 issued and outstanding Special Warrants. See "Plan of Distribution".

Price: Each Special Warrant entitles the holder thereof to acquire, at no additional cost, one Qualified Unit of the Trust at any time until 5:00 p.m. (Calgary time) on the earlier of five (5) Days after the after the Final Receipt Date and the first anniversary of the Closing Date. The Special Warrants were issued on the Closing Date pursuant to prospectus exemptions under applicable securities legislation at a price of $10.00 per Special Warrant. The offering price of the Special Warrants was determined by negotiation between Harvest, on behalf of the Trust, and the Underwriters.

Qualified Units: 1,500,000 Trust Units issuable upon exercise of 1,500,000 outstanding Special Warrants which were issued on the Closing Date pursuant to prospectus exemptions under applicable securities legislation at a price of $10.00 per Special Warrant resulting gross proceeds of $15,000,000. This prospectus is hereby qualifying for distribution the Trust Units issuable upon exercise of the Special Warrants.

Exercise Details: Each Special Warrant entitles the holder thereof to acquire, subject to adjustment, at no additional cost, one Qualified Unit at any time until 5:00 p.m. (Calgary time) on the earlier of: (i) five (5) Business Days after the Final Receipt Date; and (ii) the first anniversary of the Closing Date. Any Trust Unit issued upon the exercise of Special Warrants prior to the Final Receipt Date will be subject to relevant hold periods under applicable securities legislation. Any Special Warrants not previously exercised by holders thereof shall be deemed to have been exercised immediately prior to the Expiry Time. As at the date hereof, none of the Special Warrants have been exercised.

In the event that a Final MRRS decision document is not obtained by the Trust on or prior to the Qualification Deadline on behalf of the Canadian securities regulatory authority in each of the Filing Provinces, then each holder of Special Warrants in each of the Filing Provinces on whose behalf a Final MRRS decision document has not been obtained (or, if a Final MRRS decision document has not been obtained on behalf of the Province of Alberta, all holders wherever resident) shall be entitled after the Qualification Deadline to receive on the exercise or deemed exercise of the Special Warrants an additional 0.09 of a Trust Unit for each such Special Warrant so exercised without additional payment. Special Warrants not previously exercised by the holders thereof shall be deemed to be exercised immediately prior to the Expiry Time without further action on the part of the holder. The Trust will continue to use its best efforts to obtain a Final MRRS decision document on behalf of the Canadian securities regulatory authority in each Filing Province where a Final MRRS decision document is not obtained on or before the Qualification Deadline until February 4, 2004.

Use of Proceeds: The gross proceeds realized by the Trust from the issuance of the Special Warrants was $15,000,000 (before deducting the Underwriters' fee of $750,000 and the expenses in connection with the issuance of the Special Warrants and the qualification for distribution of the Qualified Units, estimated to be $200,000, which will be paid out of the general funds of the Trust) which were used by the Trust to partially repay the advance made under the Current Bank Facility which was used previously to partially fund the Additional Properties Acquisition and for working capital. See "Use of Proceeds".

Cash Distributions: Unitholders of record on a Record Date will be entitled to receive monthly cash distributions of the Distributable Cash which will become payable on the 15th day following the Record Date, and if such date of payment is not a Business Day then such payment will be made on the next Business Day. Holders of Special Warrants of record on a Record Date will be entitled to receive monthly cash distributions of Distributable Cash in accordance with the terms of the Special Warrant Indenture. See "Plan of Distribution".

The Trust retains a portion of the Cash Available For Distribution in the Capital Fund to facilitate future acquisitions and development of the Properties. Management of the Corporation believes this will assist in maintaining distributions for a longer period than would otherwise be the case if all of the Cash Available For Distribution were immediately distributed to the Unitholders. See "Description of the Trust – Cash Available For Distribution", "Description of the Trust – Capital Fund", "Description of the Trust – Distributable Cash" and "Risk Factors".

Recent Developments

The Corporation was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. The Board of Directors reviewed its strategic alternatives and based on such review determined that the formation of an energy royalty trust was the optimal structure to meet its objectives. On July 10, 2002, the Trust was formed pursuant to the Trust Indenture. On the same date, the Corporation and the Trust entered into the NPI Agreement. The Corporation's first transaction was the purchase of the Initial Properties and the Initial Direct Royalties from the Initial Properties Vendors on July 10, 2002. See "Acquisition of the NPI" and "Initial Properties". The Corporation financed the purchase of the Initial Properties and the Initial Direct Royalties through a previous credit facility, which has now been repaid in full with funds advanced under the Current Bank Facility and indirectly through the Interim Loan. At the same time, the Corporation sold the Initial Direct Royalties to the Trust pursuant to a Direct Royalties Sale Agreement. See "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan", "Acquisition of the NPI" and "Initial Properties – Acquisition of Initial Properties and Initial Direct Royalties".

The Harvest Board continued to evaluate additional properties considered suitable for an investment pursuant to the NPI Agreement. On August 1, 2002, the Corporation entered into the Additional Properties Agreement with the Additional Properties Vendor to purchase the Additional Properties and the Additional Direct Royalties for a purchase price of $71.8 million, prior to adjustments. The effective date of the acquisition of the Additional Properties and the Additional Direct Royalties was June 1, 2002, and the acquisition closed on November 15, 2002. The Additional Properties Acquisition Cost of $53.2 million was funded by an advance under the Current Bank Facility, and indirectly through an additional advance under the Interim Loan.

On December 5, 2002, the Trust completed the Initial Public Offering, which resulted in aggregate gross proceeds of $34,500,000. Approximately $22.2 million from the net proceeds of the Initial Public Offering was used to repay the Interim Loan (including accrued interest) and approximately $5.4 million from the net proceeds of the Initial Public Offering was used to partially repay the advance made under the Current Bank Facility which had been used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Capitalization of the Trust".

On December 17, 2002, the Trust issued 562,500 Trust Units to the Underwriters as a result of the exercise by the Underwriters of an over-allotment option granted to them in connection with the Initial Public Offering. The $4.2 million in net proceeds from the sale of such Trust Units were used to partially repay the advance made under the Current Bank Facility which had been used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Capitalization of the Trust".

Selected Pro Forma Information

The following pro forma information reflects combined information related to the Initial Properties and the Additional Properties. See "Initial Properties", "Additional Properties", "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Balance Sheet Harvest Energy Trust As at September 30, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at September 30, 2002 and for the nine months ended September 30, 2002 and year ended December 31, 2001" included in this prospectus for a description of each group of properties and their related reserve information, production information and direct revenue and operating expenses.

Selected Pro Forma Reserve Information

The following summary is based upon the McDaniel Report. **The McDaniel Report evaluates the crude oil, natural gas and natural gas liquids reserves attributable to the Initial Properties and the Initial Direct Royalties as at August 1, 2002 and evaluates as of June 1, 2002, with mechanical updates only, to August 1, 2002, crude oil, natural gas and natural gas liquids reserves attributable to the Additional Properties and the Additional Direct Royalties prior to provision for income taxes, interest costs (including Debt Service Charges), general and administrative expenses (including General and Administrative Costs), facility site restoration, well abandonment, wellsite restoration costs and salvage recovery, but after providing for estimated royalties, operating costs and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the table below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net cash flows estimated by McDaniel represent the fair market value of these reserves.** Additional assumptions and qualifications relating to costs, prices for future production and other matters are found under "Selected Pro Forma Information – Pro Forma Reserve Information".

Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Escalating Cost and Price Case(1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (1)(2) Discounted at			
	Gross (1)(2)	Net (1)(2)	Gross (1)(2)	Net (1)(2)	0%	10%	15%	20%
Proved Reserves								
Producing Reserves	9,251	8,225	1,348.3	1,078.8	99,174	83,660	77,911	73,079
Non-Producing Reserves	1,903	1,565	298.1	232.9	18,378	14,416	12,882	11,567
Total Proved Reserves	11,154	9,790	1,646.4	1,311.7	117,552	98,076	90,793	84,646
Risked Probable Reserves	1,272	1,113	169.9	133.1	15,200	10,439	8,927	7,763
Established Reserves	12,426	10,903	1,816.2	1,444.8	132,752	108,515	99,720	92,409

Notes:

(1) See Notes (2) through (11) to "Initial Properties – Oil and Natural Gas Reserves" and Note 3 to "Additional Properties – Oil and Natural Gas Reserves".

(2) Columns may not add due to rounding.

Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Constant Cost and Price Case(1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (1)(2) Discounted at			
	Gross (1)	Net (1)	Gross (1)	Net (1)	0%	10%	15%	20%
Proved Reserves								
Producing Reserves	9,254	8,218	1,349.0	1,079.4	127,416	104,243	95, 835	88,860
Non-Producing Reserves	1,903	1,564	298.1	232.9	22,139	17,376	15, 544	13,978
Total Proved Reserves	11,157	9,782	1,647.1	1,312.3	149,555	121,619	111, 379	102,838
Risked Probable Reserves	1,272	1,112	169.9	133.1	19,508	13,092	11, 075	9,534
Established Reserves	12,429	10,893	1,817.0	1,445.4	169,063	134,711	122,454	112,372

Notes:

(1) See Notes (2) through (11) to "Initial Properties – Oil and Natural Gas Reserves" and Note 3 to "Additional Properties – Oil and Natural Gas Reserves".
(2) Columns may not add due to rounding.

Pro Forma Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to take advantage of possible development potential and increase existing production in the Initial Properties and Additional Properties which are supplemental to the future development projects included in the determination of the Reserve Values contained in the McDaniel Report. A summary of the opportunities being considered are noted below. See "Initial Properties – Incremental Exploitation and Development Potential" and "Additional Properties – Incremental Exploitation and Development Potential".

- **Hayter:** Drilling additional in-fill wells using shorter horizontal wells (200-300 metres in length), spaced at 20-25 metres to access reserves currently not being effectively depleted through existing wells.

- **West Provost:** Potential opportunity to selectively drill horizontal wells within structurally high areas in the pool.

- **Thompson Lake:** Drilling 10 additional development locations.

- **David North:** Undertaking 20 well re-completions to convert wells which have been producing in the Lloydminster and/or Dina zones to oil producers from the Cummings and Sparky formations.

- **Bellshill Lake:** Drilling additional horizontal wells which have been identified through a review of 3-D seismic data.

Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the McDaniel Report.

The Corporation may also identify further development projects and other opportunities to optimize production from the Initial Properties and the Additional Properties and implement operational efficiencies to lower operating expenses from those forecasted in the McDaniel Report as it enhances its understanding of the operations of the Initial Properties and the Additional Properties.

Selected Pro Forma Production Information

The sales volumes of crude oil, natural gas, and natural gas liquids attributable to the Initial Properties and the Additional Properties, before deduction of royalties, for the periods indicated are summarized below.

	9 Month Period Ended September 30, 2002[2]	Year Ended December 31,[1]		
		2001	2000	1999
	(unaudited)	(unaudited)	(unaudited)	(unaudited)
Crude oil and natural gas liquids (Mbbls)	2,634	3,938	3,642	3,326
Average daily production (Bbls/d)	9,649	10,789	9,980	9,112
Natural gas sales (Mmcf)	323	481	345	381
Average daily sales (Mcf/d)	1,182	1,315	946	1,042
Total oil equivalent (MBOE)	2,688	4,018	3,700	3,389
Average daily production (BOE/d)	9,840	11,008	10,138	9,284

Notes:

(1) Based on information provided to the Corporation by the Initial Properties Vendors in respect of the Initial Properties and the Additional Properties Vendor in respect of the Additional Properties.
(2) Based on information provided to the Corporation by the Initial Properties Vendors in respect of the Initial Properties and the Additional Properties Vendor in respect of the Additional Properties.
(3) See Notes to "Initial Properties – Production History" and "Additional Properties – Production History".

Pro Forma Direct Revenue and Operating Expenses

The following table sets forth revenue and operating expenses directly attributable to the Initial Properties and the Additional Properties for the periods indicated.

	9 Month Period Ended September 30, 2002[1]	Year Ended December 31, [1][2]		
		2001	2000	1999
	($000's) (unaudited)	($000's)	($000's)	($000's)
Revenue:				
Petroleum and natural gas sales [1]	79,536	88,290	118,422	73,199
Royalties	9,438	14,132	18,872	10,253
Operating expenses	20,299	24,419	18,133	14,719
Operating Income	49,799	49,739	81,417	48,227

Notes:

(1) See "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Balance Sheet Harvest Energy Trust As at September 30, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at September 30, 2002 and for the nine months ended September 30, 2002 and year ended December 31, 2001" included in this prospectus.

(2) See Notes to "Initial Properties – Direct Revenue and Operating Expenses" and "Additional Properties – Direct Revenue and Operating Expenses".

Description of the Trust

The Trust is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta. The Trust is not managed by a third party manager. Instead, the Trust is managed by the Corporation, its wholly-owned subsidiary, pursuant to the Trust Indenture and the Administration Agreement.

The Trust was established for the purposes of:

(a) acquiring the NPI and Direct Royalties (including the Initial Direct Royalties and the Additional Direct Royalties);

(b) making payments to the Corporation pursuant to the Deferred Purchase Price Obligation under the NPI Agreement;

(c) acquiring or investing in securities of the Corporation and in the securities of any other entity including, without limitation, bodies corporate, partnerships or trusts that are Permitted Investments, and borrowing funds or otherwise obtaining credit for that purpose;

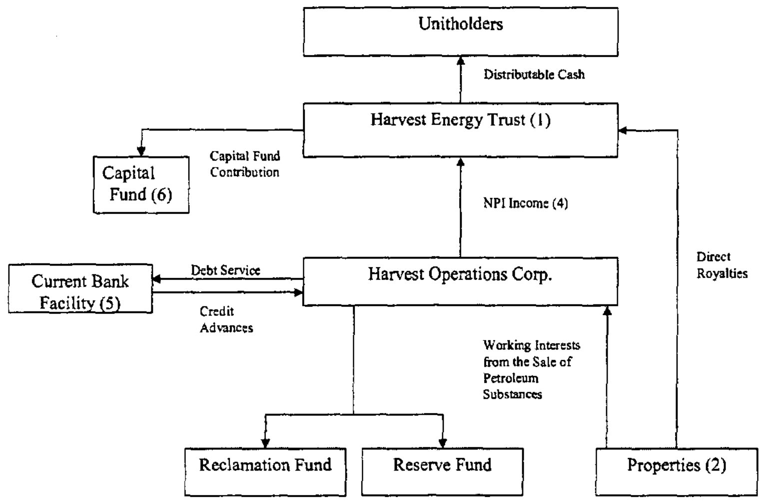
(d) disposing of any part of the Trust Fund, including, without limitation, any securities of the Corporation;

(e) temporarily holding cash and investments for the purposes of paying the expenses and the liabilities of the Trust, making other investments as contemplated by the Trust Indenture, paying amounts payable by the Trust in connection with the redemption of any Trust Unit, and making distributions to Unitholders; and

(f) paying costs, fees and expenses associated with the foregoing purposes or incidental thereto.

It is currently anticipated that the only income to be received by the Trust will be from the NPI and the Direct Royalties. See "Description of the Trust – Cash Available For Distribution" and "Description of the Trust – Distributable Cash".

The structure of the Trust and the flow of cash from the Properties to the Corporation, from the Corporation to the Trust and from the Trust to Unitholders are set forth below:



Notes:

(1) A wholly-owned subsidiary of the Trust. See "Information Respecting the Corporation".
(2) The Corporation owns the Initial Properties and the Additional Properties and may acquire or dispose of other Properties from time to time. See "Acquisition of the NPI", "Initial Properties" and "Additional Properties".
(3) In addition to the NPI, the Trust holds the Initial Direct Royalties and the Additional Direct Royalties. See "Description of the Trust – the NPI and Direct Royalties", "Acquisition of the NPI", "Initial Properties" and "Additional Properties". Direct Royalties are also anticipated to include other royalty interests acquired by the Trust from time to time.
(4) Pursuant to the NPI Agreement, the Corporation makes regular monthly payments to the Trust in the amount of the NPI Income. See "Description of the Trust – the NPI and Direct Royalties".
(5) The gross proceeds realized by the Trust from the issuance of the Special Warrants of $15,000,000 (before deducting the Underwriters' fee of $750,000 and the expenses in connection with the issuance of the Special Warrants and the qualification for distribution of the Qualified Units, estimated to be $200,000, which will be paid out of the general funds of the Trust) were used by the Trust to partially repay the advance made under the Current Bank Facility which was used previously to partially fund the Additional Properties Acquisition. See "Information Respecting the Corporation – Borrowing", "Capitalization of the Trust" and "Use of Proceeds".
(6) The Trust retains up to 50% of the Cash Available For Distribution in its Capital Fund to finance future acquisitions and development of the Properties.

An unlimited number of Trust Units may be issued pursuant to the Trust Indenture. The Trust Units represent equal undivided beneficial interests in the Trust. All Trust Units share equally in Distributable Cash paid to Unitholders and all Trust Units carry equal voting rights at meetings of Unitholders. No Unitholder is liable to pay any further calls or assessments in respect of the Trust Units. No conversion, retraction, redemption or pre-emptive rights attach to the Trust Units, other than the redemption rights described under "The Trust Indenture – Redemption Right".

The Corporation

The Corporation was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. The Board of Directors then reviewed its strategic alternatives and based on such review determined that the formation of an energy royalty trust was the optimal structure. On July 10, 2002, the Trust was formed pursuant to the Trust Indenture. On the same date, the Corporation and the Trust entered into the NPI Agreement. See "Recent Developments".

The Corporation currently has a board of directors consisting of 5 individuals. Subject to the ability of the directors of the Corporation to appoint additional directors between meetings and to fill vacancies, pursuant to the Trust Indenture future directors will be elected by the Trustee in accordance with the Ordinary Resolutions adopted at the annual meeting of the

Unitholders. Unitholders are entitled to elect of all of the directors. See "Description of the Trust – Board of Directors" and "Information Respecting the Corporation".

Pursuant to the Trust Indenture and the Administration Agreement, the Corporation manages and administers the Trust and is responsible for the oil and natural gas technical, investment, engineering, geological, land management, financial and administrative services and commodity marketing services relating to the Properties and the Trust. Each of the directors and senior management of the Corporation have been involved in the oil and natural gas industry for, on average, in excess of 18 years, and the Corporation has a staff of 37 people with key personnel having extensive experience in all technical, operating and financial aspects of the oil and natural gas industry including:

- organizing, operating, managing, developing and optimizing petroleum and natural gas properties;
- evaluating, acquiring and disposing of petroleum and natural gas properties; and
- marketing petroleum substances.

Activities undertaken by the management of the Corporation on behalf of the Trust are intended to be directed towards:

- maximizing consistent levels of Cash Available For Distribution and ultimately, the Distributable Cash paid to Unitholders;
- capturing the maximum cash flow, production and reserve recovery from the Properties; and
- striving for long-term growth in the value of the Properties and consequently the value of the NPI and the Direct Royalties held by the Trust by improving recovery levels from existing Properties and acquiring additional Properties.

These objectives are considered by the management of the Corporation as fundamental to the successful operation of the Trust and are and will continue to be pursued on a balanced basis to enhance benefits to the Unitholders.

Risk Factors

An investment in the Trust Units is subject to a number of risks, including: (i) the volatility of oil, natural gas and natural gas product prices; (ii) the Trust's and the Corporation's ability to replace reserves; (iii) depletion and recoverability of reserves; (iv) environmental concerns; (v) the Trust's and the Corporation's ability to service any outstanding debt; (vi) the Trust's and the Corporation's ability to obtain additional financing; (vii) changes in legislation; (viii) the nature of oil and natural gas operations; (ix) reliance on the Corporation; (x) any conflicts or potential conflicts of interest; (xi) investment eligibility; (xii) the nature of the Trust Unit form of security; and (xiii) any fluctuations in interest rates.

The actual amount of Cash Available For Distribution and ultimately, the Distributable Cash paid to Unitholders, will depend on, among other things, the quantity of crude oil, natural gas and natural gas liquids produced, prices received for such production, production costs, General and Administrative Costs, Debt Service Charges and net contributions by the Corporation to the Reclamation Fund and the Reserve Fund. The Trust retains up to 50% of the Cash Available For Distribution in the Capital Fund to finance acquisitions and development of the Properties, which will impact Distributable Cash. Management of the Corporation believes this will assist in maintaining distributions for a longer period than would otherwise be the case if all Cash Available For Distribution were immediately distributed to the Unitholders. See "Description of the Trust – Cash Available For Distribution", "Description of the Trust – Distributable Cash" and "Risk Factors".

The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional $5.8 million adjustment to the Additional Properties Acquisition Cost should be made in favour of the Additional Properties Vendor. This dispute relates to whether or not the value of a hedging contract held by the Additional Properties Vendor impacts the net proceeds from the Additional Properties from the effective date of the Additional Properties Acquisition of June 1, 2002 to the closing date of November 15, 2002. The Additional Properties Vendor has indicated its intent to charge the Corporation the additional $5.8 million as an interim adjustment within 90 days and in any event not later than 180 days of the closing of the Additional Properties Acquisition. Management of the Corporation believes that such amount is not owing to the Additional Property Vendor. This dispute is expected to be resolved through the arbitration process established in the Additional Properties Agreement. See "Risk Factors".

The Trust Indenture provides that Unitholders are not liable for or in respect of the obligations of the Trust and that any contracts entered into on behalf of the Trust are not to be personally binding on the Trustee, the Corporation or any Unitholder and any liability is limited to and satisfied only out of the assets of the Trust. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent that a shareholder is protected from the liabilities of a corporation. See "The Trust Indenture – Unitholder Limited Liability" and "Risk Factors – Unitholder Limited Liability".

The Reserve Value of the Initial Properties and the Additional Properties as estimated in the McDaniel Report is based in part on cash flows to be generated as a result of the development projects intended to be undertaken and related capital expenditures. The Reserve Value of the Initial Properties and the Additional Properties as estimated in the McDaniel Report will be reduced to the extent that those development projects do not achieve the level of success assumed in the McDaniel Report.

The Trust does not represent a traditional investment in the oil and natural gas sector. Investors should carefully consider the information set forth under "Risk Factors" and the other information set forth herein.

RECENT DEVELOPMENTS

The Corporation was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. The Board of Directors then reviewed its strategic alternatives and based on such review determined that the formation of an energy royalty trust was the optimal structure. On July 10, 2002, the Trust was formed pursuant to the Trust Indenture. On the same date, the Corporation and the Trust entered into the NPI Agreement. The Corporation's first transaction was the purchase of the Initial Properties and the Initial Direct Royalties from the Initial Properties Vendors on July 10, 2002. See "Acquisition of the NPI" and "Initial Properties". The Corporation financed the purchase of the Initial Properties and the Initial Direct Royalties through a previous credit facility which has been repaid in full using funds advanced under the Current Bank Facility and indirectly through the Interim Loan. At the same time, the Corporation sold the Initial Direct Royalties to the Trust pursuant to a Direct Royalties Sale Agreement. See "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan", "Acquisition of the NPI" and "Initial Properties – *Acquisition of Initial Properties and Initial Direct Royalties*".

The Board continued to evaluate additional properties considered suitable for an investment pursuant to the NPI Agreement. On August 1, 2002, the Corporation entered into the Additional Properties Agreement with the Additional Properties Vendor to purchase the Additional Properties and the Additional Direct Royalties for a purchase price of $71.8 million, prior to adjustments. The effective date of the acquisition of the Additional Properties and the Additional Direct Royalties was June 1, 2002, and the acquisition closed on November 15, 2002. The Additional Properties Acquisition Cost of $53.2 million was funded by an advance under the Current Bank Facility, and indirectly through an additional advance under the Interim Loan.

On December 5, 2002, the Trust completed the Initial Public Offering, which resulted in aggregate gross proceeds of $34,500,000. Approximately $22.9 million from the net proceeds of the Initial Public Offering was used to repay the Interim Loan (including accrued interest) and approximately $5.4 million from the net proceeds of the Initial Public Offering was used to partially repay the advance made under the Current Bank Facility which had been used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Capitalization of the Trust".

On December 17, 2002, the Trust issued 562,500 Trust Units to the Underwriters as a result of the exercise by the Underwriters of an over-allotment option granted to them in connection with the Initial Public Offering. The $4.2 million in net proceeds from the sale of such Trust Units were used to partially repay the advance made under the Current Bank Facility which had been used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Capitalization of the Trust".

ACQUISITION OF THE NPI

Pursuant to the NPI Agreement, the Trust acquired the NPI from the Corporation. The purchase price of the NPI was $12.6 million which was financed with the proceeds from the Interim Loan. See "Description of the Trust – the NPI and Direct Royalties" for more details regarding the financing of the purchase of the NPI and a description of the NPI. See also "Initial Properties" and "Additional Properties" for a description of the Properties subject to the NPI and the Initial Direct Royalties and Additional Direct Royalties acquired by the Trust in addition to the NPI.

INITIAL PROPERTIES

Acquisition of Initial Properties and Initial Direct Royalties

The acquisition of the Initial Properties and the Initial Direct Royalties by the Corporation was made pursuant to the Sale Agreement between the Corporation and the Initial Properties Vendors which closed on July 10, 2002. Pursuant to the Sale Agreement, the Corporation purchased the Initial Properties and the Initial Direct Royalties from the Initial Properties Vendors for the Initial Properties Acquisition Cost of $26.1 million. The purchase price of the Initial Properties and the Initial Direct Royalties was determined by negotiations between the Corporation and the Initial Properties Vendors and was financed with proceeds from a previous credit facility which has been repaid in full with advances made under the Current Bank Facility and indirectly from the Interim Loan. See "Description of the Trust – Interim Loan", "Information Respecting the Corporation – Borrowing" and "Capitalization of the Trust". The Initial Direct Royalties were then sold to the Trust from the Corporation for $500,000 pursuant to a Direct Royalties Sale Agreement.

Description of Initial Direct Royalties

The Initial Direct Royalties include an overriding royalty interest of 7.10688% in the Choice Viking Gas Unit No. 1, which is operated by Apache Canada Ltd. The Unit consists of rights for natural gas in the Viking formation and is located at Township 40, Ranges 9 and 10 in Alberta, with the unit currently producing from seven of nine wells at a gross rate of 475 (Mcf/d) net 33.

Description of Initial Properties

The Initial Properties include both unitized and non-unitized oil and natural gas production as well as 6,675 net acres of Undeveloped Land. The Corporation operates all of the Initial Properties with an average working interest of approximately 99%. Operatorship enables the Corporation to exercise management and operating control to potentially enhance the value of the Initial Properties for the benefit of the Trust. See "Description of the Trust – Decision Making", "Description of the Trust – Management of the Trust" and "Information Respecting the Corporation – Management Policies and Strategies".

The McDaniel Report assigned 4,573 MBOE of Established Reserves to the Initial Properties, before deduction of royalties.

The Initial Properties are concentrated in a relatively small area from Townships 39 to 43 and Ranges 3 to 12 W4M in east central Alberta. The Initial Properties include interests in the following major oilfields: Thompson Lake, David North, Bellshill Lake and Metiskow, all of which are described in more detail below. **Unless otherwise indicated, all information set forth below is net to the Corporation.**

Thompson Lake

The Corporation operates this area and has approximately a 99% working interest. Currently production is approximately 1,500 BOE/d of primarily 27° API oil, at a 99% water cut, from the Provost Glauconite "A" Pool located in Twp. 40 and 41 – 11 W4M. The McDaniel Report has assigned 2,449 MBOE of Established Reserves, before deduction of royalties, to this area. The field contains 192 gross producing wells.

The wells produce from a thick lower Cretaceous channel sand that is underlain by an active aquifer. The majority of the wells are equipped with progressive cavity pumps to maximize fluid production. The Thompson Lake fluid production is gathered at a central battery located at 4-2-41-11 W4M in which the Corporation has a 100% working interest. The battery has a capacity of approximately 210,000 Bbls/d of fluid. Oil is shipped from the battery via the Pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the EnCana Provost Gas Plant at 13-30-40-10 W4M.

A primary operating tactic to enhance the future performance of the Thompson Lake field is to improve overall fluid handling efficiency, by reducing the power requirements associated with water handling. The Initial Properties Vendors implemented the use of decentralized inclined free-water knockouts. These inclined units optimize emulsion treating and water injection systems by removing free-water from the production stream closer to the producing wells. These inclined units operate essentially at wellhead pressure eliminating the need for injection pumps, as the injection wells are able to take water on vacuum. Six inclined units have been installed to date, matched with one injection well per unit. AEUB approval has been obtained to utilize two injection wells at each inclined unit. Expanded use of the inclined free-water knockouts in the area could result in increased efficiency and lower operating costs (as a result of the lower power costs with the reduced use of injection pumps). Production optimization through total fluid increases at the wells could have a significant impact on production rates and recoveries.

Operating costs since 2001 have been slightly higher than historical averages due to the number of water injection optimization projects carried out in the year and a facility disruption that reduced production for an extended period. The combined effect of these events has resulted in higher per-unit costs. The Corporation anticipates that the results of these water injection optimization projects have not yet been fully reflected in the historical results.

David North

The Corporation has a 100% working interest in this operated property, currently producing approximately 800 BOE/d of primarily 25° API oil, at a 98% water cut, from the Lloydminster (which is under waterflood) and Dina sands located in Sections 26 and 27-40-3 W4M. The McDaniel Report assigned 1,036 MBOE of Established Reserves, before deduction of royalties, to this area. The field contains 54 gross producing wells.

The fluid production is gathered to the central battery located at 15-26-40-3 W4M in which the Corporation has a 100% working interest. The battery has a capacity of approximately 40,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the Husky North Hansman Gas Plant 8-14-39-3 W4M.

The Initial Properties Vendors implemented the use of inclined free-water knockouts in the area to optimize emulsion treating and water handling. The inclined units operate essentially at wellhead pressure and may eliminate the need for injection pumps, as the disposal wells are able to take water on vacuum. The inclined units enable significant decreases in operating costs as a result of the lower power costs with the reduced use of injection pumps. Expanded use of the inclined free-water knockouts could result in increased efficiency, lower operating costs and increased fluid handling capacity.

Further development potential exists through additional drilling. The Corporation is also considering targeting re-completions for wells that have produced in the Lloydminster and/or Dina zones to be converted to Cummings or Sparky oil producers. Up to 20 additional wells have been identified for re-completion.

Bellshill Lake

The Corporation has a 100% working interest in 1,120 acres of land in Sections 5 and 6-41-12 W4M which is adjacent to the Bellshill Blairmore Unit. Current production from this operated property is approximately 450 BOE/d of primarily 18° API oil, at a 98% water cut, from the Ellerslie "A" Pool and natural gas from the Glauconite "A" Pool. The McDaniel Report assigned 833 MBOE of Established Reserves, before deduction of royalties, to this area. The field contains 18 gross producing wells.

Production has been developed exclusively with horizontal wells. The wells produce from a thick lower Cretaceous channel sand that is underlain by an active aquifer. The majority of the wells are equipped with progressive cavity pumps to maximize fluid production. The Bellshill Lake fluid production is gathered at a central battery located at 11-5-41-12 W4M in which the Corporation has a 100% working interest. The battery has a capacity of approximately 40,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Bellshill Pipeline to the Hardisty terminal. Solution natural gas is conserved and processed at the Husky Hastings Coulee Gas Plant at 1-14-41-15 W4M. Water is re-injected back into the lower Cretaceous aquifer.

Development upside includes an additional horizontal drilling location, already identified by 3-D seismic. There is currently an estimated 180 Bbls/d of oil shut-in due to limited water injection capacity. The drilling of vertical water injection wells would also allow for production increases. The addition of inclined free-water knockouts could also increase water disposal efficiency and capacity.

Metiskow

The Corporation has a 100% working interest in this operated property, which is currently producing approximately 135 Bbls/d of 16° API oil from the Provost Dina "E" Pool located in Sections 22 and 23-39-6 W4M. The field has been developed exclusively with horizontal wells. The McDaniel Report assigned 183 MBOE of Established Reserves, before deduction of royalties, to this area. The pool contains 5 gross producing wells.

The Metiskow fluid production is gathered at a central battery located at 5-22-39-6 W4M in which the Corporation has a 100% working interest. The battery has a capacity of approximately 13,500 Bbls/d of fluid. Oil is trucked from the battery to the Hardisty terminal.

Additional potential exists for a new pool in Section 7-39-6 W4M, based on geological and geophysical mapping. The Corporation also has 3-D seismic covering a portion of the property, which may identify additional horizontal drilling locations in the Dina "E" Pool.

Undeveloped Lands

Approximately 7,892 (6,675 net) acres of Undeveloped Lands, all of which are located in the Thomson Lake area, were acquired by the Corporation from the Initial Properties Vendors as part of the purchase of Initial Properties. The Corporation has assigned a value of $333,750 to these Undeveloped Lands. The Corporation intends to conduct a review of available seismic and other data and develop an exploitation plan regarding these Undeveloped Lands. Capital expenditures, Farmouts or dispositions may result in future cash flow from these Undeveloped Lands.

Marketing Arrangements

Harvest has entered into physical swap and collar contracts with certain counter parties for certain of the production from the Initial Properties wherein it will deliver crude oil during 2003 and receive WTI pricing, as presented in the following table, less the appropriate quarterly and transportation adjustments.

Swaps:	Term	Price per Barrel
1,000 Bbls/d	January through March 2003	Cdn $38.30
1,000 Bbls/d	April through June 2003	Cdn $37.59
1,000 Bbls/d	July through September 2003	Cdn $37.10
1,000 Bbls/d	October through December 2003	Cdn $36.63
1,300 Bbls/d	January through March 2004	Cdn $24.33

Collars:	Term	Price per Barrel
500 Bbls/d	January through March 2003	Cdn $35.00 – 41.30
500 Bbls/d	April through June 2003	Cdn $35.00 – 39.60
500 Bbls/d	July through September 2003	Cdn $35.00 – 38.40
500 Bbls/d	October through December 2003	Cdn $35.00 – 37.35

The balance of production from the Initial Properties will be sold by way of evergreen contracts with 30 day cancellation notice provisions. David North, Thompson Lake and Bellshill Lake natural gas is sold on a spot market basis. See "Information Respecting the Corporation – Commodity Hedging".

Oil and Natural Gas Reserves

McDaniel has prepared the McDaniel Report dated August 21, 2002, evaluating as at August 1, 2002 the crude oil, natural gas and natural gas liquids reserves attributable to the Initial Properties and the Initial Direct Royalties. **The McDaniel Report evaluates the crude oil, natural gas and natural gas liquids reserves attributable to the Initial Properties prior to provision for income taxes, interest costs (including Debt Service Charges), general and administrative expenses (including General and Administrative Costs), facility site restoration, well abandonment, well site restoration costs and salvage recovery, but after providing for estimated royalties, operating costs and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the tables below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net production revenues estimated by McDaniel represent the fair market value of the reserves.** Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following the tables.

Initial Properties
Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows
Escalating Cost and Price Case[1]

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas [6] (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) [2][7][8][11] Discounted at			
	Gross [4]	Net [3]	Gross [4]	Net [3]	0%	10%	15%	20%
Proved Reserves[4]								
Producing Reserves[4] [12]	3,897	3,669	1,028.3	823.6	47,252	38,939	35,909	33,388
Non-Producing Reserves [4]	36	33	298.1	232.9	1,205	935	833	748
Total Proved Reserves [4]	3,933	3,702	1,326.4	1,056.5	48,457	39,873	36,742	34,136
Risked Probable Reserves [5]	393	372	160.3	125.5	5,716	3,642	3,012	2,540
Established Reserves [4]	4,326	4,073	1,486.7	1,183	54,173	43,515	39,754	36,676

Initial Properties
Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows
Constant Cost and Price Case[(1) (9)]

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas [(6)] (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) [(2)(7)(8)(10)] Discounted at			
	Gross [(4)]	Net [(3)]	Gross [(4)]	Net [(3)]	0%	10%	15%	20%
Proved Reserves[(4)]								
Producing Reserves [(4) (12)]	3,900	3,667	1,029.0	824.2	61,821	49,311	44,850	41,188
Non-Producing Reserves [(4)]	36	33	298.1	232.9	1,360	1,046	929	831
Total Proved Reserves [(4)]	3,936	3,699	1,327.1	1,057.1	63,181	50,357	45,779	42,019
Risked Probable Reserves [(5)]	393	371	160.3	125.5	7,330	4,559	3,726	3,107
Established Reserves [(4)]	4,329	4,070	1,487.4	1,183.5	70,511	54,916	49,505	45,126

Notes:

(1) Columns may not add due to rounding.

(2) Does not include the value of the Undeveloped Lands.

(3) Represents the Corporation's interest (and includes the Initial Direct Royalties of the Trust) after deduction of royalty encumbrances payable to others (excluding the Trust).

(4) The following definitions have been used in the McDaniel Report:

(b) "Gross Reserves" represents the Corporation's interest (and includes the Initial Direct Royalties of the Trust) before deduction of royalty encumbrances payable to others (excluding the Trust).

(c) "Proved Reserves" means those reserves estimated as recoverable under current technology and existing economic conditions from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir.

(d) "Probable Reserves" means those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be Proved under current technology and existing or anticipated economic conditions but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(e) "Established Reserves" means the sum of 50% of Probable Reserves and 100% of Proved Reserves.

(f) "Producing Reserves" means those reserves that are actually on production, or if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner

(g) "Non-Producing Reserves" means those proved reserves that are not currently producing either due to lack of facilities and/or markets.

(5) The present worth values and quantities of Probable Reserves have been risked by reducing those values by 50% to reflect the degree of risk associated with the recovery of such reserves.

(6) All natural gas reserves are reserves remaining after deducting surface losses due to processing shrinkage and raw natural gas used as lease fuel.

(7) The $U.S./$Cdn. exchange rate used in the McDaniel Report was $0.65 in 2002 and 2003; $0.66 in 2004; $0.67 in 2005 and $0.68 thereafter.

(8) The McDaniel Report estimates total capital expenditures (net to the Corporation) to achieve the estimated future pre-tax net cash flows from the Established Reserves, Proved Reserves and Probable Reserves based on escalating cost and price assumptions to be $240,000 ($208,000 if discounted by 15% per annum) with $Nil, $230,000, $5,000 and $5,000 of those capital expenditures estimated for the calendar years 2002, 2003, 2004 and 2005 respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Established Reserves, Proved Reserves and Probable Reserves based on constant cost and price assumptions are $235,000 ($203,000 if discounted by 15% per annum) with $Nil, $225,000, $5,000 and $5,000 of those capital expenditures estimated for the calendar years 2002, 2003, 2004 and 2005 respectively.

(9) The extent and character of the interests evaluated in the McDaniel Report and all factual data was supplied by the Initial Properties Vendors to McDaniel and were accepted by McDaniel as represented. The crude oil and natural gas reserve calculations and any projections on which the McDaniel Report is based were determined with generally accepted petroleum engineering evaluation practices.

(10) The constant cost and price evaluation was based on the average yearly general product prices for 2002 as forecast in the escalated cost and price valuation (see note 11) adjusted for transportation and quality differentials to wellhead prices as set forth below:

Crude oil (WTI)	U.S. $25.00/Bbl
Heavy oil	U.S. $25.00/Bbl
Propane	U.S. $25.20/Bbl
Butane	U.S. $24.70/Bbl
Pentanes Plus	U.S. $37.50/Bbl
Natural Gas	U.S. $4.50/Mcf

Operating and capital costs were not escalated in the constant cost and price evaluation.

(11) In respect of the escalated cost and price valuation, the average yearly general product prices utilized in the McDaniel Report for natural gas, crude oil and natural gas liquids, are outlined in the following table.

Year	Heavy Crude Oil $/Bbl	Light Crude Oil: WTI Cushing Oklahoma* $U.S./Bbl	Light Crude Oil: Edmonton Par 40° API $/Bbl	Natural gas Liquids at Edmonton: Propane $/Bbl	Natural gas Liquids at Edmonton: Butane $/Bbl	Natural gas Liquids at Edmonton: Edmonton NGL Mix $/Bbl
2002 (forecast 6 mth)	25.00	25.00	37.50	25.20	24.70	27.50
2003	24.10	23.50	35.10	24.70	23.10	26.20
2004	21.00	21.80	32.00	23.10	21.10	24.20
2005	21.10	22.20	32.10	23.00	21.20	24.20
2006	21.20	22.60	32.20	23.00	21.20	24.20
2007	21.90	23.10	32.90	23.40	21.70	24.70
2008	22.60	23.60	33.60	23.60	22.20	25.10
2009	23.30	24.10	34.30	24.00	22.60	25.60
2010	24.00	24.60	35.00	24.50	23.10	26.10
2011	24.70	25.10	35.70	25.00	23.50	26.60
2012	25.40	25.60	36.40	25.50	24.00	27.20
2013	26.10	26.10	37.10	26.10	24.50	27.70
2014	26.80	26.60	37.80	26.40	24.90	28.20
2015	27.60	27.10	38.60	27.00	25.50	28.80
2016	28.30	27.60	39.30	27.50	25.90	29.30
2017	29.10	28.20	40.10	28.20	26.40	30.00
2018	30.00	28.80	41.00	28.70	27.00	30.60
2019	30.80	29.40	41.80	29.30	27.60	31.20
2020	31.70	30.00	42.70	29.90	28.20	31.90
2021	32.50	30.60	43.50	30.50	28.70	32.50
Thereafter	32.50	30.60	43.50	30.50	28.70	32.50

* 40 degree API, 0.4% sulphur.

Year	Henry Hub $U.S./MMBTU	AECO Spot $/GJ	Alberta Spot $/MMBTU
2002	3.36	4.39	4.50
2003	3.53	4.62	4.70
2004	3.46	4.44	4.55
2005	3.48	4.40	4.50
2006	3.51	4.36	4.45
2007	3.54	4.40	4.50
2008	3.58	4.44	4.50
2009	3.62	4.48	4.55
2010	3.69	4.57	4.65
2011	3.77	4.67	4.75
2012	3.84	4.76	4.85
2013	3.92	4.85	4.95
2014	3.99	4.94	5.00
2015	4.07	5.04	5.10
2016	4.14	5.13	5.20
2017	4.23	5.24	5.35
2018	4.32	5.35	5.45
2019	4.41	5.47	5.55
2020	4.50	5.58	5.65
2021	4.59	5.69	5.80
Thereafter	4.59	5.69	5.80

Operating and capital costs have been escalated at 2% annually.

(12) All of the Proved Producing Reserves are currently on production.

The McDaniel Report will be available for inspection at the head office of the Corporation, Suite 2400, 500 - 4th Avenue S.W., Calgary, Alberta, T2P 2V6, during normal business hours during the period of distribution and for 30 days thereafter.

Summary of Selected Reserve Information

The following table sets forth the interest acquired, gross reserves, Economic Life and Reserve Value information respecting the Initial Properties as at August 1, 2002, the date of the McDaniel Report.

Property	% Interest Acquired (1)(2)	Gross Reserves (MBOE) (2)(3)	Economic Life (years) (2)(3)	Reserve Value (2)(3)(4)(5) ($000's)	%
Thompson Lake	99	2,449	7.0	20,765	47.7
Bellshill Lake	100	833	10.0	5,660	13.0
David North	100	1,036	10.0	14,664	33.7
Metiskow	100	183	7.5	1,500	3.5
Other	32	72	7.0	926	2.1
TOTAL (6) (7)	**99**	**4,573**	**8.3**	**43,515**	**100.0**

Notes:

(1) The weighted average percentage interest share of Established Reserves acquired by the Corporation from the Initial Properties Vendors before the deduction of royalties payable to others (excluding the Trust).
(2) Based on Established Reserves as derived from the McDaniel Report.
(3) Utilizing escalating cost and price assumptions.
(4) Discounted at 10%, before general and administrative expenses, interest costs, taxes, site restoration and abandonment costs.
(5) Net of capital expenditures. Does not include the value of Undeveloped Lands.
(6) Columns may not add due to rounding.
(7) Average of the Economic Life column.

Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to take advantage of possible development potential and increase existing production in the Initial Properties which are supplemental to the future development projects included in the determination of the Reserve Values contained in the McDaniel Report. Opportunities being considered include:

- an additional 10 development drilling locations at Thompson Lake;
- 20 well re-completions at David North to convert wells which have been producing in the Lloydminster and/or Dina zones to oil producers from the Cummings and Sparky formations;
- additional horizontal drilling locations which have been identified through a review of 3-D seismic over the Bellshill Lake property;
- drilling of vertical water injection wells and the addition of inclined free-water knockouts to increase water disposal capacity at Bellshill Lake which may bring onstream part of the approximately 180 Bbls/d of oil that is currently shut-in due to limited water handling capacity;
- the use of inclined free-water knockouts at Thompson Lake and David North to improve the cost efficiency of water injection on these properties; and
- there is potential for a new pool at Metiskow, with 3-D seismic supporting a horizontal drilling program.

Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the McDaniel Report.

The Corporation may also identify further development projects and other opportunities to optimize production from the Initial Properties and implement operational efficiencies to lower operating expenses from those forecasted in the McDaniel Report as it enhances its understanding of the operations of the Initial Properties.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells located on the Initial Properties as at September 30, 2002 in which the Corporation has an interest, and which are producing or which are considered by the Corporation to be capable of producing.

	Producing (4)(5)				Shut-in(1)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)
Thompson Lake	192	190	–	–	27	26	–	–
David North	54	54	–	–	10	10	–	–
Bellshill Lake	18	18	–	–	9	9	–	–
Metiskow	5	5	–	–	6	6	–	–
TOTAL	269	267	–	–	52	51	–	–

Notes:

(1) "Shut-in" wells are wells which are not producing but which are considered by the Corporation to be capable of producing. Shut-in wells in which the Corporation has a working interest are located within a reasonable distance from or are already tied into gathering systems, pipelines or other means of transportation.

(2) "Gross" wells are the total number of wells in which the Corporation has a working interest.

(3) "Net" wells means the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest acquired therein.

(4) Royalty interest wells have been assigned a net number of zero.

(5) Not all wells in which the Corporation has an interest have been assigned reserves in the McDaniel Report or are included in this table. See "Description of the Trust – Reclamation Fund".

Production History

The sales volumes of crude oil and natural gas attributable to the Initial Properties, before deduction of royalties, for the periods indicated are summarized below.

	9 Month Period Ended September 30, 2002(1)	Year Ended December 31, (2)		
		2001	2000	1999
Crude oil and natural gas liquids (Mbbls)	679	1,065	1,238	1,249
Average daily production (Bbls/d)	2,488	2,917	3,393	3,423
Natural gas sales (Mmcf)	158	263	255	244
Average daily sales (Mcf/d)	578	719	700	668
Total oil equivalent (MBOE)	**706**	**1,109**	**1,281**	**1,290**
Average daily production (BOE/d)	**2,585**	**3,037**	**3,510**	**3,534**

Notes:

(1) Based on information provided to the Corporation by the Initial Properties Vendors.

(2) Based on information provided to the Corporation by the Initial Properties Vendors and the Corporation's accounting records.

Drilling History

The following table sets forth the gross and net development wells in respect of the Initial Properties in which the Initial Properties Vendors participated during the periods indicated. The Initial Properties Vendors did not participate in any exploratory wells during such periods. The Corporation has not participated in the drilling of any wells in respect of the Initial Properties since the acquisition of the Initial Properties.

	Year Ended December 31, (4)					
	2001		2000		1999	
	Gross Wells (1)(3)	Net Wells (2)(3)	Gross Wells (1)(3)	Net Wells (2)(3)	Gross Wells (1)(3)	Net Wells (2)(3)
Oil	13	12.9	1	1.0	–	–
Natural Gas	–	–	1	1.0	1	1.0
Dry	1	1.0	–	–	–	–
TOTAL	**14**	**13.9**	**2**	**2.0**	**1**	**1.0**

Notes:

(1) "Gross Wells" means the total number of wells in which the Corporation has a working interest.

(2) "Net Wells" means the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.

(3) Royalty interest wells have been assigned a net number of zero.

(4) Based on information provided to the Corporation by the Initial Properties Vendors. The Initial Properties Vendors did not own the Initial Properties for all of 1999 and, as a result, information with respect to drilling history for 1999 is not complete.

Capital Expenditures

The following table summarizes capital expenditures made by the Initial Properties Vendors on acquisitions, exploration and development drilling and production facilities and other equipment in respect of the Initial Properties for the periods indicated.

	Year Ended December 31, (1)		
	2001	**2000**	**1999**
	(unaudited) ($000's)	(unaudited) ($000's)	(unaudited) ($000's)
Property acquisitions (2)	–	18	–
Drilling (3)	4,941	440	–
Abandonments	110	21	21
Production equipment (4)	4,208	1,168	–
Workovers	986	394	–
TOTAL	**10,245**	**2,041**	**21**

Notes:

(1) Based on information provided to the Corporation by the Initial Properties Vendors. The Initial Properties Vendors did not own the Initial Properties for all of 1999 and, as a result, information with respect to capital expenditures for 1999 is not complete.

(2) Property acquisitions include production lease and production royalty purchases and property exchanges of lease and royalty interests.

(3) Drilling includes development drilling and miscellaneous intangible expenditures.

(4) Production equipment includes production and facility equipment, pipelines and miscellaneous tangible assets.

Direct Revenue and Operating Expenses

The following table sets forth revenue and operating expenses directly attributable to the Initial Properties for the periods indicated.

	9 Month Period Ended September 30, 2002(1)	Year Ended December 31,(1)		
		2001	**2000**	**1999**
	($000's) (unaudited)	($000's)	($000's)	($000's)
Revenue:				
Petroleum and natural gas sales (2)	24,076	30,675	46,395	30,506
Royalties	2,114	2,792	4,407	2,985
Operating expenses	7,633	11,587	9,333	7,266
Operating Income	14,329	16,296	32,655	20,255

Notes:

(1) See "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999" included in this prospectus.

(2) Average product prices received: 2002 - $34.02/BOE; 2001 - $27.66/BOE; 2000 - $36.22/BOE; and 1999 - $23.65/BOE, based on information provided to the Corporation by the Initial Properties Vendors.

ADDITIONAL PROPERTIES

Acquisition of Additional Properties and Additional Direct Royalties

On August 1, 2002, the Corporation entered into the Additional Properties Agreement with the Additional Properties Vendor to purchase the Additional Properties and the Additional Direct Royalties for a purchase price of $71.8 million, prior to adjustments. The effective date of the acquisition of the Additional Properties and the Additional Direct Royalties was June 1, 2002, and the acquisition closed on November 15, 2002. The Additional Properties Acquisition Cost of $53.2 million was funded by an advance under the Current Bank Facility, and indirectly through an additional advance under the Interim Loan. The Trust used approximately $22.9 million from the net proceeds of the Initial Public Offering to repay the Interim Loan (including accrued interest) and approximately $5.4 million from the net proceeds of the Initial Public Offering to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties

Acquisition. See "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Capitalization of the Trust".

The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional $5.8 million adjustment to the Additional Properties Acquisition Cost should be made in favour of the Additional Properties Vendor. This dispute relates to whether or not the value of a hedging contract held by the Additional Properties Vendor impacts the net proceeds from the Additional Properties from the effective date of the Additional Properties Acquisition of June 1, 2002 to the closing date of November 15, 2002. The Additional Properties Vendor has indicated its intent to charge the Corporation the additional $5.8 million as an interim adjustment within 90 days and in any event not later than 180 days of the closing of the Additional Properties Acquisition. Management of the Corporation believes that such amount is not owing to the Additional Property Vendor. This dispute is expected to be resolved through the arbitration process established in the Additional Properties Agreement. See "Risk Factors".

Description of Additional Direct Royalties

As part of the Additional Properties Acquisition, the Corporation acquired a minor gross overriding royalty interest in ¼ of a section in the Hayter area to which the Corporation has assigned a $55,000 value. The Additional Direct Royalties were then sold to the Trust from the Corporation for $55,000 pursuant to a Direct Royalties Sale Agreement.

Description of Additional Properties

The Additional Properties are located in East Central Alberta. The major fields are Hayter and West Provost, both of which are operated by the Corporation. The McDaniel Report has assigned 8,155 MBOE of Established Reserves to the Additional Properties, before deduction of royalties. **Unless otherwise indicated all information set forth below is net to the Corporation.**

Hayter

Pursuant to the Additional Properties Acquisition, the Corporation acquired an average 95% working interest and assumed operatorship in this area. Currently production approximately 5,350 Bbls/d of 15° API oil from the Dina "B" Pool located in Sections 24, 25, 34 and 35-40-1 W4M. The McDaniel Report has assigned 7,203 MBOE of Established Reserves, before deduction of royalties, to this area. The Hayter pool contains 149 gross producing wells. OOIP is 138,000 MBOE with only 18,900 MBOE (14%) produced to date.

The wells produce from a high quality, thick lower Cretaceous channel sand that is underlain by an active aquifer. The high quality of the Hayter pool is characterized by porosity of approximately 30% and average permeability ranging from 2 - 5 Darcies. To take advantage of the reserve recovery benefits of the aquifer, the pool has been developed using horizontal wells. The use of horizontal wells has proven to be effective in maximizing recovery from this and many similar pools in the area. The wells are equipped with progressive cavity pumps to maximize fluid production. The Hayter fluid production is gathered into one of two central batteries located at 8-35-40-1 W4M or 1-34-40-1 W4M in which the Corporation has a 95% working interest and is the operator. The batteries have a combined capacity of approximately 200,000 Bbls/d of fluid. Oil from the Hayter area is blended with condensate and shipped from the battery via the Gibson Provost pipeline to the Hardisty terminal. Solution natural gas is conserved and utilized as fuel gas at the batteries, with the remainder processed at the Husky North Hansman Gas Plant located at 8-14-39-03 W4.

The McDaniel Report has assigned Non-Producing Reserves to 23 horizontal wells in the Dina pool, resulting in an average forecast ultimate recovery of 19%.

Management of the Corporation believes, based upon its assessment of the Hayter area, that there are also opportunities to improve the gathering and processing of produced fluid. De-bottlenecking field gathering systems and processing facilities may serve to increase fluid handling capacity, resulting in increased oil production and reduced operating costs.

Future development of this pool may also include additional in-fill drilling on closer spacing, pool extensions through the identification of by-pass reserves and re-completion of existing wells by isolating portions of the horizontal wells that are experiencing higher water production. There is also an opportunity to employ cost reduction practices to improve netbacks and ultimate recovery, similar to the Initial Properties, employing inclined free-water knockouts.

West Provost

Pursuant to the Additional Properties Acquisition, the Corporation acquired an average 37.5% working interest in this area and assumed operatorship. Currently production is approximately 650 BOE/d of primarily 26° API oil, at a 98% water cut, primarily from the Mannville "L" Pool located in Twps. 37, 38 and 39-3 W4M. Current natural gas production is approximately 200 Mcf/d. The McDaniel Report has assigned to this area 952 MBOE of Established Reserves, before deduction of royalties. The West Provost pool contains 114 gross (43 net) producing oil wells and 15 gross (6 net) producing natural gas wells.

The Mannville "L" Pool was first discovered in 1976 with the drilling of the 11-15-38-3 W4M well. The pool was subsequently developed using vertical wells. Since 1993 the pool has been developed almost exclusively using directional wells drilled from central pad locations. The area also produces oil from five vertical oil wells developed in the Rex formation. The wells in this area are equipped with progressive cavity pumps to maximize fluid production. All oil wells are tied into one of two operated batteries. The West Provost area also produces natural gas from 15 gross wells, primarily from the Viking and Colony Formations.

The majority of the West Provost fluid production in the area is gathered at a central battery located at 3-15-38-03 W4M, in which the Corporation acquired a 37.5% working interest. The battery has a capacity of approximately 115,000 Bbls/d of fluid. Oil is shipped from the battery via the Gibson Provost pipeline to the Hardisty terminal. Solution and non-associated natural gas is conserved and processed at the Husky North, Hansman Lake Gas Plant at 8-14-39-03 W4M.

The Corporation anticipates that there may be an opportunity to selectively drill horizontal wells within structurally high areas in the pool. There is also an opportunity to employ cost reduction practices to improve netbacks and ultimate recovery, similar to the Initial Properties, employing inclined free-water knockouts.

Undeveloped Lands

Approximately 21,167 (7,427 net) acres of Undeveloped Lands were acquired by the Corporation from the Additional Properties Vendor as part of the Additional Properties Acquisition. The Corporation has assigned a value of $371,000 to these Undeveloped Lands. The Corporation intends to conduct a review of available seismic and other data and develop an exploitation plan regarding these Undeveloped Lands. Capital expenditures, Farmouts or dispositions may result in future revenues from these Undeveloped Lands. The geographical area and value assigned by the Corporation to the Undeveloped Lands is as follows:

Property	Gross Area (Acres)	Net Area (Acres)	Assigned Value
Hayter	8,142	3,342	$167,000
West Provost	13,025	4,085	$204,000
TOTAL	**21,167**	**7,427**	**$371,000**

Marketing Arrangements

All of the oil production from the Additional Properties is shipped into the Bow River stream on the Gibson Provost pipeline system. Gibson Energy Ltd. supplies condensate required for blending on the Provost system and invoices the producer. The percentage of condensate required ranges from 15 to 25% of produced oil depending on the season, with more condensate required in the winter months.

As part of the closing of the Additional Properties Acquisition, the Corporation entered into a physical contract to deliver 6,000 Bbls/d of Lloydminster blend crude oil to the Additional Properties Vendor until December 31, 2003. To complete this contract the Corporation must purchase approximately 1,000 Bbls/d of condensate to blend with its production to meet the oil quality requirements at the delivery point. Under the contract, the Corporation is paid the NYMEX calendar WTI price less a fixed differential of U.S. $8.233 per Bbl, such price not to be less than U.S. $14.40 per Bbl or greater than U.S. $17.244 per Bbl. In effect, this contract applies a fixed differential to a WTI price collar between U.S. $22.633 and U.S. $25.477 per Bbl. The contract is effective until December 31, 2003. The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional $5.8 million adjustment to the Additional Properties Acquisition Cost should be made in favour of the Additional Properties Vendor. This dispute relates to whether or not the value of a hedging contract held by the Additional Properties Vendor impacts the net proceeds from the Additional Properties from the effective date of the Additional Properties Acquisition of June 1, 2002 to the closing date of November 15, 2002. The Additional Properties

Vendor has indicated its intent to charge the Corporation the additional $5.8 million as an interim adjustment within 90 days and in any event not later than 180 days of the closing of the Additional Properties Acquisition. Management of the Corporation believes that such amount is not owing to the Additional Property Vendor. This dispute is expected to be resolved through an arbitration process established in the Additional Properties Agreement. See "Risk Factors".

Produced solution natural gas is conserved, and then processed at a third party sour gas plant. Non-associated natural gas is sold under two different contracts. The first is an aggregator natural gas purchase contract with TransCanada PipeLines for the life of the reserves and the second is a 30-day evergreen contract using AECO spot pricing.

Oil and Natural Gas Reserves

McDaniel has prepared the McDaniel Report dated August 21, 2002, evaluating as at June 1, 2002 the crude oil, natural gas and natural gas liquids reserves attributable to the Additional Properties, which evaluation has been mechanically updated only to August 1, 2002. **The McDaniel Report evaluates the crude oil, natural gas and natural gas liquids reserves attributable to the Additional Properties and the Additional Direct Royalties prior to provision for income taxes, interest costs (including Debt Service Charges), general and administrative expenses (including General and Administrative Costs) facility site restoration, well abandonment, well site restoration costs, and salvage recovery, but after providing for estimated royalties, operating costs, and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the tables below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net production revenues estimated by McDaniel represent the fair market value of the reserves.** Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following the tables.

Additional Properties
Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows
Escalating Cost and Price Case (1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas(2) (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2)(3)(4) Discounted at			
	Gross (2)	Net (2)	Gross (2)	Net (2)	0%	10%	15%	20%
Proved Reserves(2)								
Producing Reserves (2)(6)	5,354	4,556	320.0	255.2	51,922	44,721	42,002	39,691
Non-Producing Reserves (2)	1,867	1,532	–	–	17,173	13,481	12,049	10,819
Total Proved Reserves (2)	7,221	6,088	320.0	255.2	69,095	58,202	54,051	50,510
Risked Probable Reserves (2)	879	741	9.6	6.7	9,484	6,797	5,915	5,223
Established Reserves (2)	8,100	6,829	329.6	261.9	78,579	64,999	59,966	55,733

Additional Properties
Petroleum and Natural Gas Reserves and Pre-Tax Net Cash Flows
Constant Cost and Price Case (1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas(2) (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2)(3)(5) Discounted at			
	Gross (2)	Net (2)	Gross (2)	Net (2)	0%	10%	15%	20%
Proved Reserves (2)								
Producing Reserves (2)(6)	5,354	4,552	320.0	255.2	65,595	54,932	50,985	47,672
Non-Producing Reserves (2)	1,867	1,532	–	–	20,779	16,330	14,615	13,147
Total Proved Reserves (2)	7,221	6,083	320.0	255.2	86,374	71,262	65,600	60,819
Risked Probable Reserves (2)	879	740	9.6	6.7	12,178	8,533	7,349	6,427
Established Reserves (2)	8,100	6,823	329.6	261.9	98,552	79,795	72,949	67,246

Notes:

(1) Columns may not add due to rounding.

(2) See Notes (2) to (7) and (9) of "Initial Properties – Oil and Natural Gas Reserves".

(3) The McDaniel Report estimates total capital expenditures (net to the Corporation) to achieve the estimated future pre-tax net cash flows from the Established Reserves, Proved Reserves and Probable Reserves based on escalating cost and price assumptions to be $12,517,000 ($12,064,000 if discounted by 15% per annum) with $9,046,000, $3,471,000 and $Nil of those capital expenditures estimated for the calendar years 2002, 2003 and 2004, respectively. The corresponding capital expenditures to achieve the estimated future pre-tax net cash flows from the Established Reserves, Proved Reserves and Probable Reserves based

on constant cost and price assumptions are $12,449,000 ($12,005,000 if discounted by 15% per annum) with $9,046,000, $3,403,000 and $Nil of those capital expenditures estimated for the calendar years 2002, 2003 and 2004, respectively.

(4) See Note (11) of "Initial Properties – Oil and Natural Gas Reserves".

(5) See Note (10) of "Initial Properties – Oil and Natural Gas Reserves".

(6) Approximately 99% of the Proved Producing Reserves are currently on production.

Summary of Selected Reserve Information

The following table sets forth the interests acquired, gross reserves, Economic Life and Reserve Value information respecting the Additional Properties as at August 1, 2002, the date of the McDaniel Report.

Property	% Interest anticipated to be Acquired (1)(2)	Gross Reserves (MBOE) (2)(3)	Economic Life (years) (2)(3)	Reserve Value (2)(3)(4)(5) ($000's)	Reserve Value (2)(3)(4)(5) %
Hayter	95.0	7,203	10	56,156	86.4
West Provost	37.5	952	10	8,843	13.6
TOTAL (6)	**79.8**	**8,155**	**10(7)**	**64,999**	**100.0**

Notes:

(1) The weighted average percentage interest share of Established Reserves acquired by the Corporation from the Additional Properties Vendor before the deduction of royalties payable to others (other than the Trust).

(2) Based on Established Reserves as derived from the McDaniel Report.

(3) Utilizing escalating cost and price assumptions.

(4) Discounted at 10%, before general and administrative expenses, interest costs, taxes, site restoration and abandonment costs.

(5) Net of capital expenditures. Does not include the value of the Undeveloped Lands.

(6) Columns may not add due to rounding.

(7) Average of Economic Life column.

Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to take advantage of possible development potential and increase existing production in the Additional Properties which are supplemental to the future development projects included in the determination of the Reserve Values contained in the McDaniel Report. Opportunities being considered include:

(a) additional in-fill drilling potential exists at Hayter using shorter horizontal wells (200-300 metres in length), spaced at 20-25 metres to access reserves currently not being effectively depleted through existing wells. In 2001 and 2002, the operator of the property drilled several 20 metre inter-well distance wells at the "toe" of existing horizontal wells. Initial results from these wells are promising, with the original recoverable proved reserves estimated by McDaniel at 90 Mbbls per well;

(b) at Hayter, forecast ultimate recovery of 19% of the OOIP in the McDaniel Report is relatively low when compared to other pools of this type and quality;

(c) the Hayter property has fluid handling limitations, which can be reduced through gathering and processing facility de-bottlenecking; and

(d) at West Provost, there may be an opportunity to selectively drill horizontal wells within structurally high areas in the pool as well as an opportunity to employ cost reduction practices to improve netbacks and ultimate recovery.

Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the McDaniel Report.

The Corporation may also identify additional development projects and other opportunities to optimize production from the Additional Properties and implement operational efficiencies to lower operating expenses from those forecasted in the McDaniel Report once it has enhanced its understanding of the operations of the Additional Properties subsequent to gaining control of such operations.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells located on the Additional Properties as at September 30, 2002 in which the Corporation has an interest, and which are producing wells or which are considered by the Corporation to be capable of producing.

	Producing (4)(5)				Shut-in(1)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)	Gross Wells (2)	Net Wells (3)
Hayter	149	141.5	–	–	33	31.3	1	1.0
West Provost	114	42.7	15	5.6	13	4.9	1	0.4
TOTAL	263	184.2	15	5.6	46	36.2	2	1.4

Notes:

(1) "Shut-in Wells" means wells which are not producing but which are considered by the Corporation to be capable of production. Shut-in Wells in which the Corporation acquired an interest are located within a reasonable distance from or are already tied into gathering systems, pipelines or other means of transportation.
(2) "Gross Wells" means the total number of wells in which the Corporation acquired a working interest.
(3) "Net Wells" means the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest acquired therein.
(4) Royalty interest wells have been assigned a net number of zero.
(5) Not all wells in which the Corporation acquired an interest have been assigned reserves in the McDaniel Report or are included in this table. See "Description of the Trust – Reclamation Fund".

Production History

The sales volumes of crude oil, natural gas, and natural gas liquids attributable to the Additional Properties, before deduction of royalties, for the periods indicated are summarized below.

	9 Month Period Ended September 30, 2002 (2)	Year Ended December 31, (1)		
		2001	2000	1999
Crude oil and natural gas liquids (Mbbls)	1,955	2,873	2,404	2,077
Average daily production (Bbls/d)	7,160	7,872	6,587	5,689
Natural gas sales (Mmcf)	165	218	90	137
Average daily sales (Mcf/d)	605	596	246	374
Total oil equivalent (MBOE)	1,982	2,909	2,419	2,099
Average daily production (BOE/d)	7,261	7,971	6,628	5,750

Notes:

(1) Based on information provided to the Corporation by the Additional Properties Vendor.
(2) Based on information provided to the Corporation by the Additional Properties Vendor and the Corporation's accounting records.

Drilling History

The following table sets forth the gross and net exploratory and development wells in respect of the Additional Properties in which the Additional Properties Vendor participated during the periods indicated. The Additional Properties Vendor did not participate in any exploratory wells during such periods. The Corporation has not completed the drilling of any wells in respect of the Additional Properties since the acquisition of the Additional Properties. However, the Corporation as of February 4, 2003 has commenced a six well drilling program.

	Year Ended December 31, [4]					
	2001		2000		1999	
	Gross Wells [1]	Net Wells [2][3]	Gross Wells [1]	Net Wells [2][3]	Gross Wells [1]	Net Wells [2][3]
Oil	21	19.6	26	23.4	10	9.1
Natural Gas	–	–	–	–	–	–
Dry	–	–	–	–	–	–
TOTAL	21	19.6	26	23.4	10	9.1

Notes:

(1) "Gross Wells" means the number of wells in which the Corporation acquired a working interest.
(2) "Net Wells" means the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest acquired by the Corporation therein.
(3) Royalty interest wells have been assigned a net number of zero.
(4) Based on information provided to the Corporation by the Additional Properties Vendor.

Capital Expenditures

The following table summarizes capital expenditures made by the Additional Properties Vendor on acquisitions, development drilling and production facilities and other equipment in respect of the Additional Properties for the periods indicated.

	Year Ended December 31, [1]		
	2001	2000	1999
	(unaudited) ($000's)	(unaudited) ($000's)	(unaudited) ($000's)
Property acquisitions [2]	–	54	–
Development expenditures [3]	12,373	14,941	5,095
Production equipment [4]	4,518	3,915	521
TOTAL	16,891	18,910	5,616

Notes:

(1) Based on information provided to the Corporation by the Additional Properties Vendor.
(2) Property acquisitions include production lease purchasers, and production royalty purchases and property exchanges of lease and royalty interests.
(3) Development expenditures include development drilling and miscellaneous intangible expenditures.
(4) Production equipment includes production and facility equipment and miscellaneous tangible assets.

Direct Revenue and Operating Expenses

The following table sets forth revenue and operating expenses directly attributable to the Additional Properties for the periods indicated.

	9 Month Period Ended September 30, 2002 [1]	Year Ended December 31, [1]		
		2001	2000	1999
	($000's) (unaudited)	($000's)	($000's)	($000's)
Revenue:				
Petroleum and natural gas sales [2]	55,460	57,615	72,026	42,693
Royalties	7,324	11,340	14,465	7,268
Operating expenses	12,666	12,832	8,800	7,453
Operating Income	35,470	33,443	48,761	27,972

Notes:

(1) See "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation years ended December 31, 2001, 2000 and 1999" included in this prospectus.

(2) Average product prices received: 2002 - \$27.98/BOE; 2001 - \$19.89/BOE; 2000 - \$29.77/BOE; and 1999 - \$20.34/BOE, based on information provided to the Corporation by the Additional Properties Vendor.

SELECTED PRO FORMA INFORMATION

The following pro forma information reflects combined information related to the Initial Properties and the Additional Properties. See "Initial Properties", "Additional Properties", "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Balance Sheet Harvest Energy Trust As at September 30, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust As at September 30, 2002 and for the nine months ended September 30, 2002 and year ended December 31, 2001" included in this prospectus for a description of each group of properties and their related reserve information, production information and direct revenue and operating expenses.

Pro Forma Description of Properties

The Initial Properties and the Additional Properties are located in the same general area in east central Alberta near Lloydminster. The Initial Properties and the Additional Properties include interests in the following major oilfields: Hayter, Thompson Lake, David North, West Provost, Bellshill Lake and Metiskow. See "Initial Properties" and "Additional Properties".

The Initial Properties and the Additional Properties are operated by the Corporation. The Corporation has approximately a 99% working interest in the Initial Properties and a 95% and 37.5% working interest in the Hayter properties and the West Provost properties, respectively. The Corporation has Established Reserves (according to the McDaniel Report using escalating price and cost assumptions), before deduction of royalties, of 5,141 Mbbls of medium gravity crude oil, 7,203 Mbbls of heavy gravity crude oil, 82 Mbbls of natural gas liquids and 1,816 Mmcf of natural gas.

Associated with these Initial Properties and Additional Properties are 15,382 net acres of Undeveloped Land, 451 net producing oil wells, 6 net producing natural gas wells, 87 net shut-in oil wells and 1.4 net shut-in natural gas wells.

This portfolio of Properties has the following characteristics:

(a) **Predictable Production Performance:** The production from the Initial Properties and Additional Properties is derived from several hundred wells, which in aggregate have demonstrated a stable and predictable production history.

(b) **Operated:** The Corporation, as operator of the Initial Properties and the Additional Properties, will be able to exercise management and operating control to enhance the value of the Properties for the benefit of the Trust. See "Information Respecting the Corporation – Operating Strategy".

(c) **Concentrated:** The Initial Properties and Additional Properties are concentrated in a relatively small area in east central Alberta. Management of the Corporation believes this will enable the Corporation to gain benefits from economies of scale in managing the Initial Properties and Additional Properties and will also enable the Corporation to effectively enhance the value of the Initial Properties and Additional Properties by applying experience gained from one property to the balance of the Properties.

(d) **Development Potential:** The Initial Properties and Additional Properties have been operated by senior oil and natural gas producers in the past. Although the Initial Properties and Additional Properties have been subject to extensive drilling and development programs, management of the Corporation believes that there are opportunities to improve the production from and to further develop the Reserves associated with these Properties. See "Selected Pro Forma Information – Pro Forma Reserve Information" and "Selected Pro Forma Information – Pro Forma Incremental Exploitation and Development Potential".

Pro Forma Reserve Information

McDaniel has prepared the McDaniel Report dated August 21, 2002, evaluating as at August 1, 2002 the crude oil, natural gas and natural gas liquids reserves attributable to the Initial Properties and the Initial Direct Royalties and evaluating as at June 1, 2002, with a mechanical update only to August 1, 2002, the crude oil, natural gas and natural gas liquids reserves attributable to the Additional Properties and the Additional Direct Royalties. **The McDaniel Report evaluates the crude**

oil, natural gas and natural gas liquids reserves attributable to the Initial Properties and the Additional Properties prior to provision for income taxes, interest costs (including Debt Service Charges), general and administrative expenses (including General and Administrative Costs), facility site restoration, well abandonment, well site restoration costs and salvage recovery, but after providing for estimated royalties, operating costs and future capital expenditures. The probable reserves and the present worth value of such reserves as set forth in the tables below have been reduced by 50% to reflect the degree of risk associated with recovery of such reserves. It should not be assumed that the discounted future net cash flows estimated by McDaniel represent the fair market value of these reserves. Additional assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following the tables.

Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Escalating Cost and Price Case (1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (2) Discounted at			
	Gross (2)	Net (2)	Gross (2)	Net (2)	0%	10%	15%	20%
Proved Reserves(2)								
Producing Reserves(2)	9,251	8,225	1,348.3	1,078.8	99,174	83,660	77,911	73,079
Non-Producing Reserves(2)	1,903	1,565	298.1	232.9	18,378	14,416	12,882	11,567
Total Proved Reserves(2)	11,154	9,790	1,646.4	1,311.7	117,552	98,076	90,793	84,646
Risked Probable Reserves(2)	1,272	1,113	169.9	133.1	15,200	10,439	8,927	7,763
Established Reserves(2)	12,426	10,903	1,816.2	1,444.8	132,752	108,515	99,720	92,409

Notes:
(1) Columns may not add due to rounding.
(2) See Notes (2) through (11) to "Initial Properties – Oil and Natural Gas Reserves" and Note 3 to "Additional Properties – Oil and Natural Gas Reserves".

Pro Forma Petroleum and Natural Gas
Reserves and Pre-Tax Net Cash Flows
Constant Cost and Price Case (1)

	Crude Oil and Natural Gas Liquids (Mbbls)		Natural Gas (Mmcf)		Estimated Present Worth of Future Pre-Tax Net Cash Flows ($000's) (1)(2) Discounted at			
	Gross (2)	Net (2)	Gross (2)	Net (2)	0%	10%	15%	20%
Proved Reserves(2)								
Producing Reserves(2)	9,254	8,218	1,349.0	1,079.4	127,416	104,243	95,835	88,860
Non-Producing Reserves(2)	1,903	1,564	298.1	232.9	22,139	17,376	15,544	13,978
Total Proved Reserves(2)	11,157	9,782	1,647.1	1,312.3	149,555	121,619	111,379	102,838
Risked Probable Reserves(2)	1,272	1,112	169.9	133.1	19,508	13,092	11,075	9,534
Established Reserves(2)	12,429	10,893	1,817.0	1,445.4	169,063	134,711	122,454	112,372

Notes:
(1) Columns may not add due to rounding.
(2) See Notes (2) through (11) to "Initial Properties – Oil and Natural Gas Reserves" and Note 3 to "Additional Properties – Oil and Natural Gas Reserves".

Estimated Pre-Tax Net Cash Flows – Established Reserves of Pro Forma Properties
Escalating Cost and Price Case (1)
(Dollar amounts in thousands)

Year	Annual Production (MBOE)	Company Interest Revenue	Royalty Burdens (2)	Operating Expenses	Other Income	Net Operating Income	Net Capital Investment	Net Cash Flow (3) (4)
2002	1,326.0	$ 36,774	$ 5,551	$ 8,950	$ 22	$ 22,296	$ 9,046	$ 13,250
2003	3,283.7	86,530	13,593	22,086	36	50,886	3,701	47,186
2004	2,365.1	55,833	7,706	21,897	32	26,262	5	26,257
2005	1,791.0	42,877	5,398	21,187	29	16,321	5	16,316
2006	1,338.0	32,567	3,804	18,206	25	10,582	–	10,582
2007	956.5	24,357	2,620	14,171	–	7,566	–	7,566
2008	697.2	18,366	1,872	11,290	–	5,204	–	5,204

Year	Annual Production (MBOE)	Company Interest Revenue	Royalty Burdens (2)	Operating Expenses	Other Income	Net Operating Income	Net Capital Investment	Net Cash Flow (3)(4)
2009	489.8	13,187	1,314	8,454	–	3,419	–	3,419
2010	261.1	7,152	716	4,836	–	1,600	–	1,600
2011	160.3	4,485	454	3,164	–	866	–	866
2012	38.7	1,204	87	804	–	313	–	313
2013	12.7	409	31	241	–	138	–	138
2014	2.8	92	14	52	–	26	–	26
2015	1.8	59	12	34	–	14	–	14
2016	1.6	54	11	34	–	8	–	8
Remainder	2.3	58	12	36	–	10	–	9
Total	12,728.7	$ 324,003	$ 43,197	$ 135,441	$ 144	$ 145,510	$ 12,757	$ 132,752

Notes:

(1) Numbers may not agree with the McDaniel Report and columns may not add due to rounding.
(2) Includes mineral taxes.
(3) Undiscounted.
(4) Net cash flow before income taxes, interest, general and administrative expenses and estimated site restoration and abandonment costs.

Pro Forma Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to take advantage of possible development potential and increase existing production in the Initial Properties and the Additional Properties which are supplemental to the future development projects included in the determination of the Reserve Value contained in the McDaniel Report. A summary of the opportunities being considered are noted below. See "Initial Properties – Incremental Exploitation and Development Potential" and "Additional Properties – Incremental Exploitation and Development Potential" for a more detailed discussion of these opportunities.

- **Hayter:** Drilling additional in-fill wells using shorter horizontal wells (200-300 metres in length), spaced at 20-25 metres to access reserves currently not being effectively depleted through existing wells.

- **West Provost:** Potential opportunity to selectively drill horizontal wells within structurally high areas in the pool.

- **Thompson Lake:** Drilling 10 additional development locations.

- **David North:** Undertaking 20 well re-completions to convert wells which have been producing in the Lloydminster and/or Dina zones to oil producers from the Cummings and Sparky formations.

- **Bellshill Lake:** Drilling additional horizontal wells which have been identified through a review of 3-D seismic data.

Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the McDaniel Report.

The Corporation may also identify further development projects and other opportunities to optimize production from the Initial Properties and the Additional Properties and implement operational efficiencies to lower operating expenses from those forecasted in the McDaniel Report as it enhances its understanding of the operations of the Initial Properties and the Additional Properties.

Selected Pro Forma Production Information

The sales volumes of crude oil, natural gas, and natural gas liquids attributable to the Initial Properties and the Additional Properties, before deduction of royalties, for the periods indicated are summarized below.

	9 Month Period Ended September 30, 2002(2)(3)	Year Ended December 31, (1)(3)		
		2001	2000	1999
Crude oil and natural gas liquids (Mbbls)	2,634	3,938	3,642	3,326
Average daily production (Bbls/d)	9,649	10,789	9,980	9,112
Natural gas sales (Mmcf)	323	481	345	381
Average daily sales (Mcf/d)	1,182	1,315	946	1,042
Total oil equivalent (MBOE)	2,688	4,018	3,700	3,389
Average daily production (BOE/d)	9,846	11,008	10,138	9,284

Notes:

(1) Based on information provided to the Corporation by the Initial Properties Vendors in respect of the Initial Properties and the Additional Properties Vendor in respect of the Additional Properties.
(2) Based in part on information provided to the Corporation by the Initial Properties Vendors and the Additional Properties Vendor.
(3) See Notes to "Initial Properties – Production History" and "Additional Properties – Production History".

Pro Forma Direct Revenue and Operating Expenses

The following table sets forth revenue and operating expenses directly attributable to the Initial Properties and the Additional Properties for the periods indicated.

	9 Month Period Ended September 30, 2002(1)	Year Ended December 31, (1)(2)		
		2001	2000	1999
	($000's) (unaudited)	($000's)	($000's)	($000's)
Revenue:				
Petroleum and natural gas sales (1)	79,536	88,290	118,422	73,199
Royalties	9,438	14,132	18,872	10,253
Operating expenses	20,299	24,419	18,133	14,719
Operating Income	49,799	49,739	81,417	48,227

Notes:

(1) See "Schedule of Revenue and Expenses for the Initial Properties Acquired from Devon Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Schedule of Revenue and Expenses for the Additional Properties Acquired from Anadarko Canada Corporation Years ended December 31, 2001, 2000 and 1999", "Balance Sheet Harvest Energy Trust As at September 30, 2002" and "Unaudited Pro Forma Consolidated Financial Statements of Harvest Energy Trust as at September 30, 2002 and for the nine months ended September 30, 2002 and year ended December 31, 2001" included in this prospectus.
(2) See Notes to "Initial Properties – Direct Revenue and Operating Expenses" and "Additional Properties – Direct Revenue and Operating Expenses".

DESCRIPTION OF THE TRUST

General

The Trust is an open-ended, unincorporated investment trust established under the laws of the Province of Alberta and created pursuant to the Trust Indenture. The head and principal office of the Trust is located at Suite 2400, 500 - 4th Avenue S.W., Calgary, Alberta, T2P 2V6. The Trust is managed by the Corporation, its wholly-owned subsidiary, pursuant to the Trust Indenture and the Administration Agreement.

The Trust was established for the purposes of:

(a) acquiring the NPI and Direct Royalties (including the Initial Direct Royalties and the Additional Direct Royalties);

(b) making payments to the Corporation pursuant to the Deferred Purchase Price Obligation under the NPI Agreement;

(c) acquiring or investing in securities of the Corporation and in the securities of any other entity including, without limitation, bodies corporate, partnerships or trusts that are Permitted Investments, and borrowing funds or otherwise obtaining credit for that purpose;

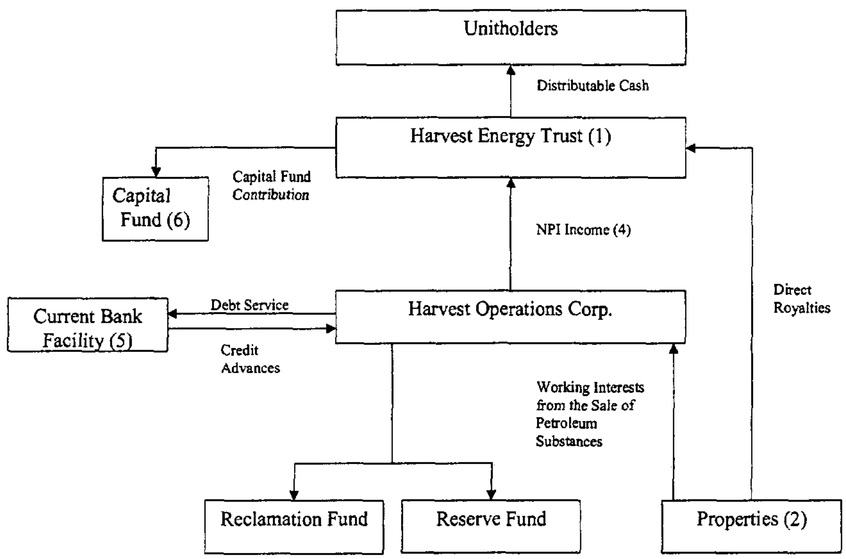
(d) disposing of any part of the Trust Fund, including, without limitation, any securities of the Corporation;

(e) temporarily holding cash and investments for the purposes of paying the expenses and the liabilities of the Trust, making other investments as contemplated by the Trust Indenture, paying amounts payable by the Trust in connection with the redemption of any Trust Units, and making distributions to Unitholders; and

(f) paying costs, fees and expenses associated with the foregoing purposes or incidental thereto.

Structure of the Trust

The structure of the Trust and the flow of cash from the Properties to the Corporation, from the Corporation to the Trust and from the Trust to Unitholders are set forth below:



Notes:

(1) A wholly-owned subsidiary of the Trust. See "Information Respecting the Corporation".

(2) The Corporation owns the Initial Properties and the Additional Properties and may acquire or dispose of other Properties from time to time. See "Acquisition of the NPI", "Initial Properties" and "Additional Properties".

(3) In addition to the NPI, the Trust holds the Initial Direct Royalties and the Additional Direct Royalties. See "Description of the Trust – the NPI and Direct Royalties", "Acquisition of the NPI", "Initial Properties" and "Additional Properties". Direct Royalties are also anticipated to include other royalty interests acquired by the Trust from time to time.

(4) Pursuant to the NPI Agreement, the Corporation makes regular monthly payments to the Trust in the amount of the NPI Income. See "Description of the Trust – the NPI and Direct Royalties".

(5) The gross proceeds realized by the Trust from the issuance of the Special Warrants of $15,000,000 (before deducting the Underwriters' fee of $750,000 and the expenses in connection with the issuance of the Special Warrants and the qualification for distribution of the Qualified Units, estimated to be $200,000, which will be paid out of the general funds of the Trust) were used by the Trust to partially repay the advance made under the Current Bank Facility which was used previously to partially fund the Additional Properties Acquisition. See "Information Respecting the Corporation – Borrowing", "Capitalization of the Trust" and "Use of Proceeds".

(6) The Trust retains up to 50% of the Cash Available For Distribution in its Capital Fund to finance future acquisitions and development of the Properties.

The NPI and Direct Royalties

Overview

The Corporation and the Trust have entered into the NPI Agreement, pursuant to which the Corporation has granted and set out to the Trust the right to receive the NPI Income on Properties held by the Corporation from time to time, including the Initial Properties and the Additional Properties.

The NPI consists of the right to receive a monthly payment from the Corporation equal to the NPI Income, which in respect of any period for which the NPI Income is calculated, means 99% of production revenues from the Properties less 99% of the amount by which all the NPI Deductions for such period exceeds Future Acquisition Costs paid with the proceeds from the sale of Properties, withdrawals from the Reserve Fund or Reclamation Fund to fund payment of the NPI Deductions and advances made pursuant to the Credit Facilities to fund the payment of the NPI Deductions. The NPI Deductions paid as part of the Deferred Purchase Price Obligation are credited to the NPI Deductions.

Pursuant to the NPI Agreement substantially all of the economic benefit derived from the assets of the Corporation accrues to the benefit of the Trust and ultimately to the Unitholders. The term of the NPI Agreement is for so long as there are Petroleum and Natural Gas Rights to which the NPI Agreement applies.

The residual 1% share of gross proceeds from the sale of Production which does not form part of the NPI Income and is retained by the Corporation, together with any income of the Corporation derived from Properties that are not working interests in Canadian resource properties (including the Corporation's 1% share of income from the royalty interests from which the Direct Royalties are derived), is used to defray certain expenses and capital expenditures of the Corporation.

Pursuant to the NPI Agreement, the Corporation is required to pay the Trust the NPI Income received by the Corporation from the Properties during the month on or before the 15th day of the next calendar month. In calculating the NPI Income, the Corporation deducts, among other costs and expenses, any amounts paid into the Reserve Fund and the Reclamation Fund. See "Description of the Trust – Reserve Fund" and "Description of the Trust – Reclamation Fund".

As consideration for granting the NPI, the Trust must pay to the Corporation the Deferred Purchase Price Obligation. To satisfy the Deferred Purchase Price Obligation, the net proceeds of any issue of the Trust Units or the proceeds from the disposition of the NPI on any Properties are paid to the Corporation. The Trust is not required to pay an amount as a Deferred Purchase Price Obligation except to the extent the Trust has such proceeds available. See "Deferred Purchase Price Obligation" below for a more detailed description of the Deferred Purchase Price Obligation.

If the Corporation wishes to dispose of any Properties which will result in proceeds in excess of $10 million, the Harvest Board is required to approve such disposition however, if the disposition represents all or substantially all of the Properties, such disposition must also be approved by a Special Resolution of the Unitholders.

The Initial Properties and Additional Properties include working interests in a number of oil treating, natural gas gathering, natural gas compression and natural gas processing facilities. There may be opportunities for the Corporation to provide services to third parties with regard to the Corporation's available capacity in such facilities. Any income from providing processing, gathering, disposal or treating services will not be included in the calculation of the NPI Income, but will be used to defray certain expenses and capital expenditures of the Corporation.

The Trust reimburses the Corporation for Crown royalties and other Crown charges payable by the Corporation in respect of production from or ownership of the Properties. The Corporation is entitled to set off its right to be so reimbursed against its obligation to pay the NPI.

Pursuant to the Trust Indenture, all substantive amendments to the NPI Agreement must be approved by Special Resolution of the Unitholders.

In addition to the NPI, the Trust owns a beneficial interest in the Initial Direct Royalties and the further Direct Royalties and may acquire further Direct Royalties. Such Direct Royalties may consist of direct petroleum and natural gas royalty interests and may be acquired from time to time.

Deferred Purchase Price Obligation

Pursuant to the NPI Agreement, the Deferred Purchase Price Obligation consists of an ongoing obligation of the Trust to pay to the Corporation, to the extent of the Trust's available funds, an amount equal to:

(a) the portion of Future Acquisition Costs incurred by the Corporation from time to time and after the date of the NPI Agreement, which are attributable to Canadian resource property, payable at the time of incurring such Future Acquisition Costs, plus

(b) certain designated drilling, completion, equipping and other costs, in respect of the Properties, payable at the time of incurring such expenditures, plus

(c) the portion of indebtedness incurred in respect of such Future Acquisition Costs and capital expenditures, payable at the time of satisfaction by the Corporation of such indebtedness. To satisfy the Deferred Purchase Price Obligation, pursuant to the NPI Agreement, the Trust is required to pay over to the Corporation the net proceeds of any issue of the Trust Units or the proceeds from the disposition of the NPI of any Properties held by the Corporation. The Trust is not obligated to pay an amount as a Deferred Purchase Price Obligation except to the extent the Trust has such proceeds available.

To the extent that the Corporation designates an expenditure as a Deferred Purchase Price Obligation:

(a) if the designated expenditure is funded by issuing additional Trust Units, by the proceeds of dispositions of the Canadian resource property component of Properties, by the disposition of Direct Royalties or by the issuance of debt, it will not be a charge against the NPI Income, and therefore will not reduce payments of the NPI Income to the Trust or distributions to Unitholders;

(b) the Trust will be obliged to pay to the Corporation ninety-nine (99%) percent of the amount of the designated expenditure to the extent not funded by borrowing by the Corporation;

(c) the cost to the Trust of the designated expenditure will be added to the Canadian oil and gas property expenditures account ("COGPE") of the Trust, thus creating additional tax deductions (see "Canadian Federal Income Tax Considerations"); and

(d) the additional revenue generated from the Properties acquired by the designated expenditure will be added to the revenues used to calculate the NPI Income, thereby potentially increasing the amount payable to the Trust under the NPI Agreement.

Acquisitions

The Corporation may acquire additional Properties from time to time and, pursuant to the NPI Agreement, is entitled to fund such acquisitions from Residual Revenues, the Deferred Purchase Price Obligation, borrowings, or working capital of the Corporation.

Dispositions

Pursuant to the NPI Agreement, to the extent that Properties are disposed of by the Corporation, in consideration for the release of the NPI from such Properties, the Trust will be entitled to 99% of the net proceeds of disposition of the Canadian resource property component thereof after retiring any borrowing which relates to such component. Alternatively, the Corporation will be entitled to reinvest such proceeds on behalf of the Trust pursuant to the Deferred Purchase Price Obligation.

The proceeds from the disposition by the Corporation of any of the Properties that are not attributable to Canadian resource properties will not be included in the NPI Income. Management of the Corporation intends to use such proceeds, together with the residual 1% of the net proceeds received by the Corporation from sales of the Canadian resource property components of the Properties, to defray certain costs and expenses and capital expenditures of the Corporation as described above or to purchase additional Properties which will be subject to the NPI.

In connection with the sale of any interests in the Direct Royalties in accordance with the Administration Agreement, the Corporation will determine whether the net proceeds of the sale should be distributed to Unitholders or reinvested in additional Properties including additional Direct Royalties.

Farmouts

Pursuant to the NPI Agreement, the Corporation is permitted to Farmout any of the Properties if the farmee agrees to incur and pay capital expenditures for purposes of exploiting such Properties and, in consideration thereof, earns an interest in such Properties. Any such Farmout shall also be a Farmout of the NPI on the same terms such that that portion of the Properties, which has been farmed out, shall terminate.

Alberta Royalty Tax Credits

The Trust is entitled to claim ARTC in respect of amounts reimbursed by it to the Corporation for Alberta Crown Royalties and other Alberta Crown charges in respect of Properties owned by the Corporation provided that the Properties (or any portion thereof) are not considered "restricted resource properties" within the meaning of the *Alberta Corporate Tax Act.*

All of the Initial Properties and Additional Properties are considered "restricted resource properties" and are not eligible for ATRC. However, the Trust will be entitled to claim ARTC in respect of amounts reimbursed by it to the Corporation for Alberta Crown royalties and other Alberta Crown charges in respect of the production from new wells drilled on the Initial Properties and the Additional Properties and from additional Properties acquired by the Corporation which are not "restricted resource properties" up to a maximum of $2,000,000 of allowable Crown royalties and other charges. See "Canadian Federal Income Tax Considerations – Entitlement to Alberta Royalty Tax Credits".

Non-Deductible Crown Royalties

Pursuant to the NPI Agreement, the Trust is required to reimburse the Corporation for 99% of all Non-Deductible Crown Royalties paid by the Corporation in respect of the Properties and the Corporation is entitled to set-off such amounts against payments otherwise required to be made to the Trust.

Reserve Fund

Under the NPI Agreement, the Corporation is entitled to pay such amounts of the revenues received from Production and any Residual Revenues received by the Corporation in respect of the Properties into the Reserve Fund if, as and when the Corporation determines, in its reasonable discretion, that it is prudent to do so in accordance with prudent business practices, to provide for payment of production costs which the Corporation estimates will or may become payable in the next six months for which there may not be sufficient revenues to satisfy such costs in a timely manner. Funds retained by the Corporation in the Reserve Fund are required to be used by the Corporation to fund the payment of production costs. To the extent that funds are drawn from the Reserve Fund and used to pay production costs such amounts will be credited to the NPI Deductions in calculating the NPI Income.

Reclamation Fund

The Corporation is liable for its share of ongoing environmental obligations and for the ultimate reclamation of the Properties upon abandonment. In connection with the acquisition of the Initial Properties and the Additional Properties, the Corporation hired engineering consultants and conducted an environmental assessment to estimate reclamation and abandonment liabilities for all wells and facilities associated with the Properties. The Corporation's staff also conducted field visits on all major properties and reviewed every major battery, as well as all natural gas processing and compressor facilities. Well abandonment and reclamation costs were determined taking into account the well type, depth, zone, and topographical considerations. Surface facilities were reviewed for soil and groundwater contamination problems. Government records and the records of the applicable Vendor were reviewed to determine whether or not there were any extraordinary environmental concerns. Cost estimates were determined based upon average actual historical costs for similar projects.

Ongoing environmental obligations are expected to be funded out of cash flow. Those obligations will reduce the amount of The NPI Income that is payable to the Trust. The Corporation currently estimates that the future environmental and reclamation obligations, after salvage recovery, in respect of the Initial Properties and the Additional Properties will aggregate approximately $4.3 million and $5.4 million, over the life of the Initial Properties and the Additional Properties respectively

Pursuant to the NPI Agreement, the Corporation is required to establish a reclamation fund, to which it makes annual contributions, which will provide for the ultimate site restoration and well and facility abandonment expenditures on an appropriate basis over the Economic Life of the relevant reserves. Contributions to the Reclamation Fund may be adjusted by the Corporation from time to time based on its assessment of its share of expected environmental and final site reclamation costs. Contributions made by the Corporation to the Reclamation Fund may not be currently deductible for income tax purposes and may therefore reduce Cash Available For Distribution without an offsetting tax deduction. To the extent that funds are drawn from the Reclamation Fund and used for site restoration and well and facility abandonment expenditures such amounts are credited to the NPI Deductions in calculating the NPI Income.

In addition to the identified producing wells and wells capable of production, the Initial Properties include interests in 43 gross (42 net) active injection, disposal or service wells and 52 gross (51 net) suspended or shut-in wells and the Additional Properties include interests in 17 gross (10 net) active injection, disposal or service wells and 48 gross (38 net) suspended or shut-in wells, all of which have been included in the total estimate of the Corporation's future environmental and reclamation obligations. **The estimates of reserves associated with the Initial Properties and the Additional Properties and the present worth of future net cash flows from such reserves contained in the McDaniel Report are stated before providing for estimated facility site restoration, well abandonment, well site restoration costs and salvage recovery.**

Insurance

The Corporation carries insurance policies to provide protection for its working interest in the Properties at or above industry standards. Insurance policies cover property damage, general liability and, for certain properties, business interruption. The ongoing level, type and maintenance of insurance is determined by the Corporation based upon the availability and cost of such insurance and the Corporation's perception of the risk of loss. The cost of insurance reduces the amount of the NPI Income payable to the Trust. See "Risk Factors – Environmental Concerns".

Cash Available For Distribution

Cash Available For Distribution consists of any amounts received by the Trust pursuant to the NPI and the Direct Royalties, any interest or other income from Permitted Investments, ARTC received by the Trust net of Non-Deductible Crown Royalties that are reimbursed by the Trust to the Corporation, dividends on the shares of the Corporation or any other dividends on securities of the Corporation less all expenses and liabilities of the Trust, including Debt Service Charges, which are due or accrued and which are chargeable to income.

Pursuant to the Trust Indenture and the Administration Agreement, the Corporation calculates the NPI Income for each calendar month and arranges for payment of certain direct expenses of the Trust from the NPI.

The actual amount of Cash Available For Distribution depends on, among other things, the quantity of crude oil, natural gas and natural gas liquids produced, prices received for such production, direct expenses of the Trust, taxes, operating costs, Capital Expenditures, Debt Service Charges, Crown and other royalties, other Crown charges, net contributions to the Corporation's Reclamation Fund and Reserve Fund, and General and Administrative costs of the Trust and the Corporation. See "Risk Factors".

The Corporation also has the discretion to incur debt or retain cash in order to modify seasonal and other variations in Cash Available For Distribution. Unitholders may also receive distributions of the net proceeds received from sales of Properties to the extent the Corporation determines not to use those proceeds to acquire additional Properties.

Delay in Cash Available For Distribution

In addition to the usual delays in payment by purchasers of oil and natural gas to the operator of the Properties, and by the operator to the Corporation or the Trust, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of Properties, or the establishment by the operator of reserves for such expenses.

Capital Fund

The Trust retains up to 50% of the Cash Available For Distribution in its Capital Fund to finance future acquisitions and development of Properties with the intent that it will be able to continue to provide or maintain the Cash Available For Distribution over a longer period of time than would otherwise be the case.

Distributable Cash

Distributable Cash consists of the balance of the Cash Available For Distribution after the retention of funds by the Trust for the Capital Fund, which is distributed to Unitholders.

Unitholders of record on a Record Date will be entitled to receive monthly cash distributions of the Distributable Cash which will become payable on the 15th day following the Record Date, and if such date of payment is not a Business Day on the next Business Day after the 15th day following the Record Date.

Income Tax Treatment

Any amounts paid by the Trust in respect of Future Acquisition Costs and the Deferred Purchase Price Obligation is Canadian oil and gas property expense ("COGPE") of the Trust in the year incurred. The Trust's share of any proceeds of disposition of Canadian resource properties which are receivable as a result of the release of the NPI will reduce the Trust's cumulative COGPE. In determining the portion of Distributable Cash that is taxable to a Unitholder, the Trust is entitled to an annual deduction in respect of its cumulative COGPE account, resource allowance and capitalized issue expenses in accordance with the provisions of the Tax Act. The portion of Distributable Cash to Unitholders that is not taxable in the Trust is treated as a return of capital and reduces the adjusted cost base of Trust Units held as capital property by a Unitholder. In this respect, the taxation of capital distributions is deferred until an actual or deemed disposition of Trust Units occurs or a holder's Trust Units have an adjusted cost base which is less than zero. See "Canadian Federal Income Tax Considerations".

Board of Directors

The Corporation has a board of directors consisting of 5 individuals. Pursuant to the Trust Indenture, Unitholders are entitled to elect the Board of Directors annually. Prior to all annual meetings, the Corporation will deliver an information circular and form of proxy to Unitholders with respect to the election of the directors of the Corporation at any such meeting. See "Information Respecting the Corporation – Directors and Officers of the Corporation".

Decision Making

Under the NPI Agreement, the Corporation has the exclusive control and authority over development of, and recovery of petroleum substances from, the Properties and lands pooled or unitized therewith, including, without limitation, making all decisions respecting whether, when and how to drill, complete, equip, produce, suspend, abandon and shut-in wells and whether to elect to convert royalties to working interests. The Harvest Board has determined that all significant operational decisions and all decisions relating to: (i) the acquisition and disposition of properties for a purchase price or proceeds in excess of $5 million; (ii) the approval of capital expenditure budgets; (iii) the approval of risk management policies and activities proposed to be undertaken, and (iv) the establishment of credit facilities, shall be made by the Board of Directors.

The Board of Directors holds meetings regularly to review the business and affairs of the Corporation and the Trust.

Management of the Trust

Pursuant to the Trust Indenture and the Administration Agreement, the Corporation is required, among other things, to:

(a) administer and manage the day-to-day operations of the Trust, act as agent for the Trust, execute documents on behalf of the Trust and make executive decisions which conform to the general policies and the general principles set forth in the Trust Indenture;

(b) keep and maintain at its offices in Calgary, Alberta at all times books, records and accounts relating to the Trust Fund and prepare all returns, filings and documents and make all determinations necessary for the discharge of the Trustee's obligations under the Trust Indenture;

(c) monitor the tax status of the Trust and provide information to the Trustee regarding the taxable portions of distributions and submit all income tax returns and filings to the Trustee so that the Trustee has a reasonable opportunity to review them, approve them, execute them and return them and arrange for their filing within the time required by applicable tax law;

(d) provide advice with respect to the Trust's obligations as a reporting issuer and ensure compliance by the Trust with continuous disclosure obligations under applicable securities legislation including the preparation and filing of reports and other documents with all applicable regulatory authorities;

(e) provide investor relations services to the Trust including assisting communications with Unitholders;

(f) at the request and under the direction of the Trustee, call and hold all annual and/or special meetings of the Unitholders pursuant to the Trust Indenture, prepare all materials (including notices of meetings and information circulars) in respect thereof and submit all such materials to the Trustee in sufficient time prior to the dates upon which they must be mailed, filed or otherwise relied upon so that the Trustee has a reasonable opportunity to review them, approve them, execute them and return them to the Corporation for filing or mailing or otherwise;

(g) provide office space, equipment and personnel including all accounting, clerical, secretarial, corporate and administrative services as may be reasonably necessary to perform its obligations under the Administration Agreement;

(h) provide or cause to be provided such audit, accounting, engineering, legal, insurance and other professional services as are reasonably required or desirable for the purposes of the Trust including, without limitation, administration of the Direct Royalties, from time to time and provide or cause to be provided such legal, engineering, financial and other advice and analysis as the Trustee may require or desire to permit it to make informed decisions in connection with the discharge by it of its responsibilities as Trustee, to the extent such advice and analysis can be reasonably provided or arranged by the Corporation;

(i) provide assistance in negotiating the terms of any financing required by the Trust or otherwise in connection with the Trust Fund;

(j) take all actions reasonably necessary in connection with, or in relation to, the banking activities of the Trustee, the redemption of Trust Units pursuant to the Trust Indenture and the voting rights on any investments in the Trust Fund or any Subsequent Investments;

(k) take all actions reasonably necessary in connection with, or in relation to, directly or indirectly, the borrowing of money from or incurring indebtedness by the Trust to any person and in connection therewith, to cause the Trust to guarantee, indemnify or act as a surety with respect to payment or performance of any indebtedness, liabilities or obligation of any kind of any person, including, without limitation, the Corporation and any subsidiary (as defined in the *Securities Act* (Alberta) of the Trust; to enter into any other obligations on behalf of the Trust; or enter into any subordination agreement on behalf of the Trust or any other person, and to assign, charge, pledge, hypothecate, convey, transfer, mortgage, subordinate, and grant any security interest, mortgage or encumbrance over or with respect to all or any of the Trust Fund or to subordinate the interests of the Trust in the Trust Fund to any other person;

(l) take all actions reasonably necessary in connection with, or in relation to, the guarantee by the Trust of obligations of the Corporation or any other affiliate of the Trust pursuant to any debt for borrowed money or obligations resulting or arising from hedging instruments incurred by the Corporation or any such affiliate, as the case may be, and pledging securities issued by the Corporation or the affiliate, as the case may be, as security for such guarantee provided that such guarantee is incidental to the Trust's direct or indirect investment in the Corporation or any such affiliate or the business and affairs (existing or proposed) of the Corporation or any such affiliate, and each such guarantee entered into by the Trustee shall be binding upon, and enforceable in accordance with its terms against, the Trust;

(m) take all actions reasonably necessary in connection with, or in relation to, the Trust providing indemnities for the directors and officers of the Corporation and any affiliates;

(n) provide or cause to be provided to the Trustee any services reasonably necessary for the Trustee to be able to consider any future acquisitions or divestitures by the Trustee of any portion of the Trust Fund;

(o) provide advice to the Trustee with respect to determining the timing and terms of potential future offerings of Units;

(p) administer all of the records and documents relating to the Trust Fund other than maintenance of a register of Unitholders;

(q) provide advice and, at the request and under the direction of the Trustee, direction to the transfer agent of the Trust;

(r) provide advice and assistance to the Trustee with respect to the performance of the obligations of the Trust and the enforcement of the rights of the Trust under all agreements entered into by the Trust;

(s) monitor the status of the Units as eligible investments for registered retirement savings plans, registered retirement income funds, and deferred profit sharing plans (all within the meaning of the Tax Act) and immediately provide the Trustee with written notice when the Corporation reasonably foresees that such Units may cease to have such status, or, if not reasonably foreseen, when the Units cease to have such status;

(t) provide such additional administrative and support services pertaining to the Trust, the Trust Fund and the Units and matters incidental thereto as may be reasonably requested by the Trustee from time to time;

(u) administer all matters relating to the Direct Royalties and the Trust, including: (i) determining the total amounts owing to Unitholders and arranging for cash distributions of Cash Available For Distribution; (ii) providing Unitholders with periodic reports on the NPI, the Direct Royalties and the Properties; and (iii) providing Unitholders with financial reports and tax information relating to the Properties, the NPI and the Direct Royalties;

(v) in the event that withholding taxes are exigible on any distributions or redemption amounts distributed under the Trust Indenture or any other agreement, the Corporation shall withhold the withholding taxes required and shall promptly remit such taxes to the appropriate taxing authority. In the event that withholding taxes are exigible on any distributions or redemption amounts distributed under the Trust Indenture or any other agreement and the Corporation is, or was, unable to withhold taxes from a particular distribution to a Unitholder or has not otherwise withheld taxes on past distributions to a Unitholder, the Corporation shall be permitted to withhold amounts from other distributions to satisfy the Corporation's withholding tax obligations;

(w) provide management services for the economic and efficient exploitation of the Properties and the Direct Royalties; and

(x) recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for the Trust.

In exercising its powers and discharging its duties under the Administration Agreement, the Corporation must act honestly and in good faith and exercise the degree of care, diligence and skill that a reasonably prudent oil and natural gas industry advisor and administrator would exercise in comparable circumstances. The Corporation's objective in exercising its powers and discharging its duties is to maximize the income distributable to the Unitholders to the extent consistent with long-term growth in the value of the Trust. In pursuing such an objective, the Corporation employs and will continue to employ prudent oil and natural gas business practices. All of the Corporation's business is and will continue to be conducted in accordance with applicable laws with a view to the best interests of the Unitholders and the Trust.

The Harvest Board reviews on an ongoing basis both the nature and extent of the services required of the Corporation by the Trust and the costs of providing such services.

General and Administrative Costs are deducted from production revenues in computing the NPI Income to the extent not paid from the residual income of the Corporation or deducted by the Trust in computing Cash Available For Distribution. General and Administrative Costs are generally charged to the Trust by the Corporation based on direct costs incurred in fulfilling the obligations of the Corporation to the Trust pursuant to the Trust Indenture and the Administration Agreement. The Corporation is entitled to reimbursement for all of its direct and indirect expenses, costs and expenditures in connection with the creation, start-up, set-up and organization of the Trust and the transition from the Initial Properties Vendors and the Additional Properties Vendor to the Corporation of ownership, management and operatorship of the Initial Properties and the Additional Properties. To the extent that such costs have been incurred to date, they have been paid by the Corporation through drawdowns under a prior credit facility and the Interim Loan.

Trust Debenture

The Trust Debenture was issued on August 15, 2002 by the Trust in exchange for $5,000,000 in cash. Upon closing of the Initial Public Offering, the Trust Debenture was settled through the issuance of 5,000,000 Trust Units to the Management Group. See "Capitalization of the Trust" and "Interests of Management and Others in Material Transactions".

Interim Loan

The Trust entered into two loan agreements dated July 10, 2002 and July 30, 2002, with Caribou. The first interim loan agreement provided for up to $13 million of debt to the Trust, and the second interim loan agreement provided for up to $30 million of debt. Each loan agreement making up the Interim Loan included the following terms: (a) interest was payable at 20% per annum on the outstanding balance; and (b) the loans matured on July 31, 2003 and were secured by all of the assets of the Trust, including the NPI, but are not secured against the Properties of the Corporation.

Upon closing of the Additional Properties Acquisition, the Trust had borrowed $23.2 million under the Interim Loan. The Trust paid these amounts to the Corporation to purchase the NPI and the Initial Direct Royalties from the Corporation and to finance the Deferred Purchase Price Obligation in respect of the Additional Properties Acquisition. See "Acquisition of the NPI", "Initial Properties" and "Additional Properties". The Trust used approximately $22.2 million from the net proceeds of the Initial Public Offering to repay the Interim Loan (including accrued interest) and approximately $4.2 million from the net proceeds of the Initial Public Offering to partially repay the advance made under the Current Bank Facility which was used to partially fund the Additional Properties Acquisition. See "Additional Properties", "Information Respecting the Corporation – Borrowing", "Description of the Trust – Interim Loan" and "Capitalization of the Trust".

Warrants

Pursuant to the Interim Loan, Caribou was granted 150,000 Warrants by the Trust to purchase an equivalent number of Trust Units at $1.00 each. The Warrants were issued as a commitment fee pursuant to the Interim Loan. M. Bruce Chernoff, a director of the Corporation, controls Caribou. The Warrants were exercised on January 23, 2003. See "Capitalization of the Trust" and "Interests of Management and Others in Material Transactions".

INFORMATION RESPECTING THE CORPORATION

The Corporation was incorporated under the *Business Corporations Act* (Alberta) on May 14, 2002 as 989131 Alberta Ltd. On May 17, 2002, the Corporation amended its Articles of Incorporation to change its name to Coyote Energy Inc. and on September 17, 2002, the Corporation changed its name to "Harvest Operations Corp.". The head and principal office of the Corporation is located at Suite 2400, 500 - 4th Avenue S.W., Calgary, Alberta, T2P 2V6 and its registered office is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9. All of the issued and outstanding shares of the Corporation are held in the name of the Trustee for the benefit of, and on behalf of, the Trust.

Business

The Corporation, a wholly-owned subsidiary of the Trust, was incorporated on May 14, 2002 to carry on oil and natural gas acquisition, development and production activities. See "Recent Developments", "Acquisition of the NPI", "Initial Properties" and "Additional Properties".

Pursuant to the Trust Indenture and the Administration Agreement, the Corporation manages and administers the Trust and is responsible for the oil and natural gas technical, investment, engineering, geological, land management, financial and administrative services and commodity marketing services relating to the Properties and the Trust. Each of the directors and senior management of the Corporation have been involved in the oil and natural gas industry for, on average, in excess of 18 years, and the Corporation has a staff of 37 people with key personnel having extensive experience in all technical, operating and financial aspects of the oil and natural gas industry including:

- organizing, operating, managing, developing and optimizing petroleum and natural gas properties;
- evaluating, acquiring and disposing of petroleum and natural gas properties; and
- marketing petroleum substances.

Management Policies and Strategies

As a result of management's past experience, the members of the management team have established proven track records in acquiring, developing and operating oil and natural gas reserves. Management of the Corporation believes that the success derived from these experiences can be attributed to several management principles, including:

(a) a focused and rigorous evaluation and acquisition strategy having an objective of acquiring operated oil and natural gas reserves at low costs;

(b) employing operating and management strategies and controls to increase production rates and enhance production netbacks, primarily through operating expense reduction;

(c) identifying upside opportunities in acquired Properties;

(d) acquiring other assets within existing operating areas to achieve operating and development efficiencies;

(e) managing risk effectively through prudent insurance and commodity hedging programs and hands-on property management.

Activities undertaken by the management of the Corporation on behalf of the Trust are intended to be directed towards:

- maximizing consistent levels of Cash Available For Distribution and ultimately, the Distributable Cash paid to Unitholders;
- capturing the maximum cash flow, production and reserve recovery from the Properties; and
- striving for long-term growth in the value of the Properties and consequently the value of the NPI and the Direct Royalties held by the Trust by improving recovery levels from existing Properties and acquiring additional Properties.

Acquisition Strategy:

In order to grow the asset base of the Corporation and offset natural production declines from existing Properties, the Corporation may acquire producing properties and/or participate in development activities that are considered to be of a low risk nature in the oil and natural gas industry. The Corporation may also from time to time present proposals for the acquisition by the Trust of additional Direct Royalties. The Corporation's acquisition strategy targets individual properties, or groups of properties, that generally comply with the following guidelines which have been established by the Harvest Board:

- each acquisition of a property, or group of properties, for a purchase price in excess of $5 million, will be based on engineering in an independent engineering report, unless specifically approved by the Board of Directors, which may be modified to incorporate the Corporation's views of the engineering analysis contained in the report;
- mature producing properties that are in geographic proximity to the Properties or to other properties about which management of the Corporation considers it has particular expertise to effectively extract value; and
- not more than 25% of the total Reserve Value of a property, or group of properties, will be attributable to a single well.

The Corporation may introduce its own technical views and may modify the independent engineering evaluation associated with Properties being acquired. The Corporation may also take into consideration the continuation of current field development activities being pursued beyond the operator's existing plans, reflecting identified opportunities for further drilling, production enhancements and lower operating costs through field and facility optimization. The Corporation may also incorporate modest fixed operating cost reductions once production from individual properties falls below a certain level to reflect expected facility rationalization.

The Corporation may acquire properties with a relatively low reserve life if the Board of Directors believes, after evaluating development and optimization opportunities associated with such properties, that the future net cash flows adequately justify the initial purchase price plus planned incremental capital investments.

These criteria serve as guidelines for the Corporation's management in presenting acquisitions for approval by the Harvest Board. The Board of Directors may vary these criteria for any particular acquisition based on management's recommendations and consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

Operating Strategy:

A primary objective of the Corporation is the maximization of operating cash flows, oil and natural gas production and reserves recovery from the Properties. This objective will be accomplished through an intensive oil and natural gas field management program. The senior management team of the Corporation possesses extensive experience in the operation of mature oil and natural gas fields. A key feature of the Corporation's strategy is the operatorship of the majority of the Properties.

The field management of an oil and natural gas property is delegated by the working interest owners to an operator, usually the largest working interest or unit interest percentage participant. The operator of a property generally originates the plans and makes the decisions regarding the development and operation of the property, including the level and timing of capital expenditures. Accordingly, the Corporation believes that it is advantageous for it to become operator wherever possible. The Initial Properties Vendors and the Additional Properties Vendor operated 100% of the production from the Initial Properties and the Additional Properties and the Corporation has replaced the Initial Properties Vendors and the Additional Properties Vendor as the successor operator of each of the Initial Properties and the Additional Properties. In evaluating acquisitions of further Properties, the Corporation will attempt to purchase Properties where it can assume operatorship.

The Corporation believes that operatorship will generally result in the following advantages for Unitholders:

- the operator's control provides opportunities to enhance production from the Properties and to positively influence netbacks through operating cost controls and marketing arrangements;

- the operator is in the best position to control the scope and timing of development activities and capital expenditures to initiate production from Proved Non-Producing Reserves, Probable Reserves and Undeveloped Lands;

- operatorship provides opportunities to enhance the value of the Properties through the application of local operating and technical knowledge and the application of new technologies;

- control of operations facilitates the management of risks associated with the Properties. The operator is directly in charge of environmental and safety loss prevention programs;

- the operator receives direct payment from the purchaser of Petroleum Substances produced from a Property without delays in cash flows that might otherwise occur; and

- the operator will acquire information and greater technical understanding about an area that may be used to pursue the development or acquisition of properties in the area or properties in adjacent areas.

Oil and Natural Gas Field Exploitation Strategy:

Management of the Corporation believes that a key tactic in optimizing the value of the Properties is an active program of oil and natural gas field exploitation. In addition to their extensive operating experience, the Corporation's senior management team has a broad base of experience in the development and exploitation of mature oil and natural gas assets.

Field exploitation of the Initial Properties and the Additional Properties by management is anticipated to result in the following advantages for Unitholders:

- typical development and exploitation activities require relatively low amounts of capital and can often provide an attractive annualized rate of return;

- incremental production can often be processed through existing facilities at only the variable operating cost rates. This may improve the net cash received from new production and can assist in defraying fixed costs for existing production;

- optimization of production transportation systems and production processing facilities may increase production levels and reduce operating costs, thereby increasing ultimate reserve recovery;

- amortizing the fixed costs of existing operations over the incremental production being developed can significantly extend the economic life of existing wells and thereby enhance reserve recovery; and

- rigorous geological and technical analysis of the oil and natural gas reserves that cannot be produced from existing wells may reveal pockets of incremental reserves. Low risk development drilling typically provides low cost production and reserve additions that extend the economic life of an oil and natural gas field. See "Description of Initial Properties – Incremental Exploitation and Development Potential" and "Description of Additional Properties – Incremental Exploitation and Development Potential".

Risk Management Strategy:

The Corporation employs the following strategies to manage risk:

- commodity price risk is managed with a hedging program utilizing swaps, collars and options. See "Information Respecting the Corporation – Commodity Hedging". Contracts typically are entered into with large, stable counterparties and, to the extent possible, the Corporation avoids concentrating significant risk with any one counterparty;

- production volume risk is managed through a program of preventative ongoing well and facility maintenance, property and business interruption insurance, as long as the cost of such insurance is economically justifiable, and minimizing production concentration to the extent possible;

- reserve risk is attempted to be minimized by acquiring additional Properties in mature, stable pools, with a history of predictable production levels;

- environmental, health and safety risk is addressed through a facility and well maintenance program as described above along with strict adherence to applicable regulations and best industry practice; and

- financial risk is minimized through cost control, maximizing efficiency of operations and prudently managing debt levels.

Subsequent Acquisitions

The Corporation may acquire Properties and fund such acquisitions from production revenues, the proceeds of the Deferred Purchase Price Obligation (which will be financed by the Trust issuing additional Trust Units or from the proceeds of disposition of the NPI in respect of Properties which are disposed of, the proceeds of disposition of Direct Royalties or borrowings), borrowings, Farmouts or with working capital of the Corporation. See "Information Respecting the Corporation – Capital Expenditures".

Dispositions

The Corporation may sell any of its interests in Properties and the Trust may release the NPI therefrom if the Corporation and the Trust determine that such sale and release would be in the best interests of the Unitholders. The Trust may sell any of its interests in the Direct Royalties if it determines that such sale would be in the best interests of the Unitholders. The Trust Indenture and the NPI Agreement permit the Trust and the Corporation to effect such sales and releases provided that the sale is approved by a Special Resolution of the Unitholders in the event the interests in the Properties being sold constitute all or substantially all of the Properties unless the sale is to an Affiliate of the Corporation and provided such sale is approved by the Harvest Board for sales of Properties for proceeds in excess of $5 million. See "Description of the Trust – Decision Making". The proceeds of a disposition of an interest in the Properties owned by the Corporation to the extent related to Canadian resource properties will be allocated 99% to the Trust after retiring any borrowing which relates to the Canadian resource property component of such interest in consideration for the release of the NPI from such Properties. The proceeds of disposition of interests in the Properties owned by the Corporation that are not attributable to interests in Canadian resource properties will be used to defray certain costs and expenses and capital expenditures of the Corporation or to purchase additional Properties which will be subject to the NPI. The Trust will receive all of the proceeds of disposition of interests in Direct Royalties.

In connection with the sale of any such interests in the Properties, the Corporation will determine whether the net proceeds of the sale should be reinvested on behalf of the Trust pursuant to the Deferred Purchase Price Obligation. Otherwise such proceeds will be paid to the Trust and form part of the Cash Available For Distribution which will be distributed to Unitholders unless retained by the Trust in the Capital Fund.

Capital Expenditures

The Corporation may approve future capital expenditures or Farmouts under the terms of the NPI Agreement. Future capital expenditures on the Properties will generally be of the type which are intended to maintain or improve production from the Properties. The Corporation may finance capital expenditures from production revenues, the proceeds of the Deferred Purchase Price Obligation (which will be financed by the Trust issuing additional Trust Units, from the proceeds of disposition of the NPI in respect of Properties which are disposed of by the Corporation, from proceeds of disposition of Direct Royalties or from borrowings by the Trust), by drawing amounts from the Capital Fund, borrowings, Farmouts or with working capital of the Corporation. **Capital expenditures, which are funded from production revenues, may have a negative short-term effect on the Trust's cash flow and Cash Available For Distribution.** The Corporation will not ordinarily initiate any exploratory drilling or participate in exploratory drilling initiated by the operator of a property but may do so where, in the opinion of the Corporation, to do so would be in the best interests of the Trust.

Although the current Direct Royalties are not subject to capital spending obligations, as those are the responsibility of the lessee and the operator under each lease, the Trust may invest capital to acquire additional Direct Royalties. Pursuant to the Trust Indenture, all such acquisitions will be made by the Corporation, on behalf of the Trust.

The Trust has implemented a distribution strategy whereby it may retain as much as 50% of Cash Available For Distribution in a particular year in the Capital Fund, to finance future acquisitions and development of the Properties. See "Description of the Trust – Capital Fund". Management of the Corporation believes this will assist in maintaining distributions for a longer period than would otherwise be the case if all Cash Available For Distribution was immediately distributed to the Unitholders. See "Risk Factors".

Borrowing

The Corporation and the Trust are permitted to incur indebtedness to the purchase of Properties, capital expenditures or other obligations or expenditures in respect of the Properties or for working capital purposes. Indebtedness of the Corporation to fund the purchase of Canadian resource properties may be repaid with funds received from the Trust pursuant to the Deferred Purchase Price Obligation. The Harvest Board has established the following guidelines with respect to the indebtedness of the Corporation: (i) amounts borrowed to finance the purchase of Properties should not exceed 50% of the Reserve Value of all Properties including those to be acquired at the time of borrowing as shown on the latest available independent engineering report, unless specifically approved by the Board of Directors; and (ii) the estimated annual Debt Service Charges for the 12 months following the borrowing on amounts borrowed to finance capital expenditures or other financial obligations or expenditures required to maintain or improve production from the Properties should not exceed 50% of the estimated the NPI Income and income from Direct Royalties for such 12 month period, unless specifically approved by the Board of Directors. The Corporation is entitled to grant security in priority to the NPI and the Trust is permitted to grant security on the NPI and Direct Royalties to secure the loan of funds directly to the Trust or secure guarantees granted by the Trust of indebtedness of the Corporation. The borrowings of the Trust require approval by the Board of Directors.

Debt Service Charges of the Corporation are deducted in computing the NPI Income and Debt Service Charges of the Trust are deducted in computing Cash Available For Distribution. Debt repayment by the Corporation is scheduled to minimize, to the extent possible, any income tax payable by the Corporation.

The Corporation has negotiated the Current Bank Facility with the Current Lender for U.S. $60 million for the purpose of funding general operating requirements and the acquisition of oil and natural gas properties. The initial borrowing base under the Current Bank Facility is U.S. $38 million. The outstanding principal amount of the Current Bank Facility bears interest at rates which vary depending upon the outstanding principal amount of the Current Bank Facility in relation to the then current borrowing base and the type of advance drawn. For direct advances, the interest rate is based on the Current Lender's prime rate (for U.S. dollar advances) and a money rate service screen rate plus 0.5% (for Canadian dollar advances) (the "CDOR Rate") plus a margin of 1.125% per annum or 1.875% per annum respectively. For Eurodollar loans and advances by way of bankers' acceptances, the interest rate is based on the rates offered to specified banks in the London interbank market (for Eurodollar loans) or the discount rates applicable to each lender (being its own rate if it is a lender which accepts bankers' acceptances or the CDOR Rate for others) plus, in each case, a margin of 2.125% per annum or 2.875% per annum. In either case, the higher margin is applied when amounts outstanding under the Current Bank Facility exceed 75% of the borrowing base. The Current Bank Facility is secured by a first floating charge over all of the Corporation's assets and a fixed charge over specified oil and gas reserves. The Current Bank Facility revolves until April 30, 2004 at which time it is due and payable in full. Dividends and other distributions by the Corporation are prohibited during a default, event of default or an unremedied borrowing base shortfall under the Current Bank Facility. The NPI, any indebtedness of the Corporation to the Trust and amounts payable to the Trustee under the Trust Indenture are specifically subordinate to the Current Bank Facility pursuant to a subordination agreement between the Current Lender, the Trustee and the Corporation dated November 14, 2002. This may restrict the ability of the Corporation to pay the NPI to the Trust or to pay interest or principal on any indebtedness to the Trust, and therefore may limit the Cash Available For Distribution during a default, event of default or an unremedied borrowing base shortfall under the Current Bank Facility.

The Corporation must meet certain minimum commodity price hedging levels and ongoing financial covenants under the Current Bank Facility and is subject to customary restrictions on its operations and activities, including restrictions on incurring indebtedness, granting of security, the issuance of incremental debt and the sale of its assets. During such time as any lender comprising the Current Lender is not a Canadian resident, payments under the Current Bank Facility to such lender will be subject to certain withholding taxes which the Corporation has agreed to assume and which may increase the effective interest rate paid by the Corporation.

The Corporation's indebtedness under the Current Bank Facility is currently approximately $38.7 million, of which approximately $12.3 million was used to repay all outstanding indebtedness under a prior credit facility, a net amount of approximately $23.2 million was used to partially fund the Additional Properties Acquisition approximately $2.3 million was paid in respect of fees and expenses to establish the Current Bank Facility and $0.9 million in interest charges. In addition, the Current Lender has issued approximately $6.6 million in letters of credit to third parties on behalf of the Corporation to secure services on the Properties. See "Properties".

Commodity Hedging

The Corporation has entered into the following oil price hedging contracts with various counterparties, including the Corporation's prior lender:

Swaps:	Term	Price per Barrel
1,000 Bbls/d	January through March 2003	Cdn $38.30
1,000 Bbls/d	April through June 2003	Cdn $37.59
1,000 Bbls/d	July through September 2003	Cdn $37.10
1,000 Bbls/d	October through December 2003	Cdn $36.63
200 Bbls/d	January through March 2003	U.S. $24.95
200 Bbls/d	April through June 2003	U.S. $24.39
1,510 Bbls/d	January through March 2004	U.S. $23.23
1,300 Bbls/d	January through March 2004	U.S. $24.33
1,430 Bbls/d	April through June 2004	U.S. $22.93
1,380 Bbls/d	July through September 2004	U.S. $22.70
1,325 Bbls/d	October through December 2004	U.S. $22.54
1,100 Bbls/d	January through March 2005	U.S. $22.38
1,030 Bbls/d	April through June 2005	U.S. $22.18

Collars:	Term	Price per Barrel
500 Bbls/d	January through March 2003	Cdn $35.00 – 41.30
500 Bbls/d	April through June 2003	Cdn $35.00 – 39.60
500 Bbls/d	July through September 2003	Cdn $35.40 – 38.40
500 Bbls/d	October through December 2003	Cdn $35.50 – 37.35

On closing the Additional Properties Acquisition, the Corporation entered into a physical contract to deliver 6,000 Bbls/d of Lloydminster blend crude oil to the Additional Properties Vendor at Hardisty, Alberta until December 31, 2003. This requires the Corporation to purchase approximately 1,000 Bbls/d of diluent to blend with its production to meet the oil quality requirements at the delivery point. Under the contract, the Corporation is paid a price equal to the NYMEX calendar WTI price less a fixed differential of U.S. $8.233 per Bbl, such price not to be less than U.S. $14.40 per Bbl or greater than U.S. $17.244 per Bbl. In effect, this contract applies a fixed differential to a WTI price collar between U.S. $22.633 and U.S. $25.477 per Bbl. This contract is effective until December 31, 2003. See "Additional Properties – Marketing Arrangements". In addition, pursuant to the Current Bank Facility, the Corporation is required to maintain commodity hedging agreements in effect from time to time with respect to not less than 66 2/3% of its production profile.

The Corporation has also entered into the following electricity price hedging swap contracts with various counterparties:

	Term	Price per MegaWatt
5MW	January through December 2003	Cdn $46.30
5MW	January through December 2004	Cdn $46.00

Directors and Officers of the Corporation

The names, municipalities of residence, present positions with the Corporation and principal occupations during the past five years of the directors and officers of the Corporation are set out in the table below and in the text which follows thereafter.

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held (1)	Principal Occupation
John A. Brussa (2)(4) Calgary, Alberta	Director	235,000	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP (a law firm).
M. Bruce Chernoff(3)(4) Calgary, Alberta	Director, Chairman	4,075,000(7)	Professional Engineer; Chairman and acting Chief Financial Officer of the Corporation; President and Director of Caribou (a private investment management company) since June 1999; from April 2000 to October 2001, Executive Vice President and Chief Financial Officer of Petrobank Energy and Resources Ltd. ("Petrobank") (a public oil and natural gas company); from February to June 1999, Executive Vice President and Chief Financial Officer of Pacalta Resources Ltd. ("Pacalta") (a public oil and natural gas company); prior thereto, Executive Vice President of Pacalta.
Hank B. Swartout (3) Calgary, Alberta	Director	500,000	Chairman, President and Chief Executive Officer of Precision Drilling Corporation since July, 1987.
Verne G. Johnson (2)(3) Calgary, Alberta	Director	20,000	President of KristErin Resources Inc., a private family company since January 2000; Senior Vice President, Funds Management of Enerplus Resources Group from 2000 to 2002; prior thereto, President and Chief Executive Officer of AltaQuest Energy Corporation from 1999 to 2000; prior thereto, President of Ziff Energy Group (an energy consulting company) from 1997 to 1999; prior thereto, President and Chief Executive Officer of ELAN Energy Inc. (a public oil and natural gas company) from 1989 to 1997.

Name and Municipality of Residence	Position with the Corporation	No. of Trust Units Held (1)	Principal Occupation
Hector J. McFadyen (2)(4) Calgary, Alberta	Director	20,000	Independent businessman and Director of Hunting PLC (a UK based public oil and natural gas company); formerly, President, Midstream Division, Alberta Energy Company Ltd. (a public oil and natural gas company). Director of Computershare Trust Company of Canada (a private Canadian company that manages the administration of shareholder and employee records from public and private companies throughout North America).
Jacob Roorda Calgary, Alberta	President	137,500(8)	Professional Engineer, President of the Corporation; from June 1999 to July 2002, Managing Director, Research Capital (a mid-sized investment banking dealer); from January 1996 to March 1999, Vice President, Corporate, Director and co-founder of PrimeWest (a public energy trust); from May 1991 to January 1996, Manager, Business Development, Fletcher Challenge (a private oil and natural gas company).
J.A. Ralston Calgary, Alberta	Vice President, Operations	106,068	Vice President, Operations of the Corporation; from 1996 to 2002, Manager, Production of Penn West (a public oil and natural gas company).
David M. Fisher Calgary, Alberta	Vice President, Finance	47,500(9)	Vice President, Finance of the Corporation since October 2002; from September 1998 to October 2002, Director, Vice President, Finance and Chief Financial Officer of Integra (a private oil and natural gas corporation); from April 1995 to July 1998, Vice President, Finance and Chief Financial Officer of Canrise (a public oil and natural gas corporation); from June 1994 to April 1995 independent consultant; from April 1985 to May 1994, Manager, Corporate Reporting of Canadian Hunter Exploration Ltd.
David J. Rain Calgary, Alberta	Corporate Secretary	80,600	Chartered Accountant; Corporate Secretary of the Corporation; Vice President, Finance and Chief Financial Officer of Petrobank since October 2001; Vice President and Director of Caribou since April 2001; from April 2000 to September 2001, Director, Corporate Finance of Petrobank; from May 1997 to June 1999, Corporate Controller and Treasurer of Pacalta.

Notes:

(1) Represents all Trust Units held directly or indirectly or over which such person exercises control or direction. Based upon information provided by the director or officer to the Trust.
(2) Member of the Audit and Corporate Governance Committee.
(3) Member of the Reserves, Safety and Environment Committee.
(4) Member of the Compensation Committee.
(5) The Corporation does not have an executive committee.
(6) The terms of office of all of the directors will expire at the next annual shareholders' meeting of the Corporation.
(7) Does not include 167,750 Special Warrants held by Mr. Chernoff but does include 150,000 Trust Units held by Caribou Capital Corp., a company controlled by Mr. Chernoff.
(8) Does not include 10,000 Special Warrants held by Mr. Roorda.

(9) Does not include 9,250 Trust Units held in the name of Mr. Fisher's children but otherwise controlled by Mr. Fisher.

The following is a brief description of the background of each of the senior officers and directors of the Corporation. The past performance of each of the individuals indicated below is not necessarily indicative of future performance.

Jacob Roorda, President

Mr. Roorda is a Professional Engineer and holds a Bachelor of Applied Science (Eng.) degree from Queens University and an MBA from the University of Calgary.

Following university, Mr. Roorda held a number of senior engineering positions with Dome Petroleum Ltd. From 1987 to 1991, Mr. Roorda was a Vice President in the equity research group and was a ranked oil and natural gas analyst at BZW Canada Ltd., in Toronto.

From 1991 to 1996, Mr. Roorda was Manager, Business Development at Fletcher Challenge. In January 1996, Mr. Roorda co-founded PrimeWest Energy Trust ("**PrimeWest**") (a public energy trust) and served as Vice President, Corporate and Director of PrimeWest. Mr. Roorda was responsible for overseeing the acquisition strategies of PrimeWest. While at Fletcher and PrimeWest, Mr. Roorda was responsible for closing in excess of $650 million of oil and natural gas property acquisitions.

From June 1999 to July 2002, Mr. Roorda was a Managing Director of Research Capital, an investment-banking firm. At Research Capital, Mr. Roorda was responsible for the overall direction and operations of the Calgary investment banking office of the firm.

J.A. Ralston, Vice President, Operations

Mr. Ralston completed the Management Development Program at the University of Calgary in 1994.

Mr. Ralston was employed with Petro-Canada from 1980 through June 1994 in a broad range of field operating positions of increasing responsibility. During his tenure at Petro-Canada, Mr. Ralston was responsible for construction of field facilities and pipelines, natural gas plant and field operations, procurement, reservoir management, drilling and workovers.

Mr. Ralston commenced employment with Penn West Petroleum ("**Penn West**") in July 1994 where he worked until June 2002. Since 1997, Mr. Ralston served as Production Manager, responsible for overseeing all of Penn West's 100,000 BOE/d production operations, 270 field staff and an annual budget of $200 million. Mr. Ralston was responsible for all areas of operations including engineering, exploitation, production optimization, capital management, planning, construction and budgeting.

David M. Fisher, Vice President, Finance

Mr. Fisher is a Chartered Accountant and graduated in 1980 with a Bachelor of Commerce degree from the University of Alberta. Mr. Fisher has in excess of 20 years experience in financial reporting, management and administration of entities active in the oil and natural gas industry.

From September 1998 to October 2002, Mr. Fisher was a founder, Director and Vice President, Finance and Chief Financial Officer of Integra, ("**Integra**") a private upstream oil and natural gas corporation with assets located in the province of Alberta. Mr. Fisher was responsible for all financial aspects of Integra including reporting systems, financial reporting, securing equity and bank financing, managing financial assets, taxation, and working with legal counsel and transfer agents in the management of shareholder and regulatory items.

From April 1995 to July 1998, Mr. Fisher was the Vice President, Finance and Chief Financial Officer of Canrise. Canrise was a public upstream oil and natural gas corporation with assets located in west-central Alberta.

During the period June 1980 to April 1995 Mr. Fisher's was an external auditor for KPMG Chartered Accountants (formerly Peat Marwick Mitchell & Co.), incentives auditor for Energy Mines and Resources Canada, Manager of Corporate Reporting for Canadian Hunter Exploration Ltd. and an independent consultant providing financial administration for domestic and international entities.

John A. Brussa, Director

Mr. Brussa is a barrister and solicitor and has been a partner at Burnet, Duckworth & Palmer LLP in Calgary since 1987. Mr. Brussa is recognized as a leading tax practitioner in Canada and sits on the board of directors of several Canadian public companies.

M. Bruce Chernoff, Director

Mr. Chernoff is a Professional Engineer with a Bachelor of Applied Science degree in Chemical Engineering from Queen's University. Mr. Chernoff commenced employment with Pacalta ("**Pacalta**") in 1988. Pacalta was a public junior oil and natural gas company with operations in Canada. Mr. Chernoff held various senior positions with Pacalta including Executive Vice-President and Chief Financial Officer. Mr. Chernoff was a director of Pacalta from 1992 until Pacalta was purchased by Alberta Energy Company in May 1999 for $1 billion.

Mr. Chernoff initiated the formation of Caribou, of which he is the President and a Director, in June 1999, to carry out investments in oil and natural gas and real estate. Mr. Chernoff became a Director, and the Executive Vice President and Chief Financial Officer of Petrobank in March 2000. Mr. Chernoff resigned as Chief Financial Officer of Petrobank in October 2001 to focus on his other business interests, but remains a director of the company. Mr. Chernoff initiated the formation of the Corporation in June 2002 to pursue oil and natural gas development and acquisition opportunities. Mr. Chernoff is also a director of several other public companies.

Hank B. Swartout, Director

Mr. Swartout is the Chairman of the Board, President and Chief Financial Officer of Precision Drilling Corporation, the largest Canadian integrated oilfield and industrial services contractor and a global provider of products and services to the energy industry.

Verne G. Johnson, Director

Mr. Johnson received a Bachelor of Science degree in Mechanical Engineering from the University of Manitoba in 1966. He immediately commenced employment with Imperial Oil Limited, which continued until 1981 (including two years with Exxon Corporation in New York from 1977 to 1979). In 1981, Mr. Johnson joined Liberty Petroleum Ltd. as President and Chief Executive Officer. In 1982, he joined Roxy Petroleum Ltd. as Vice President, Production, remaining until 1987 when he joined Paragon Petroleum Ltd. as President. In 1989, Mr. Johnson joined ELAN Energy Inc. (then Lasmo Canada Inc.) as President and a Director. Following the sale of ELAN in 1997, he became President of Ziff Energy Group until 1999, then President of AltaQuest Energy Corporation and he then joined the Enerplus Resources Group in 2000, becoming Senior Vice President of Funds Management. In February 2002, he departed from the Enerplus Resources Group and remains as President of his private family company, KristErin Resources Inc.

Hector J. McFadyen, Director

Mr. McFadyen holds a Bachelor of Arts (Econ.) degree from Sir George Williams University and a Master of Arts (Econ.) degree from the University of Calgary.

Mr. McFadyen was employed at the Alberta Energy and Utilities Board (formerly the Oil and Gas Conservation Board) between 1969 and 1976, primarily within its Economics Department.

Mr. McFadyen began work for Alberta Energy Company Ltd. ("**AEC**"), now EnCana Corporation ("**EnCana**"), in 1976. EnCana is the largest independent oil and natural gas producer in North America. Mr. McFadyen assumed positions of increasing responsibility, serving as a Vice President from 1981, and retiring from Encana in June 2002.

Mr. McFadyen developed a number of significant business units within AEC, developing experience in a broad range of businesses and disciplines. Such experience included project development and investments across North America, Latin America, Asia and Europe. At AEC, Mr. McFadyen served as a member of the senior executive team involved in recommending and implementing the strategic plan for the company. As President of the Forest Products Division since 1981, he assumed responsibility for development and implementation of the business strategy for an Alberta based forest products business. Mr. McFadyen also served as the President of the Midstream Division of AEC since 1995, having responsibility for the company's pipelines and natural gas storage businesses.

Mr. McFadyen, was recently appointed to the board of directors of Hunting PLC ("**Hunting**"), a UK-based public corporation engaged in oil and natural gas, oilfield service, and oil and natural gas marketing and distribution activities. Hunting carries on its oil and natural gas marketing and distribution activities through its majority owned subsidiary, Gibson Energy Ltd. See "Interests of Management and Others in Material Transactions". Mr. McFadyen was also recently appointed to the Board of Directors of Computershare Trust Company of Canada, a private Canadian company that manages the administration of shareholder and employee records for public and private companies throughout North America.

David J. Rain, Corporate Secretary

Mr. Rain is a Chartered Accountant and holds a Bachelor of Commerce degree from the University of Saskatchewan (1986).

Mr. Rain articled at KPMG LLP Chartered Accountants and was as a Manager in their audit group until he departed in 1992. Mr. Rain served in senior financial positions at Nowsco Well Service Ltd., an oilfield service company with worldwide operations, from 1992 through August 1996. Mr. Rain was the Chief Financial Officer of Trican Well Service Ltd, an oilfield service company with operations in Alberta and Saskatchewan, from October 1996 through April 1997. Mr. Rain joined Pacalta in May 1997 as Corporate Controller. Pacalta was an oil and natural gas exploration and production company with operations primarily in Ecuador. When AEC acquired Pacalta in 1999, Mr. Rain joined Mr. Chernoff at Caribou, and became Director, Corporate Finance at Petrobank in March 2000. Mr. Rain assumed the position of Vice President, Finance and Chief Financial Officer of Petrobank in October 2001.

Corporate Cease Trade Orders or Bankruptcies

No director, officer or promoter of the Corporation or shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation has, within the last 10 years, been a director, officer or promoter of any reporting issuer that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the Corporation access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold the assets of that person.

Penalties or Sanctions

No director, officer or promoter of the Corporation or shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, officer or promoter of the Corporation, or a shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the 10 years preceding the date of this prospectus, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to or instituted any proceeding, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual.

Other Reporting Issuer Experience

The following table sets out the directors and officers of the Corporation that are, or have been within the last five years, directors or officers of other reporting issuers, their position with such issuers and the period of their involvement with such issuers:

Name	Name of Reporting Issuer	Position	From	To
John Brussa	Allied Oil & Gas Corp.	Director	02 1998	11 2001
	Antrim Energy Inc.	Director	09 1999	10 2002
	Applied Terravision Systems Inc.	Director	03 2001	03 2002
	Ascot Energy Resources Ltd.	Director	11 1999	05 2002
	Aventura Energy Inc.	Director	09 1999	03 2002
	Barrington Petroleum Ltd.	Director	06 1996	09 1998
	Baytex Energy Ltd.	Director	08 1997	**Present**
	Brooklyn Energy Corporation	Director	11 2001	**Present**

Name	Name of Reporting Issuer	Position	From	To
	Campion Resources Ltd.	Director	05 2000	07 2002
	Chain Energy Ltd.	Director	11 2000	03 2002
	Collicutt Hanover Services Ltd.	Director	01 1999	**Present**
	Dorset Exploration Ltd.	Director	06 1990	09 1997
	Direct Energy	Director	10 1996	08 2000
	E3 Energy Ltd. (formerly Mill City International Inc.)	Director	10 2002	**Present**
	Edge Energy Inc. (formerly Alberta Oil & Gas Ltd.)	Director	01 1998	08 2000
	Endev Energy Inc.(formerly Net Shepherd Inc.)	Director	01 2002	**Present**
	Energy Savings Income Fund	Director	02 2001	**Present**
	FET Resources Inc. (formerly Storm Energy Inc., formerly Dancap Resources)	Director	10 1997	**Present**
	Focus Energy Trust (formerly Storm Energy Inc.)	Director	10 1997	**Present**
	Harvest Energy Ltd.	Director	10 2002	**Present**
	High Point Energy Corp.	Director	06 2002	**Present**
	IEI Energy Inc.	Director / Officer	03 2002	**Present**
	Imperial Metals Corporation	Director	06 1994	01 2002
	Interaction Resources Ltd.	Director	10 1997	05 2000
	Inter Pipeline Fund (formerly Koch Pipelines Canada, L.P.)	Director	11 2002	**Present**
	Magin Energy Inc.	Director	06 1996	06 2001
	Meota Resources Corp.	Director	12 1997	10 2002
	NCE Energy Corporation	Director	11 1996	07 2001
	Navigo Energy Inc. (formerly Ventus Energy Ltd.)	Director	08 1998	09 2001
	Penn West Petroleum Ltd.	Director	04 1995	**Present**
	Petrobank Energy and Resources Ltd.	Director	03 2000	**Present**
	Progress Energy Ltd.	Director	11 2000	**Present**
	Rio Alto Exploration Ltd.	Director	06 1992	07 2002
	Rio Alto Resources International Inc.	Director	07 2002	**Present**
	Southpoint Resources Ltd.	Director	08 2002	**Present**
	Tanganyika Oil Company Ltd.	Director	06 1997	09 2001
M. Bruce Chernoff	Westpoint Energy Inc. (formerly Slade Energy Inc.)	Director	01 1998	05 2000
	Brooklyn Energy Corporation	Director	11 2001	**Present**
	Canada Talon	Director	05 1197	05 1999
	International Datashare Corp.	Director	01 2000	**Present**
	Navigo Energy Inc.	Director	12 1996	**Present**
	Petrobank Energy & Resources Ltd.	Director	03 2000	**Present**
	Edge Energy Inc.	Director	12 1997	08 2000
	Pacalta Resources Ltd.	Director and Senior Officer	1988	05 1999
Hank B. Swartout	Precision Drilling Corporation	Chairman, President and Chief Executive Officer	07 1987	**Present**
Verne Johnson	AltaQuest Energy Corporation	Director & President	04 1998	12 1999
	Blue Mountain Energy Ltd.	Director	05 2002	**Present**
	ELAN Energy Inc.	Director & President	12 1989	09 1997
	Fort Chicago Energy Partners L.P.	Director	10 1997	**Present**
	Southward Energy Ltd.	Director	12 1997	**Present**
Hector McFadyen	Alberta Energy Company Ltd.	Senior Officer	09 1981	04 2002
	AEC Pipelines, L.P.	Senior Officer / Director	04 1997	09 2000
	Hunting PLC	Director	09 2002	**Present**
	Computershare Trust Company of Canada	Director	11 2002	**Present**

Name	Name of Reporting Issuer	Position	From	To
David Rain	International Datashare Corporation	Director	11 2000	**Present**
	Pacalta Resources Ltd.	Treasurer / Corp. Controller	05 1997	05 1999
	Petrobank Energy & Resources Ltd.	V.P. Finance & CFO	10 2001	**Present**
	Petrobank Energy & Resources Ltd.	Director, Corp. Finance	04 2000	09 2001
	Trican Well Service Ltd.	CFO	10 1996	05 1997
Jacob Roorda	PrimeWest Energy Inc.	Vice President & Director	10 1996	04 1999
David Fisher	Canrise Resources Ltd.	V.P. Finance & CFO	04 1995	07 1998

Remuneration of Directors and Officers

The directors of the Corporation may receive cash compensation for acting as directors of the Corporation and are entitled to reimbursement for expenses incurred in acting as directors. The directors are also entitled to participate in the Trust's Unit Incentive Plan. See "Trust Unit Incentive Plan".

The Corporation currently has three executive officers who receive annual salaries of $125,000, $100,000 and $100,000, respectively. Such officers have received and are eligible to receive non-transferable rights to purchase Trust Units in the future in accordance with the Trust's Unit Incentive Plan. See "Trust Unit Incentive Plan". The Corporation intends to enter into employment agreements with each of these officers, and any additional senior officers, and such agreements are expected to contain industry standard severance and change of control provisions.

INDEBTEDNESS OF DIRECTORS AND OFFICERS

At no time since incorporation has there been any indebtedness of any director or officer of the Corporation, or any associate of any such director or officer, to the Corporation or the Trust or to any other entity which is, or at any time since the beginning of the most recently completed financial period has been, the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Corporation or the Trust.

SHARE CAPITAL OF THE CORPORATION

The share capital of the Corporation consists of an unlimited number of common shares. As at the date hereof, one hundred common shares of the Corporation are outstanding. Such shares are held by the Trustee for and on behalf of the Trust. The voting of such shares is governed by the provisions of the Trust Indenture and the Trust is not entitled, without the direction of Unitholders, to exercise its rights as a shareholder of the Corporation except as permitted by the Trust Indenture. See "The Trust Indenture – Exercise of Voting Rights Attached to Shares of the Corporation".

THE TRUST INDENTURE

The following is a summary of the Trust Indenture and other matters regarding the structure and operations of the Trust.

Trust Units

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. Each Trust Unit entitles the holder thereof to one vote at any meeting of the holders of Trust Units and represents an equal undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding-up of the Trust. All Trust Units outstanding from time to time shall be entitled to equal shares of any distributions by the Trust, and in the event of termination or winding-up of the Trust, in any net assets of the Trust. All Trust Units shall rank among themselves equally and rateably without discrimination, preference or priority. Each Trust Unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the Trust Units held by such holder (see "The Trust Indenture Redemption Right") and to one vote at all meetings of Unitholders for each Trust Unit held. See "Risk Factors – Nature of Trust Units".

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust Fund or the obligations or affairs of the Trust or with respect to any act or omission of the Trustee or any other person in the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred upon the Trustee or such other person hereunder or with respect to any transaction entered into by the Trustee or by any other person pursuant to the Trust Indenture. No Unitholder shall be liable to indemnify the Trustee or any such other person with respect to any such liability or liabilities incurred by the Trustee or by any such other person or persons or with respect to any taxes payable by the Trust or by the Trustee or by any other person on behalf of or in connection with the Trust. Notwithstanding the foregoing, to the extent that any Unitholders are found by a court of competent jurisdiction to be subject to any such liability, such liability shall be enforceable only against, and shall be satisfied only out of, the Trust Fund and the Trust (to the extent of the Trust Fund) is liable to, and shall indemnify and save harmless any Unitholder against any costs, damages, liabilities, expenses, charges or losses suffered by any Unitholder from or arising as a result of such Unitholder not having any such limited liability. See "Risk Factors – Unitholder Limited Liability".

Issuance Of Trust Units

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Harvest Board may determine. The Trust Indenture also provides that the Corporation may authorize the creation and issuance of debentures, notes and other evidences of indebtedness of the Trust from time to time on such terms and conditions to such persons and for such consideration as the Corporation may determine.

Borrowing By the Trust

Pursuant to the Trust Indenture, the Trustee is permitted to, directly or indirectly, borrow money from or incur indebtedness to any person and in connection therewith, to guarantee, indemnify or act as a surety with respect to payment or performance of any indebtedness, liabilities or obligation of any kind of any person, including, without limitation, the Corporation and any subsidiary of the Trust; to enter into any other obligations on behalf of the Trust; or enter into any subordination agreement on behalf of the Trust or any other person, and to assign, charge, pledge, hypothecate, convey, transfer, mortgage, subordinate, and grant any security interest, mortgage or encumbrance over or with respect to all or any of the Trust Fund or to subordinate the interests of the Trust in the Trust Fund to any other person.

Debt Service Charges incurred by the Trust are deducted in computing the Cash Available For Distribution.

Redemption Right

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to the Trust of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units by the Trust, the holder thereof shall only be entitled to receive a price per Trust Unit (the "Market Redemption Price") equal to the lesser of: (i) 90% of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to the Trust for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

For the purposes of this calculation, "market price" will be an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than 5 of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day.

The "closing market price" shall be: an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of the Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The aggregate Market Redemption Price payable by the Trust in respect of any Trust Units surrendered for redemption during any calendar month shall be satisfied by way of a cheque drawn on a Canadian chartered bank or trust company in

Canadian money payable on the last day of the following month. The entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month and in any preceding calendar month during the same year shall not exceed $100,000; provided that, the Corporation may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption, and (ii) secondly, to the extent that the Trust does not hold Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes (herein referred to as "Redemption Notes") to the Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall.

If, at the time Trust Units are tendered for redemption by a Unitholder, the outstanding Trust Units are not listed for trading on the TSX and are not traded or quoted on any other stock exchange or market which the Corporation considers, in its sole discretion, to represent fair market value for the Trust Units or the normal trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such Trust Units were tendered for redemption then such Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (the "Appraised Redemption Price") equal to 90% of the fair market value thereof as determined by the Corporation as at the date on which such Trust Units were tendered for redemption. The aggregate Appraised Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Notes and/or Redemption Notes as described above.

It is anticipated that this Redemption Right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Redemption Notes which may be distributed in specie to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such Redemption Notes. Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Non-Resident Unitholders

It is in the best interests of Unitholders that the Trust qualify as a "unit trust" and a "mutual fund trust" under the Tax Act. Certain provisions of the Tax Act require that the Trust not be established nor maintained primarily for the benefit of Non-Residents. Accordingly, in order to comply with such provisions, the Trust Indenture contains restrictions on the ownership of Trust Units by Unitholders who are Non-Residents. In this regard, the Trust shall, among other things, take all necessary steps to monitor the ownership of the Trust Units. If at any time the Trust becomes aware that the beneficial owners of 49% or more of the outstanding Trust Units are or may be Non-Residents or that such a situation is imminent, the Trust, by or through the Corporation on the Trust's behalf, shall take such action as may be necessary to carry out the intentions evidenced herein. For the purposes of this Section, "Non-Residents" means non-residents of Canada within the meaning of the Tax Act.

Meetings of Unitholders

The Trust Indenture provides that meetings of Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of amendments to the Trust Indenture (except as described under " The Trust Indenture-Amendments to the Trust Indenture"), the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding-up the affairs of the Trust. Meetings of Unitholders will be called and held annually for, among other things, the election of the directors of the Corporation and the appointment of the auditors of the Trust.

A meeting of Unitholders may be convened at any time and for any purpose by the Corporation and must be convened, except in certain circumstances, if requisitioned by the holders of not less than 20% of the Trust Units then outstanding by a written requisition. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxyholder need not be a Unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 10% of the votes attaching to all outstanding Trust Units shall constitute a quorum for the transaction of business at all such meetings.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders in accordance with the requirements of applicable laws.

Exercise of Voting Rights Attached to Shares of the Corporation

The Trust Indenture prohibits the Trustee from voting the shares of the Corporation with respect to (i) the election of directors of the Corporation, (ii) the appointment of auditors of the Corporation or (iii) the approval of the Corporation's financial statements, except in accordance with an Ordinary Resolution adopted at an annual meeting of Unitholders. The Trust Indenture also provides that the Trustee shall not, after the Closing, vote the shares to authorize:

(a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets of the Corporation, except in conjunction with an internal reorganization of the direct or indirect assets of the Corporation as a result of which either the Corporation or the Trust has the same, or substantially similar, interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(b) any statutory amalgamation of the Corporation with any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(c) any statutory arrangement involving the Corporation except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(d) any amendment to the articles of the Corporation to increase or decrease the minimum or maximum number of directors; or

(e) any material amendment to the articles of the Corporation to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of the Corporation's shares in a manner which may be prejudicial to the Trust;

without the approval of the Unitholders by Special Resolution at a meeting of Unitholders called for that purpose.

Trustee

Valiant Trust Company is the trustee of the Trust. All of the administrative and management powers of the Trustee relating to the Trust and the operations of the Trust have been delegated to the Corporation pursuant to the Trust Indenture and the Administration Agreement. See "Description of the Trust – Management of the Trust". Notwithstanding this general delegation, pursuant to the Administration Agreement, the Trustee has agreed not to delegate any authority to manage the following affairs of the Trust:

(a) the issue, certification, countersigning, transfer, exchange and cancellation of certificates representing Trust Units;

(b) the maintenance of a register of Unitholders;

(c) the distribution of Distributable Cash to Unitholders, although the calculation of the amount of the distribution shall be made by the Corporation and approved by the Harvest Board and submitted by the Corporation to the Trustee for distribution to the Unitholders;

(d) the mailing of notices, financial statements and reports to Unitholders pursuant to the Trust Indenture, although the Corporation shall be responsible for the preparation or causing the preparation of such notices, financial statements and reports;

(e) the provision of a basic list of registered Unitholders to Unitholders in accordance with the procedures outlined in the Trust Indenture;

(f) the amendment or waiver of the performance or breach of any term or provision of the Trust Indenture or the NPI Agreement on behalf of the Trust;

(g) the renewal or termination of the Administration Agreement on behalf of the Trust; and

(h) any matter which requires the approval of the Unitholders under the terms of the Trust Indenture.

The Trustee is required under the Trust Indenture to exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The initial term of the Trustee's appointment is until the first annual meeting of Unitholders. The Unitholders shall, at the first annual meeting of the Unitholders, re-appoint, or appoint a successor to the Trustee for an additional one year term, and thereafter, the Unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders following the reappointment or appointment of the successor to the Trust. The Trustee may also be removed by the Corporation upon delivery of a notice in writing by the Corporation to the Trustee in limited circumstances. Such resignation or removal becomes effective only upon the approval of the Unitholders by Special Resolution, the acceptance or appointment of a successor trustee and the assumption by the successor trustee of all obligations of the Trustee and in the same capacity.

Liability of the Trustee

The Trustee, its directors, officers, employees, shareholders and agents shall not be liable to any Unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the Trust Fund, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, any action taken or not taken in good faith in reliance on any documents that are, *prima facie*, properly executed, any depreciation of, or loss to, the Trust Fund incurred by reason of the sale of any asset, any inaccuracy in any valuation provided by any other appropriately qualified person, any reliance on any such evaluation, any action or failure to act of the Corporation, or any other person to whom the Trustee has, with the consent of the Corporation, delegated any of its duties under the Trust Indenture, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by the Corporation to perform its duties under or delegated to it under the Trust Indenture or any other contract), unless such liabilities arise out of the gross negligence, willful default or fraud of the Trustee or any of its directors, officers, employees or shareholders. If the Trustee has retained an appropriate expert, adviser or legal counsel with respect to any matter connected with its duties under the Trust Indenture or any other contract, the Trustee may act or refuse to act based on the advice of such expert, adviser or legal counsel, and the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and shall be conclusively deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the Trust Fund. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Amendments to the Trust Indenture

The Trust Indenture may be amended or altered from time to time by Special Resolution. The Trustee may, without the consent, approval or ratification of any of the Unitholders, amend the Trust Indenture for the purpose of:

- ensuring the Trust's continuing compliance with applicable laws or requirements of any governmental agency or authority of Canada or of any province;
- ensuring that the Trust will satisfy the provisions of each of subsections 108(2) and 132(6) of the Tax Act as from time to time amended or replaced;
- ensuring that such additional protection is provided for the interests of Unitholders as the Trustee may consider expedient;
- removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture, any Direct Royalties Sale Agreement, and any other agreement of the Trust or any Offering Document pursuant to which securities of the Trust are issued with respect to the Trust, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of the Trust Unitholders are not prejudiced thereby;
- providing for the electronic delivery by the Trust to Unitholders of documents relating to the Trust (including annual and quarterly reports, including financial statements, notices of Unitholder meetings and information circulars and proxy related materials) once applicable securities laws have been amended to permit such electronic delivery in place of

normal delivery procedures, provided that such amendments to the Trust Indenture are not contrary to or do not conflict with such laws;

- curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee the rights of the Trustee and of the Unitholders are not prejudiced thereby; and
- making any modification in the form of the Trust Unit certificates to conform with the provisions of the Trust Indenture, or any other modifications provided the rights of the Trustee and the Unitholder are not prejudiced thereby.

Take-Over Bid

The Trust Indenture contains provisions to the effect that if a takeover bid is made for the Trust Units and not less than 90% of the Trust Units (other than Trust Units held at the date of the takeover bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust Units held by Unitholders who did not accept the takeover bid on the terms offered.

Termination of the Trust

Unitholders may vote to terminate the Trust at any meeting of the Unitholders duly called for that purpose, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20% of the outstanding Trust Units; (b) a quorum of 50% of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by Special Resolution of Unitholders.

Unless the Trust is earlier terminated or extended by vote of the Unitholders, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2099. In the event that the Trust is wound-up, the Trustee will sell and convert into cash the Direct Royalties and other assets comprising the Trust Fund in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the Trust Fund, and shall in all respects act in accordance with the directions, if any, of the Unitholders in respect of termination authorized pursuant to the Special Resolution authorizing the termination of the Trust. However, in no event shall the Trust be wound-up until the Direct Royalties have been disposed of. After paying, retiring or discharging, or making provision for the payment, retirement, or discharge of all known liabilities and obligations of the Trust and after providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of the property of the Trust among the Unitholders in accordance with their Pro Rata Share.

Reporting to Unitholders

The consolidated financial statements of the Trust will be audited annually by an independent recognized firm of chartered accountants. The audited consolidated financial statements of the Trust, together with the report of such chartered accountants, will be mailed by the Corporation to Unitholders and the unaudited interim consolidated financial statements of the Trust will be mailed to Unitholders within the periods prescribed by securities legislation. The year end of the Trust shall be December 31. The Trust will be subject to the continuous disclosure obligations under all applicable securities legislation.

TRUST UNIT INCENTIVE PLAN

The Trust has adopted a unit incentive plan (the "Unit Incentive Plan") which permits the Harvest Board to grant non-transferable rights to purchase Trust Units ("Incentive Rights") to the directors, officers, consultants, employees and other ongoing service providers of the Trust and its subsidiaries, including the Corporation. The purpose of the Unit Incentive Plan is to provide an effective long term incentive to eligible participants and to reward them on the basis of long term performance and distributions. The total number of Trust Units issuable under the Unit Incentive Plan is 875,000 Trust Units.

The Harvest Board administers the Unit Incentive Plan and determines participants in the Unit Incentive Plan, numbers of Incentive Rights granted, and the terms of vesting of Incentive Rights. The grant price of the Incentive Rights (the "Grant Price") shall be equal to the per Trust Unit closing price on the trading date immediately preceding the date of grant, unless otherwise permitted. The exercise price ("Exercise Price") per Right shall be calculated by deducting from the Grant Price the aggregate of all distributions, on a per Unit basis, made by the Trust after the Grant Date, provided the aggregate amount of such distribution represents a return of more than 0.833% of the Trust's recorded cost of capital assets less all debt, working capital deficiency (surplus) or debt equivalent instruments, depletion, depreciation and amortization charges and any future income tax liability associated with such capital assets at the end of each month.

Incentive Rights are exercisable for a maximum of five years from the date of the grant thereof and are subject to early termination upon the holder ceasing to be an eligible participant, or upon the death of the holder. In the case of early termination, a holder is entitled, from the date the holder ceased to be an eligible participant to the earlier of 30 days and the end of the exercise period, to exercise vested Incentive Rights. In the case of death, the estate of the holder is entitled, from the date of death to the earlier of 6 months and the end of the exercise period, to exercise vested Incentive Rights at the Exercise Price in effect at the date of death. Incentive Rights not vested at the date of termination of the holder or at date of the holder's death are immediately null and void. The Trust has the option to settle outstanding Incentive Rights with Trust Units and/or cash. The number of Trust Units to be issued to settle outstanding Incentive Rights shall equal the amount determined by multiplying the number of Incentive Rights by the quotient obtained by dividing the difference between the current market price of a Trust Unit and the Exercise Price by the current market price of a Trust Unit. Cash paid to settle outstanding Incentive Rights will equal the difference between the current market price of a Trust Unit less the Exercise Price multiplied by the number of Incentive Rights to be settled.

The following table sets forth information with respect to the Incentive Rights outstanding under the Unit Incentive Plan on the date hereof.

Group	Date Incentive Rights Granted	Trust Units Under Option	Exercise Price	Closing Price on Day Prior to Grant	Expiry Date	Market Value of Incentive Right [(1)]
Executive Officers (475,000)	November 25, 2002	475,000	$8.00	$8.00	November 25, 2007	$1,163,750
Directors (75,000)	November 25, 2002	75,000	$8.00	$8.00	November 25, 2005	$183,750
Employees and Consultants (270,000)	November 25, 2002 to January 24, 2003	270,000	$8.00 - $10.21	$8.00 - $10.21	November 25, 2002 to January 24, 2007	$650,190

Note:

(1) Based on the difference between the closing price of $10.45 per Trust Unit on the TSX on February 11, 2003 and the exercise price of the Incentive Right multiplied by the number of Trust Units under the Incentive Right.

DRIP PLAN

The Trust has received all applicable regulatory approvals and has implemented a Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP Plan"). **The DRIP Plan is not available to Unitholders who are residents of the United States.** The DRIP Plan provides eligible holders of Trust Units the means of accumulating additional Trust Units by reinvesting any Distributable Cash received. At the discretion of the Corporation, Trust Units will either be acquired at prevailing market rates (not exceeding 115% of the volume weighted average trading price of the Trust Units on the TSX for the 10 trading days immediately preceding the date the Trust Units are purchased) or issued from treasury at 95% of the market price of the Trust Units (calculated as the weighted average trading price of the Trust Units on the TSX for the period commencing on the second Business Day following the distribution record date and ending on the second Business Day immediately prior to the distribution payment date on which at least a board lot of Trust Units is traded). Participants in the DRIP Plan are also permitted to purchase additional Trust Units at 100% of the market price (as described above) of the Trust Units by investing additional sums to a maximum of $5,000 per month and a minimum of $1,000 per remittance; provided that the total number of Trust Units that may be issued each fiscal year pursuant to optional cash payments is restricted to not more than 2% of the number of issued and outstanding Trust Units at the commencement of that year.

CAPITALIZATION OF THE TRUST

The following table sets forth the consolidated capitalization of the Trust as at the dates noted.

Designation	Authorized	Outstanding as at September 30, 2002	Outstanding as at September 30, 2002 after giving effect to the Issuance of Special Warrants	Outstanding as at September 30, 2002 after giving effect to the exercise of Special Warrants (6)
Current Bank Facility (1)(2)(3)	U.S. $60,000,000	$Nil	$34,857,043	$34,857,043
Trust Debenture (4)	$5,000,000	$5,000,000	$Nil	$Nil
Interim Loan (5)	$43,000,000	$12,923,000	$Nil	$Nil
Trust Units (4)(6)	Unlimited	$100 (one hundred Trust Units)	$39,650,000 (9,462,500 Trust Units)	$54,650,000 (10,962,500 Trust Units)
Special Warrants	$15, 000,000	$Nil	$15,000,000 (1,500,000 warrants)	$Nil

Notes:

(1) Effective September 30, 2002, the Corporation had a credit facility with an initial borrowing base of $18 million with a Canadian chartered bank. At September 30 2002, the Corporation had drawn $13.1 million on this credit facility. On November 15, 2002, this facility was repaid in full through an advance made under the Current Bank Facility. See "Initial Properties", "Additional Properties" and "Information Respecting the Corporation – Borrowing".

(2) In connection with the Additional Properties Acquisition, the Corporation entered into the Current Bank Facility. The Corporation's current indebtedness under the Current Bank Facility is approximately $38.7 million, of which approximately $12.3 million was used to repay all outstanding indebtedness under a previous credit facility, a net amount of $23.2 million was used to partially fund the Additional Properties Acquisition, approximately $2.3 million was paid in respect of fees and expenses to establish the Current Bank Facility, and $0.9 million in interest charges. In addition the Current Lender has issued to third parties approximately $6.6 million in letters of credit. The initial borrowing base under the Current Bank Facility is $U.S. $38 million. See "Initial Properties", "Additional Properties" and "Information Respecting the Corporation – Borrowing".

(3) The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional $5.8 million adjustment to the Additional Properties Acquisition Cost should be made in favour of the Additional Properties Vendor. This dispute relates to whether or not the value of a hedging contract held by the Additional Properties Vendor impacts the net proceeds from the Additional Properties from the effective date of the Additional Properties Acquisition of June 1, 2002 to the closing date of November 15, 2002. The Additional Properties Vendor has indicated its intent to charge the Corporation the additional $5.8 million as an interim adjustment within 90 days or in any event not later than 180 days of the closing of the Additional Properties Acquisition. Management of the Corporation believes that such amount is not owing to the Additional Property Vendor. This dispute is expected to be resolved through the arbitration process established in the Additional Properties Agreement. See "Risk Factors".

(4) The Trust Debenture was issued effective as of August 15, 2002 by the Trust in exchange for $5,000,000 cash. The Trust Debenture bore interest at 2.0%, was unsecured and was due December 31, 2002. Principal and outstanding interest under the Trust Debenture could be settled in either cash or Trust Units, at the option of the holder. If settled in Trust Units, the dollar amount outstanding would be converted to Trust Units at a fixed price of $1.00 per Trust Unit. Outstanding amounts due under the Trust Debenture became due and payable on the earlier of the maturity date and the date on which the Trust qualified as a mutual fund trust through the listing of the Trust Units on a recognized Canadian stock exchange. The Trust Debenture was settled through the issuance of 5,000,000 Trust Units on completion of the Initial Public Offering.

(5) Upon closing of the Additional Properties Acquisition, the Trust had borrowed $22.2 million under the Interim Loan which bore interest at 20% per annum and was provided by Caribou, which is controlled by M. Bruce Chernoff, a director of the Corporation. The Trust paid these amounts to the Corporation to purchase the NPI and the Initial Direct Royalties from the Corporation and to finance the Deferred Purchase Price Obligation in respect of the Additional Properties Acquisition. See "Acquisition of the NPI", "Initial Properties" and "Additional Properties". The Corporation used these amounts to partially finance the acquisitions of the Initial Properties and the Additional Properties. Approximately $22.3 million from the net proceeds of the Initial Public Offering was used to repay the Interim Loan (including accrued interest). See "Additional Properties", "Information Respecting the Corporation – Borrowing" and "Description of the Trust – Interim Loan".

(6) The initial 100 Trust Units issued to settle the Trust were cancelled at the closing of the Initial Public Offering. Pursuant to the Interim Loan, the Trust issued 150,000 Warrants to Caribou to purchase an equivalent number of Trust Units for $1.00 each. These Warrants were exercised on January 23, 2003. See "Description of the Trust – Warrants" and "Interests of Management and Others in Material Transactions".

PRICE RANGE AND TRADING VOLUME

The Trust Units have been listed and posted for trading on the TSX under the trading symbol "HTE" since December 5, 2002. The following table sets forth the simple average of the reported high and low sales prices and the trading volumes for the Trust Units for the periods indicated as reported by the TSX.

	High	Low	Volume
December 5, 2003 to December 31, 2003	9.50	8.25	561,757
January 1, 2003 to January 31, 2003	11.00	9.45	396,022
February 1, 2003 to February 11, 2003	10.70	10.38	106,429

Note:

(1) On January 16, 2003, being the day of negotiation of the issue price of the Special Warrants, the closing price of the Trust Units on the TSX was $10.75. On February 11, 2003, being the last day on which the Trust Units traded prior to the date of this prospectus, the closing price of the Trust Units on the TSX was $10.45.

PRIOR SALES

On July 10, 2002, the Trust issued 100 Trust Units to the original settlor of the Trust for $100 to facilitate its organization. On December 5, 2002, 8,750,000 Trust Units were issued pursuant to the closing of the Initial Public Offering and the settlement of the Trust Debenture. On December 17, 2002, 562,500 Trust Units were issued pursuant to the exercise of an over-allotment option granted to the Underwriters in connection with the Initial Public Offering. On January 23, 2003, 150,000 Trust Units were issued to Caribou pursuant to the exercise of the Warrant.

RECORD OF CASH DISTRIBUTIONS

The following table sets forth the per Trust Unit amount of monthly cash distributions paid by the Trust since the completion of the Initial Public Offering.

2003	Distribution Per Trust Unit
January (1)	$0.20

Notes:

(1) This distribution was the first cash distribution of the Trust following the completion of the Initial Public Offering.

(2) The Trust announced on January 17, 2002 that the next monthly cash distribution of $0.20 per Trust Unit will be paid on February 17, 2003 to Unitholders of record on January 31, 2003.

(3) Unitholders of record on a Record Date will be entitled to receive monthly cash distributions of the Distributable Cash which will become payable on the 15th day following the Record Date, and if such date of payment is not a Business Day on the next Business Day after the 15th day following the Record Date.

(4) Pursuant to the Special Warrant Indenture, holders of Special Warrants are entitled to monthly cash and certain other distributions as if they were holders of Units.

ESCROWED SECURITIES

In connection with the completion of the Initial Public Offering, certain members of the Management Group holding an aggregate $4,777,500 principal amount of the Management Group Debentures (which were settled with 4,777,500 Trust Units) executed an undertaking in favour of the Underwriters not to offer or sell, agree to offer or sell, or enter into an arrangement to offer or sell any Trust Units or other securities of the Trust or the Corporation, or securities convertible into, exchangeable for, or otherwise exercisable to acquire any securities of the Trust or the Corporation then held by such holder or such holder's spouse, directly or indirectly, at any time until November 28, 2004. See "Interests of Management and Others in Material Transactions".

PLAN OF DISTRIBUTION

This prospectus is being filed in the Filing Provinces to qualify the distribution of the Qualified Units to be issued upon the exercise of the Special Warrants. All of the issued and outstanding Special Warrants are fully-paid and non-assessable and the Qualified Units, or the Trust Units issuable upon the exercise of the Special Warrants in the event that the Special Warrants are exercised prior to the issuance of a Final MRRS decision document, will, when issued, be fully-paid and non-assessable.

On the Closing Date, the Trust completed a private placement of 1,500,000 Special Warrants pursuant to prospectus exemptions under applicable securities legislation through the Underwriters in accordance with the Underwriting Agreement. Pursuant to the Underwriting Agreement, the Underwriters agreed to act as, and the Trust appointed the Underwriters as, sole and exclusive agents of the Trust to offer the Special Warrants in the Filing Provinces on a private placement basis at a price of $10.00 per Special Warrant. The Underwriters sold the Special Warrants as agents and presently do not hold any Special Warrants. Pursuant to the Underwriting Agreement, the Trust has paid a fee of $750,000 to the Underwriters. The Underwriters will receive no other fees in connection with the distribution of the Qualified Units under this prospectus. The offering price of the Special Warrants was determined by negotiation between Harvest, on behalf of the Trust, and the Underwriters.

The Trust or the Corporation shall, without prior written consent of FirstEnergy Capital Corp. on behalf of the Underwriters, which consent shall not be unreasonably withheld, create, authorize, issue or sell or announce its intention to so create, authorize, issue or sell any Trust Units or other securities of the Trust, rights to purchase such Trust Units, or other securities of the Trust, or any securities convertible into or exercisable or exchangeable for such Trust Units, or other securities of the Trust, or agree to any of the foregoing, prior to June 5, 2003, except for (i) options granted under the Trust's Unit Incentive Plan and Trust Units issued pursuant to the exercise of such options; and (ii) Trust Units issued pursuant to the DRIP Plan.

The Special Warrants were issued pursuant to the Special Warrant Indenture. Since the date of issuance, no Special Warrants have been exercised. Each Special Warrant entitles the holder to acquire, subject to adjustment, at no additional cost, one Qualified Unit of the Trust at any time until 5:00 p.m. (Calgary time) on the earlier of: (i) five (5) Business Days after the Final Receipt Date; and (ii) the first anniversary of the Closing Date.

In the event that the Trust sets a Record Date in respect of or pays a distribution or sets a Record Date in respect of or makes any other distribution in cash or property or securities of the Trust to all or substantially all of the holders of Trust Units of record on a date after February 4, 2003 (the "Effective Date") and prior to the exercise or deemed exercise of the Special Warrants, the Trust agrees that it will pay the same amount of such distribution or make the same distribution of cash, property or securities to the Warrant Trustee on behalf of entitled holders of Special Warrants, on such date as if the holders of such Special Warrants on such date were the holders of the number of Trust Units which the holders of Special Warrants are entitled to receive upon exercise of the Special Warrants and such payments or other distributions shall be held and dealt with by the Warrant Trustee in accordance with the Special Warrant Indenture.

In the event that a Final MRRS decision document is not obtained by the Trust on or prior to the Qualification Deadline on behalf of the Canadian securities regulatory authority in each of the Filing Provinces, then each holder of Special Warrants in the Filing Provinces on whose behalf a Final MRRS decision document has not been obtained (or, if a Final MRRS decision document has not been obtained on behalf of the Province of Alberta, all holders wherever resident) shall be entitled after the Qualification Deadline to receive on the exercise or deemed exercise of the Special Warrants an additional 0.09 of a Trust Unit for each such Special Warrant so exercised without additional payment. This prospectus also qualifies the distribution of the additional 0.09 of a Trust Unit per Special Warrant in the event that such units are issued. Special Warrants not previously exercised by the holders thereof shall be deemed to be exercised immediately prior to the Expiry Time without further action on the part of the holder. The Trust will continue to use its best efforts to obtain a Final MRRS decision document on behalf of the Canadian securities regulatory authority in each Filing Province where a Final MRRS decision document is not obtained on or before the Qualification Deadline until February 4, 2004.

Any Trust Units issued in exchange for Special Warrants exercised on or after the Closing Date and prior to the Final Receipt Date will be subject to relevant hold periods under applicable securities legislation.

Holders of Special Warrants who wish to exercise the Special Warrants held by them in order to acquire Trust Units hereunder should complete the exercise form attached to the Special Warrant certificate and deliver the certificates and the executed exercise forms to the Warrant Trustee at its principal office in Calgary, Alberta. The Special Warrants represented by a Special Warrant certificate shall be deemed to be surrendered only upon personal delivery of the certificate or, if sent by mail or other means of transmission, upon actual receipt thereof by the Warrant Trustee at the office referred to above.

The Special Warrant Indenture provides that in the event of certain alterations of the Trust Units, including any subdivision, consolidation or reclassification, and in the event of any form of reorganization of the Trust or the Corporation, including any amalgamation, merger or arrangement, an adjustment shall be made to the terms of the Special Warrants such that the holders shall, upon exercise of the Special Warrants following the occurrence of any of those events, be entitled to receive the same number and kind of securities that they would have been entitled to receive had they exercised their Special Warrants prior to the occurrence of those events. The holding of Special Warrants does not constitute the holder thereof a unitholder of the

Trust or entitle the holder to any right or interest in respect thereof except as expressly provided in the Special Warrant Indenture.

The Special Warrant Indenture provides that all holders of Special Warrant certificates shall be bound by any resolution passed at a meeting of the holders of Special Warrants held in accordance with the provisions of the Special Warrant Indenture and resolutions signed by the holders of Special Warrants entitled to acquire a specified majority of the Trust Units which may be acquired pursuant to all the then outstanding Special Warrant certificates.

The TSX has conditionally approved the listing of the Qualified Units subject to the Trust fulfilling all of the requirements of such exchange.

The Qualified Units have not been and will not be registered under the U.S. Securities Act. Accordingly, the Qualified Units may not be offered or sold within the United States except in certain transactions exempt from the registration requirements of the U.S. Securities Act. In addition, until 40 days after the commencement of this offering, any offer or sale of the Qualified Units within the United States by any dealer (whether or not participating in this offering) may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A of the U.S. Securities Act.

USE OF PROCEEDS

The Trust raised gross proceeds from the issuance of the Special Warrants of $15 million (before deducting the Underwriters' Fee of $750,000 and the expenses of the issuance of the Special Warrants and the qualification for distribution of the Qualified Units, estimated to be $200,000, which will be paid out of the general funds of the Trust). The Trust will not receive any cash proceeds upon the exercise of the Special Warrants. All of the net proceeds from the financing were used to partially repay outstanding balances under the Current Bank Facility, which was used to partially fund the Additional Properties Acquisition and for working capital. See "Additional Properties".

PRINCIPAL UNITHOLDERS

To the best of the knowledge of the directors and officers of the Corporation, the only person that owns, directly or indirectly, or exercises control or direction over Trust Units carrying more than 10% of the votes attached to all of the issued and outstanding Trust Units is:

		Number of Trust Units Owned		Percentage of Trust Units	
Name and Address of Shareholder	**Type of Ownership**	**Before Exercise of Special Warrants**	**After Exercise of Special Warrants**	**Before Exercise of Special Warrants**	**After Exercise of Special Warrants**
M. Bruce Chernoff	Direct and Beneficial	4,075,000(1)	4,242,750(1)	43.1%	38.7%

Notes:

(1) Includes 150,000 Trust Units owned by Caribou Capital Corp., a company controlled by Mr. Chernoff.

CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Burnet, Duckworth & Palmer LLP, counsel to the Trust, and Blake, Cassels & Graydon, LLP, counsel to the Underwriters (collectively "Counsel") the following is a summary of the principal Canadian federal income tax consequences generally applicable to persons who have acquired Special Warrants pursuant to the Special Warrant Indenture and who will acquire and dispose of Trust Units issuable on the exercise of the Special Warrants and who, for the purposes of the Tax Act and at all relevant times are resident in Canada, hold such Special Warrants and Trust Units as capital property, and deal at arm's length with the Trust. The Special Warrants and Trust Units will generally be considered capital property to the holder thereof unless either the holder holds the Special Warrants and the Trust Units in the course of carrying on a business or the holder has acquired the Special Warrants and Trust Units in a transaction or transactions considered to be, individually or collectively, an adventure in the nature of trade.

This summary is based upon the current provisions of the Tax Act, Counsel's understanding of the current published administrative practices of the CCRA, and proposed amendments to the Tax Act publicly announced by the Minister of

Finance (Canada) prior to the date hereof (the "Proposed Amendments"). This summary assumes that the Proposed Amendments will be enacted as proposed, but does not take into account or anticipate any other changes in law, whether by way of judicial, legislative or governmental decision or action, nor does it take into account any provincial, territorial or foreign income tax considerations. No assurances can be given that the Proposed Amendments will be enacted as proposed, if at all, or that legislative, judicial or administrative changes will not modify or change the statements expressed herein. No application has been made to the CCRA for an advance income tax ruling with respect to this offering.

This summary does not apply to holders that are "financial institutions" within the meaning of the "mark-to-market" rules contained in the Tax Act, or who, at any time, have an "at-risk adjustment" as defined in the Tax Act.

The Canadian federal income tax consequences of a particular holder will vary depending on a number of factors. **The following discussion of the income tax consequences is of a general nature only and is not exhaustive of all the income tax consequences and is not intended to constitute income tax advice to any particular holder. Accordingly, holders should consult their own income tax advisors with respect to the Canadian federal income tax consequences which will result from holding Special Warrants and acquiring, holding and disposing of Trust Units issuable on the exercise of the Special Warrants.**

Exercise or Disposition of Special Warrants

An original holder of a Special Warrant will have a cost for tax purposes equal to the amount paid for such Special Warrant upon subscription (plus any related acquisition costs). A holder will not realize a gain or loss upon the exercise or deemed exercise of Special Warrants to receive Trust Units. The cost for tax purposes of Trust Units acquired pursuant to the exercise of the Special Warrants will generally be equal to the tax cost of such Special Warrants. In computing the adjusted cost base of a holder's Trust Units acquired pursuant to the exercise of the Special Warrants, the cost of such Trust Units must be averaged with the cost of any other Trust Units held as capital property at that time.

A disposition or deemed disposition of Special Warrants (other than on the exercise of such Special Warrants) will result in the realization of a capital gain (or capital loss) in the taxation year of the disposition to the extent the proceeds of disposition exceed (or are exceeded by) the aggregate of the adjusted cost base of such Special Warrants, net of any reasonable disposition costs.

Distributions on Special Warrants

Although the matter is not entirely clear, distributions made to holders of Special Warrants upon exercise thereof will be required to be included in the income of the particular holder of Special Warrants for the purposes of the Act.

Disposition of Trust Units

An actual or deemed disposition of Trust Units (other than in a tax–deferred transaction) will give rise to a capital gain (or capital loss) equal to the amount by which the proceeds of disposition are greater than (or less than) the adjusted cost base to the holder of such Trust Units plus reasonable costs associated with the disposition. In computing income, a taxpayer must include one–half of the amount by which the taxpayer's capital gains for the taxation year exceed his capital losses for that year. Capital gains realized by an individual may give rise to alternative minimum tax.

Unitholders who realize capital losses upon the disposition of Trust Units in a taxation year may deduct such losses from any capital gains realized in that year. Capital losses not applied to reduce capital gains in this manner may be applied against the amount by which capital gains exceed capital losses for each of the three previous or any subsequent taxation year.

Income from Trust Units

Each Unitholder is required to include in computing income for a particular taxation year the Unitholder's pro rata share of the Trust's income for tax purposes that was payable in that year by the Trust to that Unitholder whether such amounts are paid in the form of additional Trust Units, or constitute cash distributions reinvested in additional Trust Units, and whether the amount was actually paid to the Unitholder in that year, together with all amounts designated to the Unitholder as reimbursed Crown charges in excess of the resource allowance deducted in computing the Trust's income. An amount will be considered to be payable to the Unitholders in a taxation year if it is paid in the year by the Trust or the Unitholder is entitled in that year to enforce payment of the amount. In certain limited cases, such as where the Trust uses income of the Trust to repay the principal amount of Trust borrowings or to purchase additional Direct Royalties, it is possible that such Trust income may be paid to Unitholders through the issuance of Trust Units. Generally income of a Unitholder from the Trust

Units will be considered to be income from property and not business income or income from production for purposes of the Tax Act. Any loss of the Trust for purposes of the Tax Act cannot be allocated to and treated as a loss of the Unitholders.

Adjusted Cost Base of Trust Units

The adjusted cost base of a Unitholder is a Trust Unit will include all amounts paid or payable by the Unitholder for such Trust Unit. Any additional Trust Units acquired by a Unitholder on a reinvestment of a distribution by the Trust or a distribution of additional Trust Units will have an initial cost to the Unitholder equal to the amount of the distribution so reinvested or distributed, subject to the averaging provisions of the Tax Act described above. Amounts distributed by the Trust to a Unitholder in respect of a Trust Unit (including amounts in respect of ARTC, if any) will reduce the Unitholder's adjusted cost base of the Trust Unit to the extent that the amount distributed is in excess of the Trust's income for the purposes of the Tax Act computed prior to any deduction for amounts distributed to Unitholders. To the extent that the adjusted cost base to a holder of Trust Units would otherwise be less than zero, the negative amount will be treated as a capital gain from the disposition of such Trust Units in that year, and the Trust Units will have a nil adjusted cost base to commence the subsequent year.

Status of the Trust

In the opinion of Counsel, the Trust qualifies as a "unit trust" as defined by the Tax Act, and this summary assumes that the Trust will also qualify on Closing, and will continue to qualify thereafter, as a "mutual fund trust" as defined in the Tax Act. The qualification of the Trust as a mutual fund trust requires that certain factual conditions be met throughout its existence. Firstly, in order for the Trust to qualify as a mutual fund trust, it must meet certain criteria with respect to the nature of its assets and it must not be established nor must it at any time be maintained primarily for the benefit of non-residents. Although these facts have been assumed for the purposes of this opinion, Counsel is of the view that such assumption is reasonable in light of the restrictions on the nature of the Trust's investments and on the intention of the Trust to limit ownership of Trust Units by non–resident persons. Secondly, in order for the Trust to continue to qualify as a mutual fund trust, there must be at least 150 Unitholders each of whom owns not less than one "block" of Trust Units having a fair market value of not less than $500. A "block" of Trust Units means 100 Trust Units if the fair market value of one Trust Unit is less than $25. It is intended that these requirements will be satisfied so that the Trust will continue to so qualify as a mutual fund trust, but in the event the Trust were not to so qualify, the income tax considerations would in some respects be materially different from those described below. The Trust intends to make an election in order that it will qualify as a mutual fund trust from the commencement of its first taxation year.

If the Trust ceases to qualify as a mutual fund trust, the Trust Units will cease to be qualified investments for RRSPs, RRIFs, RESPs and DPSPs ("Exempt Plans"). Where at the end of any month an Exempt Plan holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the Exempt Plan. In addition, where a trust governed by an RRSP holds Trust Units that are not qualified investments, the trust will become taxable on its income attributable to the Trust Units or any gains realized on a disposition of the Trust Units while they are not qualified investments. An RESP which holds Trust Units that are not qualified investments may have its registration revoked by the CCRA.

If the Trust ceases to qualify as a mutual fund trust, the Trust will be required to pay a tax under Part XII.2 of the Tax Act in respect of designated income distributed by the Trust. The payment of Part XII.2 tax by the Trust may have adverse income tax consequences for certain Unitholders including certain non–resident persons, and certain Exempt Plans that acquire an interest in the Trust directly or indirectly from another Unitholder.

Income of the Trust

The Trust will be required to include in computing its income for a taxation year (which will be the calendar year) all amounts that it receives in that year (or, if the Proposed Amendments become law, that becomes receivable) in respect of the NPI and the Direct Royalties, including any amounts subject to set off, and including any amounts paid by it to the Corporation in that year in respect of reimbursed Crown charges in respect of the NPI or in respect of any freehold mineral tax payable in respect of the Direct Royalties. The Trust will also be required to include in its income any interest which accrues to it on unexpended funds or in respect of loans which are made to the Corporation. Any repayments of amounts advanced to the Corporation will not be included in the Trust's income. Any interest expense or other financing expenses incurred by the Trust in respect of borrowing funds to carry out its activities will be deductible by the Trust in the year incurred, to the extent and in the manner prescribed by the Tax Act. Costs incurred in the issuance of Trust Units may generally be deducted by the Trust over a six year period. The Trust will be entitled to deduct reasonable current expenses incurred in its ongoing operation as well as annual deductions in respect of cumulative Canadian oil and natural gas property expense ("COGPE") and resource allowance as described below.

The cost to the Trust of the Direct Royalties and the NPI, including any amount paid under the Deferred Purchase Price Obligation will, when incurred, be added to the Trust's cumulative COGPE account. Any amount which is receivable by the Trust from the sale of Direct Royalties or the release of the NPI will be deducted from the Trust's cumulative COGPE account (see "Canadian Federal Tax Considerations Deferred Purchase Price Obligation and the Release of the NPI on Certain Properties"). The Trust may deduct, in computing its income from all sources for a taxation year, an amount not exceeding 10%, on a declining basis, proportionately reduced for taxation years of less than 365 days, of any positive balance of its cumulative COGPE account at the end of that year. If the balance of the cumulative COGPE account of the Trust at the end of a particular taxation year, after all additions and deductions for that year have been made, would otherwise be a negative amount, the negative amount will be included in the Trust's income for the purposes of the Tax Act for that year.

The Trust's resource allowance is computed as being 25% of its adjusted resource profits, calculated in accordance with the Regulations. Generally, the Trust's adjusted resource profits will include its income from the NPI prior to any deduction in respect of its cumulative COGPE and any amount deducted in respect of distributions to Unitholders, as described below. The Trust may not deduct Crown charges reimbursed by it to the Corporation during the year. Resource allowance may only be claimed in respect of the Direct Royalties to the extent that such royalties bear freehold mineral taxes.

The Tax Act requires the Trust to compute its income or loss for a taxation year as though it were an individual resident in Canada. The taxation year of the Trust is the calendar year. To the extent that the Trust has any income for a taxation year after the inclusions and deductions outlined above, the Trust will be permitted to deduct all amounts which are payable by it to Unitholders in the year and any amounts which constitute the excess, if any, of Crown charges reimbursed by the Trust to the Corporation or mineral taxes paid by the Trust over the resource allowance deductible by the Trust for that year, to the extent that such excess amounts are designated to the Unitholders for that year. See "Canadian Federal Income Tax Considerations – Income from Trust Units". The Trustee has agreed to designate the full amount of any such excess amounts annually in favour of the Unitholders. Accordingly, it is anticipated that the Trust will generally not have any taxable income for the purposes of the Tax Act, however, no assurances can be given in this regard. The Trust may, at its discretion, claim a deduction in computing income for a taxation year in an amount less than its income for the year that becomes payable to Unitholders in the year in order to utilize losses from prior taxation years.

Deferred Purchase Price Obligation and the Release of the NPI on Certain Properties

Where, as a result of a sale of a Property by the Corporation and the release of the NPI relating to that Property, an amount becomes receivable by the Trust in a taxation year, such amount will be required to be deducted from the balance of the Trust's cumulative COGPE account otherwise determined at the end of that year. If all or a portion of the consideration receivable in a taxation year upon the release of the NPI relating to a Property is used pursuant to the Deferred Purchase Price Obligation to acquire in that year one or more replacement Canadian resource properties, the amount so used will be added, in that year, to the cumulative COGPE account of the Trust to the extent of its share of the portion of the consideration that is so used.

Entitlement to Alberta Royalty Tax Credits

The Trust is entitled to claim ARTC with respect to amounts reimbursed by it to the Corporation for Alberta Crown royalties and other Crown charges which, under the Alberta Act, do not relate to a restricted resource property. Generally, a restricted resource property is an Alberta resource property relating to a completed oil and natural gas well which is disposed of by a person who, either alone or together with persons with which it is associated, receives maximum ARTC for the year prior to the sale of such Alberta resource property. ARTC is based on a price–sensitive formula linked to crude oil prices. Credits vary from a high of 75% of eligible Alberta Crown Royalties when the price of oil falls below U.S. $15 per barrel, to a low of 25% of Alberta Crown Royalties when the price of oil rises above U.S. $30 per barrel. The maximum Alberta Crown Royalty to which the rate applies annually is $2,000,000 per applicant or associated group of applicants. **The Trust will not be required to include any amount of ARTC in its income. Counsel has been advised that the producing wells acquired as part of the Initial Properties from the Initial Properties Vendors are restricted resource properties such that no ARTC will accrue to the Trust thereon.**

INDUSTRY CONDITIONS

Canadian Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect the operations of the Trust in a manner materially different than they would affect other oil and natural gas companies or trusts of similar size. All current legislation is a matter of public record and the Trust is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing — Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the balance between supply and demand. Oil exports may be made pursuant to export contracts with terms not exceeding 1 year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board ("NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

Pricing and Marketing — Natural Gas

In Canada, the price of natural gas sold in interprovincial and international trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3 /day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

The government of Alberta also regulates the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement ("NAFTA")

On January 1, 1994, NAFTA became effective among the governments of Canada, the United States of America and Mexico. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States of America or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period), (ii) impose an export price higher than the domestic price, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties or net profits or net carried interests.

From time to time the governments of Canada and Alberta have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil produced from horizontal extensions commenced at least 5 years after the well was originally spudded may also qualify for a royalty reduction. A 24 month, 8,000 m^3 exemption is available to production from a well that has not produced for a 12 month period, if resuming production after February 1, 1993. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992 is entitled to a 12 month royalty exemption (to a maximum of $1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

The Alberta government has also introduced a third tier royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

In the Province of Alberta, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory natural gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 is eligible for a royalty exemption for a period of 12 months, up to a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural gas wells spudded or deepened to a depth below 2,500 meters is also subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of oil or natural gas is entitled to a credit on qualified oil and natural gas production against the royalties payable to the Crown by virtue of the ARTC program. The ARTC program is based on a price-sensitive formula, and the ARTC rate varies between 75%, at prices for oil below $100 per m^3, and 25%, at prices above $210 per m^3 . The ARTC rate is applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

On December 22, 1997, the Alberta government announced that it was conducting a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than $10,000 in royalties per year and non-corporate entities from qualifying for the program.

Oil and natural gas royalty holidays and reductions for specific wells reduce the amount of Crown royalties paid to the provincial governments. In Alberta, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties. Both of these incentives have the effect of increasing the net income of oil and natural gas producers, and in this case, the Trust.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms from two years and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines and penalties.

In Alberta, environmental compliance has been governed by the *Alberta Environmental Protection and Enhancement Act* (the "AEPEA") since September 1, 1993. In addition to replacing a variety of older statutes which related to environmental matters, AEPEA also imposes certain new environmental responsibilities on oil and natural gas operators in Alberta and in certain instances also imposes greater penalties for violations.

Competitive Environment

The oil and natural gas industry has been experiencing a large number of business combinations, involving companies of all sizes. This consolidation process has resulted in a number of asset rationalization programs pursuant to which assets have become available for acquisition. This same consolidation process has resulted in some industry participants, with whom the Trust will be competing for attractive large asset or share acquisitions, becoming larger and more competitive, which may increase the demand for acquisitions.

Investors are becoming increasingly aware of the oil and natural gas royalty trust sector and the income trust sector ("Trust Sector"). Management of the Corporation believes that due to the nature of the assets held by royalty trusts, as well as their focus on development and exploitation rather than exploration, investor interest in the oil and natural gas sector has increased with the growing perception that royalty trusts offer an investment vehicle in the oil and natural gas industry that has less risk than more traditional oil and natural gas investments. Consequently, the Trust Sector has recently been able to access the capital markets more readily than traditional oil and natural gas companies. This access to capital has made the Trust Sector a competitor for oil and natural gas property and corporate acquisitions. The Trust Sector has an advantage over oil and natural gas companies in corporate taxation. A number of Canadian-based oil and natural gas companies are currently taxable, having depleted their accumulated tax pools, and therefore they generally assess the merits of potential acquisitions on an after-tax basis. Oil and natural gas royalty trusts and income trusts distribute income to their unitholders. Units of these royalty and income trusts are often held in tax sheltered vehicles such as registered retirement savings plan accounts, and distributions on the units held in such vehicles are thus generally sheltered from immediate taxation.

Non-Canadian companies have been investing heavily in the Canadian oil and natural gas industry by acquiring both properties and companies. In particular, companies from the United States have been attracted to the Canadian market to acquire supplies of natural gas, in part by the weakness of the Canadian dollar relative to the United States dollar and the development of additional pipeline facilities for the efficient transmission of natural gas to the United States markets. Management of the Corporation believes this trend will continue to influence Canadian asset valuation parameters and will result in truly North American valuations for Canadian producers.

CONFLICTS OF INTEREST

Properties will not be acquired from officers or directors of the Corporation or persons not at arm's length with such persons at prices which are greater than fair market value, nor will Properties be sold to officers or directors of the Corporation or persons not at arm's length with such persons at prices which are less than fair market value in each case as established by an opinion of an independent financial advisor and approved by the independent members of the Harvest Board. There may be circumstances where certain transactions may also require the preparation of a formal valuation and the affirmative vote of Unitholders in accordance with the requirements of Ontario Securities Commission Rule 61-501.

Circumstances may arise where members of the Harvest Board serve as directors or officers of corporations which are in competition with the interests of the Corporation and the Trust. No assurances can be given that opportunities identified by such board members will be provided to the Corporation and the Trust.

LEGAL MATTERS

Certain legal matters in connection with the distribution of the Qualified Units issuable on the exercise or deemed exercise of the Special Warrants will be passed upon by Burnet, Duckworth & Palmer LLP on behalf of the Trust and the Corporation and by Blake, Cassels & Graydon LLP on behalf of the Underwriters.

Furthermore, the opinions contained under "Canadian Federal Income Tax Considerations" have been provided by Burnet, Duckworth & Palmer LLP and Blake, Cassels & Graydon LLP. John A. Brussa, a member of the Board of Directors of the Corporation, is a Partner of Burnet, Duckworth & Palmer LLP.

INTEREST OF EXPERTS

None of Burnet, Duckworth & Palmer LLP, Blake, Cassels & Graydon LLP, KPMG LLP or McDaniel has received or will receive a direct or indirect interest in the property of the Corporation or the Trust or of any associate or affiliate of the Corporation or the Trust in connection with the offering of the Special Warrants or the distribution of the Qualified Units.

The opinions contained under "Canadian Federal Income Tax Considerations" have been provided by Burnet, Duckworth & Palmer LLP and Blake, Cassels & Graydon LLP. John A. Brussa, a member of the Board of Directors of the Corporation, is a Partner of Burnet, Duckworth & Palmer LLP. As of February 12, 2003, the partners and associates of Burnet, Duckworth & Palmer LLP as a group, will beneficially own, directly or indirectly, less than 5% of the outstanding Trust Units and the partners and associates of Blake, Cassels & Graydon LLP, as a group, will beneficially own, directly or indirectly, less than 1% of the outstanding Trust Units.

Further, as at the date hereof, the partners of KPMG LLP, as a group, did not beneficially own, directly or indirectly, any of the Trust Units of the Corporation. In addition, except for Mr. Brussa, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associates or affiliates of the Corporation.

LEGAL PROCEEDINGS

Management of the Corporation is not aware of any litigation outstanding, threatened or pending as of the date hereof or against the Trust or the Corporation or relating to the business of the Corporation which would be material to such business.

PROMOTERS

M. Bruce Chernoff and Kevin A. Bennett may be considered to be the promoters of the Trust by reason of their initiative in organizing the business and affairs of the Trust. See "Interests of Management and Others in Material Transactions".

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

M. Bruce Chernoff and Kevin A. Bennett took the initiative of founding and organizing the Corporation and the Trust and their respective businesses. See "Recent Developments".

Hector J. McFadyen, a director of the Corporation, was recently appointed to the board of directors of Hunting PLC ("Hunting"), a UK-based public corporation engaged in oil and natural gas, oilfield service, and oil and natural gas marketing and distribution activities. Hunting carries on its oil and natural gas marketing and distribution activities through its majority owned subsidiary, Gibson Energy Ltd. ("Gibson"). The Corporation had previously entered into a number of oil price physical hedging contracts with Gibson as described in "Information Respecting the Corporation – Commodity Hedging." The contracts entered into with Gibson are the 2002 and 2003 Canadian dollar-based price swaps and all of the collars described under that section of this prospectus. The Corporation may execute additional hedging contracts with Gibson in the future.

The Trust issued the Trust Debenture and incurred the Interim Loan pursuant to financing the acquisition of the Initial Properties and the Additional Properties Acquisition. The Interim Loan was provided by Caribou, a company controlled by M. Bruce Chernoff, a director of the Corporation, which bore interest at 20% per annum and was due on or before July 31, 2003. The Interim Loan was secured by all of the assets of the Trust, including the NPI, but was not secured by the Properties of the Corporation. All amounts outstanding under the Interim Loan were repaid with net proceeds from the Initial Public Offering. See "Capitalization of the Trust" and "Description of the Trust – Interim Loan".

Upon completion of the Initial Public Offering, the Trust Debenture was settled with the issuance of 5,000,000 Trust Units and such Trust Units were distributed to the Management Group in settlement of the Management Group Debentures. In addition, on January 23, 2003, the Warrants, issued to Caribou pursuant to the Interim Loan, were exercised for 150,000 Trust Units. Caribou, which is controlled by M. Bruce Chernoff, a director of the Corporation, held the Warrants. See "Capitalization of the Trust" and "Description of the Trust – Warrants".

On closing of the Initial Public Offering, certain members of the Management Group holding an aggregate $4,777,500 principal amount of the Management Group Debentures delivered an undertaking to the Underwriters not to offer or sell, agree to offer or sell, or enter into an arrangement to offer or sell any Trust Units or other securities of the Trust or the

Corporation, or securities convertible into, exchangeable for, or otherwise exercisable to acquire any securities of the Trust or the Corporation then held by such holder or such holder's spouse, directly or indirectly, at any time until November 28, 2004.

Mr. Brussa, a director of the Corporation is a partner of Burnet, Duckworth & Palmer LLP which firm receives fees for legal services provided to the Corporation and the Trust.

The following directors and/or officers of Harvest acquired the number of Special Warrants set forth opposite each of their names:

Name	Position with Harvest	Number of Special Warrants
M. Bruce Chernoff	Director, Chairman	167,750
Jacob Roorda	President	10,000
John Brussa	Director	2,750

RISK FACTORS

The following are certain factors relating to the business of the Trust. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this prospectus.

Public and Insider Ownership

As at the date hereof, prior to giving effect to the exercise of the Special Warrants, the directors and officers of the Corporation and their associates and affiliates, as a group, hold, directly or indirectly, or exercise control or direction over, 5,071,668 Trust Units, representing 54% of the issued and outstanding Trust Units. After giving effect to the exercise of the Special Warrants, the directors and officers of the Corporation, and their associates and affiliates, as a group, will beneficially own, directly or indirectly, 5,252,168 Trust Units or 48% of the outstanding Trust Units.

As part of the Initial Public Offering, certain members of the Management Group holding an aggregate $4,777,500 principal amount of the Management Group Debentures executed an undertaking in favour of the Underwriters not to offer or sell, agree to offer or sell, or enter into an arrangement to offer or sell any Trust Units or other securities of the Trust or the Corporation, or securities convertible into, exchangeable for, or otherwise exercisable to acquire any securities of the Trust or the Corporation then held by such holder or such holder's spouse, directly or indirectly, at any time until November 28, 2004.

Dilution

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Harvest Board may determine. In addition, the Trust may issue additional Trust Units from time to time pursuant to the Trust's Unit Incentive Plan and DRIP Plan. The possible issuance of these Trust Units could result in dilution to the purchasers of Trust Units pursuant to the Offering. See "The Trust Indenture – Issuance of Trust Units", "Trust Unit Incentive Plan" and "DRIP Plan".

Purchase of the NPI, the Initial Properties and Initial Direct Royalties

The price paid for the purchase of the NPI, the Initial Properties and the Direct Royalties forming part of the Initial Properties was based on engineering and economic assessments made by independent engineers. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of crude oil, natural gas and natural gas liquids, future prices of oil, natural gas and natural gas liquids and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation and the Trust. In particular, changes in the prices of and markets for petroleum, natural gas and natural gas liquids from those anticipated at the time of making such assessments will affect the return on the value of the Trust Units. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than those currently attributed to the Properties.

Acquisition of Additional Properties

The Corporation and the Additional Properties Vendor are engaged in a dispute as to whether an additional $5.8 million adjustment to the Additional Properties Acquisition Cost should be made in favour of the Additional Properties Vendor. This dispute relates to whether or not the value of a hedging contract held by the Additional Properties Vendor impacts the net proceeds from the Additional Properties from the effective date of the Additional Properties Acquisition of June 1, 2002 to the closing date of November 15, 2002. The Additional Properties Vendor has indicated its intent to charge the Corporation the additional $5.8 million as an interim adjustment within 90 days and in any event not later than 180 days of the closing of the Additional Properties Acquisition. Management of the Corporation believes that such amount is not owing to the Additional Property Vendor. This dispute is expected to be resolved through an arbitration process established in the Additional Properties Agreement. Should the Corporation be unsuccessful in recovering this amount, it will increase the amount of debt outstanding under the Current Bank Facility. This would increase the Corporation's debt service obligations which would have a negative impact on Cash Available for Distribution.

Changes in Legislation

There can be no assurance that income tax laws and government incentive programs relating to the oil and natural gas industry, such as the status of mutual fund trusts and the resource allowance, will not be changed in a manner which adversely affects Unitholders.

Investment Eligibility

If the Trust ceases to qualify as a mutual fund trust, the Trust Units will cease to be qualified investments for RRSPs, RRIFs and DPSPs ("Exempt Plans"). Where at the end of any month an Exempt Plan holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the Exempt Plan. In addition, where a trust governed by an RRSP holds Trust Units that are not qualified investments, the trust will become taxable on its income attributable to the Trust Units or any gains realized on a disposition of the Trust Units while they are not qualified investments. See "Eligibility for Investment" and "Canadian Federal Income Tax Considerations".

Operational Matters

The operation of oil and natural gas wells involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to the Corporation and possible liability to third parties. The Corporation will employ prudent risk management practices and maintain liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. The Corporation may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the NPI Income.

Continuing production from a property and to some extent, the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although the Corporation operates the Initial Properties and believes it will become the operator of the Additional Properties, there is no guarantee that it will remain operator of the Initial Properties or that the Corporation will operate the Additional Properties or any other Properties it may acquire.

Although satisfactory title reviews will generally be conducted on the Properties in accordance with industry standards, such reviews do not guarantee or certify that a defect in title may not arise to defeat the claim of the Corporation to certain Properties. A reduction of the NPI Income or income from Direct Royalties could result in such circumstances.

Reserve Estimates

The reserve and recovery information contained in the McDaniel Report is only an estimate and the actual production and ultimate reserves from the Properties may differ from the estimates prepared by McDaniel.

Environmental Concerns

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or the issuance of clean up orders in respect of the Corporation or the Properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on the Corporation. See "Industry Conditions – Environmental Regulation". Although the Corporation will establish a Reclamation Fund for the purpose of funding its estimated future environmental and reclamation obligations based on its knowledge, there can be no assurance that the Corporation will be able to satisfy its actual environmental and reclamation obligations. See "Description of the Trust – Reclamation Fund". Should the Corporation be unable to fully fund the cost of remedying an environmental problem, the Corporation might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy. It is difficult to determine if the Canadian government will ratify the Kyoto Protocol and what, if any, impact this may have on the Corporation's ongoing environmental liabilities, on prices for oil and natural gas or on other general economic factors, which may affect the Trust's Cash Available For Distribution.

Debt Service

The Corporation's indebtedness under the Current Bank Facility is currently approximately $38.7 million, of which approximately $12.3 million was used to repay all outstanding indebtedness under a prior credit facility, a net amount of approximately $23.2 million was used to partially fund the Additional Properties Acquisition, approximately $2.3 million was paid in respect of fees and expenses to establish the Current Bank Facility, $0.4 million applied to working capital and $0.9 million in interest charges. In addition, the Current Lender has issued letters of credit to third parties in approximately $6.6 million in letters of credit on behalf of the Corporation to secure services on the Properties. See "Properties".

The Current Lender was provided with security over all of the assets of the Corporation. If the Corporation and the Trust become unable to pay the Debt Service Charges or otherwise commit an event of default such as declaring bankruptcy, the Current Lender may foreclose on or sell the Properties free from, or together with, the NPI. As with most banking facilities in the oil and gas production industry, the Current Bank Facility is demand in nature.

Dividends and other distributions by the Corporation are prohibited during a default, event of default, or an unremedied borrowing base shortfall under the Current Bank Facility. The NPI, any indebtedness of the Corporation to the Trust, and amounts payable to the Trustee under the Trust Indenture are subordinate to the Current Bank Facility pursuant to a subordination agreement between the Current Lender, the Trustee, and the Corporation dated November 14, 2002. This Subordination Agreement may restrict the ability of the Corporation to pay the NPI to the Trust or pay interest or principal on any indebtedness to the Trust, and therefore may limit the Cash Available For Distribution during a default, event of default or an unremedied borrowing base shortfall under the Current Bank Facility.

The Corporation must meet certain ongoing hedging and financial covenants under the Current Bank Facility and is subject to customary restrictions on its operations and activities, including restrictions on the incurring of indebtedness, the granting of security, the issuance of incremental debt, and the sale of its assets. During such time as any lender comprising the Current Lender is not a Canadian resident, payments under the Current Bank Facility to such lender will be subject to certain withholding taxes which the Corporation has agreed to assume and which may increase the effective interest rate paid by the Corporation.

Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to service debt before payment of the NPI and cash distributions. The Corporation and the Trust may manage the risk associated with fluctuations in interest rates by entering into interest rate swap transactions from time to time. To the extent that the Corporation and the Trust engage in risk management activities, they will be subject to credit counterparty risk.

Debt Repayment

The Corporation and the Trust are permitted to borrow funds to finance the purchase of Properties, capital expenditures, or other financial obligations in respect of the Properties or for working capital purposes. Borrowings of the Corporation to fund the purchase of Canadian resource properties may be repaid with funds received from the Trust pursuant to the Deferred Purchase Price Obligation. Debt Service Charges of the Corporation will be deducted in computing the NPI Income and Debt Service Charges of the Trust will be deducted in computing Cash Available For Distribution. Variations in interest rates could result in significant changes in the amount required to be applied to debt service before payment of the NPI and Cash Available For Distribution. To the extent that advances under the Current Bank Facility are made in U.S. dollars, the interest payable thereunder is also payable in U.S. dollars. Variations in the Canadian/U.S. dollar exchange could result in a significant increase in the amount of the interest paid under the Current Bank Facility, thereby reducing the Cash Available

For Distribution. See "Information Respecting the Corporation – Borrowing" and "Information Respecting the Trust – Capitalization.

Delay in Cash Distributions

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the Properties, and by the operator to the Corporation, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of Properties or the establishment by the operator of reserves for such expenses.

Variability of Cash Distributions

The Corporation retains a portion of the cash flows from the Properties in the Capital Fund to facilitate future acquisitions and development of the Properties. The Corporation believes this will assist in maintaining distributions for a longer period than would otherwise be the case if all cash flows from the Properties were paid to the Trust pursuant to the NPI and subsequently distributed to the Unitholders. Future cash flows generated by such additional Properties may not be similar to those of the Initial Properties or the Additional Properties and may not generate sufficient cash flows to allow the Corporation to generate sufficient the NPI Income to maintain consistent distributions from the Trust over a long period of time.

Reliance on Management of the Corporation

Unitholders will be dependent on the management of the Corporation in respect of the administration and management of all matters relating to the Properties, the NPI, the Direct Royalties, the Trust, and the Trust Units. Investors who are not willing to rely on the management of the Corporation should not invest in the Trust Units.

Depletion of Reserves (Sustainability)

The Trust has certain unique attributes which differentiate it from other oil and natural gas industry participants. Cash Available For Distribution in respect of Properties, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. The Trust and the Corporation will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent additional capital investment in Properties through the use of the Capital Fund or otherwise, initial production levels and reserves attributable to the Properties will decline.

The Corporation's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on the Corporation's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are exploited.

Trust Units will have no value when reserves from the Properties can no longer be economically marketed and, as a result, subscribers for Trust Units will need to obtain a return of capital invested out of cash flow derived from their investment in Trust Units during the period when reserves can be economically recovered.

There is strong competition relating to all aspects of the oil and natural gas industry. The Corporation will actively compete for reserve acquisitions and skilled industry personnel with a substantial number of other oil and natural gas companies, many of which have significantly greater financial and other resources than the Corporation.

There can be no assurance that the Corporation will be successful in developing or acquiring additional reserves on terms that meet the Corporation's investment objectives.

The average Economic Life of the Initial Properties is 8.3 years and the average Economic Life of the Additional Properties is 10 years. See "Initial Properties – Summary of Selected Reserve Information" and "Additional Properties – Summary of Selected Reserve Information". Economic Life is largely dependent on the accuracy of the reserves and changes in commodity prices, operating costs and royalty rates, all of which could impact the length of time that the reserves associated with the Initial Properties and the Additional Properties can be economically produced.

Additional Financing

To the extent that external sources of capital, including the issuance of additional Trust Units, becomes limited or unavailable, the Trust's and the Corporation's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent the Trust or the Corporation is required to use cash flow to finance Capital Expenditures or property acquisitions, the level of Cash Available For Distribution will be reduced.

Limited Operational History

The Corporation and the Trust were only recently organized and have a limited history of operations and the Trust has made only limited distributions.

Impact of Future Capital Expenditures

The Reserve Value of the Initial Properties and the Additional Properties as estimated in the McDaniel Report is based in part on cash flows to be generated in future years as a result of future Capital Expenditures. The Reserve Value of the Initial Properties and the Additional Properties as estimated in the McDaniel Report will be reduced to the extent that such Capital Expenditures on the Initial Properties and the Additional Properties do not achieve the level of success assumed in the McDaniel Report.

Volatility of Commodity Prices

The Trust's results of operations and financial condition, and therefore the NPI and the Direct Royalties, will be dependent on the prices received for Petroleum Substances production. Prices for Petroleum Substances have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil producing regions, which are beyond the control of the Corporation or the Trust. Oil prices received from production in Canada also reflect changes in the Canadian/U.S. currency exchange rate. Any decline in Petroleum oil and gas prices or increases in differentials could have a material adverse effect on the Trust's operations, financial condition and the level of funds available for the development of its oil and natural gas reserves. The Corporation may manage the risk associated with changes in commodity prices and foreign exchange rates by entering, or causing the Trust to enter, from time to time, into crude oil and natural gas price hedges and foreign exchange contracts. To the extent that the Corporation or the Trust engages in risk management activities related to commodity prices and foreign exchange rates, it will be subject to counterparty risk. In addition, commodity hedge contracts may require, from time to time, margin payments to be made which could impact negatively on the Trust's ability to make distributions to Unitholders. The Corporation must also meet certain ongoing hedging covenants under the Current Bank Facility. To the extent that commodity prices increase significantly, Cash Available for Distribution could be negatively affected. See "Information Respecting the Corporation – Commodity Hedging."

Crude Oil Differentials

The Corporation's crude oil production from the Initial Properties and the Additional Properties will be approximately 58% heavy oil and 42% medium oil. Processing medium oil and heavy oil is more expensive than processing conventional light oil, and such processing yields less valuable products compared to refining light oil; accordingly, producers of heavy oil or medium oil receive lower wellhead prices. The differential between light oil and heavy oil or medium oil has fluctuated widely during recent years and when considered with the fluctuating prices of light oil, substantially increases the volatility of prices for heavy oil and medium oil. Any increase in the differentials could result in lower prices being received for Petroleum Substances and could have a material adverse effect on the Trust's operations, financial condition and the level of funds available for the development of its oil and natural gas reserves. Volatility in the differential is a result of an availability of supply, seasonal demand, pipeline constraints and conversion capacity of refineries, which are beyond the control of the Trust or the Corporation.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. The Corporation and the Trust will actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation and the Trust. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

Potential Conflicts of Interest

Circumstances may arise where members of the Board of Directors or officers of the Corporation are directors or officers of corporations which are in competition to the interests of the Corporation and the Trust. No assurances can be given that opportunities identified by such board members will be provided to the Corporation and the Trust. See "Conflicts of Interest".

Nature of Trust Units

Securities such as the Trust Units are hybrids in that they share certain attributes common to both equity securities and debt instruments. Trust Units are dissimilar to debt instruments in that there is no principal amount owing to Unitholders. The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in the Corporation. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The Trust's sole assets will be Permitted Investments, the NPI, the Direct Royalties and related contractual rights. The market price per Trust Unit will be a function of anticipated Cash Available For Distribution, the value of the Initial Properties acquired by the Corporation, the value of the Additional Properties and the Corporation's ability to effect long-term growth in the value of the Trust. The issue price of each Trust Unit is greater than the per Trust Unit Reserve Value of the Initial Properties. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust Fund or the obligations or affairs of the Trust or with respect to any act performed by the Trustee or by any other person pursuant to the Trust Indenture or with respect to any act or omission of the Trustee or any other person in the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred upon the Trustee or such other person hereunder or with respect to any transaction entered into by the Trustee or by any other person pursuant to the Trust Indenture. No Unitholder shall be liable to indemnify the Trustee or any such other person with respect to any such liability or liabilities incurred by the Trustee or by any such other person or persons or with respect to any taxes payable by the Trust or by the Trustee or by any other person on behalf of or in connection with the Trust. Notwithstanding the foregoing, to the extent that any Unitholders are found by a court of competent jurisdiction to be subject to any that liability, such liability shall be enforceable only against, and shall be satisfied only out of, the Trust Fund, and the Trust (to the extent of the Trust Fund) is liable to, and shall indemnify and save harmless any Unitholder against any costs, damages, liabilities, expenses, charges or losses suffered by any Unitholder from or arising as a result of such Unitholder not having any such limited liability.

The Trust Indenture also provides that all contracts signed by or on behalf of the Trust, whether by the Corporation, the Trustee, or otherwise, must (except as the Trustee or the Corporation may otherwise expressly agree with respect to their own personal liability) contain a provision to the effect that such obligation will not be binding upon Unitholders personally. The principal investment of the Trust is the NPI Agreement which contains such a provision. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against the Trust (to the extent that claims are not satisfied by the Trust) that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability to Unitholders of this nature arising is considered unlikely by the Harvest Board in view of the fact that all business operations are carried on by the Corporation.

The activities of the Trust and the Corporation, its wholly-owned subsidiary, are conducted and are intended to be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability to the Unitholders for claims against the Trust including by obtaining appropriate insurance, where available, for the operations of the Corporation and having contracts signed by or on behalf of the Trust include a provision that such obligations are not binding upon Unitholders personally.

Net Asset Value

The net asset value of the Trust will vary dependent upon a number of factors beyond the control of management, including oil and natural gas prices. The trading prices of the Trust Units is also determined by a number of factors which are beyond the control of management and such trading prices may be greater than or less than the net asset value of the Trust.

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditors of the Trust are KPMG LLP, Chartered Accountants, Suite 1200, 205 – 5th Avenue, Calgary, Alberta, T2P 4B9.

Valiant Trust Company, at its principal office in Calgary, Alberta and through its co-agent, Equity Transfer Services Inc., at its principal office in Toronto, Ontario is the transfer agent and registrar for the Trust Units.

MATERIAL CONTRACTS

The only material contracts in effect as of the date hereof entered into by the Trust or by the Corporation during the past two years, other than during the ordinary course of business, are as follows:

1. Trust Indenture referred to under "The Trust Indenture";
2. The NPI Agreement referred to under "Description of the Trust – the NPI and Direct Royalties";
3. Administration Agreement referred to under "Description of the Trust";
4. Current Bank Facility credit agreement referred to under "Information Respecting the Corporation – Borrowing";
5. the subordination agreement referred to under "Information Respecting the Corporation – Borrowing";
6. the Direct Royalties Sale Agreements referred to under "Initial Properties" and "Additional Properties";
7. the Sale Agreement referred to under "Initial Properties";
8. the Additional Properties Agreement referred to under "Additional Properties";
9. the management undertakings referred to under "Interests of Insiders and Others in Material Transactions";
10. the Underwriting Agreement referred to under "Plan of Distribution"; and
11. the Special Warrant Indenture referred to under "Plan of Distribution".

During the period of distribution of the Trust Units, copies of the foregoing documents may be examined during normal business hours at the offices of Burnet, Duckworth & Palmer LLP, First Canadian Centre, 1400, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

PURCHASERS' STATUTORY RIGHTS

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

CONTRACTUAL RIGHT OF ACTION FOR RESCISSION

In the event that a holder of a Special Warrant, who acquires a Qualified Unit upon the exercise of a Special Warrant as provided for in this prospectus, is or becomes entitled under applicable legislation to the remedy of rescission by reason of this prospectus, or any amendment thereto, containing a misrepresentation, the holder shall be entitled to rescission not only of the holder's exercise of its Special Warrant, but also of the private placement transaction pursuant to which the Special Warrant was initially acquired and shall be entitled, in connection with such rescission, to a full refund of all consideration paid to the Trust on the acquisition of the Special Warrant. In the event that such holder is a permitted assignee of the interest of the original Special Warrant subscriber, such permitted assignee shall be entitled to exercise the rights of rescission and refund described herein as if the permitted assignee was the original subscriber. The foregoing is in addition to any other right or remedy available to a holder of the Special Warrant under Section 203 of the *Securities Act* (Alberta), Section 131 of the *Securities Act* (British Columbia), Section 130 of the *Securities Act* (Ontario), similar sections of other applicable securities legislation or otherwise at law.

INDEX TO FINANCIAL STATEMENTS

KPMG

Schedule of Revenue and Expenses for the

INITIAL PROPERTIES

Acquired from Devon Canada Corporation

Years ended December 31, 2001, 2000 and 1999

AUDITORS' REPORT

To the board of directors of Harvest Operations Corp.

At the request of Harvest Operations Corp., we have audited the schedule of revenue and expenses for the properties (the "Initial Properties") referred to in the purchase and sale agreement dated May 28, 2002 between Harvest Operations Corp. and Devon Canada Corporation and Devon ARL Corporation for each of the years in the three year period ended December 31, 2001. This financial information is the responsibility of Harvest Operations Corp. Our responsibility is to express an opinion on this financial information based on our audits.

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

In our opinion, this financial information presents fairly, in all material respects, the revenue and expenses for the Initial Properties referred to in the purchase and sale agreement dated May 28, 2002 for each of the years in the three year period ended December 31, 2001.

Chartered Accountants

Calgary, Canada
September 18, 2002

INITIAL PROPERTIES

Schedule of Revenue and Expenses for the Initial Properties

	Six months ended June 30,		Years ended December 31,		
	2002	2001	2001	2000	1999
	(unaudited)		(audited)		
Revenue	$ 13,935,019	$ 16,772,213	$ 30,675,360	$ 46,395,299	$ 30,506,217
Royalties	(1,210,816)	(1,630,888)	(2,791,810)	(4,406,652)	(2,984,815)
	12,724,203	15,141,325	27,883,550	41,988,647	27,521,402
Operating costs	5,050,362	6,901,821	11,587,364	9,333,045	7,266,639
Operating income	$ 7,673,841	$ 8,239,504	$ 16,296,186	$ 32,655,602	$ 20,254,763

See accompanying notes to schedule of revenue and expenses for the Initial Properties.

1. Basis of presentation:

On May 28, 2002 Harvest Operations Corp. entered into a purchase and sale agreement to acquire the Thompson Lake properties (the "Initial Properties") from Devon Canada Corporation and Devon ARL Corporation (collectively "Devon Canada"). This acquisition closed on July 10, 2002.

The schedule of revenue and expenses for the Initial Properties includes the operations of the Initial Properties by Devon Canada.

The schedule of revenue and expenses for the Initial Properties includes only amounts applicable to the working interest of Devon Canada for the Initial Properties.

The schedule of revenue and expenses for the Initial Properties does not include any provision for the depletion and depreciation, site restoration, future capital costs, impairment of unevaluated properties, general and administrative costs and income taxes for the Initial Properties as these amounts are based on the consolidated operations of Devon Canada of which the Initial Properties formed only a part.

2. Significant accounting policies:

(a) Revenue:

Revenue from the sale of oil and natural gas is recorded at the time that the product is produced and sold.

(b) Royalties:

Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with Alberta Energy regulations or the terms of individual royalty agreements.

(c) Operating expenses:

Operating expenses include amounts incurred to bring the oil and natural gas to the surface, gather, transport, field process, treat and store same. Operating expenses are reflected net of gathering, processing and transportation revenue associated with the Initial Properties.

Schedule of Revenue and Expenses for the

ADDITIONAL PROPERTIES

Acquired from Anadarko Canada Corporation

Years ended December 31, 2001, 2000 and 1999

AUDITORS' REPORT

To the board of directors of Harvest Operations Corp.

At the request of Harvest Operations Corp., we have audited the schedule of revenue and expenses for the Additional Properties referred to in the purchase and sale agreement dated August 1, 2002 between Harvest Operations Corp. and Anadarko Canada Corporation for each of the years in the three-year period ended December 31, 2001. This financial information is the responsibility of Harvest Operations Corp. Our responsibility is to express an opinion on this financial information based on our audits.

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

In our opinion, this financial information presents fairly, in all material respects, the revenue and expenses for the Additional Properties referred to in the purchase and sale agreement dated August 1, 2002 for each of the years in the three-year period ended December 31, 2001.

Chartered Accountants

Calgary, Canada
September 18, 2002

ADDITIONAL PROPERTIES

Schedule of Revenue and Expenses for the Additional Properties

	Nine months ended September 30,		Years ended December 31,		
	2002	2001	2001	2000	1999
	(unaudited)		(audited)		
Revenue	$ 55,459,785	$ 48,198,918	$ 57,615,104	$ 72,026,276	$ 42,693,456
Royalties	(7,323,940)	(7,860,337)	(11,340,031)	(14,465,051)	(7,268,179)
	48,135,845	40,338,581	46,275,073	57,561,225	35,425,277
Operating costs	12,665,536	10,404,008	12,832,174	8,799,976	7,452,752
Operating income	$ 35,470,309	$ 29,934,573	$ 33,442,899	$ 48,761,249	$ 27,972,525

See accompanying notes to schedule of revenue and expenses for the Additional Properties.

ADDITIONAL PROPERTIES

Notes to Schedule of Revenue and Expenses for the Additional Properties

Years ended December 31, 2001, 2000 and 1999
(Information for the six months ended June 30, 2002 and 2001 is unaudited)

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1. **Basis of presentation:**

   On August 1, 2002, Harvest Operations Corp. entered into a purchase and sale agreement to acquire the Hayter and Provost properties (the "Additional Properties") from Anadarko Canada Corporation ("Anadarko"). This acquisition closed on November 15, 2002.

   The schedule of revenue and expenses for the Additional Properties includes the operations of the Additional Properties by Anadarko.

   The schedule of revenue and expenses for the Additional Properties includes only amounts applicable to the working interest of Anadarko for the Additional Properties.

   The schedule of revenue and expenses for the Additional Properties does not include any provision for the depletion and depreciation, site restoration, future capital costs, impairment of unevaluated properties, general and administrative costs and income taxes for the Additional Properties as these amounts are based on the consolidated operations of Anadarko of which the Additional Properties form only a part.

2. **Significant accounting policies:**

   (a) Revenue:

   Revenue from the sale of oil and natural gas is recorded at the time that the product is produced and sold.

   (b) Royalties:

   Royalties are recorded at the time the product is produced and sold. Royalties are calculated in accordance with Alberta Energy regulations or the terms of individual royalty agreements.

   (c) Operating expenses:

   Operating expenses include amounts incurred to bring the oil and natural gas to the surface, gather, transport, field process, treat and store same and variable operating overhead as established by Anadarko.

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Unaudited Pro Forma Consolidated Financial Statements of

HARVEST ENERGY TRUST

As at and for the nine months ended September 30, 2002

COMPILATION REPORT

To the Trustee of Harvest Energy Trust and the Directors of Harvest Operations Corp.

We have reviewed, as to compilation only, the accompanying unaudited pro forma consolidated balance sheet of Harvest Energy Trust as at September 30, 2002 and the unaudited pro forma consolidated statement of income for the nine months ended September 30, 2002. These pro forma consolidated financial statements have been prepared for inclusion in the prospectus dated February 12, 2003.

In our opinion, the unaudited pro forma consolidated balance sheet as at September 30, 2002 and the unaudited pro forma consolidated statement of income for the nine months ended September 30, 2002 have been properly compiled to give effect to the assumptions and adjustments described in the notes thereto.

Chartered Accountants

Calgary, Canada
February 12, 2002

HARVEST ENERGY TRUST

Pro Forma Consolidated Balance Sheet

As at September 30, 2002
(Unaudited)

	Actual Consolidated	Adjustments	Notes	Pro Forma Consolidated
Assets				
Current assets:				
Cash and short-term investments	$ 14,533	$ 137,122	2(d), 2(e),2(g)	$ 151,655
Accounts receivable	4,531,419	–		4,531,419
Prepaid expenses	171,404	–		171,404
	4,717,356	137,122		4,854,478
Capital assets	24,931,475	57,468,700	2(a)	82,400,175
Deferred financing charges	338,000	1,962,000	2(b)	2,300,000
Property purchase deposit	5,000,000	(5,000,000)	2(a)	–
	$ 34,986,831	$ 54,567,822		$ 89,554,653
Liabilities and Unitholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$ 1,709,438	$ –	2(e)	$ 1,709,438
Large corporation taxes payable	27,900	–		27,900
	1,737,338	–		1,737,338
Long-term debt	30,981,220	3,875,823	2(a),2(b),2(c),2(d),2(e),2(f),2(h)	34,857,043
Future income taxes	256,000	(142,000)	2(b)	114,000
Site restoration and reclamation provision	329,000	–		329,000
	33,303,558	3,733,823		37,037,381
Unitholders' equity:				
Capital contributions	100	51,029,999	2(d), 2(e), 2(f), 2(g), 2(h)	51,030,099
Accumulated income	1,683,173	(196,000)	2(b)	1,487,173
Accumulated cash distributions	–	–		–
	1,683,273	50,833,999		52,517,272
	$ 34,986,831	$ 54,567,822		$ 89,554,653

See accompanying notes to pro forma consolidated financial statements.

HARVEST ENERGY TRUST

Pro Forma Consolidated Statement of Income

Nine months ended September 30, 2002
(Unaudited)

	Initial Properties	Additional Properties	Adjustments	Notes	Pro Forma Consolidated
Revenue:					
Petroleum and natural gas sales	$24,075,804	$55,459,785	$ –		$79,535,589
Royalties	(2,114,180)	(7,323,940)	–		(9,438,120)
	21,961,624	48,135,845	–		70,097,469
Expenses:					
Operating	7,632,482	12,665,536		–	20,298,018
General and administrative	–	–	1,586,209	3(d)	1,586,209
Interest and amortization of deferred financing charges	–	–	3,000,000	3(c)	3,000,000
Site restoration	–	–	1,986,000	3(b)	1,986,000
Depletion, depreciation and amortization	–	–	18,400,000	3(a)	18,400,000
	7,632,482	12,665,536	24,972,209		45,270,227
Income (loss) before taxes	14,329,142	35,470,309	(24,972,209)		24,827,242
Taxes:					
Large corporation taxes	–	–	42,200	3(e)	42,200
Net income (loss)	$ 14,329,142	$35,470,309	$ (25,014,409)		$24,785,042
Net income per unit:				3(f)	
Basic					$ 2.26
Diluted					$ 2.23

See accompanying notes to pro forma consolidated financial statements.

1. Basis of presentation:

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust formed under the laws of Alberta. Pursuant to a trust indenture and an administration agreement, the Trust is managed by its wholly owned subsidiary, Harvest Operations Corp ("Harvest"). The Trust acquires and holds net profits interests in oil and gas properties acquired and held by Harvest.

The accompanying unaudited pro forma consolidated financial statements have been prepared by the management of Harvest in accordance with accounting principles generally accepted in Canada.

The unaudited pro forma consolidated balance sheet as at September 30, 2002 has been prepared from the unaudited balance sheet of the Trust as at September 30, 2002. The unaudited pro forma consolidated statement of earnings for the nine months ended September 30, 2002 has been based on:

- the unaudited statement of income of the Trust for the period from formation on July 10, 2002 to September 30, 2002;
- an unaudited schedule of revenue and expenses for the Initial Properties for the period from July 1, 2002 to July 10, 2002;
- the unaudited schedule of revenue and expenses for the Initial Properties for the six month period ended June 30, 2002;
- the unaudited schedule of revenue and expenses for the Additional Properties for the nine month period ended September 30, 2002.

In the opinion of management, the pro forma consolidated financial statements include all material adjustments necessary for fair presentation in accordance with generally accepted accounting principles in Canada.

The pro forma consolidated financial statements are not necessarily indicative either of the results that actually would have occurred if the events reflected herein had taken place on the dates indicated or of the results that may be obtained in the future.

It is the recommendation of management that this financial information should be read in conjunction with the financial statements and notes thereto included in this document.

2. Pro forma consolidated balance sheet assumptions and adjustments:

The unaudited pro forma consolidated balance sheet gives effect to the following transactions and assumptions as if they had occurred on September 30, 2002:

(a) Additional Properties Acquisition:

On November 15, 2002 Harvest acquired the Additional Properties for $53.2 million. This acquisition was financed by $38.2 million of bank borrowings, $10 million of loans from Caribou Capital Corp., and the application of the $5.0 million property purchase deposit. In conjunction with this acquisition, Harvest entered into a sales agreement to deliver 6,000 bbls per day of Lloydminster crude oil until December 31, 2003 at a price between U.S. $22.63 and U.S. $25.48 per bbl less a fixed price differential of U.S. $8.233 per bbl. To meet the contract requirements, Harvest will have to purchase up to 1,000 bbls per day of diluents to blend with its production. On closing, the vendor indicated its intent to charge Harvest an additional $5.8 million for the properties. Management believes that such amount is not owing to the vendor and accordingly, the additional amount has not been included in the cost of the purchase. This dispute is expected to be resolved through an arbitration process and any amount paid and not recoverable will be recorded as capital assets upon settlement.

The pro forma consolidated balance sheet assumes that the acquisition cost of the Additional Properties was $57.5 million and this amount was financed with $42.5 million of bank borrowings, $10 million in loans from Caribou Capital Corp., and application of the $5 million property purchase deposit.

(b) Bank Loans:

On July 4, 2002 Harvest entered into a bank facility agreement with a Canadian bank (the "Initial Facility"). The Initial Facility was a revolving credit facility to a maximum of $18 million. On November 14, 2002 Harvest entered into a new term credit facility with a U.S. bank (the "New Facility") for U.S. $60 million. This facility has an initial borrowing base of U.S. $38 million. On November 15, 2002 Harvest borrowed $56.5 million (U.S. $35.8 million) to repay $12.3 million owed on the Initial Facility and to partially finance the acquisition of the Additional Properties. Harvest paid fees totaling approximately $2.3 million for the New Facility.

The pro forma consolidated balance sheet at September 30, 2002 assumes that the Initial Facility was repaid with funds from the New Facility and deferred financing charges relating to the Initial Facility of $338,000 ($196,000 after income taxes) were charged against income.

(c) Interim Loan:

On July 10, 2002 and July 30, 2002 the Trust entered into loan agreements (the "Interim Loan") with Caribou Capital Corp. ("Caribou"). Caribou advanced $12.7 million and $10.0 million to the Trust to partially finance the acquisition of the Initial Properties and Additional Properties, respectively.

(d) Trust Debenture:

On August 15, 2002 the Trust issued a trust debenture (the "Trust Debenture") for proceeds totaling $5.0 million. On December 5, 2002 the Trust Debenture was settled by the issue of 5,000,000 Trust Units and $34,829 in cash for accrued interest.

The pro forma consolidated balance sheet assumes that the Trust Debenture was settled on September 30, 2002 by the issue of 5,000,000 Trust Units and a cash payment of $12,879 for accrued interest.

(e) Unit Issuance – Initial Public Offering:

On December 5, 2002 the Trust completed its initial public offering by the issue of 3,750,000 Trust Units for proceeds of $27.6 million, net of a 6% underwriters' fee and $600,000 of issue costs. The net proceeds were used to fully repay $22.4 million owed on the Interim Loan and $5.2 million to partially repay borrowings under the New Facility.

The pro forma consolidated balance sheet assumes that the initial public offering was completed on September 30, 2002 with the net proceeds being applied to fully repay the Interim Loan and to partially repay the New Facility. In addition, upon the completion of the initial public offering the 100 Trust Units held by the Trustee were cancelled by the payment of $1.

(f) Unit Issuance – Underwriters' Over-allotment Option:

On December 17, 2002 the Trust issued 562,500 in Trust Units as a result of the exercise by the underwriters of an over-allotment option granted by the Trust pursuant to the initial public offering.

The pro forma consolidated balance sheet assumes the exercise of the over-allotment option on September 30, 2002 providing $4.2 million of proceeds to repay borrowings under the New Facility.

(g) Unit Issuance – Exercise of Caribou Warrants

Warrants granted to Caribou as a fee for providing the Interim Loan were exercised on January 24, 2003.

The pro forma consolidated balance sheet assumes that the warrants were exercised on September 30, 2002 and the $150,000 proceeds were added to cash.

(h) Special Warrants Financing:

Pursuant to an underwriting agreement the Trust issued 1,500,000 Special Warrants that are exercisable into 1,500,000 Trust Units at no additional cost. The Special Warrants issue closed on February 4, 2003 and provided proceeds of $14,050,000, net of a 5% underwriters' fee and estimated issue costs of $200,000. The net proceeds were added to working capital and used to partially repay borrowings under the New Facility.

The pro forma consolidated balance sheet assumes that the Special Warrant financing was completed on September 30, 2002 and the $14.0 million of net proceeds were applied to partially repay the New Facility.

3. Pro forma consolidated statement of income assumptions and adjustments:

The pro forma consolidated statement of income for the nine months ended September 30, 2002 has been prepared assuming that the transactions described in note 2 were completed on January 1, 2002:

(a) The pro forma consolidated statement of income reflects a provision for depletion, depreciation and amortization using the full cost method of accounting based on the combined proved reserves and production volumes and incorporating the acquisition costs and $12.8 million of estimated future development costs.

(b) The pro forma consolidated statement of income has been adjusted to reflect the impact of $9.7 million of estimated future site restoration and reclamation costs.

(c) The pro forma consolidated statement of income reflects an increase in financing charges as a result of bank debt on the acquisition and the amortization of financing charges.

The pro forma consolidated statement of income assumes that the principal amount of debt borrowed under the New Facility at January 1, 2002 was approximately $34.9 million. Interest charges in respect of the debt have been determined assuming an effective interest rate of 6.805% per annum (based upon a lender's prime rate of 4.25% per annum plus an applicable margin of 1.875% per annum and withholding tax yield protection of 0.68% per annum). The U.S. dollar borrowings under the New Facility have been translated at an exchange rate of approximately $1.58 Cdn to $1.00 U.S. It has been assumed that there was no change in the Cdn to U.S. dollar exchange rate during the nine-month period ending September 30, 2002 and therefore no adjustment to income was necessary for exchange rate changes.

The pro forma consolidated statement of income reflects a charge of $1.2 million in respect of the amortization of $2.3 million in deferred financing charges being amortized over the 17-month term of the New Facility.

(d) The amount included in the statement of income for general and administrative expenses has been determined on the basis of the anticipated actual expenditures, net of $750,000 of overhead charges capitalized. The total general and administrative costs for the nine months ended September 30, 2002 amounts to approximately $0.88 per barrel of oil equivalent of production. General and administrative costs incurred by the vendors are less relevant given the different nature of their operations to those which will be carried on by the Trust. Management has reviewed the financial statements of four other public energy trusts that are similar in size to the Trust and has determined that the general and administrative expenditures of the Trust included in the nine-month pro forma financial statements are reasonable.

(e) For income tax purposes, the Trust is able to and intends to, claim a deduction for all amounts paid or payable to unitholders, and then to allocate remaining taxable income, if any, to unitholders. Accordingly, no future income taxes have been included in the pro forma consolidated statement of income.

Current taxes reflected in the pro forma consolidated statement of income are in respect of large corporation taxes of Harvest.

(f) The net income per unit calculations give effect to the issuance 10,962,500 Trust Units as at January 1, 2002.

On November 25, 2002 the Trust established a Trust Unit incentive plan. To date, the Trust has granted rights to purchase 820,000 Trust Units at an average price of 8.76 per Trust Unit. In computing diluted income per unit, it was assumed that 130,000 Trust Units would be added to the 10,962,500 Trust Units outstanding for the nine-month period ended September 30, 2002 to reflect the dilutive effect of the rights issued to date.

KPMG

Consolidated Financial Statements of

HARVEST ENERGY TRUST

Period from formation on July 10, 2002 to September 30, 2002

AUDITORS' REPORT TO THE TRUSTEE OF HARVEST ENERGY TRUST AND DIRECTORS OF HARVEST OPERATIONS CORP.

We have audited the balance sheet of Harvest Energy Trust as at July 10, 2002. This balance sheet is the responsibility of the trust's management. Our responsibility is to express an opinion on this balance sheet based on our audit.

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

In our opinion, the balance sheet presents fairly, in all material respects, the financial position of the trust as at July 10, 2002 in accordance with Canadian generally accepted accounting principles.

Chartered Accountants

Calgary, Canada
February 7, 2003

HARVEST ENERGY TRUST

Consolidated Balance Sheets

	September 30, 2002 (unaudited)	July 10, 2002 (audited)
Assets		
Current assets:		
Cash and short-term investments	$ 14,533	$ 100
Accounts receivable	4,531,419	–
Prepaid expenses	171,404	–
	4,717,356	100
Capital assets (note 3)	24,931,475	–
Deferred financing charges, net of amortization	338,000	–
Property purchase deposit	5,000,000	–
	$34,986,831	$ 100
Liabilities and Unitholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 1,709,438	$ –
Large corporation taxes payable	27,900	–
	1,737,338	–
Long-term debt (note 4)	30,981,220	–
Future income taxes (note 7)	256,000	–
Site restoration and reclamation provision (note 3)	329,000	–
	33,303,558	–
Unitholders' equity:		
Capital contributions (note 5)	100	100
Accumulated income	1,683,173	–
Accumulated cash distributions	–	–
	1,683,273	100
Subsequent events (notes 4 and 10)		
	$34,986,831	$ 100

See accompanying notes to consolidated financial statements.

Approved by the Board:

________________________ Director

________________________ Director

HARVEST ENERGY TRUST

Consolidated Statement of Income and Accumulated Income

For the period from formation on July 10, 2002 to September 30, 2002

	(unaudited)
Revenues:	
Oil and gas sales	$ 7,705,578
Royalty income	41,387
Royalties	(767,199)
	6,979,766
Expenses:	
Operating	2,167,791
General and administrative	196,380
Interest and amortization of financing charges	859,522
Site restoration	329,000
Depletion, depreciation and amortization	1,460,000
	5,012,693
Income before taxes	1,967,073
Taxes:	
Large corporation taxes	27,900
Future income taxes (note 7)	256,000
	283,900
Net income for the period, being accumulated income at September 30, 2002	$ 1,683,173

See accompanying notes to consolidated financial statements.

HARVEST ENERGY TRUST

Consolidated Statement of Cash

For the period from formation on July 10, 2002 to September 30, 2002

	(unaudited)
Cash provided by (used in)	
Operations	
Net income for the period	$ 1,683,173
Add items not involving cash:	
Depletion, depreciation and amortization	1,460,000
Site restoration	329,000
Future income taxes	256,000
Amortization of financing charges	45,242
Accrued interest expense	660,620
	4,434,035
Change in non-cash working capital (note 9)	(3,188,723)
	1,245,312
Financing:	
Bank borrowings	13,065,000
Loans from Caribou Capital Corp.	12,255,600
Debenture borrowings	5,000,000
Debt placement fees	(383,242)
	29,937,358
Investing:	
Property purchase deposit	(5,000,000)
Capital expenditures	(284,156)
Properties acquisition (*note 3*)	(26,107,319)
Change in non-cash working capital (note 9)	223,238
	(31,168,237)
Increase in cash and short-term investments	14,433
Cash and short-term investments, beginning of period	100
Cash and short-term investments, end of period	$ 14,533
Cash interest payment	$ 153,660
Cash taxes payment	–

See accompanying notes to consolidated financial statements.

1. Structure of the trust:

Harvest Energy Trust (the "Trust") is an open-ended, unincorporated investment trust formed under the laws of Alberta. Pursuant to a trust indenture and an administration agreement, the Trust is managed by its wholly owned subsidiary, Harvest Operations Corp. ("Harvest"). The Trust acquires and holds net profit interests in oil and gas properties acquired and held by Harvest.

The beneficiaries of the Trust are the holders of Trust Units. Upon completion of the initial public offering, the Trust will make monthly distributions of its distributable cash to unitholders of record on the last day of each calendar month. The amount of the distributions per Trust Unit are equal to the pro rata share of the net income of the Trust (including direct royalties received, net profit interests in the oil and gas properties and crown charges that are not deductible for income tax purposes of Harvest), dividends of Harvest, Alberta Royalty Tax Credits received less expenses (including interest and debt repayments) and net realized capital gains of the Trust less an appropriate working capital reserve.

2. Significant accounting policies:

The management of Harvest prepares the financial statements following Canadian generally accepted accounting principles. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Consolidation:

These consolidated financial statements include the accounts of the Trust and Harvest. All inter-entity transactions and balances have been eliminated upon consolidation.

(b) Capital assets:

The Trust follows the full cost method of accounting. All costs of acquiring oil and gas properties and related exploration and development costs, including overhead charges directly related to these activities, are capitalized and accumulated in one cost center. Maintenance and repairs are charged against earnings. Renewals and enhancements that extend the economic life of the capital assets are capitalized.

Gains and losses are not recognized on disposition of oil and gas properties unless that disposition would alter the rate of depletion by 20% or more.

Ceiling test

The Trust places a limit on the aggregate cost of capital assets, which may be carried forward for depletion against net revenues of future periods (the ceiling test). The ceiling test is a cost recovery test whereby: capitalized costs, less accumulated depletion and site restoration and the lower of cost and market value of unproved land, are limited to an amount equal to estimated undiscounted future net revenues from proved reserves, less general and administrative expenses, site restoration, management fees, future financing costs and applicable income taxes. Costs and prices at the balance sheet date are used. Any costs carried on the balance sheet in excess of the ceiling test limitation are charged to income.

Site restoration and reclamation provision

The Trust provides for the cost of future site restoration and reclamation, based on estimates by management, using the unit-of-production method. Actual site restoration costs are charged against the accumulated liability.

Depletion, depreciation and amortization

Provision for depletion and depreciation is calculated on the unit-of-production method, based on proved reserves before royalties. Independent petroleum engineers estimate reserves. Reserves are converted to equivalent units on the basis of approximate relative energy content.

Depreciation and amortization of office furniture and equipment is provided for a rates ranging from 10% to 33% per annum.

(c) Joint venture accounting:

Harvest conducts substantially all of its oil and gas production activities through joint ventures, and the accounts reflect only their proportionate interest in such activities.

(d) Income taxes:

The Trust is a taxable entity under the *Income Tax Act (Canada)* and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust plans to distribute all of its taxable income to the unitholders and meets the requirements of the *Income Tax Act (Canada)* applicable to a Trust, the Trust makes provision for income taxes on the taxes payable basis.

Harvest follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in its financial statements and its respective tax base, using enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets and liabilities.

(e) Unit-based compensation:

The Trust uses the intrinsic value based method of accounting for the unit-based incentive plan described in note 5. The Trust does not recognize compensation expense on the issuance of rights to employees and directors as the exercise price of rights equals the market price on the day of the grant. Under the terms of the plan, the exercise price of rights granted may be reduced in future periods. As the amount of this reduction cannot be reasonably estimated, it is not possible to determine a fair value for rights granted. Accordingly, the Trust does not recognize an expense on the issuance of rights to non-employees and compensation costs for pro forma disclosure purposes are determined based on the excess of the unit price over the exercise price at the date of the financial statements.

(f) Deferred financing charges:

Deferred financing charges relate to costs incurred on the issuance of debt and are being amortized on a straight-line basis over the life of the bank loans.

(g) Financial instruments:

Harvest uses financial instruments to manage its exposure to fluctuations in commodity prices, foreign currency exchange rates, and interest rates. Harvest does not use financial instruments for speculative trading purposes and, accordingly, they are accounted for as hedges. Gains and losses on hedging activity are reflected in revenue, or in the case of interest rate hedges, in interest charges, at the time of sale of the related hedge production, or when the monthly exchange contracts expire.

(h) Cash and short term investments:

Short-term investments with maturities less than three months are considered to be cash equivalents and are recorded at cost, which approximate market value.

(i) Foreign Currency Translation:

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in income in the period in which they arise.

3. Capital assets:

	Cost	Accumulated depreciation	Net book value
Oil and gas properties	$ 19,357,283	$ (1,071,000)	$18,286,283
Production facilities and equipment	6,970,000	(377,000)	6,593,000
Office furniture and equipment	64,192	(12,000)	52,192
	$ 26,391,475	$ (1,460,000)	$24,931,475

On July 10, 2002 Harvest acquired the Initial Properties for $26,107,319.

General and administrative costs of $60,918 have been capitalized during the period ended September 30, 2002.

All costs are subject to depletion and depreciation at September 30, 2002. In addition, future development costs of $240,000 are included in depletion and depreciation calculations at September 30, 2002.

Site restoration involves the surface clean up and reclamation of well site and field production facilities. In addition, certain plant facilities will require decommissioning, which involves dismantlement of facilities as well as the decontamination and reclamation of these lands. Total estimated future costs are approximately $5,292,000, of which $329,000 has been accrued to September 30, 2002. The board of directors of Harvest has established a fund to ensure that cash is available to carry out the future site restoration and reclamation work. Beginning in 2003, contributions are to be made to this fund at an amount yet to be determined. Contributions will be deducted from cash available for distribution to unitholders.

4. Long-term debt:

Revolving bank credit facility		$13,065,000
Loan from Caribou Capital Corp:		
Principal	$12,255,600	
Accrued interest	647,741	12,903,341
Debenture:		
Principal	$ 5,000,000	
Accrued interest	12,879	5,012,879
		$30,981,220

Revolving bank credit facility:

At September 30, 2002, Harvest had a revolving term credit facility to a maximum of $18 million, bearing interest at the lender's prime rate plus 0.25% per annum and secured by a first priority lien on all of the assets of Harvest. Under the facility, quarterly principal repayments of $1.5 million commencing September 30, 2002 were required, with an additional payment of $1.5 million to be made prior to December 31, 2003. The facility was to revolve until May 31, 2003 at which time it was to be converted to a term facility, with the terms to be established by the lender at that time.

On November 14, 2002, Harvest entered into a new term borrowing base credit facility with a U.S. bank for U.S. $60 million. This facility has an initial borrowing base of U.S.$38 million, bears interest at the lender's prime rate plus an applicable margin in the case of a base rate loan, and at a LIBOR rate or Bankers Acceptance stamping fee plus an applicable margin in the case of a Eurodollar loan or Bankers Acceptance loan. The applicable margin is 1.125% or 1.875% for a base rate loan and 2.125% or 2.875% for a Eurodollar loan or Bankers Acceptance loan, depending on the amount of the borrowing base that is drawn. To secure the credit facility, Harvest granted the lender a first priority lien on all of its assets. Certain restrictive covenants, including a requirement that Harvest maintain price hedging agreements for not less than 67% of its expected production, and financial ratios are required to be maintained for the purpose of measuring Harvest's ability to meet its obligation under the credit agreement,. The facility will revolve until April 30, 2004 at which time any outstanding principal and interest balances must be repaid.

Loan from Caribou Capital Corp.:

In July 2002, the Trust entered into agreements providing for up to $43 million of loans from Caribou Capital Corp. To September 30, 2002, Caribou Capital Corp. had advanced $12,255,600 to partially finance the acquisition of the Initial Properties. The loan bears interest at a rate of 20% per annum, is unsecured and matures on July 31, 2003.

Trust Debenture:

In August 2002, the Trust issued a debenture for proceeds of $5,000,000. The debenture bears interest at a rate of 2.25% per annum, is unsecured and is due on December 31, 2002. Principal and outstanding interest will be settled in either cash or Trust Units, at the option of the holder. If settled in Trust Units, the dollar amount outstanding will be converted to Trust Units at a fixed price of $1 per unit.

5. Unitholders' equity:

(a) Authorized:

The authorized capital consists of an unlimited number of Trust Units.

Each Trust Unit is entitled to a beneficiary interest in any distribution of the Trust and in any net assets in the event of termination or wind-up. Trust Units are redeemable at any time at the option of the holder. The redemption price is equal to the lesser of (i) 90% of the average market price of the Trust Units during a 10 day period commencing immediately after the date on which the units are tendered for redemption, or (ii) the closing market price on the date that the units are tendered for redemption date. The total amount payable by the Trust in respect of redemptions in any calendar month shall not exceed $100,000. To the extent that a unitholder is entitled to a redemption payment, it will be satisfied by a cash payment from the Trust or by the Trust distributing a pro-rata number of Harvest notes or distributing its own notes.

(b) Issued:

	Units	Amount
Issued for cash on formation, being the balance outstanding at September 30, 2002	100	$ 100

(c) Incentive plan:

A Trust Unit incentive plan has been established. Under the plan, the Trust is authorized to grant non-transferable rights to purchase Trust Units to directors, officers, consultants, employees and other service providers to an aggregate of 875,000 Trust Units. The initial exercise price of rights granted under the plan is equal to the closing market price on the date immediately prior to the date the rights are granted and the maximum term of each right is not to exceed five years. The exercise price of the rights may be adjusted downwards from time to time based upon the cash distributions made on the Trust Units in excess of a minimum distribution rate.

(d) Rights to purchase units:

Reference is made to notes 4 and 6.

6. Related party transactions:

Caribou Capital Corp., a company controlled by a director of Harvest, advanced $12,255,600 during the period ended September 30, 2002 (see note 4). Caribou Capital Corp. was granted warrants to purchase 150,000 Trust Units at $1.00 per unit as a fee for providing the credit facility. The warrants expire on July 31, 2003. Caribou Capital Corp. earned $647,450 of interest on the loan during the period ended September 30, 2002.

Certain officers and directors of the Trust and their associates provided $3,837,500 of the $5,000,000 of funds obtained pursuant to the debenture (see note 4). The officers and directors earned $9,884 of interest on the debenture during the period ended September 30, 2002.

7. Income taxes:

The provisions for future income taxes varies from the amount that would be computed by applying the combined Canadian federal and provincial income tax rates to the reported income before taxes:

Income before taxes	$ 1,967,073
Computed income tax expense at the statutory rate of 41.6%	$ 818,300
Increase (decrease) resulting from:	
Non-deductible crown royalties and other payments	141,000
Federal resource allowance	(225,900)
Amounts included in trust income	(477,400)
Future income taxes	$ 256,000

The net future income tax liability is comprised of:

Future tax liabilities:	
Capital assets in excess of tax value	$ 393,000
Future tax assets:	
Site restoration and reclamation provision	(137,000)
Net future tax liability	$ 256,000

The capital assets owned by the Trust have a tax basis of approximately $11,300,000 available for future use as a deduction from taxable income. The book value of the assets in the Trust approximate the tax basis at September 30, 2002.

Net assets of Harvest with a book value of $18,640,000 have a tax basis of $18,025,000 available for future use as deductions from taxable income. Included in the tax basis are non-capital losses carryforwards of $218,000, which expire in 2009.

8. Financial instrument and other disclosures:

(a) Commodity risk management:

The bank loan agreement requires Harvest to maintain hedging arrangements in effect with respect to not less than 67% of its expected production. Harvest uses oil sales contracts and derivative financial instruments to comply with this requirement.

A summary of the oil sales contracts with price swap or collar features at September 30, 2002 that have fixed future sales prices are as follows:

Period	Type	Volume	Price
4th Quarter 2002	swap	1200 bbls per day	$39.31
4th Quarter 2002	collar	500 bbls per day	$36.50 - $41.67
1st Quarter 2003	swap	1000 bbls per day	$38.30
1st Quarter 2003	collar	500 bbls per day	$35.00 - $41.30
2nd Quarter 2003	swap	1000 bbls per day	$37.59
2nd Quarter 2003	collar	500 bbls per day	$35.00 – $39.60
3rd Quarter 2003	swap	1000 bbls per day	$37.10
3rd Quarter 2003	collar	500 bbls per day	$35.40 - $38.40
4th Quarter 2004	swap	1000 bbls per day	$36.63
4th Quarter 2004	collar	500 bbls per day	$35.50 - $37.35

A summary of the financial instruments at September 30, 2002 to fix oil prices on future sales is as follows:

Period	Volume	Price
1st Quarter 2003	200 bbls/d	$U.S. 24.95
2nd Quarter 2003	200 bbls/d	$U.S. 24.39
1st Quarter 2004	1510 bbls/d	$U.S. 23.23
2nd Quarter 2004	1430 bbls/d	$U.S. 22.93
3rd Quarter 2004	1380 bbls/d	$U.S. 22.70
4th Quarter 2004	1325 bbls/d	$U.S. 22.54
1st Quarter 2005	1100 bbls/d	$U.S. 22.38
2nd Quarter 2005	1030 bbls/d	$U.S. 22.18

Based upon quoted rates for similar contracts, at September 30, 2002 a payment of $881,000 would be required to terminate the financial instruments.

Harvest has entered into electricity purchase price swap contracts to fix the cost of future electricity useage. These contracts fix the price on up to 5 mega watt-hours per day at $46.30 and $46.00 per mega watt-hour for the year ended December 31, 2003 and 2004, respectively. Based upon posted rates, at September 30, 2002, a payment of $17,000 would have been required to terminate these contracts.

(b) Interest rate risk:

Harvest is exposed to interest rate risk on its bank loan.

(c) Credit risk:

Substantially all of the accounts receivable are due from customers in the oil and gas industry and are subject to normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of the associated credit risks.

(d) Fair values of financial instruments:

Financial instruments carried on the balance sheet consist mainly of accounts receivable, accounts payable and accrued liabilities, taxes payable and long-term debt. At September 30, 2002, there were no significant differences between the carrying value of these financial instruments and their estimated fair value.

9. Change in non-cash working capital:

Changes in non-cash working capital items:	
Accounts receivable	$(4,531,419)
Prepaid expenses	(171,404)
Accounts payable and accrued liabilities	1,709,438
Large corporation taxes payable	27,900
	$(2,965,485)
Changes relating to investing activities	$ 223,238
Changes relating to operations	(3,188,723)
	$(2,965,485)

10. Subsequent events:

On November 15, 2002, Harvest acquired the Additional Properties for approximately $53.2 million. This acquisition was financed by $38.2 million of bank borrowings, $10 million of loans from Caribou Capital Corp., and the application of the $5.0 million property purchase deposit. In conjunction with this acquisition, Harvest entered into a sales agreement to deliver 6,000 bbls per day of Lloydminster crude oil until December 31, 2003 at a price between U.S.$22.63 and U.S.$25.48 per bbl less a fixed price differential of U.S.$ 8.233 per bbl. To meet the contract requirements, Harvest will have to purchase up to 1,000 bbl. per day of diluents to blend with its production.

On closing, the vendor indicated its intent to charge Harvest an additional $5.8 million for the properties. Management believes that such amount is not owing to the vendor and accordingly, the additional amount has not been included in the cost of the purchase. This dispute is expected to be resolved through an arbitration process and any amount paid and not recoverable will be recorded as capital assets upon settlement.

On December 5, 2002, the Trust issued 3,750,000 Trust Units for $27.6 million, net of a 6% underwriters' fee and $600,000 of issue costs. The net proceeds were used to fully repay the loan from Caribou Capital Corp. and partially repay the bank loan. In conjunction with this initial public offering, the Trust granted the underwriters an option to purchase up to an additional 562,500 Trust Units at a price of $8.00 per unit. On December 17, 2002, the underwriters exercised the option; the net proceeds were used to partially repay the bank loan.

Upon completion of the initial public offering the Trust paid the debenture principal and interest payable thereon by the issuance of 5,000,000 Trust Units and a cash payment of $34,829.

On January 24, 2003, 150,000 Trust Units were issued to Caribou Capital Corp. on the exercise of a warrant. The $150,000 in proceeds were added to working capital.

On February 4, 2003, pursuant to an underwriting agreement the Trust issued 1,500,000 special warrants for $14,050,000, net of a 5% underwriters' fee and $200,000 of issue costs. The warrants are exercisable into 1,500,000 on Trust Units at no additional cost. The net proceeds were added to working capital and used to partially repay the bank loan.

CERTIFICATE OF THE TRUST AND PROMOTERS

Dated: February 12, 2003

The foregoing constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 9 of the *Securities Act* (British Columbia), by Part 9 of the *Securities Act* (Alberta) and by Part XV of the *Securities Act* (Ontario).

HARVEST ENERGY TRUST
By: Harvest Operations Corp.

(Signed) "*Jacob Roorda*"
President and Chief Executive Officer

(Signed) "*David Fisher*"
Chief Financial Officer

On behalf of the Board of Directors

(Signed) "*M. Bruce Chernoff*"
Director

(Signed) "*Hank B. Swartout*"
Director

PROMOTERS

(Signed) "*M. Bruce Chernoff*"

(Signed) "*Kevin A. Bennett*"

CERTIFICATE OF THE UNDERWRITERS

Dated: February 12, 2003

To the best of our knowledge, information and belief, the foregoing constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required by Part 9 of the *Securities Act* (British Columbia), by Part 9 of the *Securities Act* (Alberta) and by Part XV of the *Securities Act* (Ontario).

FirstEnergy Capital Corp.

By: (signed) "*John S. Chambers*"

Haywood Securities Inc.

By: (signed) "*Fabio M. Banducci*"

(8)

04 MAR -9 AM 7:21

HARVEST ENERGY TRUST

AMENDED AND RESTATED TRUST INDENTURE

Burnet, Duckworth & Palmer LLP

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HARVEST ENERGY TRUST

AMENDED AND RESTATED TRUST INDENTURE made the 27th day of September, 2002.

BETWEEN:

VALIANT TRUST COMPANY, a trust company incorporated under the laws of Alberta, with offices in the City of Calgary, in the Province of Alberta (hereinafter called the "Trustee")

OF THE FIRST PART

and

HARVEST OPERATIONS CORP., a body corporate incorporated under the laws of Alberta, with offices in the City of Calgary, in the Province of Alberta (hereinafter called the "Corporation") and all persons who after the date hereof become holders of Trust Units as herein provided

OF THE SECOND PART

WHEREAS the Settlor has paid to the Initial Trustee an amount of one hundred dollars in lawful money of Canada for the purpose of settling the Trust;

AND WHEREAS the Trustee has agreed to replace the Initial Trustee and to act as trustee of the Trust in accordance with the provisions hereinafter set forth;

AND WHEREAS it is intended that the beneficiaries of the Trust shall be the holders of Trust Units, each of which Trust Units shall rank equally in all respects with every other Trust Unit;

AND WHEREAS it is intended that the Trust will offer the Trust Units for sale to members of the public from time to time;

AND WHEREAS it is intended that the Trust shall qualify as a "unit trust" and as a "mutual fund trust" under the provisions of paragraph 108(2)(b) and subsection 132(6) of the Tax Act;

AND WHEREAS the parties hereto desire to set out the terms and conditions which shall govern the settlement and the administration of the Trust;

NOW THEREFORE THIS INDENTURE WITNESSETH that in consideration of the premises and the mutual and respective covenants and agreements contained herein, the Trustee declares and covenants and agrees with and in favour of the holders from time to time of the Trust Units and the Corporation as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Indenture including the recitals and in the Trust Certificates and schedules hereto, unless the context otherwise requires, the following words and expressions shall have the following meanings:

(a) "**ABCA**" means the *Business Corporations Act* (Alberta) as amended from time to time, including the regulations promulgated thereunder;

(b) **"Affiliate"** has the meaning set forth in the *Securities Act* (Alberta), as amended from time to time;

(c) **"Agency Agreement"** means any underwriting, agency or similar agreement entered into by the Trustee and investment dealers, and such other persons including the Corporation as may be a party thereto relating to an Offering;

(d) **"Agent's Fees"** means the amounts so designated in any Agency Agreement;

(e) **"Administration Agreement"** means the agreement dated September 27, 2002 between the Trustee and the Corporation pursuant to which the Corporation has agreed to provide certain administrative and advisory services in connection with the Trust;

(f) **"Appraised Redemption Price"** has the meaning set forth in Section 18.6;

(g) **"ARTC"** means Alberta Royalty Tax Credit within the meaning of the *Alberta Corporate Tax Act*

(h) **"Associate"** has the meaning set forth in the *Securities Act* (Alberta) as amended from time to time;

(i) **"Auditors"** means KPMG LLP, or such other firm of chartered accountants as may be appointed as auditor or auditors of the Trust by or in accordance with Article 15;

(j) **"Business Day"** means a day other than a Saturday, Sunday or holiday in the City of Calgary in the Province of Alberta;

(k) **"Capital Fund"** means the cash flow retained by the Trust from cash otherwise available for distribution which shall be advanced to the Corporation to finance future acquisitions and development of the Properties;

(l) **"Closing"** means the completion of the Initial Offering and **"Date of Closing"** means the date on which the Closing occurs;

(m) **"Counsel"** means a law firm (which may be counsel to the Corporation) reasonably acceptable to the Trustee;

(n) **"Corporation"** means Harvest Operations Corp.;

(o) **"Credit Agreement"** means the letter dated June 14, 2002 between the Bank of Nova Scotia and the Corporation or such similar agreement which supplements or replaces this agreement between the Corporation and a Lender;

(p) **"Debt Service Charges"** means all interest and principal repayments and other costs, expenses and disbursements relating to the borrowing of funds by the Trust and the Corporation which are attributable to the Properties;

(q) **"Deferred Purchase Price Obligation"** has the meaning ascribed thereto in the NPI Agreement;

(r) **"Direct Royalties"** means royalty interests in petroleum and natural gas rights acquired by the Trust from time to time, other than the NPI, including the Initial Direct Royalties to be acquired by the Trust from the Corporation pursuant to a Direct Royalties Sale Agreement;

(s) **"Direct Royalties Sale Agreement"** means any purchase and sale agreement between the Trust and the Corporation providing for the purchase by the Trust from the Corporation of the Direct Royalties including the amended and restated agreement dated September 27, 2002 in respect of the purchase of the Initial Direct Royalties;

(t) **"Distribution Record Date"** means the last day of each calendar month or such other date as may be determined from time to time by the Trustee upon the recommendation of the board of directors of the Corporation, except that December 31 shall in all cases be a Distribution Record Date;

(u) **"Indemnified Parties"** has the meaning set forth in Section 7.9;

(v) **"Initial Direct Royalties"** means a 99% undivided interest in the royalty interests forming part of the Initial Properties to be acquired by the Trust from the Corporation pursuant to a Direct Royalties Sale Agreement;

(w) **"Initial Offering"** means the Offering pursuant to the Prospectus;

(x) **"Initial Properties"** means the properties and assets to be acquired by the Corporation from the Vendors pursuant to the Sale Agreement;

(y) **"Initial Trustee"** means Caribou Capital Corp.;

(z) **"Issue Expenses"** means all expenses of an Offering payable by the Trust including legal fees, accounting fees and printing expenses and all other fees and expenses which may be described, whether generally or specifically, in any Offering Document relating to the particular Offering, but excluding Underwriter's Fees;

(aa) **"Lender"** means the lender or lenders (or any of its or their Affiliates) providing one or more credit or debt facilities, hedging or swap facilities or any other ancillary facilities to the Trust, the Corporation or any other Affiliate of the Trust for the ownership and operation of its assets, business and affairs;

(bb) **"Material Contracts"** means this Trust Indenture, the NPI, a Direct Royalties Sale Agreement, the Administration Agreement and the Credit Agreement, each as amended or replaced from time to time, and any Underwriting Agreement and any loan agreement, credit agreement, royalty agreement, indenture or other agreement entered into by the Trust for the purpose of making any Subsequent Investment;

(cc) **"NPI"** means the right to be granted to the Trust under the NPI Agreement to receive payments on petroleum and natural gas rights held by the Corporation from time to time as more particularly described in the NPI Agreement;

(dd) **"NPI Agreement"** means the amended and restated net profit interest agreement regarding the creation and sale of the NPI to the Trust dated September 27, 2002 between the Corporation and the Trustee;

(ee) **"Notes"** means the promissory notes issued by the Corporation in series pursuant to a note indenture to be redeemed in consideration for a portion of the NPI having a fair market value equal to such principal amount on the following terms and conditions:

(i) unsecured and bearing interest at 6% per annum payable monthly in arrears on the 20th day of the next following month;

(ii) subordinate to all senior indebtedness which includes all indebtedness for borrowed money or owing in respect of property purchases on any default in payment of any such senior indebtedness, and to all trade debt of the Corporation or any subsidiary of the Corporation or the Trust on any creditor proceedings such as bankruptcy, liquidation or insolvency;

(iii) subject to earlier prepayment, being due and payable on the 15th anniversary of the date of issuance;

(iv) in an aggregate principal amount not exceeding $500 million, and

(v) subject to such other standard terms and conditions as would be included in a note indenture for promissory notes of this kind, as may be approved by the board of directors of the Corporation;

(ff) "**Offering**" means any issuance or offering of Trust Units or any rights, warrants or other securities to purchase, to convert into or exchange into Trust Units on a public or private basis in Canada or elsewhere, including the Initial Offering;

(gg) "**Offering Documents**" means any one or more of a prospectus, information memorandum, private placement memorandum and similar public or private offering document, including the Prospectus, or any understanding, commitment or agreement to issue or offer Trust Units;

(hh) "**Ordinary Resolution**" means a resolution approved at a meeting of Unitholders by more than 50% of the votes cast in respect of the resolution by or on behalf of Unitholders present in person or represented by proxy at the meeting;

(ii) "**outstanding**", in relation to Trust Units, has the meaning attributed thereto in Section 1.2 hereof;

(jj) "**Payment Date**" has the meaning set forth in Section 5.7;

(kk) "**Permitted Investments**" means:

(i) loan advances to the Corporation, including loans made in connection with the Capital Fund;

(ii) interest bearing accounts of certain financial institutions including Canadian chartered banks and the Trustee;

(iii) obligations issued or guaranteed by the Government of Canada or any province of Canada or any agency or instrumentality thereof;

(iv) term deposits, guaranteed investment certificates of deposit or bankers' acceptances of or guaranteed or accepted by any Canadian chartered bank or other financial institution (including the Trustee and any Affiliate of the Trustee) the short term debt or deposits of which have been rated at least A or the equivalent by Standard & Poor's Corporation, Moody's Investors Service, Inc. or Dominion Bond Rating Service Limited;

(v) commercial paper rated at least A or the equivalent by Canadian Bond Rating Service Inc. or Dominion Bond Rating Service Limited; and

(vi) investments in bodies corporate, partnerships or trusts engaged in the oil and natural gas business;

provided that any investment of the type referred to in Section 4.3 shall not be a Permitted Investment;

(ll) "**person**" means an individual, partnership, body corporate, association or trust;

(mm) "**Pro Rata Share**" of any particular amount in respect of a Unitholder at any time shall be the product obtained by multiplying the number of Trust Units that are owned by that Unitholder at that time by the quotient obtained when the particular amount is divided by the total number of all Trust Units that are issued and outstanding at that time;

(nn) "**Properties**" means the working, royalty or other interests of the Corporation from time to time in any petroleum and natural gas rights, tangibles and miscellaneous interests, including the Initial Properties and properties which may be acquired by the Corporation at a future date and including the Direct Royalties acquired by the Trust from time to time;

(oo) "**Prospectus**" means the prospectus for the Initial Offering of Units which is expected to be dated not later than October 31, 2002;

(pp) "**Sale Agreement**" means the purchase and sale agreement between the Corporation and the Vendors providing for the purchase by the Corporation from the Vendors of the Initial Properties;

(qq) "**Settled Amount**" means the amount of one hundred dollars in lawful money of Canada paid by the Settlor to the Trustee for the purpose of settling the Trust;

(rr) "**Settlor**" means Caribou Capital Corp.;

(ss) "**Shares**" means the issued and outstanding common shares of the Corporation as of the date hereof and also means shares of any class issued by the Corporation thereafter;

(tt) "**Special Resolution**" has the meaning attributed thereto in Section 10.6 hereof;

(uu) "**Subsequent Investment**" means any of the investments which the Trust may make pursuant to Subsections 4.1(b), (c) or (f);

(vv) "**Tax Act**" has the meaning ascribed thereto in Section 1.3;

(ww) "**Transfer Agent**" means the Trustee, its successors or assigns, in its capacity as transfer agent for the Trust Units or such other company as may from time to time be appointed by the Trustee to act as transfer agent for the Trust Units together, in either such case, with any subtransfer agent duly appointed by the transfer agent;

(xx) "**Trust**" means Harvest Energy Trust and refers to the trust relationship between the Trustee and the Unitholders with respect to the Trust Fund, upon the terms and conditions set out herein from time to time and, if the context requires, may also refer to the Trust Fund;

(yy) "**Trust Certificate**" or "**Trust Unit Certificate**" means a certificate, in the form approved by the Trustee, evidencing one or more Trust Units, issued and certified in accordance with the provisions hereof;

(zz) "**Trust Debenture**" means the debenture dated effective August 15, 2002 and issued by the Trust to 990148 Alberta Ltd., in the aggregate principal amount of $5,000,000 which may be repaid at the option of 990148 Alberta Ltd. in cash or Trust Units;

(aaa) "**Trust Expenses**" means all expenses incurred by the Trustee or any third party, in each case for the account of the Trust, in connection with this Indenture, the establishment and ongoing management of the Trust and the ongoing administration of the Trust Units, including without limitation those amounts payable to the Trustee under Sections 7.6, 7.7 and 7.8;

(bbb) "**Trust Fund**", at any time, shall mean such of the following monies, properties and assets that are at such time held by the Trustee on behalf of the Trust for the purposes of the Trust under this Indenture:

(i) the Settled Amount;

(ii) all funds realized from the issuance of Trust Units;

(iii) any Permitted Investments in which funds may from time to time be invested;

(iv) all rights in respect of and income generated under the NPI Agreement, including the NPI;

(v) all rights in respect of and income generated under a Direct Royalties Sale Agreement;

(vi) any Subsequent Investment;

(vii) any proceeds of disposition of any of the foregoing property including, without limitation, the Direct Royalties; and

(viii) all income, interest, profit, gains and accretions and additional assets, rights and benefits of any kind or nature whatsoever arising directly or indirectly from or in connection with or accruing to such foregoing property or such proceeds of disposition;

(ccc) **"Trust Unit"** means a trust unit of the Trust created, issued and certified hereunder and for the time being outstanding and entitled to the benefits hereof;

(ddd) **"Trustee"** means Valiant Trust Company, or its successor or successors for the time being as trustee hereunder;

(eee) **"Underwriting Agreement"** means any underwriting, agency or similar agreement entered into by the Trustee and investment dealers, and such other persons including the Corporation as may be a party thereto relating to an Offering;

(fff) **"Underwriter's Fees"** means the amounts so designated in any Underwriting Agreement;

(ggg) **"Unitholders"** means the holders from time to time of one or more Trust Units;

(hhh) **"Vendors"** means Devon Canada and Devon ARL Corporation; and

(iii) **"year"** means initially, the period commencing on the date hereof and ending on December 31, 2002, and thereafter means a calendar year.

1.2 Meaning of "Outstanding"

Every Trust Unit created, issued, certified and delivered hereunder shall be deemed to be outstanding until it shall be cancelled or delivered to the Trustee for cancellation provided that when a new Trust Certificate has been issued in substitution for a Trust Certificate which has been lost, stolen or destroyed, only one of such Trust Certificates shall be counted for the purpose of determining the number of Trust Units outstanding.

1.3 Income Tax Act

In this Indenture, any reference to the Tax Act shall refer to the *Income Tax Act*, Revised Statutes of Canada 1985, Chapter 1 (5th Supplement) and the Income Tax Regulations as amended from time to time applicable with respect thereto. Any reference herein to a particular provision of the Tax Act shall include a reference to that provision as it may be renumbered or amended from time to time. Where there are proposals for amendments to the Tax Act which have not been enacted into law or proclaimed into force on or before the date on which such proposals are to become effective, the Trustee may take such proposals into consideration and apply the provisions hereof as if such proposals had been enacted into law and proclaimed into force.

1.4 Headings

The division of this Indenture into articles and sections, subsections, clauses, subclauses and paragraphs and the provision of headings is for convenience of reference only and shall not affect the construction or interpretation of this Indenture.

1.5 Construction of Terms

Words importing the singular number only shall include the plural, and vice versa, and words importing gender shall include the masculine, feminine and neuter genders. References in this Indenture to "this

Trust Indenture", "this Indenture", "hereto", "herein", "hereof", "hereby", "hereunder" and similar expressions shall be deemed to refer to this instrument and not to any particular Article, Section or portion hereof, and include any and every instrument supplemental or ancillary hereto or in implementation hereof.

1.6 References to Acts Performed by the Trust

Any reference in this Indenture to an act to be performed by the Trust shall be construed and applied for all purposes as if it referred to an act to be performed by the Trustee on behalf of the Trust or, to the extent applicable, by the Corporation on behalf of the Trust.

ARTICLE 2
DECLARATION OF TRUST

2.1 Settlement of Trust

The Settlor has paid the Settled Amount to the Initial Trustee and the Initial Trustee has accepted the Settled Amount for the purpose of creating and settling the Trust and the Settlor has been issued one hundred initial Trust Units in the Trust to the Initial Trustee which have been transferred to the Trustee.

2.2 Declaration of Trust

The Trustee hereby agrees to act as Trustee and that it does and shall hold the Trust Fund in trust for the use and benefit of the Unitholders, their permitted assigns and personal representatives upon the trusts and subject to the terms and conditions hereinafter declared and set forth, such trust to constitute the Trust hereunder.

2.3 Name

The Trust shall be known and designated as "Harvest Energy Trust" and, whenever lawful and convenient, the affairs of the Trust shall be conducted and transacted under that name. If the Trustee determines that the use of the name "Harvest Energy Trust" is not practicable, legal or convenient, it may use such other designation or it may adopt such other name for the Trust as it deems appropriate and the Trust may hold property and conduct its activities under such other designation or name.

2.4 Nature of the Trust

The Trust is an open-end unincorporated investment trust, established for the purposes specified in Section 4.1 hereof. The Trust is not and is not intended to be, shall not be deemed to be and shall not be treated as a general partnership, limited partnership, syndicate, association, joint venture, company, corporation or joint stock company, nor shall the Trustee or the Unitholders or any of them or any person be, or be deemed to be, treated in any way whatsoever as liable or responsible hereunder as partners or joint venturers. The Trustee shall not be, or be deemed to be, an agent of the Unitholders. The relationship of the Unitholders to the Trustee shall be solely that of beneficiaries of the Trust and their rights shall be limited to those conferred upon them by this Trust Indenture.

2.5 Legal Entitlements and Restrictions of Unitholders

(a) The rights of each Unitholder to call for a distribution or division of assets, monies, funds, income and capital gains held, received or realized by the Trustee are limited to those contained herein.

(b) Subject to the terms and conditions of this Indenture, no Unitholder or Unitholders shall be entitled to interfere or give any direction to the Trustee or the Corporation with respect to the affairs of the Trust or in connection with the exercise of any powers or authorities conferred upon the Trustee or the Corporation under this Indenture or the Material Contracts.

(c) The legal ownership of the assets of the Trust and the right to conduct the business of the Trust (subject to the limitations contained herein) are vested exclusively in the Trustee and the Unitholders shall have no interest therein and they shall have no right to compel or call for any partition, division, dividend or distribution of the Trust Fund or any of the assets of the Trust. The Trust Units shall be personal property and shall confer upon the holders thereof only the interest and rights specifically set forth in this Indenture. No Unitholder has or is deemed to have any right of ownership in any of the assets of the Trust.

2.6 Liability of Unitholders

No Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort or of any other kind whatsoever to any person in connection with the Trust Fund or the obligations or the affairs of the Trust or with respect to any act performed by the Trustee or by any other person pursuant to this Indenture or with respect to any act or omission of the Trustee or any other person in the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred upon the Trustee or such other person hereunder or with respect to any transaction entered into by the Trustee or by any other person pursuant to this Indenture. No Unitholder shall be liable to indemnify the Trustee or any such other person with respect to any such liability or liabilities incurred by the Trustee or by any such other person or persons or with respect to any taxes payable by the Trust or by the Trustee or by any other person on behalf of or in connection with the Trust. Notwithstanding the foregoing, to the extent that any Unitholders are found by a court of competent jurisdiction to be subject to any such liability, such liability shall be enforceable only against, and shall be satisfied only out of, the Trust Fund and the Trust (to the extent of the Trust Fund) is liable to, and shall indemnify and save harmless any Unitholder against any costs, damages, liabilities, expenses, charges or losses suffered by any Unitholder from or arising as a result of such Unitholder not having any such limited liability.

2.7 Contracts of the Trust

Every contract entered into by or on behalf of the Trust, whether by the Trustee, the Corporation, or otherwise, shall (except as the Trustee or the Corporation may otherwise expressly agree in writing with respect to their own personal liability) include a provision substantially to the following effect:

> The parties hereto acknowledge that the [Trustee] [Corporation] is entering into this agreement solely [in its capacity as Trustee] [on behalf] of the Trust and the obligations of the Trust hereunder shall not be personally binding upon the [Trustee] [Corporation] or any of the Unitholders of the Trust and that any recourse against the Trust or any Unitholder in any manner in respect of any indebtedness, obligation or liability of the Trust arising hereunder or arising in connection herewith or from the matters to which this agreement relates, if any, including without limitation claims based on negligence or otherwise tortious behaviour, shall be limited to, and satisfied only out of, the Trust Fund as defined in the Trust Indenture dated as of July 10, 2002 as amended from time to time.

The omission of such a provision from any such written instrument shall not operate to impose personal liability on the Trustee, the Corporation or any Unitholder.

2.8 Head Office of Trust

The head office of the Trust hereby created shall be located at Suite 2400, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6 or at such other place or places in Canada as the Trustee may from time to time designate.

ARTICLE 3
ISSUE AND SALE OF TRUST UNITS

3.1 Nature and Ranking of Trust Units

(a) The beneficial interests in the Trust shall be divided into interests of one class, described and designated as Trust Units, which shall be entitled to the rights and subject to the limitations, restrictions and conditions set out herein; and the interest of each Unitholder shall be determined by the number of Trust Units registered in the name of the Unitholder.

(b) Each Trust Unit shall entitle the holder or holders thereof to one vote at any meeting of the Unitholders and represents an equal fractional undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding-up of the Trust. All Trust Units outstanding from time to time shall be entitled to equal shares in any distributions by the Trust and, in the event of termination or winding-up of the Trust, in the net assets of the Trust. All Trust Units shall rank among themselves equally and rateably without discrimination, preference or priority.

3.2 Authorized Number of Trust Units

The aggregate number of Trust Units which are authorized and may be issued hereunder is unlimited.

3.3 No Fractional Trust Units

Fractions of Trust Units shall not be issued, except pursuant to distributions of additional Trust Units to all Unitholders pursuant to Section 5.8.

3.4 Re-Purchase of Initial Trust Units by Trust

Immediately after the Closing, the Trust will repurchase the initial Trust Units from the Trustee, and the Trustee shall sell the initial Trust Units to the Trust for a purchase price of one hundred dollars and, upon the completion of such purchase and sale, the initial Trust Units shall be cancelled and shall no longer be outstanding for any of the purposes of this Indenture.

3.5 Offerings of Trust Units and Indebtedness

(a) Trust Units, including rights, warrants or other securities to purchase, to convert into or exchange into Trust Units, may be created, issued, sold and delivered pursuant to Offering Documents on terms and conditions and at such time or times as the board of directors the Corporation may determine.

(b) The board of directors of the Corporation may authorize the creation and issuance of debentures, notes and other evidences of indebtedness of the Trust which debentures, notes or other evidences of indebtedness may be created and issued from time to time on such terms and conditions, to such persons and for such consideration as the Corporation may determine.

3.6 Ranking of Trust Units

Each Trust Unit represents an equal fractional undivided beneficial interest in the Trust Fund. All Trust Units outstanding from time to time shall be entitled to an equal fractional undivided share of any distributions by the Trust and, in the event of termination of the Trust, in the net assets of the Trust. All Trust Units shall rank among themselves equally and rateably without discrimination, preference or priority whatever may be the actual date or terms of issue thereof.

3.7 Trust Units Fully Paid and Non-Assessable

Trust Units shall be issued only when fully paid in money or property or past service, provided that property will include a promissory note or promise to pay given by the allottee. The Unitholders shall not thereafter be required to make any further contribution to the Trust with respect to such Trust Units.

3.8 No Conversion, Retraction, Redemption or Pre-Emptive Rights

No person shall be entitled, as a matter of right, to subscribe for or purchase any Trust Unit. There are no conversion, retraction, redemption or pre-emptive rights attaching to the Trust Units.

3.9 Consolidation of Trust Units

Immediately after any pro rata distribution of additional Trust Units to all Unitholders pursuant to Sections 5.5 or Section 5.8, the number of outstanding Trust Units will be consolidated such that each Unitholder will hold after the consolidation the same number of Trust Units as the Unitholder held before the distribution of additional Trust Units. In such case, each Trust Unit Certificate representing a number of Trust Units prior to the distribution of additional Trust Units is deemed to represent the same number of Trust Units after the distribution of additional Trust Units and the consolidation.

3.10 Non-Resident Holders

It is in the best interest of Unitholders that the Trust qualify as a "unit trust" and a "mutual fund trust" under the Tax Act. Accordingly, it is intended that the Trust comply with the requirements under the Tax Act for "unit trusts" and "mutual fund trusts" at all relevant times such that the Trust maintain the status of a unit trust and a mutual fund trust for purposes of the Tax Act. In this regard, the Trust shall, among other things, take all necessary steps to monitor the ownership of the Trust Units to carry out such intentions. If at any time the Trust, becomes aware that the beneficial owners of 49% or more of the Trust Units then outstanding are or may be Non-Residents or that such a situation is imminent, the Trust, by or through the Corporation on the Trust's behalf, shall take such action as may be necessary to carry out the intentions evidenced herein. For the purposes of this Section, "Non-Residents" means non-residents of Canada within the meaning of the Tax Act.

ARTICLE 4
INVESTMENTS OF TRUST FUND

4.1 Purpose of the Trust

The Trust is hereby created for the following purposes:

(a) acquiring the NPI and Direct Royalties (including the Initial Direct Royalties);

(b) making payments to the Corporation pursuant to the Deferred Purchase Price Obligation under the NPI Agreement;

(c) making loans to the Corporation in connection with the Capital Fund;

(d) acquiring or investing in securities of the Corporation and in the securities of any other entity including without limitation bodies corporate, partnerships or trusts, and borrowing funds or otherwise obtaining credit for that purpose;

(e) disposing of any part of the Trust Fund, including, without limitation, any securities of the Corporation;

(f) temporarily holding cash and investments for the purposes of paying the expenses and the liabilities of the Trust, making other investments as contemplated by Section 4.2 hereof, paying amounts payable by the Trust in connection with the redemption of any Trust Units, and making distributions to Unitholders; and

(g) paying costs, fees and expenses associated with the foregoing purposes or incidental thereto.

4.2 Permitted Investments

Any funds within the Trust Fund that are not required to be invested as provided in Section 4.1 shall be used by the Trust only to acquire Permitted Investments or as permitted by Section 7.2(f) or Section 7.2(u).

4.3 Other Investment Restrictions

Notwithstanding anything contained in this Indenture, under no circumstances shall the Trustee acquire any investment which (a) would result in the cost amount to the Trust of all "foreign property" (as defined in the Tax Act) which is held by the Trust to exceed the amount prescribed by Regulation 5000(l) of the regulations to the Tax Act, (b) is a "small business security" as that term is used in Part L1 of the Regulations to the Tax Act, or (c) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act. The Trustee may consult with and receive direction from the Corporation with respect to any investment to ensure compliance with this provision.

ARTICLE 5
DISTRIBUTIONS

5.1 Determination of Net Income of the Trust

In this Article 5, the "Net Income of the Trust" for the period ending on a Distribution Record Date shall be the amount calculated, for the period commencing immediately following the preceding Distribution Record Date (or, for the first Distribution Record Date, the period commencing on the date hereof) and ending on such Distribution Record Date, on the following basis:

(a) any amounts received pursuant to the NPI and the Direct Royalties, any interest or other income from Permitted Investments, ARTC received by the Trust and other Crown charges that are not deductible by the Corporation for income tax purposes and that are reimbursed by the Trust to the Corporation shall be included in Net Income of the Trust on an accrual basis and shall accrue from day to day;

(b) dividends on the Shares or any other dividends on securities of the Corporation shall be included in Net Income of the Trust when received including dividends deemed to have been received on such Shares or securities pursuant to the Tax Act; and

(c) all expenses and liabilities of the Trust, including Debt Service Charges, which are due or accrued and which are chargeable to income shall be deducted in computing Net Income of the Trust.

Items of income or expense not provided for above or in Section 5.3 shall be included in such calculation on such basis as may be considered appropriate by the Trustee upon the recommendation of the Corporation.

5.2 Net Income of the Trust to Become Payable

The Trustee may, upon the recommendation of the Corporation, on or before any Distribution Record Date, declare payable to the Unitholders on that Distribution Record Date all or any part of the Net Income of the Trust for the period ending on that Distribution Record Date determined in accordance with Section 5.1. The share of each Unitholder in the amount so payable shall be the Pro Rata Share of such Unitholder determined as at that Distribution Record Date; and subject to Section 5.7, such amount shall be payable on that Distribution Record Date. Notwithstanding the foregoing, the amount of any Net Income of the Trust that is determined by the Trustee to be required to be retained by the Trust in order to pay any tax liability of the Trust shall not be payable by the Trust to Unitholders.

5.3 Net Realized Capital Gains to Become Payable

The Trustee may, on or before any Distribution Record Date, declare payable to the Unitholders on that Distribution Record Date all or part of the net realized capital gains of the Trust to the extent not previously declared payable. The share of each Unitholder in the amount so payable shall be the Pro Rata Share of such Unitholder determined as at that Distribution Record Date; and subject to Section 5.7, such amount shall be payable on that Distribution Record Date. For the purposes of this Article 5, "net realized capital gains" of the Trust means the total of all capital gains realized by the Trust less the total of all capital losses realized by the Trust.

5.4 Net Income and Net Realized Capital Gains for Income Tax Purposes to Become Payable

On December 31 of each year, an amount equal to the Net Income of the Trust for such year (excluding net realized capital gains) determined in accordance with the Tax Act, other than paragraph 82(1)(b) thereof, to the extent not previously payable pursuant to Section 5.2 on any Distribution Record Date in the year (including December 31 of that fiscal year) to any Unitholder, shall be declared payable to Unitholders as at the end of that year. The share of each Unitholder in the amount so payable shall be the Pro Rata Share of such Unitholder determined as at the end of such year.

On December 31 of each fiscal year, an amount equal to the net realized capital gains of the Trust, to the extent not previously payable pursuant to Section 5.3 on any Distribution Record Date or pursuant to this paragraph on any prior December 31, shall be declared payable to Unitholders as at the end of that fiscal year. The share of each Unitholder in the amount so payable shall be the Pro Rata Share of such Unitholder determined as at the end of such year.

Any amounts payable pursuant to this Section 5.4 may, at the option of the Trustee, be paid through a distribution of additional Trust Units having a value equal to the amount payable. For the purposes of this Section 5.4, the value of the additional Trust Units issued shall be determined using the closing trading price (or, if there was no trade, the average of the last bid and the last ask prices) of the Trust Units on December 31 (or, if December 31 is not a Business Day, on the last preceding Business Day) on the principal stock exchange where the Trust Units are listed or, if no so listed, such other value as the Trustee shall determine.

5.5 Other Amounts

Any amounts not otherwise payable to Unitholders prior to the end of a particular fiscal year of the Trust pursuant to the provisions of Article 5 may be declared by the Trustee, upon the recommendation of the Corporation, to be payable to Unitholders in the same manner as provided for in Section 5.2.

5.6 Enforcement

Each Unitholder shall have the right to enforce payment of any amount payable to the Unitholder under this Article 5 (or a distribution of additional Trust Units under Section 5.8, if applicable) at the time the amount became payable unless a Payment Date is specified under Section 5.7 in respect of such amount payable, in which case the right to enforce payment shall arise at the later of the time the amount became payable and the applicable Payment Date specified under Section 5.7.

5.7 Payment of Amounts Payable

Amounts payable to Unitholders pursuant to Sections 5.2 and 5.3 may be paid by the Trust on any date (the "Payment Date") specified by the Trustee as the applicable Distribution Record Date, or a day within 30 days after the applicable Distribution Record Date and in the same calendar year.

5.8 Distribution of Additional Trust Units

Where after the last Distribution Record Date and on or before the next Distribution Record Date an amount or amounts of cash has or have been or is or are being paid under Section 18.3 in respect of Trust Units tendered for redemption, the distribution payable to Unitholders on such next Distribution Record Date shall include a distribution of additional Trust Units having a value equal to the aggregate of such amounts, in which case the amount of cash to be distributed on the distribution shall be reduced by the aggregate of such amounts. In addition, if on any Distribution Record Date the Trust does not have cash in an amount sufficient to pay the full distribution to be made on such Distribution Record Date in cash, the distribution payable to Unitholders on such Distribution Record Date may, at the option of the Trustee, include a distribution of additional Trust Units having a value equal to the cash shortfall, in which case the amount of cash to be distributed on the distribution shall be reduced by the amount of such cash shortfall. For the purposes of this Section 5.8, the value of the additional Trust Units to be issued shall be determined using the closing trading price (or if there was no trade, the average of the last bid and the last ask prices) of the Trust Units on the Distribution Record Date (or, if the Distribution Record Date is not a Business Day, on the last Business Day preceding the Distribution Record Date) on the principal stock exchange where the Trust Units are listed or, if not so listed, such other value as the Trustee shall determine.

5.9 Withholding Taxes

For greater certainty, in the event that withholding taxes are exigible on any distributions or redemption amounts distributed under this Indenture, the Trustee shall withhold the withholding taxes required and shall promptly remit such taxes to the appropriate taxing authority. In the event that withholding taxes are exigible on any distributions or redemption amounts distributed under this Indenture and the Trustee is, or was, unable to withhold taxes from a particular distribution to a Unitholder or has not otherwise withheld taxes on past distributions to the Unitholder, the Trustee shall be permitted to withhold amounts from other distributions to satisfy the Trustee's withholding tax obligations.

ARTICLE 6
APPOINTMENT, RESIGNATION AND REMOVAL OF TRUSTEE

6.1 Trustee's Term of Office

Subject to Sections 6.2 and 6.3, Valiant Trust Company is hereby appointed as Trustee hereunder for an initial term of office which shall expire upon the conclusion of the first annual meeting of Unitholders. The Unitholders shall, at the first annual meeting of the Unitholders, re-appoint, or appoint a successor to the Trustee, and thereafter, the Unitholders shall reappoint or appoint a successor to the Trustee on each successive annual meeting of Unitholders following the reappointment or appointment of the successor to the Trustee. Any such reappointment or appointment shall be made either by an Ordinary Resolution at such meeting of Unitholders or shall be made in the manner set out in Section 6.4. Notwithstanding the foregoing, if a Trustee is not reappointed at the meeting of Unitholders held immediately before the term of office of such Trustee expires and if no successor to such Trustee is appointed at that meeting, such Trustee shall continue to hold the office of Trustee under this Indenture until a successor has been appointed under Section 6.4.

6.2 Resignation of Trustee

The Trustee may resign from the office of trustee hereunder on giving not less than 60 days' notice in writing to the Corporation; provided that no such resignation shall be effective until (i) the appointment of, and acceptance of such appointment by, a new Trustee in the place of the resigning Trustee has been made in the manner set out in Section 6.4, and (ii) the legal and valid assumption by the new Trustee of all obligations of the Trustee related hereto in the same capacities as the resigning Trustee.

6.3 Removal of Trustee

The Trustee shall be removed by notice in writing delivered by the Corporation to the Trustee in the event that, at any time, the Trustee shall no longer satisfy all of the requirements in Section 6.6, or shall be declared bankrupt or insolvent, or shall enter into liquidation, whether compulsory or voluntary (and not being merely a voluntary liquidation for the purposes of amalgamation or reconstruction), or if the assets of the Trustee shall otherwise become liable to seizure or confiscation by any public or governmental authority, or if the Trustee shall otherwise become incapable of performing, or shall fail in any material respect to perform its responsibilities under this Indenture or as a result of a material increase in the fees charged by the Trustee. No decision to remove a Trustee under this Section 6.3 shall become effective until (i) approved by a Special Resolution at a meeting of Unitholders duly called for that purpose (ii) the appointment of, and acceptance of such appointment by, a new

Trustee under Section 6.4 in the place of the Trustee to be removed, and (iii) the legal and valid assumption by the new Trustee of all obligations of the Trustee related hereto in the same capacities as the resigning Trustee.

6.4 Appointment of Successor to Trustee

(a) A successor Trustee to a Trustee which has been removed by a Special Resolution of Unitholders under Section 6.3, shall be appointed by an Ordinary Resolution at a meeting of Unitholders duly called for that purpose, provided the successor meets the requirements of Section 6.6.

(b) Subject to Section 6.6, the Corporation may appoint a successor to any Trustee which has been removed by a Special Resolution of the Unitholders under Section 6.3, or which has not been reappointed under Section 6.1, if the Unitholders fail to do so at such meeting.

(c) Subject to Section 6.6, the Corporation may appoint a successor to any trustee which has given a notice of resignation under Section 6.2.

No appointment of any successor Trustee shall be effective until such successor Trustee shall have complied with the provisions of Section 6.2(ii).

6.5 Failure to Appoint Successor

In the event that no successor Trustee to a Trustee who has delivered a notice of resignation in accordance with Section 6.2, or who has received notice of removal in accordance with Section 6.3, has accepted an appointment within 120 days after the receipt by the Corporation of the notice of resignation, or 60 days after the receipt by the Trustee of the notice of removal, the Trustee, the Corporation or any Unitholder may apply to a court of competent jurisdiction for the appointment of a successor to the Trustee. The appointment of such successor by such court shall not require the approval of Unitholders.

6.6 Qualifications of Trustee

The Trustee and any successor to the Trustee or new Trustee appointed under this Article 6 shall be a corporation incorporated under the laws of Canada or of a province thereof and shall be a resident of Canada for the purposes of the Tax Act. Such corporation must at all times when it is the Trustee be registered under the laws of the Province of Alberta to carry on the business of a trust company and must have undertaken in writing to discharge all of the obligations and responsibilities of the Trustee under this Indenture.

ARTICLE 7
CONCERNING THE TRUSTEE

7.1 Powers of the Trustee and the Corporation

(a) Subject to the terms and conditions of this Indenture or other contracts or obligations of the Trustee or the Trust, the Trustee may exercise from time to time in respect of the Trust Fund any and all rights, powers and privileges that could be exercised by a beneficial owner thereof except as specifically designated in Subsection (b) below. The responsibilities of the Trustee hereunder are however limited to those specific powers granted to it (subject to delegations to the Corporation) and the Trustee has no obligations to Unitholders or to the Corporation beyond the obligations specifically set out herein.

(b) The Corporation shall exercise from time to time any and all rights, powers and privileges in relation to all matters relating to the maximization of Unitholder value in the context of a response to an offer for Trust Units or for all or substantially all of the property and assets of the Trust or the Corporation or any subsidiary of the Corporation or the Trust (an "Offer") including (i) any Unitholder rights protection plan either prior to or during the course of any Offer; (ii) any defensive action either prior to or during the course of any Offer; (iii) the preparation of any "Directors' Circular" in response to any Offer; (iv) consideration on behalf of Unitholders and recommendations to Unitholders in response to any Offer; (v) any regulatory or court action in respect of any related matters and (vi) the carriage of all related and ancillary matters; and the Corporation accepts such responsibility and agrees that, in respect of such matters, it shall carry out its functions honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. The Corporation may, and if directed by the Corporation in writing, the Trustee shall, execute any agreements on behalf of the Trust as the Corporation shall have authorized within the scope of the exercise of any such rights, powers or privileges.

7.2 Specific Powers and Authorities

Subject only to the express limitations contained in this Indenture or other contracts or obligations of the Trustee or the Trust, and in addition to any powers and authorities conferred by this Indenture (including, without limitation, Section 7.1 hereof) or which the Trustee may have by virtue of any present or future statute or rule of law, the Trustee, without any action or consent by the Unitholders, shall have the following powers and authorities which may be exercised by it from time to time or delegated by it, as herein provided, in its sole judgment and discretion and in such manner and upon such terms and conditions as it may from time to time deem proper, provided that the exercise of such powers and authorities does not adversely affect the status of the Trust as a "unit trust" and a "mutual fund trust" for the purposes of the Tax Act:

(a) to accept subscriptions for Trust Units received by the Trust and to issue Trust Units pursuant thereto;

(b) to maintain books and records;

(c) to provide timely reports to Unitholders in accordance with the provisions hereof;

(d) to effect payment of distributions to Unitholders;

(e) to apply for ARTC;

(f) to deposit funds of the Trust in interest-bearing accounts in banks, the Alberta Treasury Branch or trust companies whose short term obligations constitute Permitted Investments, including those of the Trustee, the same to be subject to withdrawal on such terms and in such manner and by such person or persons (including any one or more officers, agents or representatives) as the Trustee may determine;

(g) to, directly or indirectly, borrow money from or incur indebtedness to any person and in connection therewith, to guarantee, indemnify or act as a surety with respect to payment or performance of any indebtedness, liabilities or obligation of any kind of any person, including, without limitation, the Corporation and any subsidiary of the Trust (as defined in the *Securities Act* (Alberta)); to enter into any other obligations on behalf of the Trust; or enter into any subordination agreement on behalf of the Trust or any other person, and to assign, charge, pledge, hypothecate, convey, transfer, mortgage, subordinate, and grant any security interest, mortgage or encumbrance over or with respect to all or any of the Trust Fund or to subordinate the interests of the Trust in the Trust Fund to any other person;

(h) to possess and exercise all the rights, powers and privileges pertaining to the ownership of all or any part of the assets of the Trust, to the same extent that an individual might, unless otherwise limited herein, and, without limiting the generality of the foregoing, to vote or give any consent, request or notice, or waive any notice, either in person or by proxy or power of attorney, with or without power of substitution, to one or more persons, which proxies and power of attorney may be for meetings or action generally or for any particular meeting or action and may include the exercise of discretionary power;

(i) where reasonably required, to engage or employ any persons as agents, representatives, employees or independent contractors (including, without limitation, investment advisers, registrars, underwriters, accountants, lawyers, appraisers, brokers or otherwise) in one or more capacities;

(j) to collect, sue for and receive all sums of money coming due to the Trust, and to engage in, intervene in, prosecute, join, defend, compromise, abandon or adjust, by arbitration or otherwise, any actions, suits, proceedings, disputes, claims, demands or other litigation relating to the Trust, the assets of the Trust or the Trust's affairs, to enter into agreements therefor, whether or not any suit is commenced or claim accrued or asserted and, in advance of any controversy, to enter into agreements regarding the arbitration, adjudication or settlement thereof, provided that prior to taking any such action the Trustee may require from the Corporation a specific indemnity in relation thereto and funding with respect to the expenses or costs associated with such action. The Trustee shall in any event be reimbursed by the Corporation for all costs and expenses incurred in respect of the matters provided for in this Subsection;

(k) to arrange for insurance contracts and policies insuring the assets of the Trust against any and all risks and insuring the Trust and/or any or all of the Trustee or the Unitholders against any and all claims and liabilities of any nature asserted by any person arising by reason of any action alleged to have been taken or omitted by the Trust or by the Trustee or Unitholders;

(l) to cause legal title to any of the assets of the Trust to be held by and/or in the name of the Trustee, or except as prohibited by law, by and/or in the name of the Trust, or any other person, on such terms, in such manner, with such powers in such person as the Trustee may determine and with or without disclosure that the Trust or the Trustee is interested therein, provided that should legal title to any of the assets of the Trust be held by and/or in the name of any person other than the Trustee or the Trust, the Trustee shall require such person to execute a trust agreement acknowledging that legal title to such assets is held in trust for the benefit of the Trust;

(m) to make, execute, acknowledge and deliver any and all deeds, contracts, waivers, releases or other documents of transfer and any and all other instruments in writing necessary or proper for the accomplishment of any of the powers herein granted;

(n) to pay out of the Trust Fund the Trust Expenses;

(o) except as prohibited by law, to delegate any or all of the management and administrative powers and duties of the Trustee to the Corporation or to any one or more agents, representatives, officers, employees, independent contractors or other persons without liability to the Trustee except as provided in this Indenture;

(p) to guarantee the obligations of the Corporation or any other Affiliate of the Trust pursuant to any debt for borrowed money or obligations resulting or arising from hedging instruments incurred by the Corporation or any such Affiliate, as the case may be, and pledging securities issued by the Corporation or the Affiliate, as the case may be, as security for such guarantee provided that such guarantee is incidental to the Trust's direct or indirect investment in the Corporation or any such Affiliate or the business and affairs (existing or proposed) of the Corporation or any such Affiliate, and each such guarantee entered into by the Trustee shall be binding upon, and enforceable in accordance with its terms against, the Trust;

(q) notwithstanding any limitations contained in this Indenture or any other contracts or obligations of the Trustee or the Trust and the introductory proviso to this Section 7.2, to enter into on behalf of the Trust and observe and perform its obligations and the obligations of the Trust under any agreements with any Lender, including, without limitation, compliance with any provisions thereof which may restrict the powers of the Trustee hereunder or preclude the Trustee from acting in certain circumstances on resolutions of the Unitholders as might otherwise be provided for hereunder, and each such agreement entered into by the Trustee shall be binding upon, and enforceable in accordance with its terms against, the Trust;

(r) to enter into a subordination agreement with any Lender to the Corporation or any Affiliate of the Trust pursuant to which the Trust agrees to subordinate its right to receive income (or any other obligations of the Corporation or any Affiliate to the Trust) to the right of any such Lender to be paid obligations owing to it by the Corporation or any Affiliate of the Trust, and which agreement may further provide, without limitation, that in the event of a default by the Corporation or any such Affiliate to any of its Lenders, including any such default in connection with credit or debt facilities, swap or hedging agreements or any other ancillary facilities, none of the Corporation or any such Affiliate will make any further payments in respect of such obligations to the Trust and the Trust will not make any further cash distributions to Unitholders, and each such subordination entered into by the Trustee shall be binding upon, and enforceable in accordance with its terms against, the Trust;

(s) to do all such other acts and things as are incidental to this Section 7.2, and to exercise all powers which are necessary or useful to carry on the business of the Trust, to promote any of the purposes for which the Trust is formed and to carry out the provisions of this Indenture;

(t) to use reasonable efforts to ensure that the Trust complies at all times with the requirements of Subsections 108(2) and 132(6) of the Tax Act;

(u) to advance any amount to the Corporation or other Affiliate of the Trust as a loan, including amounts in the Capital Fund which shall be advanced to the Corporation to finance future acquisition and development of the Properties;

(v) to enter into, perform and enforce the Material Contracts;

(w) without limiting any of the provisions hereof, to pay out of the Trust Fund:

(i) Agent's Fees;

(ii) the purchase price of the NPI and the Direct Royalties, the Deferred Purchase Price Obligations and amounts in respect of Permitted Investments and Subsequent Investments; and

(iii) Issue Expenses;

all as contemplated by the Offering Documents, this Indenture, the NPI Agreement or the other Material Contracts;

(x) to charge, mortgage, hypothecate and/or pledge on behalf of the Trust all or any of the currently owned or subsequently acquired monies, properties and assets comprising the Trust Fund to secure any monies borrowed, and to execute and deliver a guarantee or other assurance in favour of any Lender for the obligations of the Corporation or any Affiliate of the Trust or the Corporation and any security, deposit or offset agreements or arrangements in respect of any such guarantee or assurance and each such agreement entered into by the Trustee shall be binding upon, and enforceable in accordance with its terms against, the Trust;

(y) to convey the NPI and/or the Direct Royalties in connection with any security to or realization by any Lender upon the Properties;

(z) to form any subsidiary of the Trust for the purpose of making any Subsequent Investment and entering into or amending any unanimous shareholders agreement or other agreement on such terms as may be approved by the board of directors of the Corporation;

(aa) to provide indemnities for the directors and officers of any Affiliates;

(bb) to hold the Notes issued by the Corporation;

(cc) to distribute Notes as provided in Article 18;

(dd) to vote Subsequent Investments held by the Trust which carry voting rights in such manner as may be approved by the board of directors of the Corporation; and (ee) without limit as to amount, cost, or conditions of reimbursement, to issue any type of debt securities or convertible debt securities and to borrow money or incur any other form of indebtedness for the purpose of carrying out the purposes of the Trust or for other expenses incurred in connection with the Trust and for such purposes may draw, make, execute and issue promissory notes and other negotiable and non-negotiable instruments or securities and evidences of indebtedness, secure the payment of sums so borrowed or indebtedness incurred and mortgage, pledge, assign or grant a security interest in any money owing to the Trust or engage in any other means of financing the Trust.

7.3 Restrictions on the Trustee's Powers

Notwithstanding anything contained in this Indenture:

(a) the Trustee shall not vote the Shares with respect to the election of directors of the Corporation, the appointment of auditors of the Corporation, or the approval of the Corporation's financial statements except in accordance with an Ordinary Resolution adopted at an annual meeting of Unitholders;

(b) the Trustee shall not, after the Date of Closing, vote the Shares to authorize:

(i) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets of the Corporation, except in conjunction with an internal reorganization of the direct or indirect assets of the Corporation as a result of which either the Corporation or the Trust has the same, or substantially similar, interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(ii) any statutory amalgamation of the Corporation with any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (i) above;

(iii) any statutory arrangement involving the Corporation except in conjunction with ain internal reorganization as referred to in paragraph (i) above;

(iv) any amendment to the articles of the Corporation to increase or decrease the minimum or maximum number of directors; or

(v) any material amendment to the articles of the Corporation to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of the Corporation 's Shares in a manner which may be prejudicial to the Trust;

without the approval of the Unitholders by Special Resolution at a meeting of Unitholders called for that purpose.

7.4 Banking

The banking activities of the Trust, or any part thereof, shall be transacted with such financial institution (including the Trustee or an Affiliate thereof) or other person carrying on a financial services business as the Trustee may designate, appoint or authorize from time to time and all such financial services business, or any part thereof, shall be transacted on the Trust's behalf by such one or more officers of the Trustee and/or other persons as the Trustee may designate, appoint or authorize from time to time (who may be officers or employees of the Corporation) including, but without restricting the generality of the foregoing, the operation of the Trust's accounts; the making, signing, drawing, accepting, endorsing, negotiating, lodging, depositing or transferring of any cheques, promissory notes, drafts, bankers' acceptances, bills of exchange, letters of credit and orders for the payment of money; the giving of receipts for and orders relating to any property of the Trust; the execution of any agreement relating to any property of the Trust; the execution of any agreement relating to any such financial services business and defining the rights and powers of the parties hereto; and the authorizing of any officer of such financial institution, or any trustee or agent thereof to do any act or thing on the Trust's behalf to facilitate such banking business.

7.5 Standard of Care

Except as otherwise provided herein, the Trustee shall exercise its powers and carry out its functions hereunder as Trustee honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances, subject to compliance by the Trustee with any agreements contemplated hereby which may be binding on the Trustee or the Trust. Unless otherwise required by law, the Trustee shall not be required to give bond, surety or security in any jurisdiction for the performance of any duties or obligations hereunder. The Trustee, in its capacity as trustee, shall not be required to devote its entire time to the business and affairs of the Trust.

7.6 Fees and Expenses

The Trustee shall be paid by the Corporation such fees as may be agreed upon from time to time by the Corporation and the Trustee and if such fees are not paid by the Corporation within 30 days after the date of any invoice in respect thereof, the Trustee shall be entitled to have such fees paid out of the Trust Fund. As part of the Trust Expenses, the Trustee may pay or cause to be paid reasonable fees, costs and expenses incurred in connection with the administration and management of the Trust, including (without limitation) fees of auditors, lawyers, appraisers and other agents, consultants and professional advisers employed by or on behalf of the Trust and the cost of reporting or giving notices to Unitholders. All costs, charges and expenses (including any amounts payable to the Trustee under Section 7.8 or 7.9) properly incurred by the Trustee on behalf of the Trust shall be payable by the Corporation, and if any such costs, charges and expenses are not paid by the Corporation within 30 days after the date of any invoice in respect thereof, the Trustee shall be entitled to have such costs, charges and expenses paid out of the Trust Fund. The Trustee shall have a lien on the Trust Fund (which shall have priority over the interests of the Unitholders pursuant hereto) to enforce payment of the fees, costs, expenses and other amounts payable or reimbursable by the Trust to the Trustee.

7.7 Limitations on Liability of Trustee

The Trustee, its directors, officers, employees, shareholders and agents shall not be liable to any Unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the Trust Fund, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under this Indenture, including, without limitation, any action taken or not taken in good faith in reliance on any documents that are, *prima facie*, properly executed, any depreciation of, or loss to, the Trust Fund incurred by reason of the sale of any asset, any inaccuracy in any evaluation provided by any appropriately qualified person, any reliance on any such evaluation, any action or failure to act of the Corporation, or any other person to whom the Trustee has, with the consent of the Corporation, delegated any of its duties hereunder, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by the Corporation to perform its duties under or delegated to it under this Indenture or any other contract), unless such liabilities arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees, shareholders, or agents. If the Trustee has retained an appropriate expert or adviser or Counsel with respect to any matter connected with its duties under this Indenture or any other contract, the Trustee may act or refuse to act based on the advice of such expert, adviser or Counsel, and the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or Counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under this Indenture, the Trustee is and shall be conclusively deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the Trust Fund.

7.8 Indemnification of Trustee

The Trust (to the extent of the Trust Fund) is liable to, and shall indemnify and save harmless the Trustee and each of its directors, officers, employees, shareholders and agents in respect of:

(a) any liability and all costs, charges and expenses sustained or incurred in respect of any action, suit or proceeding that is proposed or commenced against the Trustee or against such directors, officers, employees, shareholders or agents, as the case may be, for or in respect of any act, omission or error in respect of the Trust and the Trustee's execution of all duties and responsibilities and exercise of all powers and authorities pertaining thereto; and

(b) all other costs, charges, taxes, penalties and interest in respect of unpaid taxes; and

(c) all other expenses and liabilities sustained or incurred by the Trustee in respect of the administration or termination of the Trust;

unless any of the foregoing arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees, shareholders or agents, in which case the provisions of this Section 7.8 shall not apply.

7.9 Environmental Indemnity

The Trust (to the extent of the Trust Fund) is liable to, and shall indemnify and save harmless, the Trustee, its directors, officers, employees, shareholders and agents, and all of their successors and assigns (collectively, the "Indemnified Parties") against any loss, expense, claim, charge, damage, penalty, liability or asserted liability (including strict liability and costs and expenses of abatement and remediation of spills or releases of contaminants and liabilities of the Indemnified Parties to third parties, including governmental agencies, in respect of bodily injuries, property damage, damage to or impairment of the environment or any other injury or damage and including liabilities of the Indemnified Parties to third parties for the third parties' foreseeable and unforeseeable consequential damages) incurred as a result of:

(a) the administration of the Trust created hereby, or

(b) the exercise by the Trustee of any rights or obligations hereunder,

and which result from or relate, directly or indirectly, to

(c) the presence or release or threatened presence or release of any contaminants, by any means or for any reason, on or in respect of the Properties, whether or not such presence or release or threatened presence or release of the contaminants was under the control, care or management of the Trust or the Corporation, or of a previous owner or operator of a Property,

(d) any contaminant present on or released from any property adjacent to or in the proximate area of the Properties,

(e) the breach or alleged breach of any federal, provincial or municipal environmental law, regulation, bylaw, order, rule or permit by the Trust or the Corporation or an owner or operator of a Property, or

(f) any misrepresentation or omission of a known fact or condition made by the Corporation relating to any Property.

For the purpose of this Section 7.9, "liability" shall include: (i) liability of an Indemnified Party for costs and expenses of abatement and remediation of spills and releases of contaminants; (ii) liability of an Indemnified Party to a third party to reimburse the third party for bodily injuries, property damage and other injuries or damages which the third party suffers, including (to the extent, if any, that the Indemnified Party is liable therefor) foreseeable and unforeseeable consequential damages suffered by the third party; and (iii) liability of the Indemnified Party for damage to or impairment of the environment.

Notwithstanding the foregoing, the Trust shall not be liable to indemnify an Indemnified Party against any loss, expense, claim, liability or asserted liability to the extent resulting from the gross negligence, wilful default or fraud of the Indemnified Party.

7.10 Apparent Authority

No purchaser, transfer agent or other person dealing with the Trustee or with any officer, employee or agent of the Trustee shall be bound to make any inquiry concerning the validity of any transaction purporting to be made by the Trustee or by such officer, employee or agent or make inquiry concerning, or be liable for, the application of money or property paid, lent or delivered to or on the order of the Trustee or of such officer, employee or agent. Any person dealing with the Trustee in respect of any matter pertaining to the Trust Fund and any right, title or interest therein shall be entitled to rely on a certificate, statutory declaration or resolution executed or certified on behalf of the Trustee as to the capacity, power and authority of any officer, employee or any other person to act for and on behalf and in the name of the Trust.

7.11 Notice to Unitholders of Non-Eligibility for Deferred Income Plans

If the Trustee becomes aware that the Trust Units have ceased to be eligible investments for registered retirement savings plans, registered retirement income funds, registered education savings plans and deferred profit sharing plans (all within the meaning of the Tax Act) or any of such plans, the Corporation shall give notice to Unitholders at their latest address as shown on the register of Unitholders that Trust Units have ceased to be eligible investments for such plans. Notwithstanding the foregoing, the Trustee and the Corporation shall not be liable to the Trust or to any Unitholder for any costs, expenses, charges, penalties or taxes imposed upon a Unitholder as a result of or by virtue of a Trust Unit not being an eligible investment for any such plan, notwithstanding any failure or omission of the Corporation to have given such notice, provided the Trustee has complied with Section 7.5.

7.12 Declaration as to Beneficial Ownership

The Trustee may require any Unitholder, as shown on the register of Unitholders, to provide a declaration in a form prescribed by the Corporation as to the beneficial ownership of Trust Units registered in such Unitholder's name and as to the jurisdiction in which such beneficial owners are resident.

7.13 Conditions Precedent to Trustee's Obligations to Act

The obligation of the Trustee to call any meeting pursuant to Article 10 or to commence to wind up the affairs of the Trust pursuant to Article 12 shall be conditional upon the Unitholders or another person furnishing, when required by notice in writing by the Trustee, sufficient funds to commence or continue such act, action or proceeding and indemnity (to the extent sufficient funds for such purpose are not available in the Trust Fund) reasonably satisfactory to the Trustee to protect and hold harmless the Trustee against the costs, charges and expenses and liabilities to be incurred therein and any loss and damage it may suffer by reason thereof and the obligation of the Trustee to commence or continue any act, action or proceeding for the purpose of enforcing the rights of the Trustee and of the Unitholders shall, if required by notice in writing by the Trustee, be subject to the same conditions as to funding and indemnity. None of the provisions contained in this Indenture shall require the Trustee to expend or risk its own funds or otherwise incur financial liability in the performance of any of its duties or in the exercise of any of its rights or powers unless indemnified as aforesaid.

7.14 Survival of Indemnities

All indemnities, all limitations of liability and all other provisions for the protection of the Trustee provided for in this Trust Indenture shall survive the termination of this Indenture under Article 12 and the removal or resignation of the Trustee under Article 6.

7.15 Trustee May Have Other Interests

Subject to applicable securities laws, and without affecting or limiting the duties and responsibilities or the limitations and indemnities provided in this Indenture, the Trustee is hereby expressly permitted to

(a) be an Associate or an Affiliate of a person from or to whom assets of the Trust have been or are to be purchased or sold;

(b) be, or be an Associate or an Affiliate of, a person with whom the Trust or the Corporation contracts or deals or which supplies services to the Trust or the Corporation;

(c) acquire, hold and dispose of, either for its own account or the accounts of its customers, any assets not constituting part of the Trust Fund, even if such assets are of a character which could be held by the Trust, and exercise all rights of an owner of such assets as if it were not a trustee;

(d) carry on its business as a trust company in the usual course while it is the Trustee, including the rendering of trustee or other services to other trusts and other persons for gain; and

(e) derive direct or indirect benefit, profit or advantage from time to time as a result of dealing with the Trust or the relationships, matters, contracts, transactions, affiliations or other interests stated in this Section 7.15 without being liable to the Trust or any Unitholder for any such direct or indirect benefit, profit or advantage.

Subject to applicable laws, none of the relationships, matters, contracts, transactions, affiliations or other interests permitted above shall be, or shall be deemed to be or to create, a material conflict of interest with the Trustee's duties hereunder.

7.16 Documents Held by Trustee

Any securities, documents of title or other instruments that may at any time be held by the Trustee subject to the trusts hereof may be placed in the deposit vaults of the Trustee or of any chartered bank in Canada, including an Affiliate of the Trustee, or deposited for safekeeping with any such bank.

ARTICLE 8
DELEGATION OF POWERS

8.1 The Corporation

Except as expressly prohibited by law, the Trustee may grant or delegate to the Corporation such authority as the Trustee may in its sole discretion deem necessary or desirable to effect the actual administration of the duties of the Trustee under this Indenture, without regard to whether such authority is normally granted or delegated by trustees. The Trustee may grant broad discretion to the Corporation to administer and manage the day-to-day operations of the Trust Fund, to act as agent for the Trust Fund, to execute documents on behalf of the Trust Fund and to make executive decisions which conform to general policies and general principles set forth herein or previously established by the Trustee. The Corporation shall have the powers and duties expressly provided for herein and in any other agreement providing for the management or administration of the Trust including, without limitation, the power to retain and instruct such appropriate experts or advisors to perform those duties and obligations herein which it is not qualified to perform (and the Corporation shall notify the Trustee of the name of the person or persons retained or instructed and the terms and conditions thereof).

8.2 Offerings

The Trustee hereby delegates to the Corporation responsibility for any and all matters relating to an Offering including (i) ensuring compliance with all applicable laws, (ii) all matters relating to the content of any Offering Documents, the accuracy of the disclosure contained therein, and the certification thereof, (iii) all matters concerning the terms of the Material Contracts, and (iv) all matters concerning any Underwriting Agreement providing for the sale of Trust Units or rights to Trust Units. The Corporation accepts such delegation and agrees that, in respect of such matters, it shall carry out its functions honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. The Corporation may, and if directed by the Corporation in writing the Trustee shall, execute any agreements on behalf of the Trust as the Corporation shall have authorized within the scope of any authority delegated to it hereunder.

8.3 Power of Attorney

Without limiting any of the other provisions of this Article 8, the Trustee hereby delegates to the Corporation from time to time the full power and authority, and constitutes the Corporation its true and lawful attorney in fact, to sign on behalf of the Trust all rights plans, prospectuses, annual information forms, management proxy circulars, other Offering Documents and any other documents ancillary or similar thereto required to be signed by the Trust from time to time, including any Agency Agreements, indemnity agreements (pursuant to which the Trust and not the Trustee provides indemnities) or documents ancillary or similar thereto.

8.4 Liability of Trustee

The Trustee shall have no liability or responsibility for any matters delegated to the Corporation hereunder or under any of the Material Contracts, and the Trustee, in relying upon the Corporation and in entering into the Material Contracts, shall be deemed to have complied with its obligations under Section 7.5 and shall be entitled to the benefit of the indemnities, limitations of liability and other protection provisions provided for herein.

ARTICLE 9
AMENDMENT

9.1 Amendment

Except as specifically provided otherwise herein, the provisions of this Indenture and the Administration Agreement, may only be amended by the Trustee with the consent of the Unitholders by Special Resolution.

Any of the provisions of this Indenture may be amended by the Trustee at any time or times, without the consent, approval or ratification of any of the Unitholders or any other person for the purpose of:

(a) ensuring that the Trust will comply with any applicable laws or requirements of any governmental agency or authority of Canada or of any province;

(b) ensuring that the Trust will satisfy the provisions of each of subsections 108(2) and 132(6) of the Tax Act as from time to time amended or replaced;

(c) ensuring that such additional protection is provided for the interests of Unitholders as the Trustee may consider expedient;

(d) removing or curing any conflicts or inconsistencies between the provisions of this Indenture or any supplemental indenture, any Direct Royalties Sale Agreement and any other agreement of the Trust or any Offering Document with respect to the Trust, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of the Unitholders are not prejudiced thereby;

(e) providing for the electronic delivery by the Trust to Unitholders of documents relating to the Trust (including annual and quarterly reports, including financial statements, notices of Unitholder meetings and information circulars and proxy related materials) once applicable securities laws have been amended to permit such electronic delivery in place of normal delivery procedures, provided that such amendments to the Trust Indenture are not contrary to or do not conflict with such laws;

(f) curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee the rights of the Trustee and of the Unitholders are not prejudiced thereby; and

(g) making any modification in the form of Trust Unit Certificates to conform with the provisions of this Indenture, or any other modifications, provided the rights of the Trustee and of the Unitholders are not prejudiced thereby.

Notwithstanding the foregoing, no amendment shall reduce the percentage of votes required to be cast at a meeting of the Unitholders for the purpose of amending this Section 9.1 without the consent of the holders of all of the Trust Units then outstanding.

ARTICLE 10
MEETINGS OF UNITHOLDERS

10.1 Annual and Special Meetings of Unitholders

Annual meetings of the Unitholders shall be called by the Trustee, commencing in 2003, on a day, at a time and at a place to be set by the Corporation. The business transacted at such meetings shall include the transaction of such business as Unitholders may be entitled to vote upon as hereinafter provided in this Article 10, or as the Corporation may determine. Special meetings of the Unitholders may be called at any time by the Corporation and shall be called by the Corporation upon a written request of Unitholders holding in the aggregate not less than 20% of the Trust Units then outstanding, such request specifying the purpose or purposes for which such meeting is to be called. Meetings of Unitholders shall be held in the City of Calgary, or at such other place as the Corporation shall designate. The Chairman of any annual or special meeting shall be a person designated by the Corporation for the purpose of such meeting except that, on the motion of any Unitholder, any person may be elected as Chairman by a majority of the votes cast at the meeting instead of such designated person or in the event that no person shall be designated by the Corporation.

10.2 Notice of Meetings

Notice of all meetings of Unitholders shall be given by unregistered mail postage prepaid addressed to each Unitholder at his registered address, mailed at least 21 days and not more than 50 days before the meeting. Such notice shall set out the time when, and the place where, such meeting is to be held and shall specify the nature of the business to be transacted at such meeting in sufficient detail to permit a Unitholder to form a reasoned judgment thereon, together with the text of any resolution in substantially final form proposed to be passed. Any adjourned meeting may be held as adjourned without further notice. The accidental omission to give notice to or the non-receipt of such notice by the Unitholders shall not invalidate any resolution passed at any such meeting.

10.3 Quorum

At any meeting of the Unitholders, subject as hereinafter provided, a quorum shall consist of two or more persons either present in person or represented by proxy and representing in the aggregate not less than 5% of the outstanding Trust Units. If a quorum is not present at the appointed place on the date for which the meeting is called within one half hour after the time fixed for the holding of such meeting, the meeting, if convened on the requisition of Unitholders, shall be dissolved, but in any other case it shall stand adjourned to such day being not less than fourteen (14) days later and to such place and time as may be appointed by the Chairman of the meeting. If at such adjourned meeting a quorum as above defined is not present, the Unitholders present either personally or by proxy shall form a quorum, and any business may be brought before or dealt with at such an adjourned meeting which might have been brought before or dealt with at the original meeting in accordance with the notice calling the same.

10.4 Voting Rights of Unitholders

Only Unitholders of record shall be entitled to vote and each Trust Unit shall entitle the holder or holders of that Trust Unit to one vote at any meeting of the Unitholders. Every question submitted to a meeting, other than a Special Resolution, shall, unless a poll vote is demanded, be decided by a show of hands vote, on which every person present and entitled to vote shall be entitled to one vote. At any meeting of Unitholders, any holder of Trust Units entitled to vote thereat may vote by proxy and a proxy need not be a Unitholder, provided that no proxy shall be voted at any meeting unless it shall have been placed on file with the Trustee, or with such agent of the Trustee as the Trustee may direct, for verification prior to the commencement of such meeting no later than the time for which proxies are to have been received as set forth in the notice of such meeting. If approved by the Trustee, proxies may be solicited in the name of the Trustee. When any Trust Unit is held jointly by several persons, any one of them may vote at any meeting in person or by proxy in respect of such Trust Unit, but if more than one of them shall be present at such meeting in person or by proxy, and such joint owners of their proxies so present disagree as to any vote to be cast, the joint owner present or represented whose name appears first in the register maintained pursuant to Section 11.3 shall be entitled to cast such vote.

10.5 Resolutions

(a) The Trustee shall in accordance with an Ordinary Resolution passed by the Unitholders: (i) change the Auditors as provided in Section 15.3; and (ii) elect the directors of the Corporation.

(b) The Trustee shall in accordance with a Special Resolution passed by the Unitholders:

(i) subject to Section 9.1, amend this Indenture;

(ii) subdivide or consolidate Trust Units;

(iii) sell or agree to sell the property of the Trust Fund as an entirety or substantially as an entirety;

(iv) resign if removed pursuant to Section 6.3; and

(v) commence to wind-up and wind-up the affairs of the Trust if requested pursuant to Section 12.2.

Except with respect to the above matters set out in this Section 10.5 and the matters set forth in Sections 6.3, 6.4 and 12.2 hereof, no action taken by the Unitholders or resolution of the Unitholders at any meeting shall in any way bind the Trustee.

10.6 Meaning of "Special Resolution"

The expression "Special Resolution" when used in this Indenture means, subject as hereinafter in this Article provided, a resolution proposed to be passed as a special resolution at a meeting of Unitholders (including an adjourned meeting) duly convened for the purpose and held in accordance with the provisions of this Article at which two or more holders of at least 10% of the aggregate number of Trust Units then outstanding are present in person or by proxy and passed by the affirmative votes of the holders of not less than 66 2/3% of the Trust Units represented at the meeting and voted on a poll upon such resolution.

If, at any such meeting, the holders of 10% of the aggregate number of Trust Units outstanding are not present in person or represented by proxy within 30 minutes after the time appointed for the meeting, then the meeting, if convened by or on the requisition of Unitholders, shall be dissolved; but in any other case it shall stand adjourned to such date, being not less than 21 nor more than 60 days later, and to such place and time as may be appointed by the chairman. Not less than ten days' prior notice shall be given of the time and place of such adjourned meeting in the manner provided in Section 10.2. Such notice shall state that at the adjourned meeting the Unitholders present in person or represented by proxy shall form a quorum but it shall not be necessary to set forth the purposes for which the meeting was originally called or any other particulars. At the adjourned meeting, the Unitholders present in person or represented by proxy shall form a quorum and may transact the business for which the meeting was originally convened, and a resolution proposed at such adjourned meeting and passed by the requisite vote as provided in this Section 10.6 shall be a Special Resolution within the meaning of this Indenture, notwithstanding that the holders of less than 10% of the aggregate number of Units then outstanding are present or represented by proxy at such adjourned meeting.

Votes on a Special Resolution shall always be given on a poll and no demand for a poll on a Special Resolution shall be necessary. No Special Resolution changing or amending any provision hereof relating to or affecting: (i) the Trustee, including the qualification, powers, authorities, appointment, removal or resignation thereof; or (ii) the provisions of Articles 9, 10 or 12 shall be effective prior to 60 days from the adoption thereof in accordance with the provisions hereof or such shorter period as may be approved by Unitholders.

10.7 Record Date for Voting

For the purpose of determining the Unitholders who are entitled to vote or act at any meeting or any adjournment thereof, the Trustee may fix a date not more than 50 days and not less than 21 days prior to the date of any meeting of Unitholders as a record date for the determination of Unitholders entitled to vote at such meeting or any adjournment thereof, and any Unitholder who was a Unitholder at the time so fixed shall be entitled to vote at such meeting or any adjournment thereof even though he has since that time disposed of his Trust Units, and no Unitholder becoming such after that time shall be so entitled to vote at such meeting or any adjournment thereof. In the event that the Trustee does not fix a record date for any meeting of Unitholders, the record date for such meeting shall be the Business Day immediately preceding the date upon which notice of the meeting is given as provided under Section 10.2.

10.8 Binding Effect of Resolutions

Every Ordinary Resolution and every Special Resolution passed in accordance with the provisions of this Indenture at a meeting of Unitholders shall be binding upon all the Unitholders, whether present at or absent from such meeting, and each and every Unitholder shall be bound to give effect accordingly to every such Ordinary Resolution and Special Resolution.

10.9 Solicitation of Proxies

A Unitholder shall have the right to appoint a proxy to attend and act for the Unitholder at any meeting of Unitholders. The Trustee shall solicit proxies from Unitholders in connection with all meetings of Unitholders. In connection therewith, the Trustee shall comply, as near as may be possible, with all provisions of the *Business Corporations Act* (Alberta) and the requirements of Canadian securities legislation applicable to the solicitation of proxies.

10.10 No Breach

Notwithstanding any provisions of this Indenture, Unitholders shall have no power to effect any amendment hereto which would require the Trustee to take any action or conduct the affairs of the Trust in a manner which would constitute a breach or default by the Trust or the Trustee under any agreement binding on or obligation of the Trust or the Trustee.

ARTICLE 11
CERTIFICATES, REGISTRATION AND TRANSFER OF TRUST UNITS

11.1 Nature of Trust Units

The nature of a Trust Unit and the relationship of a Unitholder to the Trustee and the relationship of one Unitholder to another is as described in Sections 2.4 and Subsection 2.5(c) and the provisions of this Article 11 shall not in any way alter the nature of Trust Units or the said relationships of a Unitholder to the Trustee and of one Unitholder to another, but are intended only to facilitate the issuance of certificates evidencing the beneficial ownership of Trust Units and the recording of all such transactions whether by the Trust, securities dealers, stock exchanges, transfer agents, registrars or other persons.

11.2 Certificates

(a) The form of certificate representing Trust Units shall be substantially as set out in the Schedule hereto or such other form as is authorized from time to time by the Trustee. Each such certificate shall bear an identifying serial number and shall be certified manually on behalf of the Trustee. Any additional signature required by the Trustee to appear on such certificate may be printed, lithographed or otherwise mechanically reproduced thereon and, in such event, certificates so signed are as valid as if it had been signed manually. Any certificate which has one manual signature as hereinbefore provided shall be valid notwithstanding that one or more of the persons whose signature is printed, lithographed or mechanically reproduced no longer holds office at the date of issuance of such certificate. The Trust Certificates may be engraved, printed or lithographed, or partly in one form and partly in another, as the Trustee may determine.

(b) Any Trust Unit Certificate validly issued prior to the date hereof in accordance with the terms of this Indenture in effect at such time shall validly represent issued and outstanding Trust Units, notwithstanding that the form of such Trust Unit Certificate may not be in the form currently required by this Indenture.

11.3 Register of Unitholders

A register shall be maintained at the principal corporate trust office of the Trustee in the City of Calgary by the Trustee or by a Transfer Agent designated to act on behalf and under the direction of the Trustee, which register shall contain the names and addresses of the Unitholders, the respective numbers of Trust Units held by them, the certificate numbers of the certificates representing such Trust Units and a record of all transfers thereof. Branch transfer registers shall be maintained at such other offices of the Trustee or Transfer Agent as the Trustee may from time to time designate. The Trustee shall designate an office in the City of Toronto at which a branch register shall be maintained. Except in the case of the registers required to be maintained at the Cities of Calgary and Toronto, the Trustee shall have the power at any time to close any register of transfers and in that event shall transfer the records thereof to another existing register or to a new register.

Only Unitholders whose certificates are so recorded shall be entitled to receive distributions or to exercise or enjoy the rights of Unitholders hereunder. The Trustee shall have the right to treat the person registered as a Unitholder on the register of the Trust as the owner of such Trust Units for all purposes, including, without limitation, payment of any distribution, giving notice to Unitholders and determining the right to attend and vote at meetings of Unitholders, and the Trustee shall not be bound to recognize any transfer, pledge or other disposition of a Trust Unit or any attempt to transfer, pledge or dispose of a Trust Unit, or any beneficial interest or equitable or other right or claim with respect thereto, whether or not the Trustee shall have actual or other notice thereof, until such Trust Unit shall have been transferred on the register of the Trust as herein provided.

The register and the branch transfer register referred to in this Section 11.3 shall at all reasonable times be open for inspection by the Unitholders, the Corporation and the Trustee.

11.4 Transfer of Trust Units

(a) Subject to the provisions of this Article 11, the Trust Units shall be fully transferable without charge as between persons, but no transfer of Trust Units shall be effective as against the Trustee or shall be in any way binding upon the Trustee until the transfer has been recorded on the register or one of the branch transfer registers maintained by the Trustee or Transfer Agent. No transfer of a Trust Unit shall be recognized unless such transfer is of a whole Trust Unit.

(b) Subject to the provisions of this Article 11, Trust Units shall be transferable on the register or one of the branch transfer registers of Unitholders of the Trust only by the Unitholders of record thereof or their executors, administrators or other legal representatives or by their agents hereunto duly authorized in writing, and only upon delivery to the Trustee or to the Transfer Agent of the Trust if appointed, of the certificate therefor, if certificates representing Trust Units are issued, properly endorsed or accompanied by a duly executed instrument of transfer and accompanied by all necessary transfer or other taxes imposed by law, together with such evidence of the genuineness of such endorsement, execution and authorization and other matters that may reasonably be required by the Trustee. Upon such delivery the transfer shall be recorded on the register of Unitholders and a new Trust Certificate for the residue thereof (if any) shall be issued to the transferor. Unless the Corporation agrees to assume liability for the transfer and exchange fees the Unitholder shall be responsible for such fees and expenses.

(c) Any person becoming entitled to any Trust Units as a consequence of the death, bankruptcy or incompetence of any Unitholder or otherwise by operation of law, shall be recorded as the holder of such Trust Units and shall receive a new Trust Certificate therefor only upon production of evidence satisfactory to the Trustee thereof and delivery of the existing Trust Certificate to the Trustee, but until such record is made the Unitholder of record shall continue to be and be deemed to be the holder of such Trust Units for all purposes whether or not the Trustee shall have actual or other notice of such death or other event.

11.5 Trust Units Held Jointly or in a Fiduciary Capacity

The Trustee may treat two or more persons holding any Trust Units as joint owners of the entire interest therein unless their ownership is expressly otherwise recorded on the register of the Trust, but no entry shall be made in the register or on any Trust Certificate that any person is in any other manner entitled to any future, limited or contingent interest in any Trust Units; provided, however, that any person recorded as a Unitholder may, subject to the provisions hereinafter contained, be described in the register or on any Trust Certificate as a fiduciary of any kind and any customary words may be added to the description of the holder to identify the nature of such fiduciary relationship. Where any Trust Certificate is registered in more than one name, the distributions (if any) in respect thereof may be paid to the order of all such holders failing written instructions from them to the contrary and such payment shall be a valid discharge to the Trustee and any Transfer Agent. In the case of the death of one or more joint holders, the distributions (if any) in respect of any Trust Units may be paid to the survivor or survivors of such holders and such payment shall be a valid discharge to the Trustee and any Transfer Agent.

11.6 Performance of Trust

The Trustee, the Unitholders and any officer or agent of the Trustee shall not be bound to be responsible for or otherwise inquire into or ensure the performance of any trust, express, implied or constructive, or of any charge, pledge or equity to which any of the Trust Units or any interest therein are or may be subject, or to ascertain or enquire whether any transfer of any such Trust Units or interests therein by any such Unitholder or by his personal representatives is authorized by such trust, charge, pledge or equity, or to recognize any person as having any interest therein except for the person recorded as Unitholder.

11.7 Lost Certificates

In the event that any Trust Certificate is lost, stolen, destroyed or mutilated, the Trustee may authorize the issuance of a new Trust Certificate for the same number of Trust Units in lieu thereof. The Trustee may in its discretion, before the issuance of such new Trust Certificate, require the owner of the lost, stolen, destroyed or mutilated Trust Certificate, or the legal representative of the owner to make an affidavit or statutory declaration setting forth such facts as to the loss, theft, destruction or mutilation as the Trustee may deem necessary, to surrender any mutilated Trust Certificate and may require the applicant to supply to the Trust a "lost certificate bond" or a similar bond in such reasonable sum as the Trustee may direct indemnifying the Trustee and its agent for so doing. The Trustee shall have the power to require from an insurer or insurers a blanket lost security bond or bonds in respect of the replacement of lost, stolen, destroyed or mutilated Trust Certificates. The Trustee shall pay all premiums and other funds of money payable for such purpose out of the Trust Fund with such contribution, if any, by those insured as may be determined by the Trustee in its sole discretion. If such blanket lost security bond is required, the Trustee may authorize and direct (upon such terms and conditions as the Trustee may from time to time impose) any agent to whom the indemnity of such bond extends to take such action to replace any lost, stolen, destroyed or mutilated Trust Certificate without further action or approval by the Trustee.

11.8 Death of a Unitholder

The death of a Unitholder during the continuance of the Trust shall not terminate the Trust or any of the mutual or respective rights and obligations created by or arising under this Indenture nor give such Unitholder's personal representative a right to an accounting or take any action in court or otherwise against other Unitholders or the Trustee or the Trust Fund, but shall entitle the personal representatives of the deceased Unitholder to demand and receive, pursuant to the provisions hereof, a new Trust Certificate for Trust Units in place of the Trust Certificate held by the deceased Unitholder, and upon the acceptance thereof such personal representatives shall succeed to all rights of the deceased Unitholder under this Indenture.

11.9 Unclaimed Interest or Distribution

In the event that the Trustee shall hold any amount of interest or other distributable amount which is unclaimed or which cannot be paid for any reason, the Trustee shall be under no obligation to invest or reinvest the same but shall only be obliged to hold the same in a current non-interest-bearing account pending payment to the person or persons entitled thereto. The Trustee shall, as and when required by law, and may at any time prior to such required time, pay all or part of such interest or other distributable amount so held to the Public Trustee (or other appropriate Government official or agency) whose receipt shall be a good discharge and release of the Trustee.

11.10 Exchanges of Trust Certificates

Trust Certificates representing any number of Trust Units may be exchanged without charge for Trust Certificates representing an equivalent number of Trust Units in the aggregate. Any exchange of Trust Certificates may be made at the offices of the Trustee or at the offices of any Transfer Agent where registers are maintained for the Trust Certificates pursuant to the provisions of this Article 11. Any Trust Certificates tendered for exchange shall be surrendered to the Trustee or appropriate Transfer Agent and shall be cancelled. The Corporation shall reimburse the Trustee for all exchange fees associated with any such exchange.

11.11 Offer for Units

(a) In this Section 11.11:

(i) "**Dissenting Unitholder**" means a Unitholder who does not accept an Offer referred to in Subsection (b) and includes any assignee of the Unit of a Unitholder to whom such an Offer is made, whether or not such assignee is recognized under this Indenture;

(ii) "**Offer**" means an offer to acquire outstanding Units where, as of the date of the offer to acquire, the Units that are subject to the offer to acquire, together with the Offeror's Units, constitute in the aggregate 20% or more of all outstanding Units;

(iii) "**offer to acquire**" includes an acceptance of an offer to sell;

(iv) "**Offeror**" means a person, or two or more persons acting jointly or in concert, who make an Offer to acquire Units;

(v) "**Offeror's Notice**" means the notice described in Subsection (c); and

(vi) "**Offeror's Units**" means Units beneficially owned, or over which control or direction is exercised, on the date of an Offer by the Offeror, any Affiliate or Associate of the Offeror or any person or company acting jointly or in concert with the Offeror.

(b) If an Offer for all of the outstanding Units (other than Units held by or on behalf of the Offeror or an Affiliate or Associate of the Offeror) is made and

(i) within the time provided in the Offer for its acceptance or within 45 days after the date the Offer is made, whichever period is the shorter, the Offer is accepted by Unitholders representing at least 90% of the outstanding Units, other than the Offeror's Units;

(ii) the Offeror is bound to take up and pay for, or has taken up and paid for the Units of the Unitholders who accepted the Offer; and

(iii) the Offeror complies with Subsections (c) and (e);

the Offeror is entitled to acquire, and the Dissenting Unitholders are required to sell to the Offeror, the Units held by the Dissenting Unitholders for the same consideration per Unit payable or paid, as the case may be, under the Offer.

(c) Where an Offeror is entitled to acquire Units held by Dissenting Unitholders pursuant to Subsection (b), and the Offeror wishes to exercise such right, the Offeror shall send by registered mail within 30 days after the date of termination of the Offer a notice (the "Offeror's Notice") to each Dissenting Unitholder stating that:

(i) Unitholders holding at least 90% of the Units of all Unitholders, other than Offeror's Units, have accepted the Offer;

(ii) the Offeror is bound to take up and pay for, or has taken up and paid for, the Units of the Unitholders who accepted the Offer;

(iii) Dissenting Unitholders must transfer their respective Units to the Offeror on the terms on which the Offeror acquired the Units of the Unitholders who accepted the Offer within 21 days after the date of the sending of the Offeror's Notice; and

(iv) Dissenting Unitholders must send their respective Unit Certificate(s) to the Trustee within 21 days after the date of the sending of the Offeror's Notice.

(d) A Dissenting Unitholder to whom an Offeror's Notice is sent pursuant to Subsection (c) shall, within 21 days after the sending of the Offeror's Notice, send his or her Unit Certificate(s) to the Trustee, duly endorsed for transfer.

(e) Within 21 days after the Offeror sends an Offeror's Notice pursuant to Subsection (c), the Offeror shall pay or transfer to the Trustee, or to such other person as the Trustees may direct, the cash or other consideration that is payable to Dissenting Unitholders pursuant to Subsection (b).

(f) The Trustee, or the person directed by the Trustee, shall hold in trust for the Dissenting Unitholders the cash or other consideration it receives under Subsection (e). The Trustee, or such person, shall deposit cash in a separate account in a Canadian chartered bank, and shall place other consideration in the custody of a Canadian chartered bank or similar institution for safekeeping.

(g) Within 30 days after the date of the sending of an Offeror's Notice pursuant to Subsection (c), the Trustee, if the Offeror has complied with Subsection (e), shall:

(i) do all acts and things and execute and cause to be executed all instruments as in the Trustee's opinion may be necessary or desirable to cause the transfer of the Units of the Dissenting Unitholders to the Offeror;

(ii) send to each Dissenting Unitholder who has complied with Subsection (d) the consideration to which such Dissenting Unitholder is entitled under this Section 11.11; and

(iii) send to each Dissenting Unitholder who has not complied with Subsection (d) a notice stating that:

(A) his or her Units have been transferred to the Offeror;

(B) the Trustee or some other person designated in such notice is holding in trust the consideration for such Units; and

(C) the Trustee, or such other person, will send the consideration to such Dissenting Unitholder as soon as practicable after receiving such Dissenting Unitholder's Unit

Certificate(s) or such other documents as the Trustee, or such other person may require in lieu thereof,

and the Trustee is hereby appointed the agent and attorney of the Dissenting Unitholders for the purposes of giving effect to the foregoing provisions.

(h) An Offeror cannot make an Offer for Units unless, concurrent with the communication of the Offer to any Unitholder, a copy of the Offer is provided to the Trust.

ARTICLE 12
TERMINATION

12.1 Termination Date

Unless the Trust is terminated or extended earlier, the Trustee shall commence to wind up the affairs of the Trust on December 31, 2099.

12.2 Termination by Special Resolution of Unitholders

The Unitholders may vote by Special Resolution to terminate the Trust at any meeting of Unitholders duly called for that purpose, whereupon the Trustee shall commence to wind up the affairs of the Trust, provided that such a vote may only be held if requested in writing by the holders of not less than 20% of the outstanding Trust Units and a quorum of holders of not less than 50% of the outstanding Trust Units are present in person or represented by proxy at the meeting or any adjournment thereof at which the vote is taken.

12.3 Procedure Upon Termination

Forthwith upon being required to commence to wind up the affairs of the Trust, the Trustee shall give notice thereof to the Unitholders, which notice shall designate the time or times at which Unitholders may surrender their Trust Units for cancellation and the date at which the register of the Trust shall be closed.

12.4 Powers of the Trustee upon Termination

After the date on which the Trustee is required to commence to wind up the affairs of the Trust, the Trustee shall carry on no activities except for the purpose of winding up the affairs of the Trust as hereinafter provided and for these purposes, the Trustee shall continue to be vested with and may exercise all or any of the powers conferred upon the Trustee under this Indenture.

12.5 Sale of Investments

After the date referred to in Section 12.4, the Trustee shall proceed to wind up the affairs of the Trust as soon as may be reasonably practicable and for such purpose shall, subject to the terms of any agreements binding on or obligations of the Trust and the Trustee, sell and convert into money the Direct Royalties and other assets comprising the Trust Fund in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the Trust Fund, and shall in all respects act in accordance with the directions, if any, of the Unitholders in respect of a termination authorized under Section 12.2. Notwithstanding anything herein contained, in no event shall the Trust be wound up until the Direct Royalties shall have been disposed of.

12.6 Distribution of Proceeds

After paying, retiring or discharging or making provision for the payment, retirement or discharge of all known liabilities and obligations of the Trust and providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the Direct Royalties and other assets together with any cash forming part of the Trust Fund among the Unitholders in accordance with their Pro Rata Share.

12.7 Further Notice to Unitholders

In the event that all of the Unitholders shall not surrender their Trust Units for cancellation within six (6) months after the time specified in the notice referred to in Section 12.3, such remaining Trust Units shall be deemed to be cancelled without prejudice to the rights of the holders of such Trust Units to receive their Pro Rata Share of the amounts referred to in Section 12.6 and the Trustee may either take appropriate steps, or appoint an agent to take appropriate steps, to contact such Unitholders (deducting all expenses thereby incurred from the amounts to which such Unitholders are entitled as aforesaid) or, in the discretion of the Trustee, may pay such amounts into court.

12.8 Responsibility of Trustee after Sale and Conversion

The Trustee shall be under no obligation to invest the proceeds of any sale of the Direct Royalties or other assets or cash forming part of the Trust Fund after the date referred to in Section 12.4 and, after such sale, the sole obligation of the Trustee under this Indenture shall be to hold such proceeds in trust for distribution under Section 12.6.

ARTICLE 13
SUPPLEMENTAL INDENTURES

13.1 Provision for Supplemental Indentures

From time to time the Trustee and the Corporation may, subject to the provisions hereof, and it shall, when so directed in accordance with the provisions hereof, execute and deliver by its proper officers, indentures or instruments supplemental hereto, which thereafter shall form part hereof, for any one or more or all of the following purposes:

(a) giving effect to any amendment as provided in Article 9;

(b) giving effect to any Special Resolution passed as provided in Article 10;

(c) making such provision not inconsistent with this Indenture as may be necessary or desirable with respect to matters or questions arising hereunder, provided that such provisions are not, in the opinion of the Trustee, prejudicial to the interests of the Unitholders;

(d) making any modification in the form of Trust Certificates which does not materially affect the substance thereof; and

(e) for any other purpose not inconsistent with the terms of this Indenture, including the correction or rectification of any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions herein, provided that in the opinion of the Trustee, the rights of the Trustee and the Unitholders are not prejudiced thereby;

provided that the Trustee may in its sole discretion decline to enter into any such supplemental indenture which in its opinion may not afford adequate protection to the Trustee when the same shall become operative.

Notwithstanding Section 10.5 and the foregoing, on or before the Date of Closing, the Trustee may execute and deliver such indentures or instruments supplemental hereto, which may add to or delete or amend, vary or change any of the provisions hereof, as the Corporation may direct in writing.

13.2 Provision for Amended and Restated Indenture

Notwithstanding Section 13.1, following any amendments to this Indenture, the parties to the Indenture may enter into an amended and restated version of the Indenture which shall include and give effect to all amendments to the Indenture in effect at the applicable time.

ARTICLE 14
NOTICES TO UNITHOLDERS

14.1 Notices

Any notice required to be given under this Indenture to the Unitholders shall be given by letter or circular sent through ordinary post addressed to each registered holder at his last address appearing on the register; provided that if there is a general discontinuance of postal service due to strike, lockout or otherwise, such notice may be given by publication twice in the National Edition of The Globe and Mail or The National Post or any other newspaper having national circulation in Canada; provided further that if there is no newspaper having national circulation, then by publishing twice in a newspaper in each city where the register or a branch transfer register is maintained. Any notice so given shall be deemed to have been given on the day following that on which the letter or circular was posted or, in the case of notice being given by publication, the day following the day of the second publication in the designated newspaper or newspapers. In proving notice was posted, it shall be sufficient to prove that such letter or circular was properly addressed, stamped and posted.

14.2 Failure to Give Notice

The failure by the Trustee, by accident or omission or otherwise unintentionally, to give the Unitholders any notice provided for herein shall not affect the validity or effect of any action referred to in such notice, and the Trustee shall not be liable to any Unitholder for any such failure.

14.3 Joint Holders

Service of a notice or document on any one of several joint holders of Trust Units shall be deemed effective service on the other joint holders.

14.4 Service of Notice

Any notice or document sent by post to or left at the address of a Unitholder pursuant to this Article shall, notwithstanding the death or bankruptcy of such Unitholder, and whether or not the Trustee has notice of such death or bankruptcy, be deemed to have been fully served and such service shall be deemed sufficient service on all persons interested in the Trust Units concerned.

ARTICLE 15
AUDITORS

15.1 Qualification of Auditors

The Auditors shall be an independent recognized firm of chartered accountants which has an office in Alberta.

15.2 Appointment of Auditors

The Trustee hereby appoints KPMG LLP, Chartered Accountants, as the auditors of the Trust, to hold such office until the first annual meeting of the Unitholders at such remuneration as may be approved by the Trustee from time to time. The Auditors will be selected at each annual meeting of Unitholders.

15.3 Change of Auditors

The Auditors may at any time be removed by the Trustee with the approval of the Unitholders by means of an Ordinary Resolution at a meeting of Unitholders duly called for that purpose and, upon the resignation or the removal of Auditors as aforesaid, new auditors may be appointed by the Trustee with the approval of the Unitholders by means of an Ordinary Resolution at a meeting duly called for the purpose. A vacancy created by the removal of the Auditors as aforesaid may be filled at the meeting of Unitholders at which the Auditors are removed or, if not so filled, may be filled under Section 15.4.

15.4 Filling Vacancy

In the event that the Auditors resign as auditors of the Trust, the Trustee shall forthwith fill the vacancy with such new auditors as is approved by the members of the Board of Directors of the Corporation whom are independent of the Corporation, and such new auditors shall act as auditors of the Trust for the unexpired term of the predecessor auditors of the Trust.

15.5 Reports of Auditors

The Auditors shall audit the accounts of the Trust at least once in each year and a report of the Auditors with respect to the annual financial statements of the Trust shall be provided to each Unitholder as set out in Section 16.3.

ARTICLE 16
ACCOUNTS, RECORDS AND FINANCIAL STATEMENTS

16.1 Records

The Trustee shall keep such books, records and accounts as are necessary and appropriate to document the Trust Fund and each transaction of the Trust. Without limiting the generality of the foregoing, the Trustee will, at its principal office in Calgary, Alberta, keep records of all transactions of the Trust, a list of the Direct Royalties and other assets of the Trust Fund from time to time and a copy of this Indenture.

16.2 Quarterly Reporting to Unitholders

The Trustee will mail to each Unitholder within 60 days after March 31, June 30 and September 30 in each year, an unaudited quarterly financial statement of the Trust for the most recent calendar quarter. The Corporation will review any forecast provided in any Offering Document and, if necessary, will provide the Trustee with a quarterly update. The Trustee will mail any such update to Unitholders.

16.3 Annual Reporting to Unitholders

The Trustee will mail:

(a) to each Unitholder, within 140 days after the end of each year, the audited consolidated financial statements of the Trust for the most recently completed year together with the report of the Auditors thereon; and

(b) to each person who received a distribution from the Trust during a year, within 90 days after the end of such year, the tax reporting information relating to such year as prescribed by the Tax Act.

16.4 Information Available to Unitholders

(a) Each Unitholder shall have the right to obtain, on demand and on payment of reasonable reproduction costs, from the head office of the Trust, a copy of this Indenture and any indenture supplemental hereto or any Material Contract.

(b) Each Unitholder, upon payment of a reasonable fee and upon sending to the Trustee the affidavit referred to in paragraph (d) below, may upon application require the Trustee to furnish within 10 days from the receipt of the affidavit a list (the "basic list") made up to a date not more than 10 days before the date of receipt of the affidavit setting out the names of the Unitholders, the number of Trust Units owned by each Unitholder and the address of each Unitholder as shown on the records of the Trustee.

(c) A person requiring the Trustee to supply a basic list may, if he states in the affidavit referred to in paragraph (d) below that he requires supplemental lists, require the Trustee upon payment of a reasonable fee to furnish supplemental lists setting out any changes from the basic list in the names or addresses of the Unitholders and the number of Trust Units owned by each Unitholder for each business day following the date the basic list is made up to.

(d) The affidavit referred to in paragraph (b) above shall state:

(i) the name and address of the applicant;

(ii) the name and address for service of the body corporate if the applicant is a body corporate; and

(iii) that the basic list and any supplemental lists will not be used except as permitted under paragraph (e) below.

(e) A list of Unitholders obtained under this Section shall not be used by any person except in connection with:

(i) an effort to influence the voting of Unitholders;

(ii) an offer to acquire Trust Units; or

(iii) any other matter relating to the affairs of the Trust.

16.5 Income Tax: Obligation of the Trustee

The Trustee shall discharge all obligations and responsibilities of the Trustee under the Tax Act or any similar provincial legislation, and neither the Trust nor the Trustee shall be accountable or liable to any Unitholder by reason of any act or acts of the Trustee consistent with any such obligations or responsibilities.

16.6 Income Tax: Designations

In the return of its income under Part I of the Tax Act for each year the Trust shall make such designations to Unitholders with respect to any amounts distributed or payable to Unitholders in the year including, without restricting the generality of the foregoing, designations pursuant to subsection 104(29) of the Tax Act and designations with respect to any taxable capital gains realized and distributed to Unitholders by the Trust in the year, as shall be permitted under the provisions of the Tax Act and as the Trustee in its sole discretion shall deem to be appropriate. In the first tax year, in filing a return of income for the Trust, the Trust shall elect that the Trust be deemed to be a mutual fund trust for the entire year.

16.7 Income Tax: Deductions, Allowances and Credits

The Corporation shall determine the tax deductions, allowances and credits to be claimed by the Trust in any year, and the Trustee shall claim such deductions, allowances and credits for the purposes of computing the income of the Trust and the amount payable by the Trust pursuant to the provisions of the Tax Act.

16.8 Fiscal Year

The fiscal year of the Trust shall end on December 31 of each year.

ARTICLE 17
MISCELLANEOUS

17.1 Continued Listing

The Trustee hereby appoints the Corporation as its agent and the Corporation hereby covenants to the Trustee and agrees that it shall, at the cost and expense of the Trust, take all steps and actions and do all things that may be required to obtain and maintain the listing and posting for trading of the Trust Units on the Toronto Stock Exchange and to maintain its status as a "reporting issuer" not in default of the securities legislation and regulations in each of the provinces of Canada as determined necessary by the Corporation or Counsel.

17.2 Successors and Assigns

The provisions of this Indenture shall enure to the benefit of and be binding upon the parties and their successors and assigns.

17.3 Counterparts

This Indenture may be simultaneously executed in several counterparts, each of which so executed shall be deemed to be an original, and such counterparts, together, shall constitute but one and the same instrument, which shall be sufficiently evidenced by any such original counterparts.

17.4 Severability

If any provision of this Indenture shall be held invalid or unenforceable in any jurisdiction, such invalidity or unenforceability shall attach only to such provision in such jurisdiction and shall not in any manner affect or render invalid or unenforceable such provision in any other jurisdiction or any other provision of this Indenture in any jurisdiction.

17.5 Day Not a Business Day

In the event that any day on or before which any amount is to be determined or any action is required to be taken hereunder is not a Business Day, then such amount shall be determined or such action shall be required to be taken at or before the requisite time on the next succeeding day that is a Business Day.

17.6 Time of the Essence

Time shall be of the essence in this Indenture.

17.7 Governing Law

This Indenture and the Trust Certificates 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 Alberta contracts. The parties hereby irrevocably submit to the jurisdiction of the Courts of the Province of Alberta.

17.8 Notices to Trustee and the Corporation

(a) Any notice to the Trustee under this Indenture shall be valid and effective if delivered or if given by registered letter, postage prepaid, addressed to the attention of Valiant Trust Company at Suite 510, 550 – 6th Avenue S.W., Calgary, Alberta, T2P 0S2, Attention: Manager Corporate Trust (Fax (403) 233-2857), or may be given by electronic or telecommunications device, and shall be deemed to have been given on the date of delivery or, if mailed, effective five days after deposit in the Canadian mail.

(b) Any notice to the Corporation under this Indenture shall be valid and effective if delivered or if given by registered letter, postage prepaid, addressed to the Corporation at Suite 1800, 500 – 4th Avenue S.W., Calgary, Alberta, T2P 2V6, Attention: Secretary (Fax (403) 693-0070 may be given by electronic or telecommunications device, and shall be deemed to have been effectively given on the date of delivery or, if mailed, five days after deposit in the Canadian mail.

(c) The Corporation or the Trustee may from time to time notify the other in writing of a change of address which thereafter, until changed by like notice, shall be the address of the Corporation or the Trustee for all purposes of this Indenture.

(d) If, by reason of a strike, lockout or other work stoppage, actual or threatened, involving postal employees, any notice to be given hereunder could reasonably be considered unlikely to reach its destination, such notice shall be valid and effective only if it is delivered at the appropriate address provided in this Section, by cable, telegram, electronic, telecommunications device or other means of prepaid, transmitted and recorded communication.

17.9 References to Agreements

Any reference herein to any agreement, contract or obligation shall refer to such agreement, contract or obligation as the same may be amended from time to time.

ARTICLE 18
REDEMPTION OF TRUST UNITS

18.1 Right of Redemption

Each Unitholder shall be entitled to require the Trust to redeem at any time or from time to time at the demand of the Unitholder all or any part of the Trust Units registered in the name of the Unitholder at the prices determined and payable in accordance with the conditions hereinafter provided.

18.2 Exercise of Redemption Right

To exercise a Unitholder's right to require redemption under this Article 18, a duly completed and properly executed notice requiring the Trust to redeem Trust Units, in a form approved by the Trustee, shall be sent to the Trust at the head office of the Trust, together with the Trust Unit Certificate or Trust Unit Certificates representing the Trust Units to be redeemed. No form or manner of completion or execution shall be sufficient unless the same is in all respects satisfactory to the Corporation and is accompanied by any further evidence that the Corporation may reasonably require with respect to the identity, capacity or authority of the person giving such notice.

Upon receipt by the Trust of the notice to redeem Trust Units, the Unitholder shall thereafter cease to have any rights with respect to the Trust Units tendered for redemption (other than to receive the redemption payment therefor) including the right to receive any distributions thereon. Trust Units shall be considered to be tendered for redemption on the date that the Trust has, to the satisfaction of the Corporation, received the notice, Trust Unit Certificates and other required documents or evidence as aforesaid.

18.3 Calculation of Redemption Price Based on Market Price

Subject to Section 18.6, upon receipt by the Trust of the notice to redeem Trust Units in accordance with Section 18.2, the holder of the Trust Units tendered for redemption shall be entitled to receive a price per Trust Unit (hereinafter called the "Market Redemption Price") equal to the lesser of:

(a) 90% of the market price of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 day trading period commencing immediately after the date on which the Trust Units were tendered to the Trust for redemption; and

(b) the closing market price on the principal market on which the Trust Units are quoted for trading, on the date that the Trust Units were so tendered for redemption.

For the purposes of Subsection 18.3(a), the market price shall be an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than 5 of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days; the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day.

For the purposes of subsection 18.3(b), the closing market price shall be: an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

18.4 Cash Payment of Market Redemption Price

Subject to Section 18.5, the Market Redemption Price, payable in respect of the Trust Units tendered for redemption during any calendar month shall be paid by cheque, drawn on a Canadian chartered bank or a trust company in lawful money of Canada, payable at par to or to the order of the Unitholder who exercised the right of redemption on the last day of the calendar month following the month in which the Trust Units were tendered for redemption. Payments made by the Trust of the Market Redemption Price are conclusively deemed to have been made upon the mailing of a cheque in a postage pre-paid envelope addressed to the former Unitholder unless such cheque is dishonoured upon presentment. Upon such payment, the Trust shall be discharged from all liability to the former Unitholder in respect of the Trust Units so redeemed.

18.5 Limitation Regarding Cash Payment of Market Redemption Price

Section 18.4 shall not be applicable to Trust Units tendered for redemption by a Unitholder if the total amount payable by the Trust pursuant to Section 18.4 in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month exceeds $100,000; provided that the Corporation may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived for such calendar month, the Market Redemption Price payable in respect of the Trust Units tendered for redemption in such calendar month shall be paid on the last day of the calendar month following such month as follows:

(a) firstly, by the Trust distributing Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption, and,

(b) secondly, to the extent that the Trust does not hold Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes to the Unitholders who exercise the right of redemption having an aggregate principal amount equal to any such shortfall, which promissory notes, (herein referred to as "**Redemption Notes**") shall have terms and conditions substantially identical to those of the Notes.

Upon such distribution of Notes or issuance of Redemption Notes, the Trust shall be discharged from all liability to the former Unitholder in respect of the Trust Units so redeemed. For greater certainty, the Trust shall be entitled to all interest accrued and unpaid on the Notes so distributed to and including the date upon which such Notes are required to be distributed.

18.6 Calculation of Redemption Price in Certain Other Circumstances

Section 18.3 shall not be applicable to Trust Units tendered for redemption by a Unitholder, if:

(a) at the time the Trust Units are tendered for redemption, the outstanding Trust Units of the Trust are not listed for trading on the Toronto Stock Exchange or the TSX Venture Exchange and are not traded or quoted on any other stock exchange or market which the Corporation considers in its sole discretion, provides representative fair market value prices for the Trust Units; or

(b) the normal trading of the outstanding Trust Units of the Trust is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date that such Trust Units tendered for redemption were tendered to the Trust for redemption or for more than five trading days during the 10 day trading period commencing immediately after the date on which such Trust Units tendered for redemption were tendered to the Trust for redemption,

and in either such case, such Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (herein referred to as the "Appraised Redemption Price") equal to 90% of the fair market value thereof as determined by the Corporation as at the date upon such Trust Units were tendered for redemption. The Appraised Redemption Price payable in respect of Trust Units tendered for redemption in any calendar month shall be paid on the last day of the third calendar month following the month in which such Trust Units were tendered for redemption, by at the option of the Trust:

(i) cash payment, in which case the provisions of Section 18.4 shall apply *mutatis mutandis*; or

(ii) in the manner provided for in Section 18.5, in which case the provisions of Section 18.5 shall apply *mutatis mutandis*.

18.7 Cancellation of Certificates for all Redeemed Trust Units

All certificates representing Trust Units which are redeemed under this Article 18 shall be cancelled and such Trust Units shall no longer be outstanding and shall not be reissued.

IN WITNESS WHEREOF each of the parties has caused these presents to be executed by its proper officers duly authorized in its behalf as of the 27th day of September, 2002.

HARVEST OPERATIONS CORP.

By: (signed) "*Jacob Roorda*"

VALIANT TRUST COMPANY

By: (signed) "*Zinat H. Damji*"

By: (signed) "*Cheryl Dahlager*"

SCHEDULE

To the annexed amended and restated indenture dated as of September 27, 2002
and made between

HARVEST OPERATIONS CORP.
and
VALIANT TRUST COMPANY

(Form of Certificate for the Trust
Units in the English Language)

TRUST UNITS

HARVEST ENERGY TRUST

(a trust created under the laws of the Province of Alberta)

No. ____ _______

Trust Units

CUSIP ______________________________

THIS CERTIFIES THAT

______________________________________ is the registered holder of ______________ fully paid Trust Units issued by HARVEST ENERGY TRUST (the "Trust") transferable only on the books of the Trust by the registered holder hereof in person or by attorney duly authorized upon surrender of this certificate properly endorsed.

The Trust Units represented by this certificate are issued upon the terms and subject to the conditions of an amended and restated indenture (which indenture together with all other instruments supplemental or ancillary thereto is herein referred to as the "Trust Indenture") dated September 27, 2002 and made between Harvest Operations Corp. (the "Corporation") and Valiant Trust Company (the "Trustee") which Trust Indenture is binding upon all holders of Trust Units and, by acceptance of this certificate, the holder assents to the terms and conditions of the Trust Indenture. Terms defined in the Trust Indenture have the same meaning when used herein.

A copy of the Trust Indenture pursuant to which this certificate and the Trust Units represented hereby are issued may be obtained by any Unitholder on demand and on payment of reasonable reproduction costs from the head office of the Trust.

This certificate may only be transferred, upon compliance with the conditions prescribed in the Trust Indenture, on the register to be kept at the office of the transfer agent in the City of Calgary and the City of Toronto, as applicable and at such other place or places, if any, as the Trustee may designate, by the registered holder thereof or his executors or administrators or other legal representatives or his or their attorney duly appointed by an instrument in writing in form and execution satisfactory to the Trustee, and upon compliance with such reasonable requirements as the Trustee may prescribe.

The Trust Indenture contains provisions for the holding of meetings of Unitholders and rendering resolutions passed at such meetings binding upon all Unitholders.

The Trust Indenture contains restrictions on the ownership of Trust Units by non-residents of Canada within the meaning of the *Income Tax Act* (Canada) and the Trust shall take all necessary steps to monitor the ownership of Trust Units to carry out such intentions. If at any time the Trust, becomes aware that the beneficial owners of 49% or more of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, the Trust, by or through the Corporation on the Trust's behalf, shall take such action as may be necessary to carry out the intentions evidenced in the Indenture.

The Trust Indenture provides that no Unitholder shall incur or be subject to any liability in connection with the Trust Fund or the obligations or the affairs of the Trust or with respect to any act performed by the Trustee or by any other person pursuant to the Trust Indenture.

The Trust Indenture provides that Trust Units shall be issued only when fully paid and the Unitholders shall not thereafter be required to make any further contribution to the Trust with respect to such Trust Units.

This certificate shall not be valid for any purpose until it shall have been countersigned and registered by the transfer agent of the Trust.

IN WITNESS WHEREOF the Corporation has caused this certificate to be signed by its duly authorized officers.

DATED _______

HARVEST OPERATIONS CORP.

By: ________________________________
Authorized Officer

By: ________________________________
Authorized Officer

Countersigned and Registered
VALIANT TRUST COMPANY
Transfer Agent and Registrar of the Trust

By: ________________________________
Authorized Officer

TRANSFER FORM

FOR VALUE RECEIVED the undersigned sells, assigns and transfers unto

____

(please print or typewrite name and address of assignee)

__________ Trust Units of HARVEST ENERGY TRUST represented by this certificate and hereby irrevocable constitutes and appoints ____________________ Attorney to transfer the said Trust Units on the registers of the Trust for the said purpose, with full power of substitution in the premises.

Dated ________________________________

____

(SIGNATURE OF TRANSFEROR)

____

The signature of the registered holder of the within certificate to the foregoing assignment must be guaranteed by a chartered bank, by a trust company or a member firm of the Toronto Stock Exchange, the Montreal Exchange, the TSX Venture Exchange, a national securities exchange in the United Sates or the National Association of Securities Dealers, Inc. who are members of the Securities Transfer Association Medallion Program ("STAMP").

(9)

SUBORDINATION AGREEMENT

This Agreement dated as of November 14, 2002

AMONG:

VALIANT TRUST COMPANY, a trust company under the laws of Alberta with offices in Calgary, Alberta as trustee (who and whose successors and assigns as trustee under the Harvest Trust Indenture, are the "**Trustee**"), for and on behalf of **Harvest Energy Trust**, a trust formed in accordance with the laws of Alberta ("**Harvest Trust**")

- and -

WESTLB AG, NEW YORK BRANCH, for itself and as agent (the "**Agent**") for and on behalf of (a) all Banks (as such term is defined in the Credit Agreement) from time to time under the Credit Agreement, (b) any Bank, or any Affiliate of any of them, as party to any Hedging Agreements with the Borrower, and (c) in each case their respective transferees, successors and assigns pursuant to the Credit Agreement or any Hedging Agreement (collectively, the "**Beneficiaries**")

- and -

HARVEST OPERATIONS CORP., a corporation under the laws of Alberta (the "**Borrower**") and each person that hereafter becomes a Subsidiary Guarantor (together with the Borrower, the "**Obligors**")

04 MAR -9 AM 7:21

WHEREAS:

1. Certain Beneficiaries have provided a senior secured credit facility to the Borrower pursuant to the Credit Agreement, certain Beneficiaries may enter into Hedging Agreements with the Borrower, and certain Persons may hereafter become Subsidiary Guarantors and guarantee the obligations of the Borrower to the Beneficiaries under the Credit Agreement and any Hedging Agreement;

2. The Borrower has granted to Harvest Trust, the NPI pursuant to the NPI Agreement and may from time to time incur indebtedness pursuant to the Subordinated Obligations;

3. Pursuant to the Credit Agreement, the Borrower granted the Senior Security to the Agent to secure the Borrower's obligations and liabilities to the Beneficiaries under the Credit Agreement, the Notes, and the Hedging Agreements including, *inter alia*, security providing for a charge on all of the Borrower's present and after-acquired real and personal property; and

4. Harvest Trust has agreed that all obligations owing by the Borrower to Harvest Trust including, without limitation, the NPI Agreement and the NPI, any Subordinated Notes held by it and the Trust Indenture Obligations, shall be fully subordinated to the Credit Agreement, the Notes, the Senior Security, the Hedging Agreements and the Senior Obligations in accordance with the terms of this Agreement, and that upon an Event of Default under the Credit Agreement and the provision of an Acceleration Notice by the Agent to the Borrower, the Harvest Properties may be realized upon and disposed of by the Agent free and clear of any Junior Document and the Subordinated Obligations.

NOW THEREFORE, in consideration of the covenants and agreements herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

ARTICLE 1
DEFINITIONS

1.1 Definitions. The following expressions used in this Agreement mean as follows:

"**Acceleration Notice**" means a written notice given by the Agent to an Obligor upon or after the occurrence of an Event of Default, as such term is defined in the Credit Agreement, declaring all obligations thereunder to be immediately due and payable.

"**Administration Agreement**" means the Administration Agreement dated September 27, 2002 between Valiant Trust Company, in its capacity as trustee of Harvest Trust, and the Borrower, as amended, modified, restated and in effect from time to time.

"**Affiliate**" means any person which, directly or indirectly, controls, is controlled by or is under common control with another person, and for the purposes of this definition, "control" (including, with correlative meanings, the terms "controlled by" or "under common control with") means the power to direct or cause the direction of the management and policies of any person, whether through the ownership of voting capital stock of such person by contract or otherwise.

"**Agent**" has the meaning given to it on the first page of this Agreement and includes any other agent, trustee or security trustee, from time to time, appointed by and acting for and on behalf of the Beneficiaries pursuant to the Senior Security.

"**Agreement**" means this Subordination Agreement, and includes all amendments and supplements made hereto, all restatements hereof and all substitutions and replacements therefor.

"**Borrowing Base**" has the meaning given to it in the Credit Agreement.

"**Credit Agreement**" means the Credit Agreement dated November 14, 2002 among the Obligors, the Agent and the Banks party thereto, as amended, modified, supplemented or restated from time to time.

"**Current Proceeds**" has the meaning given to it in Section 2.2.

"**Default**" has the meaning given to it in Section 2.5.

"**Deficiency Amount**" means, at any time and from time to time, any amount due and owing to the Beneficiaries in respect of the Senior Obligations which has not been paid when due.

"**Deficiency Notice**" means a notice in writing by any Obligor or the Agent to the Trustee that a Deficiency Amount has not been paid when due and specifying such Deficiency Amount.

"**Designated Property**" has the meaning given to it in Section 3.1(a).

"**Enforcement Notice**" has the meaning given to it in Section 3.1.

"**Event of Default**" has the meaning given to it in Section 2.5.

"**Harvest Properties**" means the property and assets of the Borrower that are or from time to time become subject to the NPI Agreement, the Subordinated Note Indenture or any of them or any other Junior Document, and "**Harvest Property**" means any of such property and assets.

"**Harvest Trust Indenture**" means the amended and restated trust indenture dated September 27, 2002 pursuant to which Harvest Trust was formed and subsists as at the date hereof, as such indenture may hereafter be amended or amended and restated from time to time.

"**Hedging Agreement**" means any Hedging Agreement (as defined in the Credit Agreement) to which an Obligor and any Beneficiary is a party.

"**Insolvency Notice**" means a notice in writing by any Obligor or the Agent to the Trustee that an Insolvency Proceeding has been commenced or is outstanding.

"**Insolvency Proceeding**" has the meaning given to it in Section 6.1.

"**Junior Documents**" means the NPI Agreement, the Harvest Trust Indenture and the Administration Agreement, and each other document and agreement, including guarantees, delivered to or for the benefit of Harvest Trust pursuant to the foregoing documents, and any other document, agreement or instrument which creates a Subordinated Obligation whether now or in the future.

"**Majority Banks**" has the meaning given to it in the Credit Agreement.

"**Notes**" has the meaning given to it in the Credit Agreement.

"**NPI**" means, collectively, the net profits interest payable by the Borrower to Harvest Trust pursuant to the NPI Agreement and all rights of Harvest Trust with respect thereto and all other rights and benefits of Harvest Trust under or pursuant to the NPI Agreement, including all rights to receive any payments other than or in addition to the net profits interest payable thereunder.

"**NPI Agreement**" means the Amended and Restated Net Profit Interest Agreement dated September 27, 2002 between the Borrower and Harvest Trust as such agreement may hereafter be amended or restated from time to time.

"**Payment Notice**" means any notice in writing given by any Obligor or the Agent to the Trustee that an Obligor has made a payment to the Trustee in contravention of Section 2.5 or Section 6.6.

"**person**" includes any individual, firm, company, partnership, corporation, government, government body or agency, instrumentality, trust or unincorporated body or association.

"**Realization Notice**" has the meaning given to it in Section 3.1(a).

"**Remedy Notice**" has the meaning given to it in Section 2.2.

"**Restriction Notice**" means a Deficiency Notice, Payment Notice or Insolvency Notice.

"**Restriction Circumstance**" has the meaning given to it in Section 2.2.

"**Senior Documents**" means the Credit Agreement, the Notes, the Senior Security, any Hedging Agreement, and each other document or agreement, including guarantees by an Obligor delivered to or for the benefit of the Beneficiaries or any of them pursuant to the foregoing documents.

"**Senior Obligations**" means all indebtedness, liabilities and obligations of the Obligors to the Beneficiaries (i) under the Credit Agreement and the Notes (including, without limitation, principal, interest, and all other amounts accruing subsequent to the filing of an Insolvency Proceeding, (ii) arising in respect of transactions pursuant to any Hedging Agreement, and (iii) under the Senior Security, in each case whether present or future, direct or indirect, absolute or contingent, matured or not.

"**Senior Security**" means (a) the U.S. $120,000,000 Demand Debenture and Negative Pledge dated November 14, 2002 and issued by the Borrower as security for its obligations under the Credit Agreement, the Notes and Hedging Agreements, (b) the Deposit Agreement executed and delivered by the Borrower in connection with such Debenture, and (c) all other documents and agreements that may hereinafter be executed by an Obligor granting or intending to grant security interests to or for the benefit of the Agent on behalf of the Beneficiaries for the Senior Obligations, and includes all amendments and supplements made thereto, all restatements thereof and all substitutions and replacements therefor, in each case from time to time, and where the context or subject matter requires, means and includes the mortgages, charges, pledges and other security interests constituted thereby.

"**Shares**" means any and all shares or other equity interests now owned or hereafter acquired by or for the benefit of Harvest Trust in the capital of an Obligor.

"**Subordinated Note Indenture**" means a note indenture entered into after the date hereof between the Borrower and a trustee on behalf of the noteholders thereunder providing for the issuance of the Subordinated Notes, as contemplated by the Harvest Trust Indenture as a note indenture referenced thereunder.

"**Subordinated Notes**" means any of the promissory notes which may be issued by the Borrower pursuant to a Subordinated Note Indenture from time to time.

"**Subordinated Obligations**" means all indebtedness, liabilities and obligations of the Obligors to Harvest Trust, whether present or future, matured or unmatured, absolute or contingent, and howsoever arising, and including, without limitation, the NPI, any Subordinated Notes held by the Trustee and all other obligations of the Obligors to Harvest Trust under the Junior Documents and the right to receive any payments on or in respect of the Shares.

"**Subsidiaries**" has the meaning given to it in the Credit Agreement.

"**Subsidiary Guarantors**" has the meaning given to it in the Credit Agreement, and "**Subsidiary Guarantor**" means any one of them.

"**Trust Indenture Obligations**" means all indebtedness, liabilities and obligations of the Borrower to Harvest Trust pursuant to or referred to in the Harvest Trust Indenture, or pursuant to any document or agreement entered into to give effect to any transaction referred to or contemplated in the Harvest Trust Indenture, including, without limitation, any obligations in respect of advances or credit that may be made or extended by Harvest Trust to the Borrower, or evidenced by any notes, or representing overpayments of deferred royalty payment obligations, or otherwise.

"**Trustee Expenses**" means, at any time and from time to time, any fees, or expense reimbursements then due and payable by Harvest Trust or the Borrower to Valiant Trust Company with respect to the performance and discharge of its trustee duties pursuant to the Harvest Trust Indenture, and any such fees or expenses which have accrued at that time pursuant to services rendered in the performance of such duties since the last regularly scheduled billing of such fees or costs by Valiant Trust Company but which have not at such time been billed or collected.

ARTICLE 2
HARVEST TRUST'S ACKNOWLEDGEMENT OF PRIORITY OF BENEFICIARIES

2.1 Subordination by Harvest Trust. The Trustee declares, covenants and agrees, for and on behalf of Harvest Trust, that the Junior Documents and the Subordinated Obligations are hereby fully subordinated and postponed to and in favour of the Senior Documents and the Senior Security, and all claims of the Beneficiaries thereunder, and to the Senior Obligations, in accordance with the terms hereof. The Beneficiaries, in respect of the Senior Obligations, shall have the first priority over the Subordinated Obligations, and first priority over any claims of

Harvest Trust in respect of the Obligors and all their property and assets of every nature and kind now existing or hereafter acquired by the Obligors, including, without limitation, the Harvest Properties, the NPI and the Subordinated Notes, to discharge and satisfy the Senior Obligations, all in priority to any claim of Harvest Trust under the Junior Documents and the Subordinated Obligations, in accordance with the terms hereof.

Notwithstanding anything to the contrary contained in this Agreement, the Trustee may continue to make payments to the unitholders pursuant to the Trust Indenture until it is in receipt of a Restriction Notice or again after receipt of a Remedy Notice, in accordance with the terms hereof. At any time when there is a Deficiency Amount, the Agent may give a Deficiency Notice to the Trustee.

2.2 Payments Held in Trust. Upon receipt of any Restriction Notice, the Trustee shall hold all amounts previously received under the Junior Documents or in respect of the Subordinated Obligations but not at the time distributed to the unitholders of Harvest Trust (collectively the "**Current Proceeds**"), and all amounts thereafter received under the Junior Documents or in respect of the Subordinated Obligations, in trust for the benefit of the Beneficiaries and will not make any further payments to unitholders of Harvest Trust until the Senior Obligations have been fully satisfied and discharged or until the circumstance giving rise to the Restriction Notice (a "**Restriction Circumstance**") has been remedied to the satisfaction of the Agent, acting reasonably. If the Restriction Notice provided is a Deficiency Notice or Enforcement Notice, the Trustee will upon demand by the Agent, pay all such amounts so held in trust to the Agent. The Agent will, on the Borrower's request and provided there is not any Default, Event of Default or other Restriction Circumstance outstanding, provide timely notice of such remedying in writing to the Obligors and the Trustee, terminating the outstanding Restriction Notice and directing that payments may be reinstated as otherwise permitted hereunder. Upon receipt of a Remedy Notice the Trustee will be entitled to pay any remaining Current Proceeds to the unitholders of Harvest Trust in accordance with the provisions of the Trust Indenture.

Notwithstanding the provisions of Section 2.1, this Section 2.2 or Section 2.3, if, at the time the Trustee receives any Restriction Notice, it is holding any Current Proceeds, the Trustee shall be entitled to apply such Current Proceeds to such Trustee Expenses.

2.3 Subordination Absolute. The subordination and postponement of the Junior Documents and the Subordinated Obligations on the terms set out in this Agreement shall apply in all events and circumstances and notwithstanding the release and discharge of any or all of the Senior Security. Without limiting the generality of the foregoing, the rights and priority of the Beneficiaries hereunder and in respect of an Obligor and its property and assets, and the subordination and postponement of the Junior Documents and the Subordinated Obligations pursuant to and on the terms set out in this Agreement, shall not be affected by:

(a) the time, sequence or order of creating, granting, executing, delivering of, or registering or failing to register any security notice, caveat, financing statement or other notice in respect of the Senior Security or the Junior Documents;

(b) the date of any payments made to the Trustee under any of the Junior Documents;

(c) the time or order of giving any notice or the making of any demand under the Senior Documents or the Senior Security, or the Junior Documents, or the attachment, perfection or crystallization of the Senior Security;

(d) the taking of any collection, enforcement or realization proceedings pursuant to the Senior Documents or the Senior Security, or the Junior Documents;

(e) the date of obtaining of any judgment or the order of any bankruptcy court or any court administering bankruptcy, insolvency or similar proceedings as to the entitlement of either the Beneficiaries or Harvest Trust to any money or property of an Obligor;

(f) the giving or failure to give any notice, or the order of giving any notice, to an Obligor;

(g) the failure to exercise any power or remedy reserved to the Beneficiaries under the Senior Documents or the Senior Security, or to insist upon a strict compliance with any of the terms thereof;

(h) the failure by the Borrower to comply with any restrictions on borrowing or granting of the Senior Security set forth in any of the Junior Documents, regardless of any knowledge thereof which the Beneficiaries may have or be deemed to have or with which the Beneficiaries may be charged; or

(i) any other factor of legal relevance including, without limitation, any priority granted to the Trustee, Harvest Trust, or any of the Junior Documents by any applicable principle of law or equity.

2.4 No Impairment of Senior Obligations. The Obligors and the Trustee hereby acknowledge, covenant and agree that nothing contained in this Agreement, or any of the Junior Documents is intended to or shall impair, affect, reduce or limit the liabilities and obligations of the Obligors under the Senior Documents or the Senior Security, including, without limitation, the obligation of the Obligors to satisfy and discharge the Senior Obligations as and when the same shall become due and payable. Without limiting the generality of the foregoing, the Obligors and the Trustee hereby acknowledge, covenant and agree that the liabilities and obligations of the Obligors to the Beneficiaries under the Senior Documents and the Senior Security shall not be impaired, affected, reduced or limited by a failure by any Obligor to comply with the restrictions on borrowing or granting the Senior Security or the provisions of agreements referred to in Section 2.3(h), regardless of any knowledge thereof which the Beneficiaries may have or be deemed to have or with which the Beneficiaries may be charged. Nothing contained in this Agreement or any of the Junior Documents is intended to or shall prevent the Beneficiaries from exercising at any time and from time to time all their rights and remedies under or in respect of the Senior Documents and the Senior Security, and the Senior Obligations.

2.5 No Payments if Default Exists. The Obligors covenant and agree that if there exists an Event of Default, as defined in the Credit Agreement ("**Event of Default**"), or if an Obligor has knowledge (but not including constructive knowledge) of the existence of a Default, as defined in the Credit Agreement ("**Default**"), the Obligors will not (a) make any further payments to Harvest Trust under any of the Junior Documents or in respect of the Subordinated Obligations until such Event of Default or Default has been fully remedied, or (b) effect any set-off, the effect of which would be to reduce any amount owing by Harvest Trust to an Obligor. The Obligors further covenant and agree that if the Agent gives an Acceleration Notice to an Obligor, the Obligor will not make any further payments to Harvest Trust under any of the Junior Documents or in respect of the Subordinated Obligations until the Senior Obligations have been fully satisfied and discharged or until the circumstance has been remedied to the satisfaction of the Agent, acting reasonably.

As between the Obligors, the Agent and the Beneficiaries it is acknowledged that the existence of a Borrowing Base Deficiency (as defined in the Credit Agreement) shall not, in circumstances where no Default (other than one that could occur by reason of the continuance of a Borrowing Base Deficiency beyond the "Deficiency Cure Period" (as defined in the Credit Agreement)) or Event of Default has occurred and is continuing, preclude the Borrower from making payments under any of the Junior Documents or in respect of any Subordinated Obligations if, at the date of such payment, the "Deficiency Cure Period" (as defined in the Credit Agreement) has not expired, but without limiting the right of the Agent to provide a Restriction Notice in accordance with the terms of this Agreement.

2.6 No Set-Off. The Trustee shall not, at any time after it has received any Restriction Notice which has not been terminated by any subsequent Remedy Notice, offset any amounts that it may owe to an Obligor against any amounts that (but for Section 2.5) would be payable by an Obligor to the Trustee, with the result that any amount owing to such Obligor by the Trustee (under any of the Junior Documents), would thereby be reduced.

2.7 Registrations. Upon the request of the Agent, the Trustee shall cooperate with the Agent to the extent necessary in order to allow the Agent to file such notices and other documents at any public registries and offices as may be necessary or desirable to reflect the subordination and postponement of the Junior Documents and Subordinated Obligations effected by this Agreement.

ARTICLE 3
REALIZATION BY HOLDERS

3.1 Realization Free and Clear of Subordinated Obligations. The Obligors and the Trustee hereby acknowledge, covenant and agree that the Agent's rights in relation to the Harvest Properties shall rank in priority to the rights of the Obligors, the Trustee and Harvest Trust, and that if an Event of Default exists and an Enforcement Notice has been provided to the Trustee, the Beneficiaries shall be entitled to realize on the Senior Security in respect of the Harvest Properties absolutely free and clear of the Junior Documents and the Subordinated Obligations. Without limiting the generality of the foregoing and in addition to any other rights and remedies available to the Beneficiaries under this Agreement, the Senior Documents or the Senior Security, if the Agent gives written notice to the Trustee that an Acceleration Notice has been given (an "**Enforcement Notice**"):

(a) the Agent may at any time and from time to time thereafter give written notice to the Trustee ("**Realization Notice**") that it has elected to enforce its rights and remedies against all of the Harvest Properties or a portion thereof, as may be specified in the Enforcement Notice (each such specified Harvest Property being herein referred to as a "**Designated Property**", which term shall include all proceeds of disposition of the Harvest Properties, all production from the Harvest Properties, and revenues attributable thereto, and all proceeds of any thereof, in whatever form), and the Obligors and the Trustee hereby agree that, effective concurrently with any disposition of a Designated Property to any person (including the Beneficiaries) pursuant to an exercise of the Agent's rights, powers and remedies against such Designated Property:

(i) the NPI and any other interest or instrument in respect of the Subordinated Obligations insofar as they pertain to such Designated Property, and all rights, title and interest of the Trustee and Harvest Trust in, and all claims of the Trustee and Harvest Trust to, such Designated Property shall terminate and be extinguished and such Designated Property shall no longer be subject to any of the Junior Documents or the Subordinated Obligations,

(ii) the person(s) acquiring such Designated Property shall acquire such Designated Property absolutely free and clear of the Junior Documents and the Subordinated Obligations, all without any further action, or the payment of any further consideration, on the part of the Obligors, the Beneficiaries, the Trustee or Harvest Trust,

(iii) Harvest Trust and the Trustee, shall have no claim whatsoever against any person(s) acquiring such Designated Property under any of the Junior Documents or in respect of the Subordinated Obligations whether on account of past, present or future liabilities in respect thereto, howsoever arising, and

(iv) subject to Section 3.2, Harvest Trust and the Trustee shall have no claim to any proceeds of any such disposition of a Designated Property, all notwithstanding any provisions to the contrary in the Junior Documents or in any other document whatsoever;

(b) each of the Obligors and the Trustee shall forthwith execute and deliver all such documents and instruments (addressed to such persons as the Agent may direct from time to time) and do all such further acts and things as may be requested by the Agent from time to time in connection with the realization of the Senior Security on the Harvest Properties, free and clear of the Junior Documents and the Subordinated Obligations, and including, without limitation, all quit claims and other documents, instruments and assurances as may be requested by the Agent from time to time confirming that, concurrently with a disposition of a Designated Property, the NPI and any other interest or instrument in respect of the Subordinated Obligations insofar as they pertain to such Designated Property has been or will be (effective upon such disposition becoming effective) absolutely terminated and extinguished, that the Trustee and Harvest Trust has ceased or will cease (effective upon such disposition becoming effective) to have any rights, title or interest in or claim in respect of such Designated Property, and that such Designated Property is no longer or will no longer (effective upon such disposition becoming effective) be in any way subject to or burdened by the Junior Documents and Subordinated Obligations.

For the purpose of this Section 3.1, a "**disposition**" in relation to a Designated Property shall include a sale, lease or disposition of any nature whatsoever (including to the Beneficiaries) pursuant to or under any title documentation pertaining to such Designated Property, whether made by the Beneficiaries or any person on their behalf or a privately or court appointed receiver, and a foreclosure, and may in the Agent's sole discretion include any partial disposition of any interest carved out of the Designated Properties or any of them.

3.2 Excess Proceeds. If the Agent enforces its rights and remedies in respect of any of the Senior Documents or the Senior Security, and the Senior Obligations against the Harvest Properties and there is any surplus remaining after the liabilities and obligations of the Obligors to the Beneficiaries are fully satisfied and discharged which is received by any Obligor, then Harvest Trust and the Obligors agree that the surplus shall be dealt with in accordance with the terms of the applicable Junior Document in the same manner as proceeds of sale in accordance with such Junior Document.

3.3 Confirmation of Nature of NPI and Subordinated Notes. The Obligors acknowledge and confirm to the Beneficiaries that:

(a) the NPI and any other interest or instrument in respect of the Subordinated Obligations are not, and are not intended (including in such case any Subordinated Notes which may hereafter be issued) to be, secured in any manner, nor are they guaranteed by any person, nor do they constitute an interest in land under any Junior Document nor are they payable in kind;

(b) Harvest Trust has not been granted any security interest whatsoever in the Designated Properties or any other properties of the Obligors, nor any claim against the Obligors in respect of the Designated Properties, other than its interest and claims derived under the terms of the NPI Agreement, under any Subordinated Note and any other Junior Document; and

Harvest Trust acknowledges the above confirmations of the Obligors.

ARTICLE 4
RIGHTS TO DEAL WITH BORROWER

4.1 Dealing with Borrower and others. The Beneficiaries shall be entitled to deal with the Obligors, the Senior Documents and the Senior Security and any other persons, and the Senior Obligations as the Beneficiaries may see fit without in any manner affecting the subordination or postponement of the Junior Documents and the Subordinated Obligations, to the Senior

Documents and the Senior Security and the Senior Obligations, and in particular, without limiting the generality of the foregoing, the Beneficiaries may from time to time:

(a) grant time, renewals, extensions, releases, discharges or other indulgences or forbearance to the Obligors and any other person;

(b) waive timely and strict compliance with or refrain from exercising any rights under the Senior Documents or the Senior Security; and

(c) take additional security from the Borrower or any other person in the Harvest Properties or any other assets or properties or otherwise and amend, supplement, restate, substitute or replace any of the Senior Documents or the Senior Security, all of which shall have the benefit of the subordinations and postponements set out herein.

ARTICLE 5
NOTICE BY TRUSTEE

5.1 Performance Advice. From time to time upon written request from the Agent, acting reasonably, the Trustee shall within a reasonable time thereafter, notify the Agent in writing of the particulars as to payments made in respect of the Subordinated Obligations including, without limitation, the NPI, any Subordinated Notes held by it and the Trust Indenture Obligations, and the performance of the Borrower's obligations under any of the Junior Documents.

5.2 Trustee to Cease Enforcement. If the Trustee shall become entitled to enforce any rights or remedies against the Obligors by reason of a default by any Obligor under any of the Junior Documents, the Trustee shall promptly provide to the Agent written notice of any such default, together with reasonable particulars thereof. If there exists a Default or Event of Default and the Agent has given the Trustee written notice thereof, or if the Agent has given an Enforcement Notice to the Trustee, then the Trustee shall not thereafter, while such notice remains outstanding and unremedied or unrescinded, exercise or continue to exercise any rights or remedies it may have under the Junior Documents or otherwise, against the Obligors without the prior written consent of the Agent. The Trustee shall not be entitled at any time to enforce any security interest it may hold, or have at any time been granted, in any properties of the Obligors, save and except to the limited extent permitted by the last paragraph of Section 2.2.

ARTICLE 6
HOLDER'S ENTITLEMENT TO DISTRIBUTIONS

6.1 Insolvency Distributions. The Trustee agrees that, in the event of any distribution, division or application, partial or complete, voluntary or involuntary, by operation of law or otherwise, of all or any part of the property and assets of any Obligors by reason of the liquidation, dissolution or other winding-up of any Obligor's business, any judicial or other sale in connection with a realization on any property or assets of an Obligor, any receivership, insolvency, bankruptcy, assignment for the benefit of creditors, or any other proceeding by or against any Obligor for any relief under any bankruptcy or insolvency law or laws relating to the relief of debtors, readjustment of indebtedness, reorganization relating to the relief of debtors, composition or extension, then and in every such event (an "**Insolvency Proceeding**"), all proceeds or distributions of any kind or character, either in cash, securities or other property, which shall be payable or deliverable to the Trustee or Harvest Trust pursuant to the Junior Documents or in respect of the Subordinated Obligations shall, to the extent of the Senior Obligations, be received and held by the Trustee for the benefit of the Beneficiaries and shall be segregated and forthwith paid over to the Agent in the form received for the benefit of the Beneficiaries.

6.2 Contest Documents. The Obligors, the Trustee and Harvest Trust shall not at any time challenge, dispute or contest the validity or enforceability of the Senior Documents or the Senior Security or the priorities applicable to the Senior Security, nor shall the Trustee or Harvest Trust at any time challenge, dispute or contest the validity or enforceability of the subordination and postponement provided for herein or take any action whereby the subordination and postponement contemplated hereby may be prejudiced.

6.3 No Prejudice. The Beneficiaries shall not be prejudiced in their respective rights and remedies hereunder by any act or failure to act of the Obligors, or any failure by the Obligors to comply with any agreement or obligation, regardless of any knowledge thereof which the Beneficiaries may have or be deemed to have or with which the Beneficiaries or the Agent may be charged.

6.4 Contest NPI and Subordinated Notes. Subject to Section 3.1, and so long as Harvest Trust and the Trustee are not in default of this Agreement, the Agent and the Beneficiaries shall not at any time challenge, dispute or contest the validity or enforceability of the NPI Agreement, the Subordinated Note Indenture, the Harvest Trust Indenture or any other Junior Document.

6.5 Permitted Distributions. Notwithstanding any other provision of this Agreement, the Agent and the Beneficiaries acknowledge that:

(a) any monies received by the Trustee on account of the Subordinated Obligations set forth in items (b) (i), (ii), and (iii) below and actually paid out to unitholders of Harvest Trust in accordance with the Harvest Trust Indenture prior to receipt by the Trustee of a Restriction Notice (and thereafter until terminated by a Remedy Notice) shall not be the subject of this Agreement and neither the Trustee nor Harvest Trust shall have any obligation or liability whatsoever to the Beneficiaries or the Agent in respect of any such amounts; and

(b) unless any of the provisions of Section 2.5 would prevent any Obligor from making payments under any of the Junior Documents or in respect of the Subordinated Obligations or the Borrower is in receipt of a Restriction Notice (until terminated by a Remedy Notice) the Borrower shall be entitled to make payments to Harvest Trust in respect of the following Subordinated Obligations:

   (i) scheduled monthly payments of the NPI in accordance with the NPI Agreement;

   (ii) scheduled interest payments and scheduled principal payments in accordance with the terms of the Subordinated Obligations; and

(iii) any other payments made with the prior written consent of the Agent.

Nothing contained in this Section shall affect the subordination of the Junior Documents and the Subordinated Obligations to the Senior Documents, the Senior Security, and the Senior Obligations.

6.6 Prohibited Payments. The Borrower shall not be entitled to pay to Harvest Trust any proceeds of disposition of any properties that are part of the Borrowing Base without the prior written consent of the Agent on behalf of the Beneficiaries except for proceeds of disposition permitted by Section 9.05 (Prohibition of Fundamental Changes; Disposition of Assets) of the Credit Agreement.

ARTICLE 7
ADDITIONAL COVENANTS OF THE TRUSTEE AND THE BORROWER

7.1 Acknowledgement and Covenant to Pay. The Obligors hereby acknowledge the subordination and postponement of the Junior Documents and the Subordinated Obligations to and in favour of the Senior Documents, the Senior Security and the Senior Obligations hereunder. The Obligors agree to make all payments to the Beneficiaries in accordance with the priorities provided in this Agreement and the other terms and conditions hereof.

7.2 Representations. Each of the Obligors and the Trustee, represent and warrant to the Agent, for and on behalf of the Beneficiaries, that:

(a) it has due authority, power and capacity to enter into and perform their obligations under this Agreement, and that its execution, delivery and performance of this Agreement is not in conflict with any of the Junior Documents or any other agreement to which it is a party, or any applicable laws;

(b) this Agreement constitutes a valid and legally binding obligation of it, enforceable against it in accordance with its terms, subject however, to limitations with respect to enforcement imposed by law in connection with bankruptcy, insolvency, reorganization or other laws affecting creditors' rights generally and to the qualification that equitable remedies such as specific performance and injunction are only available in the discretion of the court from which they are sought and general equitable principles.

Additionally, the Trustee represents and warrants to the Agent, for and on behalf of the Beneficiaries that the Trustee is the trustee of Harvest Trust and has all necessary power and authority to enter into this Agreement.

7.3 No Disposition of NPI or Subordinated Notes by Harvest Trust. The Trustee hereby covenants and agrees that Harvest Trust will not sell, transfer, assign, mortgage, charge, grant a security interest in or otherwise encumber or dispose of in any manner whatsoever any interest or instrument in respect of the Subordinated Obligations including, without limitation, the NPI Agreement or the NPI (except to the Borrower as permitted by Section 9.13 (Transactions with Affiliates) of the Credit Agreement and in connection with a disposition of Harvest Properties by the Borrower permitted by Section 9.05 (Prohibition of Fundamental Changes; Disposition of

Assets) of the Credit Agreement, in order to release such NPI from such disposed properties), or any Subordinated Notes held by it or any part thereof without the prior written consent of the Agent. In any event, Harvest Trust shall not make any such sale, transfer, assignment, mortgage, charge, security interest or other encumbrance or disposition to any person, other than a disposition where the NPI or the Subordinated Notes held by it, or any other interest or instrument in respect of the Subordinated Obligations, terminates immediately upon such disposition, unless such person shall have first become bound by the obligations of the Trustee and Harvest Trust under this Agreement.

7.4 Issuance of Subordinated Notes. The Borrower covenants and agrees with the Agent and the Beneficiaries that, prior to the issuance of any Subordinated Notes, the Borrower shall cause the note trustee under the Subordinated Note Indenture to enter into a subordination agreement with the Agent on the terms and conditions substantially similar to this Agreement.

ARTICLE 8
RESTRICTION ON SUBROGATION

8.1 Restriction on Subrogation. Harvest Trust shall not exercise any rights which it may acquire by way of subrogation or contribution under this Agreement as a result of any payment made hereunder or otherwise until this Agreement has ceased to be effective in accordance with Section 10.11. While this Agreement remains effective, if any amount is paid to the Trustee or Harvest Trust on account of such subrogation or contribution rights at any time, such amount shall be held in trust by the Trustee for the benefit of the Beneficiaries and shall be forthwith paid to the Agent for the benefit of the Beneficiaries.

ARTICLE 9
DEALINGS WITH DEBTORS

9.1 Beneficiaries Not Bound by Restrictions. Each of the Obligors and Harvest Trust hereby acknowledge, covenant and agree that the liabilities and obligations of the Obligors to the Beneficiaries under the Senior Documents and the Senior Security, and the Senior Obligations shall not be impaired, affected, reduced or limited by a failure by any Obligor to comply with any restrictions on borrowing or granting security under the terms of any of the Junior Documents or in respect of the Subordinated Obligations, regardless of any knowledge thereof which the Agent or the Beneficiaries may have or be deemed to have or with which the Agent or the Beneficiaries may be charged. Nothing contained in this Agreement, or any of the Junior Documents or any other agreement or instrument relating to the Subordinated Obligations is intended to or shall prevent the Beneficiaries from exercising at any time and from time to time all their rights and remedies under the Senior Documents or the Senior Security or in respect of the Senior Obligations.

ARTICLE 10
MISCELLANEOUS

10.1 Interpretation. All references in this Agreement to, or representations and warranties by, covenants of, actions and steps by, or the performance of the terms and conditions hereof or thereof by, Harvest Trust shall, as the context requires, be and shall be construed as being to or by Valiant Trust Company (in its capacity as trustee of Harvest Trust and not in its individual capacity) on behalf of Harvest Trust and shall include, as the context requires, both Valiant Trust Company (in its capacity as trustee of Harvest Trust and not in its individual capacity) and Harvest Trust.

10.2 Acknowledgement. The parties hereto acknowledge that the Trustee is entering into this Agreement in its capacity as Trustee and the obligations of Harvest Trust hereunder shall not be personally binding upon the Trustee or any of the unitholders of Harvest Trust and that any recourse against Harvest Trust or any unitholder in any manner in respect of any indebtedness, obligation or liability of Harvest Trust arising hereunder or arising in connection herewith or from the matters to which this Agreement relates, if any, including, without limitation, claims based on negligence or otherwise tortious behaviour, shall be limited to, and satisfied only out of, the assets of the Trust Fund (as defined in the Harvest Trust Indenture).

10.3 Notices. Any notice required or permitted to be made under this Agreement may be delivered or transmitted by facsimile or by overnight courier to the applicable addresses stated below. Any notice given shall be deemed to have been received on actual receipt. The addresses for notices may be changed by notice given under this provision.

(a) If to the Beneficiaries:

WestLB AG, New York Branch
1211 Avenue of the Americas
New York, New York 10036
United States of America

Attention: Associate Director, Transaction Management
Fax No: (212) 921-5947

If to the Trustee:

Valiant Trust Company
510, 550 - 6th Avenue S.W.
Calgary, Alberta
T2P 0S2

Attention: President
Fax No.: (403) 233-2857

(b) If to the Borrower:

Harvest Operations Corp.
2400, 500 – 4th Avenue S.W.
Calgary, Alberta
T2P 2V6
CANADA

Attention: Bruce Chernoff
Fax No.: (403) 266-1438

10.4 Further Assurances. The Trustee shall, at the request of the Majority Banks and at the expense of the Obligors, execute such additional documents and instruments, in registrable form where required, and do such further acts or things as may be reasonably necessary to give full force and effect to the intent of this Agreement.

10.5 Amendments. No consent or agreement of the Obligors shall be necessary to any amendment to the terms hereof made by the Trustee and the Beneficiaries, and any such amendment shall be effective as against the Obligors upon delivery of a copy thereof to the Obligors or their representative.

10.6 Enurement. This Agreement shall enure to the benefit of and be binding upon the Beneficiaries, the Trustee, Harvest Trust and the Obligors and their respective successors and assigns.

10.7 Governing Law. This Agreement shall be governed by and constructed in accordance with the laws of the Province of Alberta.

10.8 Counterpart Execution. This Agreement may be executed in any number of counterparts, and by facsimile, each of which shall be deemed to be an original and all of which shall be construed together as one Agreement.

10.9 No Partnership. Nothing contained in this Agreement and no action taken by the Beneficiaries, the Trustee or the Obligors pursuant hereto is intended to constitute or shall be deemed to constitute the Beneficiaries, the Trustee and the Obligors as a partnership, joint venture or other similar type of association.

10.10 Severability. If any provision of this Agreement shall be invalid, illegal or unenforceable in any respect in any jurisdiction, it shall not affect the validity, legality or enforceability of such provision in any other jurisdiction or the validity, legality or enforceability of any other provision of this Agreement.

10.11 Termination. This Agreement shall remain in full force and effect until the Beneficiaries have irrevocably received, in cash, the full amount of the Senior Obligations, but shall be reinstated if, for any reason, the Agent or any Beneficiary is not entitled to any such amount received from the Corporation in respect of the Senior Obligations.

10.12 Conflict. The provisions of this Agreement shall govern notwithstanding any terms of the Junior Documents to the contrary and whether or not any bankruptcy, receivership or any other insolvency proceedings shall have been commenced by or against any Obligor. In the event of any conflict between the provisions hereof and any of the Junior Documents or any other agreement or instrument in respect of the Subordinated Obligations, the provisions hereof shall prevail.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the date first above written.

VALIANT TRUST COMPANY, as Trustee for and on behalf of HARVEST ENERGY TRUST

By: *(signed)*

By: *(signed)*

WESTLB AG, for itself and on behalf of all Beneficiaries

By: *(signed)*

By: *(signed)*

HARVEST OPERATIONS CORP.

By: *(signed)*

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04 MAR -9 AM 7:21

THIS AGREEMENT made as of the 28th day of May 2002.

BETWEEN:

DEVON CANADA, a general partnership, having an office in the City of Calgary, in the Province of Alberta (hereinafter referred to as "Devon")

DEVON ARL CORPORATION, a body corporate, having an office in the City of Calgary, in the Province of Alberta (hereinafter referred to as "ARL")

(Devon and ARL are hereinafter collectively referred to as "Vendor")

-and-

COYOTE ENERGY INC., a body corporate, having an office in the City of Calgary, in the Province of Alberta (hereinafter referred to as "Purchaser")

WHEREAS Vendor wishes to sell and Purchaser wishes to purchase the interest of Vendor in and to the Assets, subject to and in accordance with the terms and conditions hereof;

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the premises and the mutual covenants and agreements hereinafter set forth, the Parties have agreed as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement, unless the context otherwise requires:

(a) "AFE's" means the authorities for expenditure, operations notices, amounts budgeted pursuant to the Unit Agreements and mail ballots, if any, set out in Schedule "B" under the heading "AFE's";

(b) "Assets" means the Petroleum and Natural Gas Rights, the Tangibles and the Miscellaneous Interests;

(c) "Business Day" means a day other than a Saturday, a Sunday or a statutory holiday in Calgary, Alberta;

(d) "Certificate" means a written certification of a matter or matters of fact which, if required from a corporation, shall be made by an officer of the corporation, on behalf of the corporation and not in any personal capacity;

(e) "Closing" means the closing of the purchase and sale herein provided for;

(f) "Closing Place" means the offices of Vendor, or such other place as may be agreed upon in writing by Vendor and Purchaser;

(g) "<u>Closing Time</u>" means the hour of 2:00 p.m. local time on the later of:

(i) June 28, 2002;

(ii) the third Business Day following the day on which any and all preferential, pre-emptive or first purchase rights of Third Parties that become operative by virtue of this Agreement or the transaction to be effected by it shall have been exercised or waived by the holders thereof or all time periods within which such rights may be exercised shall have expired;

(iii) the day of release of the Assets and Purchase Price from escrow as set out in the Escrow Agreement, if applicable;

or such other time and date as may be agreed upon in writing by Vendor and Purchaser;

(h) "<u>Deposit</u>" means the sum of money set out in section 2.7;

(i) "<u>Effective Date</u>" means the hour of 8:00 a.m., Calgary time, on the 1st day of January, 2002;

(j) "<u>Environmental Defect</u>" means, for the purposes of Article 11, an occurrence of environmental damage, an event of environmental contamination or an environmentally hazardous condition pertaining to a portion or part of the Assets (in this definition referred to as the Affected Assets) which is sufficiently adverse that it would, on a commercially reasonable assessment thereof, cause a purchaser acquiring only those Affected Assets, to not purchase the Affected Assets having regard to the loss of value in and thereto;

(k) "<u>Escrow Agreement</u>" means that agreement which may be entered into by the Parties in accordance with sub-clause 2.2(b) herein;

(l) "<u>Facilities</u>" means any facilities used in the processing, gathering, treating, transmission, compressing and injecting of the Leased Substances, including, without limiting the generality of the foregoing, the facility or facilities, if any, set out in Schedule "B" under the heading "Facilities";

(m) "<u>Lands</u>" means the lands set out and described in Schedule "A";

(n) "<u>Leased Substances</u>" means all Petroleum Substances, rights to or in respect of which are granted, reserved or otherwise conferred by or under the Unit Agreements, or by or under the Title Documents (but only to the extent that the Title Documents pertain to the Lands);

(o) "<u>Miscellaneous Interests</u>" means, subject to any and all limitations and exclusions provided for in this definition, all property, assets, interests and rights pertaining to the Petroleum and Natural Gas Rights and the Tangibles, or either of them, but only to the extent that such property, assets, interests and rights pertain to the Petroleum and Natural Gas Rights and the Tangibles, or either of them, including without limitation any and all of the following:

(i) contracts and agreements relating to the Petroleum and Natural Gas Rights and the Tangibles, or either of them, including without limitation gas purchase contracts, processing agreements, transportation agreements and agreements for the construction, ownership and operation of facilities;

(ii) rights to enter upon, use or occupy, the surface of any lands which are or may be used to gain access to or otherwise use the Petroleum and Natural Gas Rights and the Tangibles, or either of them, excluding any such rights that pertain only to a well or wells other than the Wells;

(iii) all records, books, documents, licences, reports and data which relate to the Petroleum and Natural Gas Rights and the Tangibles, or either of them, but expressly excluding any of the foregoing that pertain to seismic, geological or geophysical matters other than the Seismic; and

(iv) the Wells (and no other wells), including the wellbores and any and all casing; and

(v) the Seismic;

(p) "Party" means a party to this Agreement;

(q) "Permitted Encumbrances" means:

(i) liens for taxes, assessments and governmental charges which are not due or the validity of which is being diligently contested in good faith by or on behalf of Vendor;

(ii) liens incurred or created in the ordinary course of business as security in favour of the person who is conducting the development or operation of the property to which such liens relate for Vendor's proportionate share of the costs and expenses of such development or operation;

(iii) mechanics', builders' and materialmen's liens in respect of services rendered or goods supplied for which payment is not due;

(iv) easements, rights of way, servitudes and other similar rights in land (including without limitation rights of way and servitudes for highways and other roads, railways, sewers, drains, gas and oil pipelines, gas and water mains, electric light, power, telephone, telegraph and cable television conduits, poles, wires and cables) which do not materially impair the use of the Assets affected thereby;

(v) the right reserved to or vested in any municipality or government or other public authority by the terms of any lease, licence, franchise, grant or permit or by any statutory provision, to terminate any such lease, licence, franchise, grant or permit or to require annual or other periodic payments as a condition of the continuance thereof;

(vi) rights of general application reserved to or vested in any governmental authority to levy taxes on the Leased Substances or any of them or the income therefrom, and governmental requirements and limitations of general application as to production rates on the operations of any property;

(vii) statutory exceptions to title, and the reservations, limitations, provisos and conditions in any original grants from the Crown of any of the mines and minerals within, upon or under the Lands;

(viii) any security held by any Third Party encumbering Vendor's interest in and to the Assets or any part or portion thereof, in respect of which Vendor delivers a discharge or no-interest letter from such Third Party to Purchaser at or prior to Closing; and

(ix) all royalty burdens, liens, adverse claims, penalties, reductions in interests and other encumbrances set out in Schedule "A";

(r) "Petroleum and Natural Gas Rights" means all rights to and in respect of the Unit Agreements, the Leased Substances and the Title Documents (but only to the extent that the Title Documents pertain to the Lands), including without limitation the interests set out and described in Schedule "A";

(s) "Petroleum Substances" means any of crude oil, crude bitumen and products derived therefrom, synthetic crude oil, petroleum, natural gas, natural gas liquids, and any and all other substances related to any of the foregoing, whether liquid, solid or gaseous, and whether hydrocarbons or not, including without limitation sulphur;

(t) "Prime Rate" means an annual rate of interest equal to the annual rate of interest announced from time to time by the main Calgary branch of Royal Bank of Canada as the reference rate then in effect for determining interest rates on Canadian dollar commercial loans in Canada;

(u) "Production and Marketing Contracts" means the agreement or agreements, if any, set out in Schedule "B" under the heading "Production and Marketing Contracts";

(v) "Purchase Price" means the sum of money first set out in section 2.6;

(w) "Seismic" means a copy only of any seismic information and data in which Vendor has a 100% proprietary interest (excluding non-proprietary trade and less than 100% owned proprietary seismic data) but only to the extent that any such seismic information and data cross the Lands and only that portion of the data crossing the lands and an area of one (1) mile surrounding the Lands;

(x) "Specific Conveyances" means all conveyances, assignments, transfers, novations and other documents or instruments that are reasonably required or desirable to convey, assign and transfer the interest of Vendor in and to the Assets to Purchaser and to novate Purchaser in the place and stead of Vendor with respect to the Assets;

(y) "Take or Pay Obligations" means obligations to sell or deliver Petroleum Substances or any of them, rights to which are granted, reserved or otherwise conferred pursuant to the Title Documents, without being entitled in due course to receive and retain full payment for such Petroleum Substances, including those identified on Schedule "B" attached hereto;

(z) "Tangibles" means any Facilities and any and all tangible depreciable property and assets which are located within, upon or in the vicinity of the Lands and which are used or are intended to be used to produce, process, gather, treat, measure, make marketable or inject the Leased Substances or any of them or in connection with water injection or removal operations that pertain to the Petroleum and Natural Gas Rights, including without limitation any and all gas plants, oil batteries, buildings, production equipment, pipelines, pipeline connections, meters, generators, motors, compressors, treaters, dehydrators, scrubbers, separators, pumps, tanks, boilers and communication equipment but excluding any motorized vehicles;

(aa) "Third Party" means any individual or entity other than Vendor and Purchaser, including without limitation any partnership, corporation, trust, unincorporated organization, union, government and any department and agency thereof and any heir, executor, administrator or other legal representative of an individual;

(bb) "this Agreement", "herein", "hereto", "hereof" and similar expressions mean and refer to this Agreement of Purchase and Sale;

(cc) "Title Defect" means, for the purposes of Article 11, a defect or deficiency in the beneficial title of the Vendor to any portion or part of the Assets (in this definition referred to as the Affected Assets), which on its own deprives the Vendor of the substantial use, benefit and financial revenue from such Affected Assets, having regard to laws respecting limitations of actions, and is sufficiently adverse such that it would, on a commercially reasonable assessment thereof, cause a purchaser acquiring only those Affected Assets, to not purchase the same having regard to the loss of value in and thereto, but notwithstanding anything to the contrary herein, specifically excludes, (i) the Permitted Encumbrances and (ii) any Lands which have expired or been terminated between the date hereof and the Closing Time other than through lack of action required of the Vendor pursuant to Article 8;

(dd) "Title Documents" means, collectively, any and all certificates of title, leases, reservations, permits, licences, assignments, trust declarations, operating agreements, royalty agreements, gross overriding royalty agreements, participation agreements, farm-in agreements, sale and purchase agreements, pooling agreements and any other documents and agreements granting, reserving or otherwise conferring rights to (i) explore for, drill for, produce, take, use or market Petroleum Substances, (ii) share in the production of Petroleum Substances, (iii) share in the proceeds from, or measured or calculated by reference to the value or quantity of, Petroleum Substances which are produced, and (iv) rights to acquire any of the rights described in items (i) to (iii) of this definition; but only if the foregoing pertain in whole or in part to Petroleum Substances within, upon or under the Lands; including without limitation those, if any, set out and described in Schedule "A";

(ee) "Unit Agreements" means any and all unit agreements and unit operating agreements, including any and all amendments thereto, pertaining to the unit or units, if any, set out in Schedule "B" under the heading "Units"; and

(i) "Wells" means all wells which are or may be used in connection with the Petroleum and Natural Gas Rights, including without limitation producing, shut-in, abandoned, water source, water disposal and water injection wells, and without limiting the generality of the foregoing, includes the well or wells, if any, set out in Schedule "B" under the heading "Wells".

1.2 Headings

The expressions "Article", "section", "subsection", "clause", "subclause", "paragraph" and "Schedule" followed by a number or letter or combination thereof mean and refer to the specified article, section, subsection, clause, subclause, paragraph and schedule of or to this Agreement.

1.3 Interpretation Not Affected by Headings

The division of this Agreement into Articles, sections, subsections, clauses, subclauses and paragraphs and the provision of headings for all or any thereof are for convenience and reference only and shall not affect the construction or interpretation of this Agreement.

1.4 Included Words

When the context reasonably permits, words suggesting the singular shall be construed as suggesting the plural and vice versa, and words suggesting gender or gender neutrality shall be construed as suggesting the masculine, feminine and neutral genders.

1.5 Schedules

There are appended to this Agreement the following schedules pertaining to the following matters:

Schedule "A" - Lands
- Petroleum and Natural Gas Rights

Schedule "B" - Production and Marketing Contracts
- Facilities
- AFE's
- Units
- Take or Pay Obligations
- Wells

Schedule "C" - General Conveyance

Such schedules are incorporated herein by reference as though contained in the body hereof. Wherever any term or condition of such schedules conflicts or is at variance with any term or condition in the body of this Agreement, such term or condition in the body of this Agreement shall prevail.

1.6 Damages

All losses, costs, claims, damages, expenses and liabilities in respect of which a Party has a claim pursuant to this Agreement include without limitation reasonable legal fees and disbursements on a solicitor and client basis.

ARTICLE 2
PURCHASE AND SALE AND CLOSING

2.1 Purchase and Sale

Vendor hereby agrees to sell, assign, transfer, convey and set over to Purchaser, and Purchaser hereby agrees to purchase from Vendor, all of the right, title, estate and interest of Vendor (whether absolute or contingent, legal or beneficial) in and to the Assets, subject to and in accordance with the terms of this Agreement.

2.2 Closing

(a) Closing shall take place at the Closing Place at the Closing Time if there has been satisfaction or waiver of the conditions of Closing herein contained. Subject to all other provisions of this Agreement, possession, risk and beneficial ownership of Vendor's interest in and to the Assets shall be deemed to pass from Vendor to Purchaser at the Effective Date. Subject to the terms of this Agreement, the Parties shall execute the General Conveyance set out in Schedule "C" at Closing;

(b) At Vendor's sole option, prior to the Closing Time, Vendor may give written notice to Purchaser that it wishes to close the transactions contemplated by this Agreement into escrow pending receipt of consents from the Alberta Energy and Utilities Board ("AEUB") to the assignment of all licences, approvals and permits pertaining to the Assets and registered at the AEUB to the Purchaser. If such notice is given, the Parties shall enter into a mutually agreed upon escrow agreement (the "Escrow Agreement") which shall set out the terms and conditions relative to the escrow. The escrow agreement shall include the escrow of the assets and the Purchase Price. It is the intention of the Parties that the escrow shall terminate at the time the AEUB provides its full consent to the assignment of such licences, approvals and permits to Purchaser and Purchaser is the registered holder of such licences, approvals and permits (in which case Closing as contemplated by this Agreement shall take place) or August 31, 2002, which ever is earlier. If the AEUB does not provide its full consent to the assignment of such licences, approvals and permits to Purchaser and Purchaser is not the registered holder of such licences, approvals and permits by August 31, 2002, this Agreement shall terminate and the Parties shall be released from all of their obligations relative thereto and the Deposit and actual interest earned (as opposed to interest at the Prime Rate) shall be returned to the Purchaser.

2.3 Specific Conveyances

Vendor shall prepare the Specific Conveyances at its cost, none of which shall confer or impose upon a Party any greater right or obligation than contemplated in this Agreement. Vendor shall prepare and deliver the Specific Conveyances at Closing. Any Specific Conveyances that are prepared and circulated to Purchaser a reasonable time prior to the Closing Time shall be executed and delivered by the Parties at Closing. Forthwith after full execution of all Specific Conveyances, Vendor shall have the option of circulating and registering, as the case may be, all Specific Conveyances that by their nature may be circulated or registered and Purchaser shall be responsible for any registration costs.

2.4 Title Documents and Miscellaneous Interests

Within the time periods set out in this clause, Vendor shall deliver to Purchaser those agreements and documents to which the Assets are subject and the original copies of those contracts, agreements, records, books, documents, licences, reports and data comprising Miscellaneous Interests which are now in the possession of Vendor or of which it gains possession prior to Closing (the "Files"). Within seven (7) days of Closing, Vendor shall deliver to Purchaser any Files associated with Specific Conveyances executed and delivered at Closing including any Files not necessary for Vendor to complete the balance of the Specific Conveyances after Closing. Vendor shall deliver to Purchaser within seven (7) days of full execution of the balance of the Specific Conveyances, the balance of the Files pertaining thereto. Notwithstanding the foregoing, if and to the extent such Files also pertain to interests other than the Assets, photocopies or other copies may be provided to Purchaser in lieu of original copies.

2.5 Form of Payment

All payments to be made pursuant to this Agreement shall be in Canadian funds. All payments to be made pursuant to this Agreement shall be made by certified cheque or bank draft.

2.6 Intentionally Deleted

2.7 Intentionally Deleted

2.8 Intentionally Deleted

2.9 Interest

At Closing, Purchaser shall pay to Vendor an amount equal to the interest that would have accrued on the Purchase Price (less any interest earned by the Vendor to be calculated at the Prime Rate on the Deposit), at the Prime Rate, calculated daily and not compounded, from and including the Effective Date to and including the day prior to the Closing Time, which amount shall constitute an increase to the Purchase Price and shall be allocated to the Petroleum and Natural Gas Rights.

ARTICLE 3
CONDITIONS OF CLOSING

3.1 Purchaser's Conditions

The obligation of Purchaser to purchase Vendor's interest in and to the Assets is subject to the following conditions precedent, which are inserted herein and made part hereof for the exclusive benefit of Purchaser and may be waived by Purchaser:

(a) the representations and warranties of Vendor herein contained shall be true in all material respects when made and as of the Closing Time, and a Certificate to that effect shall have been delivered by Vendor to Purchaser at Closing;

(b) all obligations of Vendor contained in this Agreement to be performed prior to or at Closing shall have been timely performed in all material respects;

(c) at or prior to Closing, Vendor shall deliver to Purchaser any releases and registrable discharges in a form satisfactory to Purchaser, of any adverse liens and encumbrances that are not Permitted

Encumbrances as well as a discharge or no-interest letter from any Third Party related to security held by such Third Party against the Assets or any part or portion thereof;

(d) there shall be no adverse substantial damage or alteration to the Assets (other than production of Petroleum Substances, a decline in oil and natural gas prices, future cash flow therefrom or the quality, quantity or recoverability of the Leased Substances) between the date hereof and the Closing Time, other than that to which Purchaser has provided its consent;

(e) Purchaser shall conduct accounting, financial, operational and environmental due diligence respecting the Assets and shall have the right, by providing Vendor with written notice on or before June 17, 2002, to terminate this Agreement in its entirety as a result of a material flaw in the condition of the Assets determined from such review;

(f) Purchaser's rights to terminate this Agreement pursuant to Article 11 hereof.

If any one or more of the foregoing conditions precedent has or have not been satisfied, complied with, or waived by Purchaser, at or before the Closing Time (or such other time specified in a certain condition), other than those conditions which have not been met due to any failure on the part of the Purchaser, Purchaser may in addition to any other remedies which it may have available to it, rescind this Agreement by written notice to Vendor. If Purchaser rescinds this Agreement, Vendor shall forthwith return the Deposit to Purchaser and Purchaser and Vendor shall be released and discharged from all obligations hereunder except as provided in sections 3.3 and 13.15.

3.2 Vendor's Conditions

The obligation of Vendor to sell its interest in and to the Assets is subject to the following conditions precedent, which are inserted herein and made part hereof for the exclusive benefit of Vendor and may be waived by Vendor:

(a) the representations and warranties of Purchaser herein contained shall be true in all material respects when made and as of the Closing Time, and a Certificate to that effect shall have been delivered by Purchaser to Vendor at Closing;

(b) all obligations of Purchaser contained in this Agreement to be performed prior to or at Closing shall have been timely performed in all material respects;

(c) all amounts to be paid by Purchaser to Vendor at Closing shall have been paid to Vendor in the form stipulated in this Agreement;

If any one or more of the foregoing conditions precedent has or have not been satisfied, complied with, or waived by Vendor, at or before the Closing Time, other than those conditions which have not been met due to any failure on the part of the Vendor, Vendor may in addition to any other remedies which it may have available to it, rescind this Agreement by written notice to Purchaser. If Vendor rescinds this Agreement, Vendor shall be entitled to retain the Deposit as liquidated damages and not as a penalty, with no right to claim further damages or other remedies from Purchaser, and Purchaser and Vendor shall be released and discharged from all obligations hereunder except as provided in sections 3.3 and 13.15.

3.3 Efforts to Fulfil Conditions Precedent

Purchaser and Vendor shall proceed diligently and in good faith and use all reasonable efforts to satisfy and comply with and assist in the satisfaction and compliance with the conditions precedent. If there is a condition precedent that is to be satisfied or complied with prior to the Closing Time, and if, prior to the Closing Time, the Party for whose benefit the condition precedent exists fails to notify the other Party whether or not the condition precedent has been satisfied or complied with, the condition precedent shall be conclusively deemed to have been satisfied or complied with.

ARTICLE 4
REPRESENTATIONS AND WARRANTIES

4.1 Representations and Warranties of Vendor

Purchaser acknowledges that it is purchasing Vendor's interest in and to the Assets on an "as is, where is" basis, without representation and warranty and without reliance on any information provided to or on behalf of Purchaser by Vendor or any Third Party, whether verbal or in writing and whether contained herein including in a schedule attached hereto or otherwise, except that Vendor and Devon's managing partner, Devon Canada Corporation makes only the following representations and warranties to Purchaser as at the date of this Agreement and also as at the Closing Date, no claim in respect of which shall be made or be enforceable by Purchaser unless written notice of such claim, with reasonable particulars, is given by Purchaser to Vendor within a period of twelve (12) months from the Closing Time:

(a) Devon is a general partnership duly organized, validly existing and authorized to carry on business in the Province in which the Lands are located. Devon now has good right, full power and absolute authority to sell, assign, transfer, convey and set over the interest of Devon in and to the Assets according to the true intent and meaning of this Agreement;

(b) ARL is a body corporate duly organized, validly existing and authorized to carry on business in the Province in which the Lands are located. ARL now has good right, full power and absolute authority to sell, assign, transfer, convey and set over the interest of ARL in and to the Assets according to the true intent and meaning of this Agreement;

(c) the execution, delivery and performance of this Agreement has been duly and validly authorized by any and all requisite actions and will not result in any violation of, be in conflict with or constitute a default under any partnership agreement, bylaws, articles or other governing document to which Vendor, is bound;

(d) the execution, delivery and performance of this Agreement will not result in any violation of, be in conflict with or constitute a default under any term or provision of any agreement or document to which Vendor is party or by which Vendor is bound, nor under any judgement, decree, order, statute, regulation, rule or license applicable to Vendor;

(e) this Agreement and any other agreements delivered in connection herewith constitute valid and binding obligations of Vendor enforceable against Vendor in accordance with their terms;

(f) no authorization or approval or other action by, and no notice to or filing with, any governmental authority or regulatory body exercising jurisdiction over the Assets is required for the due execution, delivery and performance by Vendor of this Agreement, other than authorizations, approvals or exemptions from requirement therefor, previously obtained and currently in force;

(g) Vendor has not incurred any obligation or liability, contingent or otherwise, for brokers' or finders' fees in respect of this Agreement or the transaction to be effected by it for which Purchaser shall have any obligation or liability;

(h) Vendor is not a non-resident within the meaning of section 116 of the Income Tax (Canada) and the interest of Vendor in and to the Assets does not constitute all or substantially all the property of Vendor;

(i) other than Permitted Encumbrances, (i) Vendor has not alienated or encumbered the Assets or any part or portion thereof, (ii) Vendor has not committed any act or omission whereby the interest of Vendor in and to the Assets or any part or portion thereof may be cancelled or determined; (iii) to the best of its knowledge information and belief, none of the Petroleum and Natural Gas Rights are subject to material reduction or conversion by reference to payout of any well, farmout or otherwise; and (iv) the Assets are now free and clear of all liens, royalties, conversion rights and other claims of Third Parties, created by, through or under Vendor;

(j) to the best of the knowledge, information and belief of Vendor, after due inquiry, no suit, action or other proceeding before any court or governmental agency has been commenced against Vendor or has been threatened against Vendor, which might result in a material impairment or loss of the interest of Vendor in and to the Assets or which might otherwise materially and adversely affect the Assets;

(k) all amounts owing to Third Parties prior to the date hereof and pertaining to the Assets have been fully paid, including without limitation (i) any and all ad valorem and property taxes, (ii) any and all production, severance and similar taxes, charges and assessments based upon or measured by the ownership or production of the Leased Substances or any of them or the receipt of proceeds therefor, and (iii) all amounts due and payable in connection with Permitted Encumbrances;

(l) except as may be set out in Schedule "B", there are no Take or Pay Obligations;

(m) in respect of the Assets, except in connection with the AFE's, there are no financial commitments of Vendor which are over $25,000.00 (Vendor's share) other than usual operating expenses incurred in the normal conduct of operations;

(n) except for the Production and Marketing Contracts and Take or Pay Obligations, Vendor is not a party to and Vendor's interest in and to the Assets is not otherwise bound or affected by any production sales contracts or commitments to sell or deliver Petroleum Substances, pertaining to the leased substances or any of them which are not terminable on 45 days or less notice without penalty;

(o) to the best of its knowledge, information and belief, Vendor has not received any notice of material default relating to the Assets, or any of them;

(p) To the Vendor's knowledge, Vendor has complied with, performed, observed and satisfied all material terms, conditions, obligations and liabilities which have heretofore arisen and which are obligations of Vendor under any of the provisions of any agreement affecting the Assets, including any Title Document or any then exiting statute, order, writ, injunction or decree of any governmental agency or court relating to the Assets and there is no particular circumstance that the Vendor reasonably believes to be a material and reportable event under any law, policy or regulation;

(q) In respect of those Assets operated by Vendor, there are no contract operating agreements other than those disclosed;

(r) Vendor has and will have made available to Purchaser, prior to Closing, all of the Title Documents in Vendor's possession relevant to Vendor's title to the Lands;

(s) From the Effective Date, none of the Wells have been produced in excess of regulatory production allowables or are in breach thereof;

(t) Vendor is not aware of and has not received:

(i) any orders or directives specific to the Assets or a portion thereof which relate to environmental matters and which require any work, repairs, construction or capital expenditures with respect to the Assets, where such orders or directives have not been complied with in all material respects; or

(ii) any demand or notice issued with respect to the breach of any environmental, health or safety law specifically applicable to the Assets or a portion thereof only, including without limitation, respecting the use, storage, treatment, transportation or disposition of environmental contaminants, which demand or notice remains outstanding on the date hereof.

4.2 Limitation

(a) Vendor makes no representations or warranties except as expressly set forth in section 4.1 and, in particular, and without limitation, Vendor hereby expressly negates any representations or warranties by it (except those contained in section 4.1) whether contained in any information, memorandum or otherwise, whether provided to Purchaser directly or through Vendor's agents, with respect to:

(i) any data or information supplied by Vendor in connection herewith;

(ii) the quality, quantity or recoverability of Petroleum Substances within or under the Lands or any lands pooled or unitized therewith;

(iii) the value of the Assets or the future cash flow therefrom;

(iv) the quality, condition, fitness or merchantability of any tangible depreciable equipment or property interests which are comprised in the Assets; and

(v) the title of Vendor in and to the Assets

(b) Purchaser acknowledges that it has only relied upon the representations and warranties contained in section 4.1 and not on any representations or warranties outside this Agreement and Vendor shall have no liability, whether under contract, tort, statute or otherwise in respect of any statements, information, representations or warranties made by it or by its employees, agents or representatives, except liability for the representations and warranties contained in section 4.1, which liability shall be subject to the limitations contained in this Agreement. Purchaser acknowledges and confirms that except for the representations and warranties in section 4.1, it has performed its own due diligence and has relied, and will continue to rely, upon its own engineering and due diligence with respect to the state or condition of the Assets.

4.3 Representations and Warranties of Purchaser

Purchaser makes the following representations and warranties to Vendor, no claim in respect of which shall be made or be enforceable by Vendor unless written notice of such claim, with reasonable particulars, is given by Vendor to Purchaser within a period of twelve (12) months from the Closing Time:

(a) Purchaser is a corporation duly organized and validly existing under the laws of the jurisdiction of incorporation of Purchaser, is authorized to carry on business in the Province in which the Lands are located, and now has good right, full power and absolute authority to purchase the interest of Vendor in and to the Assets according to the true intent and meaning of this Agreement;

(b) the execution, delivery and performance of this Agreement has been duly and validly authorized by any and all requisite corporate, shareholders' and directors' actions and will not result in any violation of, be in conflict with or constitute a default under any articles, charter, bylaw or other governing document to which Purchaser is bound;

(c) the execution, delivery and performance of this Agreement will not result in any violation of, be in conflict with or constitute a default under any term or provision of any agreement or document to which Purchaser is party or by which Purchaser is bound, nor under any judgement, decree, order, statute, regulation, rule or license applicable to Purchaser;

(d) this Agreement and any other agreements delivered in connection herewith constitute valid and binding obligations of Purchaser enforceable against Purchaser in accordance with their terms;

(e) no authorization or approval or other action by, and no notice to or filing with, any governmental authority or regulatory body exercising jurisdiction over the Assets is required for the due execution, delivery and performance by Purchaser of this Agreement, other than authorizations, approvals or exemptions from requirement therefor, previously obtained and currently in force;

(f) Purchaser has made inquiries and believes in good faith that it will not have to post any security deposits required by any regulatory bodies having jurisdiction over the Assets, or will be able to post such deposits and is not aware of any other regulatory impediments to the transfer of the licences, permits and approvals pertaining to the Assets which impediments arise solely as a result of certain risk assessments pertaining to Purchaser, and carried out by such regulatory bodies;

(g) Purchaser has not incurred any obligation or liability, contingent or otherwise, for brokers' or finders' fees in respect of this Agreement or the transaction to be effected by it for which Vendor shall have any obligation or liability;

(h) Purchaser is entering into this Agreement and will acquire the Assets for itself and not as agent or representative for any other Third Party, however Purchaser may sell a working interest in the Assets following the Closing Time; and

(i) Purchaser is not a non-Canadian person for the purposes of the Investment Canada Act.

ARTICLE 5
INDEMNITIES FOR REPRESENTATIONS AND WARRANTIES

5.1 Vendor's Indemnities for Representations and Warranties

Vendor shall be liable to Purchaser for and shall, in addition, indemnify Purchaser, its affiliates, and directors and officers thereof, from and against, all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Purchaser which would not have been suffered, sustained, paid or incurred had all of the representations and warranties contained in section 4.1 been accurate and truthful, provided however that nothing in this section 5.1 shall be construed so as to cause Vendor to be liable to or indemnify Purchaser in connection with any representation or warranty contained in section 4.1 if and to the extent that Purchaser, in its sole discretion, did not rely upon such representation or warranty.

5.2 Purchaser's Indemnities for Representations and Warranties

Purchaser shall be liable to Vendor for and shall, in addition, indemnify Vendor, its affiliates, and directors and officers thereof, from and against, all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor which would not have been suffered, sustained, paid or incurred had all of the representations and warranties contained in section 4.3 been accurate and truthful, provided however that nothing in this section 5.2 shall be construed so as to cause Purchaser to be liable to or indemnify Vendor in connection with any representation or warranty contained in section 4.3 if and to the extent that Vendor, in its sole discretion, did not rely upon such representation or warranty.

5.3 Time Limitation

No claim under this Article 5 shall be made or be enforceable by a Party unless written notice of such claim, with reasonable particulars, is given by such Party to the Party against whom the claim is made within a period of twelve (12) months from the Closing Time.

ARTICLE 6
PURCHASER'S INDEMNITIES

6.1 General Indemnity

Purchaser shall be liable to Vendor for and shall, in addition, indemnify Vendor from and against, all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor which arise out of any matter or thing occurring or arising from and after the Closing Date and which relates to the Assets, provided however that Purchaser shall not be liable to nor be required to indemnify Vendor in respect of any losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor which arise out of breach of Vendor's representations and warranties contained in Clause 4.1 hereunder.

6.2 Abandonment and Reclamation

Purchaser shall see to the timely performance of all abandonment and reclamation obligations pertaining to the Assets which in the absence of this Agreement would be the responsibility of Vendor. Purchaser shall be liable to Vendor for and shall, in addition, indemnify Vendor from and against, all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor should Purchaser fail to timely perform such obligations.

6.3 Environmental Matters

Purchaser shall be liable to Vendor for and shall, in addition, indemnify Vendor from and against, all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor which pertain to environmental damage or contamination or other environmental problems pertaining to or caused by the Assets or operations thereon or related thereto, however and by whomsoever caused, and whether such environmental damage or contamination or other environmental problems occur or arise in whole or in part prior to, at or subsequent to the Effective Date. Purchaser shall not be entitled to exercise and hereby waives any rights or remedies Purchaser may now or in the future have against Vendor in respect of such environmental damage or contamination or other environmental problems, whether such rights and remedies are pursuant to the common law or statute or otherwise, including without limitation, the right to name Vendor as a third party to any action commenced by any Third Party against Purchaser. Without limiting the generality of the foregoing, such environmental damage or contamination or other environmental problems shall include (I) surface, underground, air, ground water or surface water contamination, (ii) the abandonment or plugging of or failure to abandon or plug any of the Wells, (iii) the restoration or reclamation of or failure to restore or reclaim any part of the Assets, (iv) the breach of applicable government rules and regulations in effect at any time, and (v) the removal of or failure to remove foundations, structures or equipment.

6.4 Limitation

Notwithstanding any other provision in this Agreement, Purchaser shall not be liable to nor be required to indemnify Vendor in respect of any losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor in respect of which Vendor is liable to and has indemnified Purchaser pursuant to section 5.1, and Vendor shall not be liable to nor be required to indemnify Purchaser in respect of any losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Purchaser in respect of which Purchaser is liable to and has indemnified Vendor pursuant to section 5.2, in both cases disregarding the time limit set out in section 5.3.

ARTICLE 7
OPERATING ADJUSTMENTS

7.1 Operating Adjustments

(a) Subject to all other provisions of this Agreement, all benefits and obligations of any kind and nature relating to the operation of the Assets conveyed pursuant to this Agreement, including without limitation maintenance, development, operating and capital costs, government incentives, royalties and other burdens, and proceeds from the sale of production (based on the weighted average price received by Vendor for its gas produced after the Effective Date and from the province in which the Lands are situated and referred to by Vendor as Vendor's "Corporate Pool Price"), whether accruing, payable or paid and received or receivable, shall be adjusted between the Parties as of the Effective Date in accordance with generally accepted accounting principles. For greater certainty, adjustments in respect of production, if any, shall be made in favour of Vendor in respect of production beyond the wellhead at the Effective Date and in favour of Purchaser in respect of all other production. The adjustments shall constitute an increase or decrease, as the case may be, to the Purchase Price and to the amount allocated to the Petroleum and Natural Gas Rights. Vendor shall provide to Purchaser within a reasonable time prior to the Closing Time a written statement of all such adjustments to be made at Closing, and shall cooperate with Purchaser to enable Purchaser to verify the accuracy of such statement. Adjustments not settled or incorrectly settled prior to or at Closing shall be settled by payment to or by Vendor and Purchaser, as the case may be, as soon as practicable after Closing. The intention of the Parties is that final settlement shall occur within 180 days following the Closing Time and shall be prepared by Vendor. No adjustments shall be made after 1 year from the Closing Time unless written notice of the requested adjustment, with reasonable particulars, is given within 1 year from the Closing Time, provided however that adjustments arising as a consequence of Crown royalty audits, joint venture audits, and facility operating agreement 13 month adjustments are subject to a 3 year limit.

(b) During the period of one (1) year following the Closing Time ("Audit Period"), the Purchaser may audit the books, records and accounts of the Vendor respecting the Assets, for the purpose of effecting adjustments pursuant to this Article. Such audit shall be conducted upon reasonable notice to the Vendor at the Vendor's offices during the Vendor's normal business hours, and shall be conducted at the sole expense of the Purchaser. Any claims of discrepancies disclosed by such audit shall be made in writing to the Vendor within the Audit Period and the Vendor shall respond in writing to any claims of discrepancies within the Audit Period.

(c) Payments of lessor royalties, relating to the production months prior to the Closing Time for which production revenue has been received by Vendor shall be paid by Vendor, either before or after the Closing Time, and will be dealt with by way of the statement of adjustments described herein for those production months between the Effective Date and the Closing Time.

(d) From the Effective Date until the Closing Time, Vendor, where it is the operator, shall retain all overhead recoveries earned pursuant to any Title Document(s), and the adjustments in this Article shall include any and all such overhead chargeable and recovered by Vendor.

(e) The Parties agree that Vendor shall book and report for tax accounting and tax filing purposes all revenue, expenses capital items, income or losses pertaining and accruing to the Assets from the Effective Date to the Closing Time. The Purchaser shall book and report for tax accounting and tax filing purposes all revenue, expenses capital items, income or losses pertaining and accruing to the Assets after the Closing Time.

ARTICLE 8
MAINTENANCE OF ASSETS

8.1 Maintenance of Assets

From the date hereof, until the Closing Time, Vendor shall, to the extent that the nature of its interest permits, and subject to the Title Documents and any other agreements and documents to which the Assets are subject:

(a) maintain the Assets in a proper and prudent manner in material compliance with all applicable laws, rules, regulations, orders and directions of governmental and other competent authorities; and

(b) pay or cause to be paid all costs and expenses relating to the Assets which become due from the date hereof to the Closing Time.

8.2 Consent of Purchaser

Notwithstanding section 8.1, Vendor shall not from the date hereof to the Closing Time, without the prior written consent of Purchaser, which consent shall not be unreasonably withheld by Purchaser and which, if provided, shall be provided in a timely manner:

(a) make any commitment or propose, initiate or authorize any capital or other expenditure with respect to the Assets of which Vendor's share is in excess of $25,000.00, except in case of an emergency or in respect of amounts which Vendor may be committed to expend or be deemed to authorize for expenditure without Vendor's consent;

(b) surrender or abandon any of the Assets or fail to make any required payments under the Title Documents;

(c) materially amend or wholly terminate any Title Document or any other agreement or document to which the Assets are subject, or enter into any new agreement or commitment relating to the Assets; or

(d) sell, encumber or otherwise dispose of any of the Assets or any part or portion thereof excepting sales of the Leased Substances in the normal course of business.

ARTICLE 9
RIGHTS OF FIRST REFUSAL

9.1 Rights of First Refusal

(a) Within Five (5) Business Days of the execution and delivery of this Agreement, Vendor shall advise Purchaser which of the Assets are subject to preferential, pre-emptive or first purchase rights (the "ROFRs") that become operative by virtue of this Agreement or the transaction to be effected by it. Within Two (2) Business Days of receiving such advice, Purchaser shall advise Vendor in writing of its bona fide allocations of value for Vendor's interest in and to such Assets. Vendor shall comply with the applicable provisions of such ROFRs and shall courier notices to the Third Parties (and Purchaser, if applicable) holding such rights no later than Two (2) Business Days after it receives the bona fide allocations of Purchaser, in a form that is acceptable to Purchaser acting reasonably, using the bona fide allocations of Purchaser. Vendor shall notify

Purchaser in writing forthwith upon each Third Party exercising or waiving such a right. If any such Third Party elects to exercise such a right, the definition of Assets shall be deemed to be amended to exclude those Assets in respect of which the right has been exercised, such Assets shall not be conveyed to Purchaser and the Purchase Price, and the tax allocations shall be reduced accordingly. If there are any Take or Pay Obligations and/or Production and Marketing Contracts pertaining to such Assets, Purchaser shall not assume such Take or Pay Obligations and/or obligations under Production and Marketing Contracts and any amounts owing as a result of the Take or Pay Obligations to be paid by Vendor to Purchaser shall be reduced accordingly.

(b) Purchaser hereby confirms to Vendor that the values to be allocated by Purchaser with respect to the applicable ROFRs being operative by virtue of this Agreement, will be bona fide values allocated by Purchaser to each specific interest after diligent review and analysis. To the extent that a Third Party issues and forwards to Vendor or Purchaser an objection letter or a notice of objection which pertains to such notice of ROFR forwarded by Vendor, Purchaser hereby agrees to be liable to Vendor for and in addition, hereby indemnifies Vendor from and against, all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor which are attributable to, or arise out of the disputes, issues and matters relating to the values selected by Purchaser as set forth in the notice of ROFR forwarded to the Third Party. Such indemnity shall extend, without limitation to solicitor and his client costs and expenses and Vendor will be entitled to retain its own counsel in relation to any such dispute.

ARTICLE 10
PRE-CLOSING INFORMATION

10.1 Production of Documents

At all reasonable times from the date hereof until the Closing Time, Vendor shall make available to Purchaser and Purchaser's counsel in Vendor's offices in Calgary the following information pertaining to the Assets to which Vendor has possession:

(a) all title opinions and reports;

(b) all environmental reports prepared by a Third Party;

(c) all of the Title Documents and any other agreements and documents to which the Assets are subject;

(d) evidence with respect to the payment of all bonuses, rentals and royalties due under the Title Documents; and

(e) lease and contract records and well files.

ARTICLE 11
TITLE DEFECTS AND ENVIRONMENTAL REVIEW

11.1 Title Review and Environmental Review

From time to time, as soon as reasonably practicable after execution of this Agreement, Purchaser and purchaser's counsel shall have the opportunity to review the title of Vendor in and to the Assets and the environmental condition thereof and Vendor shall, to the extent that its interest permits, provide all reasonable access to the Assets for Purchaser to do so.

11.2 Termination on Title Defects or Environmental Review

Prior to the Closing Time, Purchaser may terminate this Agreement in its entirety where either (i) the cumulative amount by which the value of any Title Defects is, in Purchaser's opinion acting reasonably, 7.5% or more of the Purchase Price, or (ii) the cumulative amount by which the value of any Environmental Defects is, in Purchaser's opinion acting reasonably, 7.5% or more of the Purchase Price, or (iii) the cumulative amount by which the value of any Environmental Defects and Title Defects is, in Purchaser's opinion acting reasonably, 10% or more of the Purchase Price. In both cases, in order for these rights of termination to be operative, Purchaser shall provide to Vendor a written notice of Title Defects and/or a written notice of Environmental Defects, as applicable, and such notices shall include the nature of the Title Defect and/or Environmental Defect, as applicable and a breakdown of the total cumulative value among each of the Assets affected by each of the Title Defects and/or Environmental Defects, as applicable. For sake of clarity, Purchaser shall not include Title Defects on any written notices relating to Environmental Defects and vice versa, unless the total value of the Title Defects and Environmental Defects exceeds 10% of the Purchase Price. If Vendor agrees, acting reasonably that the value or values, as the case might be, allocated by Purchaser are reasonable, the Parties shall be released of all obligations hereunder except clause 13.15 and Vendor shall forthwith return the Deposit and accrued interest to Purchaser.

11.3 Value Disputes

If Vendor disagrees, acting reasonably, with the value or values allocated by Purchaser to the Title Defects or Environmental Defects, or both, Vendor shall have the sole option to terminate this Agreement by written notice to Purchaser, or to delay Closing and refer the matter of valuation of the Title Defects or the Environmental Defects, or both, to arbitration. If Vendor elects to delay Closing and refer the matter of valuation to arbitration, the Parties shall forthwith meet in good faith to discuss the issue. If after such a meeting the issue has not been resolved or if a Party does not forthwith meet to discuss the issue, the issue shall be resolved by a single arbitrator pursuant to the provisions of the Arbitration Act (Alberta). The decision of the arbitrator shall be final and shall not be subject to review. All costs of arbitration shall be borne by the Parties equally. The arbitrator will be asked to render a decision within thirty (30) days of being presented with its instructions as to the arbitration. If the value determined by the arbitrator to the Title Defects or the Environmental Defects, as applicable, is less than 7.5% of the Purchase Price and the value determined by the arbitrator to the Title Defects and Environmental Defects combined is less than 10% of the Purchase Price, the Parties shall forthwith close the transactions contemplated by this Agreement without any adjustment to the Purchase Price. If any of the values determined by the arbitrator are in excess of the limits set forth in Article 11.2 above, the Parties shall be released of all obligations hereunder except clause 13.15, and Vendor shall forthwith return the Deposit and accrued interest to Purchaser.

ARTICLE 12
INTENTIONALLY DELETED

ARTICLE 13
GENERAL

13.1 Further Assurances

Each Party will, from time to time and at all times after Closing, without further consideration, do such further acts and deliver all such further assurances, deeds and documents as shall be reasonably required in order to fully perform and carry out the terms of this Agreement.

13.2 No Merger

The covenants, representations, warranties and indemnities contained in this Agreement shall be deemed to be restated in any and all assignments, conveyances, transfers and other documents conveying the interests of Vendor in and to the Assets to Purchaser, subject to any and all time and other limitations contained in this Agreement. There shall not be any merger of any covenant, representation, warranty or indemnity in such assignments, conveyances, transfers and other documents notwithstanding any rule of law, equity or statute to the contrary and such rules are hereby waived.

13.3 Entire Agreement

The provisions contained in any and all documents and agreements collateral hereto shall at all times be read subject to the provisions of this Agreement and, in the event of conflict, the provisions of this Agreement shall prevail. No amendments shall be made to this Agreement unless in writing, executed by the Parties. This Agreement supersedes all other agreements, documents, writings and verbal understandings among the Parties relating to the subject matter hereof, including a letter option agreement between Red Mountain Resources Inc. (as agent for Purchaser) and Devon Canada Corporation dated February 27, 2001 and expresses the entire agreement of the Parties with respect to the subject matter hereof.

13.4 Subrogation

The assignment and conveyance to be effected by this Agreement is made with full right of substitution and subrogation of Purchaser in and to all covenants, representations, warranties and indemnities previously given or made by others in respect of the Assets or any part or portion thereof.

13.5 Governing Law

This Agreement shall, in all respects, be subject to, interpreted, construed and enforced in accordance with and under the laws of the Province of Alberta and the laws of Canada applicable therein and shall, in every regard, be treated as a contract made in the Province of Alberta. The Parties irrevocably attorn and submit to the jurisdiction of the courts of the Province of Alberta and courts of appeal therefrom in respect of all matters arising out of this Agreement.

13.6 Enurement

This Agreement may not be assigned by a Party without the prior written consent of the other Party, which consent may be unreasonably and arbitrarily withheld. This Agreement shall be binding upon and shall enure to the benefit of the Parties and their respective administrators, trustees, receivers, successors and permitted assigns.

13.7 Time of Essence

Time shall be of the essence in this Agreement.

13.8 Notices

The addresses for service and the fax numbers of the Parties shall be as follows:

Vendor - Devon Canada and Devon ARL Corporation

1600, 324- 8th Avenue S.W.
Calgary, Alberta
T2P 2Z5

Attention: Land Department
Fax: (403) 213-7900

Purchaser - Coyote Energy Inc.
c/o Caribou Capital Corp.
2200, 400 — 3 Avenue S.W.
Calgary, Alberta
T2P 4H2

Attention: David Rain
Fax: (403) 266-1438

All notices, communications and statements required, permitted or contemplated hereunder shall be in writing, and shall be delivered as follows:

(a) by personal service on a Party at the address of such Party set out above, in which case the item so served shall be deemed to have been received by that Party when personally served;

(b) by facsimile transmission to a Party to the fax number of such Party set out above, in which case the item so transmitted shall be deemed to have been received by that Party when transmitted; or

(c) except in the event of an actual or threatened postal strike or other labour disruption that may affect mail service, by mailing first class registered post, postage prepaid, to a Party at the address of such Party set out above, in which case the item so mailed shall be deemed to have been received by that Party on the third Business Day following the date of mailing.

A Party may from time to time change its address for service or its fax number or both by giving written notice of such change to the other Parties.

13.9 Operatorship

Purchaser acknowledges that Vendor is unable to assign to Purchaser operatorship of the Assets, if any, operated by Vendor and in respect of which Vendor does not have a 100% interest. Vendor shall, however, use reasonable best efforts to assist Purchaser in its attempts to obtain operatorship.

13.10 Limit of Liability

In no event shall the liability of Vendor to Purchaser in respect of claims of Purchaser arising out of or in connection with this Agreement exceed, in the aggregate, the Purchase Price, taking into account any and all increases or decreases to the Purchase Price that occur by virtue of the terms of this Agreement.

13.11 Invalidity of Provisions

In case any of the provisions of this Agreement should be invalid, illegal or unenforceable in any respect, the validity, legality or enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

13.12 Waiver

No failure on the part of any Party in exercising any right or remedy hereunder 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 right or remedy in law or in equity or by statute or otherwise conferred. No waiver of any provision of this Agreement, including without limitation, this section, shall be effective otherwise than by an instrument in writing dated subsequent to the date hereof, executed by a duly authorized representative of the Party making such waiver.

13.13 Amendment

This Agreement shall not be varied in its terms or amended by oral agreement or by representations or otherwise other than by an instrument in writing dated subsequent to the date hereof, executed by a duly authorized representative of each Party.

13.14 Agreement not Severable

This Agreement extends to the whole of the Assets and is not severable without Purchaser's express written consent or as otherwise herein provided.

13.15 Confidentiality and Public Announcements

Until Closing has occurred, each Party shall keep confidential all information obtained from the other Party in connection with the Assets and shall not release any information concerning this Agreement and the transactions herein provided for, without the prior written consent of the other Party, which consent shall not be unreasonably withheld. Nothing contained herein shall prevent a Party at any time from furnishing information (i) to any governmental agency or regulatory authority or to the public if required by applicable law, provided that the Parties shall advise each other in advance of any public statement which they propose to make, (ii) in connection with obtaining consents or complying with preferential, pre-emptive or first purchase rights contained in Title Documents and any other agreements and documents to which the Assets are subject, or (iii) to procure the consent of Vendor's lenders.

13.16 Counterpart Execution

This Agreement may be executed in counterpart, no one copy of which need be executed by Vendor and Purchaser. A valid and binding contract shall arise if and when counterpart execution pages are executed and delivered by Vendor and Purchaser.

IN WITNESS WHEREOF the Parties have executed this Agreement as of the day and year first above written.

DEVIN CANADA by its Managing Partner DEVON CANADA CORPORATION	COYOTE ENERGY INC.
Per: *(signed)*	Per: *(signed)*

DEVON ARL CORPORATION

Per: *(signed)*

SCHEDULES INTENTIONALLY DELETED

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DIRECT ROYALTIES SALE AGREEMENT

DATED NOVEMBER 15, 2002

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DIRECT ROYALTIES SALE AGREEMENT

THIS AGREEMENT dated the 15th day of November, 2002.

BETWEEN:

HARVEST OPERATIONS CORP., a body corporate, incorporated pursuant to the *Business Corporations Act* (Alberta) (hereinafter referred to as the "Corporation")

OF THE FIRST PART

AND

VALIANT TRUST COMPANY, in its capacity as Trustee of the Harvest Energy Trust (hereinafter referred to as the "Trust")

OF THE SECOND PART

WHEREAS the Corporation has granted the NPI to the Trust, pursuant to the NPI Agreement;

AND WHEREAS certain of the assets acquired by the Corporation pursuant to the Sale Agreement take the form of direct royalty interests and the Corporation has agreed to sell to the Trust ninety-nine (99%) percent of such direct royalty interests on the terms hereinafter set forth;

AND WHEREAS it is the intention of the parties that the Corporation retain any and all rights relating to the Conveyed Assets which would result in the Conveyed Assets being an interest in real property, including fee simple interests;

NOW THEREFORE THIS AGREEMENT WITNESSES that in consideration of the premises and the mutual covenants and agreements hereinafter set forth, the Parties have agreed as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement, including the recitals, unless the context otherwise requires or unless otherwise defined below, terms which are defined in the NPI Agreement have the meanings in this agreement ascribed to them in the NPI Agreement and:

(a) "**Conveyed Assets**" means an undivided ninety-nine (99%) percent interest in the royalty interests acquired by the Corporation pursuant to the Sale Agreement, and for greater certainty shall exclude the Excluded Assets;

(b) "**Effective Time**" has the meaning ascribed thereto in the Sale Agreement;

(c) "**Excluded Assets**" means:

(i) the Corporation's fee simple interests in the Conveyed Assets, if any;

(ii) the Corporation's rights to re-enter the Conveyed Assets on termination of an existing or subsequent lease;

(iii) the Corporation's rights to convert any royalty interests forming part of the Conveyed Assets to working interests together with the working interests acquired on such conversions; and

(iv) any other rights which, if they were comprised in the Conveyed Assets would result in the Conveyed Assets being an interest in real property;

(d) "**NPI**" means the net profits interest payable by Coyote to the Trust pursuant to the NPI Agreement;

(e) "**NPI Agreement**" means that certain amended and restated agreement dated the 27th day of September, 2002 between the Corporation and the Trust;

(f) "**Parties**" means the parties to this Agreement and "Party" means any one of them;

(g) "**Sale Agreement**" means that certain agreement so titled dated the 1st day of August, 2002 among Anadarko Canada Corporation and the Corporation;

(h) "**the Trust**" means Harvest Energy Trust, a trust formed pursuant to the laws of Alberta pursuant to the Trust Indenture;

(i) "**this Agreement**", " herein", "hereto", "hereof" and similar expressions refer to this Direct Royalties Sale Agreement, any agreement amending this agreement and any agreement which is supplemental or ancillary to this agreement;

(j) "**Trust Indenture**" means the amended and restated Trust Indenture dated as the 27th day of September, 2002 among the Corporation and the Trustee; and

(k) "**Trustee**" means Valiant Trust Company in its capacity as trustee of the Trust and includes any successor trustee of the Trust.

1.2 Interpretation Not Affected by Headings

The headings in this Agreement are for convenience only and shall not affect the construction or interpretation of this Agreement.

1.3 Included Words

In this Agreement, where the context reasonably permits, words suggesting the singular shall be construed as suggesting the plural and vice versa, and words suggesting one gender shall be construed as suggesting other genders.

ARTICLE 2
CONVEYANCE

2.1 Conveyance

Pursuant to and for the purchase price (the "Conveyed Assets Purchase Price") equal to Fifty Five Thousand ($55,000) DOLLARS which amount has been prepaid by the Trust to the Corporation (and receipt whereof is hereby acknowledged by the Corporation) and is subject to adjustment pursuant to Section 2.3, the Corporation hereby sells, assigns, transfers, conveys and sets over to the Trust, the Corporation's entire beneficial right, title, estate and interest in and to the Conveyed Assets, to have and to hold the same absolutely, together with all benefit and advantage to be derived therefrom.

2.2 Possession and Ownership

Possession and ownership of the Conveyed Assets shall pass from the Corporation to the Trust at the Effective Time.

2.3 Adjustments

Subject to other provisions of this agreement, all benefits, income, costs and expenses of every kind and nature relating to the Conveyed Assets, including without limitation, royalty revenues and proceeds from the sale of production, other than income taxes, shall be apportioned between the Corporation and the Trust as of the Effective Time, on an accrual basis, and the Conveyed Assets Purchase Price shall be adjusted by such apportionment. It is acknowledged that the Sale Agreement provides for adjustments to the Purchase Price (as defined therein), including adjustments relating to the Conveyed Assets, and it is agreed that the apportionment and adjustment to the Conveyed Assets Purchase Price pursuant to this Section 2.3 shall be based upon the adjustments to the Purchase Price (as defined in the Sale Agreement) to the extent such adjustments relate to the Conveyed Assets.

ARTICLE 3
EXCLUDED ASSETS, CONVEYED ASSETS

3.1 Severance

In the event that for any reason an Excluded Asset cannot be severed from the applicable Conveyed Asset, the Corporation shall hold all rights, title, interests, revenues and benefits accruing with respect to such Conveyed Asset in trust for and on behalf of the Trust and shall execute and deliver such declarations of trust or other documents as the Trust may reasonably request in order to further document such trust. Further, in the event the Conveyed Assets cannot be held in trust for and on behalf of the Trust in the manner contemplated above, the Corporation shall pay to the Trust a royalty which shall be equal to 99% of all revenues received from time to time by the Corporation in respect of the Conveyed Assets, which payments shall be made by the Corporation to the Trust forthwith upon receipt by the Corporation of such revenues, and the Corporation shall execute and deliver such agreements, instruments or other documents as the Trust may reasonably request in order to provide for such royalty which agreements, instruments or other documents shall include, without limitation, provisions similar to the provisions provided for in Articles 4 and 5 hereof, to the extent applicable.

ARTICLE 4
COLLECTION AND PAYMENT

4.1 Initial Royalty Payments

The Corporation and the Trust acknowledge the royalties comprising the Conveyed Assets may initially be paid to the Corporation and that the Corporation will pay the Trust's share of such royalties to the Trust in accordance with the terms hereof.

4.2 Collection of Royalties

The Corporation will use all commercially reasonable efforts to obtain the payment of all royalties comprising the Conveyed Assets but shall not have any liability to the Trust to the extent that it fails to collect them, provided it makes commercially reasonable efforts to do so.

4.3 Payments

The Corporation shall not later than the 5th business day of every month pay to the Trust all royalties comprising the Conveyed Assets which it has received in the prior month.

4.4 Quarterly Statements

The Corporation shall provide the Trust with quarterly statements setting forth the amount of the royalty payments paid to the Trust in the previous quarter.

4.5 Trust's Right to Collect

Nothing contained in this Agreement shall restrict the Trust's right to collect its share of the royalties comprising the Conveyed Assets directly if it so elects.

ARTICLE 5
MISCELLANEOUS

5.1 Inurement

This agreement shall be binding upon and shall inure to the benefit of each of the parties hereto and their respective trustees, receivers, receiver-managers, successors and assigns.

5.2 Acknowledgement

The parties hereto acknowledge that the Trustee is entering into this agreement solely in its capacity as Trustee on behalf of the Trust and the obligations of the Trust hereunder shall not be personally binding upon the Trustee or any of the Unitholders of the Trust and that any recourse against the Trust, Trustee or any Unitholder of the Trust in any manner in respect of any indebtedness, obligation or liability of the Trust arising hereunder or arising in connection herewith or from the matters to which this agreement relates, if any, including without limitation claims based on negligence or otherwise tortious behaviour, shall be limited to, and satisfied only out of, the Trust Fund as defined in the Trust Indenture.

5.3 Further Assurances

Each party hereto will, from time to time and at all times hereafter, at the request of the other party but without further consideration, do all such further acts and execute and deliver all such further documents as shall be reasonably required in order to fully perform and carry out the terms hereof.

5.4 Counterpart Execution and Facsimile Delivery

This Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall constitute one agreement. Delivery of a facsimile of an executed counterpart of this Agreement shall be as legally effective as delivery of an original executed counterpart and if each party to this Agreement delivers either an original or a facsimile copy of a counterpart of this Agreement executed by it, this Agreement shall be a valid and binding agreement between them.

IN WITNESS WHEREOF the parties hereto have executed this agreement on the date first above written.

HARVEST OPERATIONS CORP.

Per: *(signed)*

VALIANT TRUST COMPANY, in its capacity as Trustee of the Harvest Energy Trust

Per: *(signed)*

(12)

04 MAR -9 AM 7:21

AMENDED AND RESTATED
DIRECT ROYALTIES SALE AGREEMENT

DATED SEPTEMBER 27, 2002

AMENDED AND RESTATED
DIRECT ROYALTIES SALE AGREEMENT

THIS AGREEMENT dated the 27th day of September, 2002.

BETWEEN:

HARVEST OPERATIONS CORP., a body corporate, incorporated pursuant to the *Business Corporations Act* (Alberta) (hereinafter referred to as the "Corporation")

OF THE FIRST PART

AND

VALIANT TRUST COMPANY, in its capacity as Trustee of the Harvest Energy Trust (hereinafter referred to as the "Trust")

OF THE SECOND PART

WHEREAS the Corporation has granted the NPI to the Trust, pursuant to the NPI Agreement;

AND WHEREAS certain of the assets acquired by the Corporation pursuant to the Sale Agreement take the form of direct royalty interests and the Corporation has agreed to sell to the Trust ninety-nine (99%) percent of such direct royalty interests on the terms hereinafter set forth;

AND WHEREAS it is the intention of the parties that the Corporation retain any and all rights relating to the Conveyed Assets which would result in the Conveyed Assets being an interest in real property, including fee simple interests;

NOW THEREFORE THIS AGREEMENT WITNESSES that in consideration of the premises and the mutual covenants and agreements hereinafter set forth, the Parties have agreed as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement, including the recitals, unless the context otherwise requires or unless otherwise defined below, terms which are defined in the NPI Agreement have the meanings in this agreement ascribed to them in the NPI Agreement and:

(a) "**Conveyed Assets**" means an undivided ninety-nine (99%) percent interest in the royalty interests acquired by the Corporation pursuant to the Sale Agreement, and for greater certainty shall exclude the Excluded Assets;

(b) "**Effective Time**" has the meaning ascribed thereto in the Sale Agreement;

(c) "**Excluded Assets**" means:

(i) the Corporation's fee simple interests in the Conveyed Assets, if any;

(ii) the Corporation's rights to re-enter the Conveyed Assets on termination of an existing or subsequent lease;

(iii) the Corporation's rights to convert any royalty interests forming part of the Conveyed Assets to working interests together with the working interests acquired on such conversions; and

(iv) any other rights which, if they were comprised in the Conveyed Assets would result in the Conveyed Assets being an interest in real property;

(d) "**NPI**" means the net profits interest payable by Coyote to the Trust pursuant to the NPI Agreement;

(e) "**NPI Agreement**" means that certain amended and restated agreement dated the 27th day of September, 2002 between the Corporation and the Trust;

(f) "**Parties**" means the parties to this Agreement and "Party" means any one of them;

(g) "**Sale Agreement**" means that certain agreement so titled dated the 28th day of May, 2002, as amended pursuant to an amending agreement dated the 4th day of July, 2002 among Devon Canada, a general partnership, Devon ARL Corporation and the Corporation;

(h) "**the Trust**" means Harvest Energy Trust, a trust formed pursuant to the laws of Alberta pursuant to the Trust Indenture;

(i) "**this Agreement**", " herein", "hereto", "hereof" and similar expressions refer to this Direct Royalties Sale Agreement, any agreement amending this agreement and any agreement which is supplemental or ancillary to this agreement;

(j) "**Trust Indenture**" means the amended and restated Trust Indenture dated as the 27th day of September, 2002 among the Corporation and the Trustee; and

(k) "**Trustee**" means Valiant Trust Company in its capacity as trustee of the Trust and includes any successor trustee of the Trust.

1.2 Interpretation Not Affected by Headings

The headings in this Agreement are for convenience only and shall not affect the construction or interpretation of this Agreement.

1.3 Included Words

In this Agreement, where the context reasonably permits, words suggesting the singular shall be construed as suggesting the plural and vice versa, and words suggesting one gender shall be construed as suggesting other genders.

ARTICLE 2
CONVEYANCE

2.1 Conveyance

Pursuant to and for the purchase price (the "Conveyed Assets Purchase Price") equal to Five Hundred Thousand ($500,000) DOLLARS which amount has been prepaid by the Trust to the Corporation (and receipt whereof is hereby acknowledged by the Corporation) and is subject to adjustment pursuant to Section 2.3, the Corporation hereby sells, assigns, transfers, conveys and sets over to the Trust, the Corporation's entire beneficial right, title, estate and interest in and to the Conveyed Assets, to have and to hold the same absolutely, together with all benefit and advantage to be derived therefrom.

2.2 Possession and Ownership

Possession and ownership of the Conveyed Assets shall pass from the Corporation to the Trust at the Effective Time.

2.3 Adjustments

Subject to other provisions of this agreement, all benefits, income, costs and expenses of every kind and nature relating to the Conveyed Assets, including without limitation, royalty revenues and proceeds from the sale of production, other than income taxes, shall be apportioned between the Corporation and the Trust as of the Effective Time, on an accrual basis, and the Conveyed Assets Purchase Price shall be adjusted by such apportionment. It is acknowledged that the Sale Agreement provides for adjustments to the Purchase Price (as defined therein), including adjustments relating to the Conveyed Assets, and it is agreed that the apportionment and adjustment to the Conveyed Assets Purchase Price pursuant to this Section 2.3 shall be based upon the adjustments to the Purchase Price (as defined in the Sale Agreement) to the extent such adjustments relate to the Conveyed Assets.

ARTICLE 3
EXCLUDED ASSETS, CONVEYED ASSETS

3.1 Severance

In the event that for any reason an Excluded Asset cannot be severed from the applicable Conveyed Asset, the Corporation shall hold all rights, title, interests, revenues and benefits accruing with respect to such Conveyed Asset in trust for and on behalf of the Trust and shall execute and deliver such declarations of trust or other documents as the Trust may reasonably request in order to further document such trust. Further, in the event the Conveyed Assets cannot be held in trust for and on behalf of the Trust in the manner contemplated above, the Corporation shall pay to the Trust a royalty which shall be equal to 99% of all revenues received from time to time by the Corporation in respect of the Conveyed Assets, which payments shall be made by the Corporation to the Trust forthwith upon receipt by the Corporation of such revenues, and the Corporation shall execute and deliver such agreements, instruments or other documents as the Trust may reasonably request in order to provide for such royalty which agreements, instruments or other documents shall include, without limitation, provisions similar to the provisions provided for in Articles 4 and 5 hereof, to the extent applicable.

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COLLECTION AND PAYMENT

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The Corporation and the Trust acknowledge the royalties comprising the Conveyed Assets may initially be paid to the Corporation and that the Corporation will pay the Trust's share of such royalties to the Trust in accordance with the terms hereof.

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The Corporation shall not later than the 5^{th} business day of every month pay to the Trust all royalties comprising the Conveyed Assets which it has received in the prior month.

4.4 Quarterly Statements

The Corporation shall provide the Trust with quarterly statements setting forth the amount of the royalty payments paid to the Trust in the previous quarter.

4.5 Trust's Right to Collect

Nothing contained in this Agreement shall restrict the Trust's right to collect its share of the royalties comprising the Conveyed Assets directly if it so elects.

ARTICLE 5
MISCELLANEOUS

5.1 Inurement

This agreement shall be binding upon and shall inure to the benefit of each of the parties hereto and their respective trustees, receivers, receiver-managers, successors and assigns.

5.2 Acknowledgement

The parties hereto acknowledge that the Trustee is entering into this agreement solely in its capacity as Trustee on behalf of the Trust and the obligations of the Trust hereunder shall not be personally binding upon the Trustee or any of the Unitholders of the Trust and that any recourse against the Trust, Trustee or any Unitholder of the Trust in any manner in respect of any indebtedness, obligation or liability of the Trust arising hereunder or arising in connection herewith or from the matters to which this agreement relates, if any, including without limitation claims based on negligence or otherwise tortious behaviour, shall be limited to, and satisfied only out of, the Trust Fund as defined in the Trust Indenture.

5.3 Further Assurances

Each party hereto will, from time to time and at all times hereafter, at the request of the other party but without further consideration, do all such further acts and execute and deliver all such further documents as shall be reasonably required in order to fully perform and carry out the terms hereof.

5.4 Counterpart Execution and Facsimile Delivery

This Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall constitute one agreement. Delivery of a facsimile of an executed counterpart of this Agreement shall be as legally effective as delivery of an original executed counterpart and if each party to this Agreement delivers either an original or a facsimile copy of a counterpart of this Agreement executed by it, this Agreement shall be a valid and binding agreement between them.

IN WITNESS WHEREOF the parties hereto have executed this agreement on the date first above written.

HARVEST OPERATIONS CORP.

Per: (signed) "*Jacob Roorda*"

Per: ________________

VALIANT TRUST COMPANY, in its capacity as Trustee of the Harvest Energy Trust

Per: (signed) "*Zinat H. Damji*"

Per: (signed) "*Cheryl Dahlager*"

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HARVEST OPERATIONS CORP.

and

SUBSIDIARY GUARANTORS

CREDIT AGREEMENT

Dated as of November 14, 2002

WESTLB AG,
NEW YORK BRANCH
as Administrative Agent

TABLE OF CONTENTS

This Table of Contents is not part of the Agreement to which it is attached but is inserted for convenience of reference only.

CREDIT AGREEMENT dated as of November 14, 2002, among: HARVEST OPERATIONS CORP., a corporation duly organized and validly existing under the laws of the Province of Alberta, Canada (the "Company"); each Subsidiary of the Company that becomes a Subsidiary Guarantor pursuant to Section 9.16 hereof (individually, a "Subsidiary Guarantor" and, collectively, the "Subsidiary Guarantors" and, together with the Company, the "Obligors" and individually, an "Obligor"); each of the lenders that is a signatory hereto identified under the caption "BANKS" on the signature pages hereto or which, pursuant to Section 12.06(b) hereof, shall become a "Bank" hereunder (individually, a "Bank" and, collectively, the "Banks"); WESTLB AG, NEW YORK BRANCH, as the initial letter of credit issuing bank and WESTLB AG, NEW YORK BRANCH, a joint stock company organized under the laws of Germany, as administrative agent for the Banks (in such capacity, together with its successors in such capacity, the "Administrative Agent").

SECTION 1. DEFINITIONS AND ACCOUNTING MATTERS.

1.01 Certain Defined Terms. As used herein, the following terms shall have the following meanings (all terms defined in this Section 1.01 or in other provisions of this Agreement in the singular to have the same meanings when used in the plural and vice versa):

"Acceptance Date" shall mean any date, which must be a Business Day, on which a Bankers' Acceptance is or is to be issued.

"Accepting Lender" shall mean, with respect to the Company, any Bank which has issued a Bankers' Acceptance of the Company under this Agreement.

"Additional Costs" shall have the meaning given to such term in Section 5.01(a) hereof.

"Administration Agreement" shall mean the administration agreement dated September 27, 2002 between the Trustee and the Company pursuant to which the Company has agreed to provide certain administrative and advisory services in connection with the Trust as amended, modified, restated and in effect from time to time.

"Administrative Questionnaire" shall mean an administrative questionnaire in a form supplied by the Administrative Agent.

"Advance Date" shall have the meaning given to such term in Section 4.06 hereof.

"Affiliate" shall mean, with respect to a specified Person, another Person that directly or indirectly controls, or is under common control with, or is controlled by, the Person specified. As used in this definition, "control" (including, with its correlative meanings, "controlled by" and "under common control with") shall mean possession, directly or indirectly, of power to direct or cause the direction of management or policies (whether through ownership of securities or partnership or other ownership interests, by contract or otherwise), provided that, in any event, any Person that owns directly or indirectly securities having 10% or more of the voting power for the election of directors or other governing body of a corporation or 10% or more of the partnership or other ownership interests of any other Person (other than as a limited partner of such other Person) will be deemed to control such corporation or other Person. Notwithstanding the foregoing, (a) no individual shall be an Affiliate solely by reason of his or her being a director, officer or employee of the Company or any of its Subsidiaries and (b) none of the Restricted Subsidiaries of the Company shall be, for purposes of this definition, Affiliates of the Company.

"Aggregate Borrowings" shall have the meaning given such term in Section 2.10(f) hereof.

"Anadarko Crude Contract" shall mean the Crude Oil Purchase Agreement dated September 6, 2002 between Anadarko Canada Corporation and Coyote Energy Inc, the predecessor to the Company, as amended or amended and restated from time to time.

"Applicable Commitment Fee Rate" shall mean for any period during which the Usage Ratio is within the range specified under "Range of Usage Ratio" in the following table, the percentage per annum set forth opposite the range in such table:

Range of Usage Ratio	Applicable Commitment Fee Rate
less than 0.75:1.00	1.000%
greater than or equal to 0.75:1.00	0.500%

"Applicable Lending Office" shall mean, for each Bank and for each Type of Loan, the "Lending Office" of such Bank (or of an affiliate of such Bank) designated for such Type of Loan in the Administrative Questionnaire of such Bank or such other office of such Bank (or of an affiliate of such Bank) as such Bank may from time to time specify to the Administrative Agent and the Company as the office by which its Loans of such Type are to be made and maintained.

"Applicable Margin" shall mean with respect to each Type of Loan for any period during which the Usage Ratio is within the range specified under "Range of Usage Ratio" in the following table, the number of basis points set forth opposite the range in such table to be expressed as percentages per annum for purposes of the interest calculations in this Agreement, provided that the "Applicable Margin" shall be increased or reduced, as applicable, on the date of the borrowing of a Loan, the issuance of a Letter of Credit or the acceptance of a Bankers' Acceptance, or the repayment of a Loan, expiration of a Letter of Credit or maturity of a Bankers' Acceptance, as the case may be, which results in the Usage Ratio shifting from one range to another but that the "Applicable Margin" for any BA Loan, Bankers' Acceptance, Eurocanadian Loan or Eurodollar Loan outstanding prior to such date shall remain the same until the maturity of such Bankers' Acceptance or the end of the Interest Period for such BA Loan, Eurocanadian Loan or Eurodollar Loan, respectively:

Range of Usage Ratio	Base Rate Loans or Canadian Base Rate Loans	Eurodollar Loans, Eurocanadian Loans, or BA Fee Rate
less than 0.75:1.00	1.125%	2.125%
greater than or equal to 0.75:1.00	1.875%	2.875%

"BA Fee Rate" shall mean the then applicable rate used in calculating Stamping Fees for Bankers' Acceptances and BA Loans as referred to in the definition of Applicable Margin.

"BA Loans" shall have the meaning given in Section 2.11(h) hereof.

"Bankers' Acceptance Documents" shall mean, with respect to any Bankers' Acceptance, collectively, any application therefor and any other agreements, instruments, guarantees or other documents (whether general in application or applicable only to such Bankers' Acceptance) governing or providing for (a) the rights and obligations of the parties concerned or at risk with respect to such Bankers' Acceptance or (b) any collateral security for any of such obligations, each as the same may be modified and supplemented and in effect from time to time.

"Bankers' Acceptance Liability" shall mean, with respect to any Bankers' Acceptance, the obligation of the Company to pay to the Administrative Agent the Principal Amount of any Bankers' Acceptances for which the Company has not reimbursed the Accepting Lender.

"Bankers' Acceptance Rate" shall mean the average of the per annum discount rates, computed on the basis of a year of 365 days, announced by each Accepting Lender as its bankers' acceptance rate for a Bankers' Acceptance having a Maturity Date of 30, 60, 90 or 180 days (whichever most closely approximates the Maturity Date of the applicable Bankers' Acceptance). Where there is only one Accepting Lender, the Bankers' Acceptance Rate shall be that Accepting Lender's discount rate. For each Bank that is not an Accepting Lender, the Bankers' Acceptance Rate shall be the CDOR Rate plus 0.10%.

"Bankers' Acceptances" shall mean bankers' acceptances denominated in Canadian Dollars in the form of either a depository bill, as defined in the Depository Bills and Notes Act (Canada), or a blank non-interest bearing bill of exchange, as defined in the Bills of Exchange Act (Canada), in either case drawn by the Company and accepted by a Bank at the request of the Company, such depository bill or bill of exchange to be substantially in the standard form of such Bank.

"Bankruptcy and Insolvency Act (Canada)" shall mean, collectively, the Bankruptcy and Insolvency Act (Canada) and the Companies' Creditors Arrangement Act (Canada), each as amended from time to time and any similar statute of Canada or any province thereof.

"Base Rate Loans" shall mean Loans that bear interest at rates based upon the Base Rate.

"Base Rate" shall mean, for any day, a rate per annum equal to the higher of (a) the Federal Funds Effective Rate for such day plus 1/2 of 1% and (b) the Prime Rate for such day. Each change in any interest rate provided for herein based upon the Base Rate resulting from a change in the Base Rate shall take effect at the time of such change in the Base Rate.

"Borrowing Base" shall have the meaning given to such term in Section 1.03(b) hereof.

"Borrowing Base Deficiency" shall have the meaning given to such term in Section 2.10(a) hereof.

"Business Day" shall mean (i) any day (other than a Saturday or Sunday) on which commercial banks are not authorized or required to close in New York City, Calgary or Toronto, Canada, and (ii) if such day relates to a borrowing of, a payment or prepayment of principal of or interest on, a Conversion of or into, or an Interest Period for, a Eurodollar Loan or Eurocanadian Loan or a notice by the Company with respect to any such borrowing, payment, prepayment, Conversion or Interest Period, any day (other than a Saturday or Sunday) on which dealings in U.S. Dollar deposits or Canadian Dollar deposits, as applicable, are carried out in the London interbank market.

"Canadian Base Rate" shall mean, for any day, the CDOR Rate for one month plus 0.50%.

"Canadian Base Rate Loans" shall mean Loans that bear interest at rates based upon the Canadian Base Rate.

"Canadian Dollar Obligations" shall have the meaning set forth in Section 2.03(a) hereof.

"Canadian Dollars" and "C$" shall mean lawful money of Canada.

"Canadian Letter of Credit" shall mean a Letter of Credit denominated in Canadian Dollars.

"Canadian Letter of Credit Liabilities" shall mean Letter of Credit Liabilities under Canadian Letters of Credit.

"Canadian Loans" shall mean Eurocanadian Loans, Canadian Base Rate Loans and BA Loans.

"Capital Expenditures" shall mean, for any period, expenditures (including, without limitation, the aggregate amount of Capital Lease Obligations incurred during such period) made by the Company or any of its Restricted Subsidiaries in connection with the acquisition and exploitation of, or the exploration for or development or production of, hydrocarbon reserves or to acquire or construct fixed assets, plant and equipment (including renewals, improvements and replacements, but excluding repairs) during such period computed in accordance with GAAP.

"Capital Lease Obligations" shall mean, for any Person, all obligations of such Person to pay rent or other amounts under a lease of (or other agreement conveying the right to use) Property to the extent such obligations are required to be classified and accounted for as a capital lease on a balance sheet of such Person under GAAP, and, for purposes of this Agreement, the amount of such obligations shall be the capitalized amount thereof, determined in accordance with GAAP.

"Capital Stock" shall mean, with respect to any Person, any and all shares, interests, participations or other equivalents (however designated) of corporate stock or membership or partnership interests and any and all warrants, options and rights with respect thereto (whether or not currently exercisable), including each class of common stock and preferred stock of such Person.

"Casualty Event" shall mean, with respect to any Property of any Person, any loss of or damage to, or any condemnation or other taking of, such Property for which such Person or any of its Subsidiaries receives insurance proceeds, or proceeds of a condemnation award or other compensation.

"CDOR Rate" shall mean the per annum rate of interest which is the rate determined as being the arithmetic average of the rates per annum (calculated on the basis of a year of three hundred and sixty-five (365) days) applicable to Canadian Dollar bankers' acceptances having identical issue and comparable maturity dates as the Bankers' Acceptances proposed to be issued by the Company displayed and identified as such on the display referred to as the "CDOR Page" (or any display substituted therefor) of Reuter Monitor Money Rates Service as at approximately 8:00 a.m. (New York time) on such day (as adjusted by the Administrative Agent in good faith after 8:00 a.m. (New York time) to reflect any error in a posted rate of interest or in the posted average annual rate of interest).

"Change of Control" shall mean any circumstances arising after the date hereof, other than as permitted by Section 9.05 hereof, in which a Person or combination of Persons acting jointly or in concert (within the meaning of the Securities Act (Alberta), as amended) acquires beneficial ownership of 50% or more of the trust units in the Trust, or otherwise acquires any rights for the election of a majority of the directors or equivalent management under ordinary circumstances of the Trust, the Company or any Restricted Subsidiary.

"Commitment Percentage" shall mean, with respect to any Bank, the ratio of the amount of the Commitment of such Bank to the aggregate amount of the Commitments of all of the Banks.

"Commitment Termination Date" shall mean April 30, 2004.

"Commitments" shall mean, with respect to each Bank, the obligation of such Bank to make Loans, to accept Bankers' Acceptances or to participate in Letters of Credit in an aggregate principal or face amount at any one time outstanding up to but not exceeding (a) in the case of a Bank that is a party to this Agreement as of the date hereof, the amount set opposite the name of such Bank on Annex I hereto under the caption "Commitment" or (b) in the case of any other Bank, the aggregate amount of the Commitments of other Banks acquired by it pursuant to

Section 12.06(b) hereof (in each case, as the same may be reduced from time to time pursuant to Section 2.04 hereof or increased or reduced from time to time pursuant to said Section 12.06(b)).

"Commodity Hedging Agreement" shall mean, for any Person, (a) any swap, forward, cap, floor, collar or other similar transaction between such Person and one or more financial institutions or other entities relating to the price of any category of hydrocarbons or any index calculated based on the price of one or more categories of hydrocarbons, (b) any option with respect to any of the foregoing transactions, (c) physical forward contracts for set prices provided that payment is not made prior to delivery and (d) any combination of the foregoing transactions.

"Consolidated Subsidiary" shall mean, for any Person, each Subsidiary of such Person (whether now existing or hereafter created or acquired) the financial statements of which are (or should have been) consolidated with the financial statements of such Person in accordance with GAAP.

"Continue", "Continuation" and "Continued" shall refer to the continuation pursuant to Section 2.09 hereof of a Eurodollar Loan, Eurocanadian Loan or BA Loan from one Interest Period to another Interest Period or the continuation of a Bankers' Acceptance.

"Convert", "Conversion" and "Converted" shall refer to a conversion pursuant to Section 2.09 hereof of all or a portion of one Type of Loan or Bankers' Acceptance into another Type of Loan or Bankers' Acceptance, which may be accompanied by the transfer by a Bank (at its sole discretion) of a Loan or Bankers' Acceptance from one Applicable Lending Office to another.

"Currency Exchange Agreement" shall mean, for any Person, an agreement or arrangement between such Person and one or more financial institutions or other entities providing for the transfer or mitigation of risks of fluctuations in the exchange rate between currencies either generally or under specific contingencies.

"Default" shall mean an Event of Default or an event that with notice or lapse of time or both would become an Event of Default.

"Deficiency Cure Period" shall have the meaning assigned such term in Section 2.10(a).

"Deficiency Notice" shall have the meaning assigned to such term in Section 2.10(a) hereof.

"Determination Date" shall mean 45 days after the date that the Reserve Evaluation Report and/or such other information as is required to be delivered to the Administrative Agent for the purposes of any redetermination of the Borrowing Base shall be delivered to the Administrative Agent.

"Determination Period" shall mean (i) initially, the period commencing on the date hereof and ending on the first Determination Date thereafter and, (ii) each period commencing on a Determination Date and ending on the day next preceding the next succeeding Determination Date.

"Direct Royalties" shall mean (i) the 99% undivided interest in the royalty interests acquired by the Trust from the Company in relation to the Devon properties and the Anadarko properties, respectively, pursuant to the Direct Royalties Sale Agreement and (ii) any other royalty interests similarly acquired from time to time by the Trust from the Company or a Subsidiary and which have been purchased by the Company or a Subsidiary, as applicable, from third parties and resold to the Trust at the same price paid for such interests and which in no event have been included in the Borrowing Base.

"Direct Royalties Sale Agreement" shall mean the Amended and Restated Direct Royalties Sale Agreement dated September 27, 2002 between the Company and the Trustee (for and on behalf of the Trust) in respect of the Devon properties, and the Direct Royalties Sale Agreement dated as of the date hereof between the Company and the Trustee (for and on behalf of the Trust) in respect of the Anadarko properties, as amended or restated from time to time and includes any similar agreements entered into from time to time between the Trustee and the Company, a Subsidiary or a third party.

"Disposition" shall mean any sale, assignment, transfer or other disposition of any Property (whether now owned or hereafter acquired) by the Company or any of its Restricted Subsidiaries to any Person (other than by any such Restricted Subsidiary to the Company or any other Restricted Subsidiary, or by the Company to a Restricted Subsidiary), excluding any sale, assignment, transfer or other disposition of (i) any Property sold or disposed of in the ordinary course of business and on ordinary business terms, (ii) any Unrestricted Properties or (iii) any stock of an Unrestricted Subsidiary.

"Distribution" shall mean (a) any payment of the NPI or Subordinated Indebtedness, and any other payment or other distribution of any kind or nature, whether in cash or otherwise, whereby any production or revenues derived from the assets of the Company or any Restricted Subsidiary are paid or distributed to any Affiliate of any of them, other than to the Company or another Subsidiary Guarantor, (b) any payment in respect of the Subordinated Notes, (c) any declaration, order or payment of dividends or other capital distributions by the Company or any Restricted Subsidiary other than to the Company or another Subsidiary Guarantor, (d) any redemption, retraction, purchase or other acquisition of shares, directly or indirectly, in the capital of the Company or any Restricted Subsidiary other than in the case of a Restricted Subsidiary held by another Restricted Subsidiary or the Company, (e) any payment of principal or other amounts in respect of Indebtedness owed to a shareholder of the Company or an Affiliate of such shareholder other than the Company or a Subsidiary Guarantor, (f) any transfer of property by the Company or any Restricted Subsidiary for a consideration less than fair market value to a shareholder of the Company or to an Affiliate of the Company or such shareholder other than the Company or a Subsidiary Guarantor or (g) any loan, advance or other payment of any kind by the Company or any Restricted Subsidiary to the Trust or any Affiliate of the Trust.

"Dollar-Denominated Production Payments" shall mean production payment obligations of the Company or any of its Restricted Subsidiaries which are payable from a specified share of proceeds received from production from specific Properties, together with all undertakings and obligations in connection therewith, but, for certainty, excluding the NPI.

"EBITDA" shall mean, for any period, the revenues of the Company and its Restricted Subsidiaries for such period from continuing operations, minus associated costs (generally excluding Interest Expense, income taxes, depreciation and amortization and NPI payments), determined in each case on a consolidated basis in accordance with GAAP.

"Effective Date" shall mean the date upon which all of the conditions of Section 7.01 hereof are either satisfied or waived.

"Environmental Claim" shall mean, with respect to any Person, any written or oral notice, claim, demand or other communication (collectively, a "claim") by any other Person alleging or asserting such Person's liability for investigatory costs, cleanup costs, governmental response costs, damages to natural resources or other Property, personal injuries, fines or penalties arising out of, based on or resulting from (i) the presence, or Release into the environment, of any Hazardous Material at any location, whether or not owned by such Person, or (ii) circumstances forming the basis of any violation, or alleged violation, of any Environmental Law. The term "Environmental Claim" shall include, without limitation, any claim by any Governmental Authority for enforcement, cleanup, removal, response, remedial or other actions or damages pursuant to any applicable Environmental Law, and any claim by any third party seeking damages, contribution, indemnification, cost recovery, compensation or injunctive relief resulting from the presence of Hazardous Materials or arising from alleged injury or threat of injury to health, safety or the environment.

"Environmental Laws" shall mean any and all present and future Federal, state, Canadian Federal, provincial, local and foreign laws, rules or regulations, and any orders or decrees, in each case as now or hereafter in effect and having the force of law, relating to the regulation or protection of human health, safety or the environment or to emissions, discharges, releases or threatened releases of pollutants, contaminants, chemicals or toxic or hazardous substances or wastes into the indoor or outdoor environment, including, without limitation, ambient air, soil, surface water, ground water, wetlands, land or subsurface strata, or otherwise relating to the manufacture, processing, distribution, use, treatment, storage, disposal, transport or handling of pollutants, contaminants, chemicals or toxic or hazardous substances or wastes.

"Equity Issuance" shall mean (a) any issuance or sale by the Company or any of its Restricted Subsidiaries after the date of this Agreement of (i) any of its Capital Stock, (ii) any warrants or options exercisable in respect of its Capital Stock or (iii) any other security or instrument representing an equity interest (or the right to obtain any equity interest) in the Company or any of its Restricted Subsidiaries or (b) the receipt by the Company or any of its Restricted Subsidiaries after the date of this Agreement of any capital contribution (whether or not evidenced by any equity security issued by the recipient of such contribution); provided that Equity Issuance shall not include (x) any such issuance or sale by any Restricted Subsidiary of the Company to the Company or any other Wholly Owned Subsidiary of the Company which is a Restricted Subsidiary, (y) any capital contribution by the Company or any Wholly Owned Subsidiary of the Company which is a Restricted Subsidiary to any other Restricted Subsidiary of the Company or (z) any warrants or options issued to directors, officers or employees of the

Company and its Restricted Subsidiaries pursuant to any employee benefit plans, incentive plans or similar programs established in the ordinary course of business.

"Equity Rights" shall mean, with respect to any Person, any outstanding subscriptions, options, warrants, commitments, preemptive rights or agreements of any kind (including, without limitation, any stockholders' or voting trust agreements) for the issuance, sale, registration or voting of, or securities convertible into, any additional shares of Capital Stock of any class, or partnership or other ownership interests of any type in, such Person.

"Equivalent Amount" shall mean as at any date the amount of Canadian Dollars into which an amount of U.S. Dollars may be converted, or the amount of U.S. Dollars into which an amount of Canadian Dollars may be converted, in either case at WestLB's mid-point spot rate of exchange for such date in New York City at approximately 11:00 a.m., New York City time on such date.

"Eurocanadian Base Rate" shall mean, with respect to any Eurocanadian Loan for any Interest Period therefor, the arithmetic mean (rounded upward, if necessary, to the nearest 1/16 of 1%) as determined by the Administrative Agent, of the rates per annum quoted by the respective LIBOR Reference Banks at approximately 11:00 a.m. London time (or as soon thereafter as practicable) on the date two Business Days prior to the first day of such Interest Period for the offering by such LIBOR Reference Banks to leading banks in the London interbank market of Canadian Dollar deposits having a term comparable to such Interest Period and in amounts comparable to the principal amount of the Eurocanadian Loan to be made by the respective LIBOR Reference Banks for such Interest Period. If any LIBOR Reference Bank is not participating in any Eurocanadian Loans during any Interest Period therefor, the Eurocanadian Base Rate for such Loans for such Interest Period shall be determined by reference to the amount of such Loans that such LIBOR Reference Bank would have made or had outstanding had it been participating in such Loan during such Interest Period.

"Eurocanadian Loans" shall mean Loans the interest rates on which are determined on the basis of rates referred to in the definition of "Eurocanadian Base Rate" in this Section 1.01.

"Eurocanadian Rate" shall mean, for any Eurocanadian Loan for any Interest Period therefor, a rate per annum (rounded upwards, if necessary, to the nearest 1/100 of 1%) determined by the Administrative Agent to be equal to the Eurocanadian Base Rate for such Loan for such Interest Period divided by 1 minus the Reserve Requirement for such Loan for such Interest Period.

"Eurodollar Base Rate" shall mean, with respect to any Eurodollar Loan for any Interest Period therefor, arithmetic mean (rounded upward, if necessary to the nearest 1/16 of 1%) as determined by the Administrative Agent of the rates per annum quoted by the respective LIBOR Reference Banks at approximately 11:00 a.m. London time (or as soon thereafter as practicable) on the date two Business Days prior to the first day of such Interest Period for the offering by such LIBOR Reference Banks to leading banks in the London interbank market of U.S. Dollar deposits having a term comparable to such Interest Period and in amounts comparable to the principal amount of the Eurodollar Loan to be made by the respective LIBOR

Reference Banks for such Interest Period. If any LIBOR Reference Bank is not participating in any Eurodollar Loans during any Interest Period therefor, the Eurodollar Base Rate for such Loans for such Interest Period shall be determined by reference to the amount of such Loans that such LIBOR Reference Bank would have made or had outstanding had it been participating in such Loan during such Interest Period.

"Eurodollar Loans" shall mean Loans the interest rates on which are determined on the basis of rates referred to in the definition of "Eurodollar Base Rate" in this Section 1.01.

"Eurodollar Rate" shall mean, for any Eurodollar Loan for any Interest Period therefor, a rate per annum (rounded upwards, if necessary, to the nearest 1/100 of 1%) determined by the Administrative Agent to be equal to the Eurodollar Base Rate for such Loan for such Interest Period divided by 1 minus the Reserve Requirement for such Loan for such Interest Period.

"Event of Default" shall have the meaning assigned to such term in Section 10 hereof.

"Exchange Rate Deficiency" shall have the meaning assigned to such term in Section 2.10(f) hereof.

"Excluded Taxes" shall mean, with respect to the Administrative Agent, any Bank, the Issuing Bank or any other recipient of any payment to be made by or on account of any obligation of the Company or any Subsidiary Guarantor under any Loan Document, (a) income or franchise or capital taxes imposed on (or measured by) its net income or capital by the United States of America, or by the jurisdiction under the laws of which such recipient is organized or in which its principal office is located or in which its Applicable Lending Office is located, (b) any branch profits taxes imposed by the United States of America or any similar tax imposed by any other jurisdiction in which the Applicable Lending Office of the recipient is located and (c)(i) in the case of a Foreign Lender, other than a Foreign Lender that is a party to this Agreement on the Effective Date or becomes a Bank pursuant to the initial syndication referred to in Section 12.04 (each an "Original Lender"), or any Person which becomes a Bank hereunder and is assigned a Commitment which was obtained by way of assignment directly from an Original Lender or indirectly from an Original Lender through one or more prior assignments (an "Assignment Commitment", and the Original Lenders and the Foreign Lenders holding any Assignment Commitments collectively referred to as the "Withholding Lenders"), any withholding tax that is imposed on any amounts payable or accruing to such Foreign Lender at and from the time such Foreign Lender becomes a party to this Agreement (or designates a new Applicable Lending Office) but only to the extent of withholding taxes imposed at a rate in excess of the rate applicable to WestLB as of the date hereof (provided, however, that any such excess shall not be Excluded Taxes if it results from any change in tax law or treaty applicable to such Foreign Lender subsequent to the date hereof) or (ii) in the case of any Withholding Lender, any withholding tax that is imposed on amounts paid or credited to such Foreign Lender to the extent that such withholding taxes are imposed at a rate in excess of that imposed on the Original Lender which is the Withholding Lender or from which such Withholding Lender derived its Assignment Commitment, other than due to, and only to the extent of, an increase in the rate of withholding under the tax treaty applicable to such Withholding Lender at the time it became a Withholding Lender.

"Federal Funds Effective Rate" shall mean, for any day, the rate per annum (rounded upwards, if necessary, to the nearest 1/100 of 1%) equal to the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System arranged by Federal funds brokers on such day, as published by the Federal Reserve Bank of New York on the Business Day next succeeding such day, provided that (a) if the day for which such rate is to be determined is not a Business Day, the Federal Funds Effective Rate for such day shall be such rate on such transactions on the next preceding Business Day as so published on the next succeeding Business Day and (b) if such rate is not so published for any Business Day, the Federal Funds Effective Rate for such Business Day shall be the average determined by the Administrative Agent, of the quotations of such rate for such transactions on such Business Day from three Federal funds brokers of recognized standing selected by the Administrative Agent.

"Fee Letter" shall mean the letter agreement dated as of November 14, 2002, between the Company and the Administrative Agent.

"Fixed Charge Coverage Ratio" shall mean, as of any date of determination, the ratio of (a) the EBITDA of the Company and the Restricted Subsidiaries for the previous 12 months to (b) the Interest Expense (other than Interest Expense relating to Subordinated Indebtedness owing to the Trust) of the Company and the Restricted Subsidiaries for the previous 12 months plus Distributions on account of the Company's preferred stock paid during the previous 12 months.

"Foreign Lender" means any Bank that is organized under the laws of a jurisdiction other than that in which the Company or any Subsidiary Guarantor is located; provided that a Bank organized under the laws of Canada or any province thereof or which is registered pursuant to Schedule II or Schedule III of the Bank Act (Canada) shall not be a Foreign Lender; provided that WestLB shall be a Foreign Lender until such time that it notifies the Company that it has transferred its Commitments hereunder to a bank listed on Schedule II or Schedule III of the Bank Act (Canada).

"Future Net Revenues" shall mean, for any period, the future gross revenues attributable to all or a part (as specified herein) of Proved Reserves constituting part of the Hydrocarbon Properties for such period less the sum for such period of all projected Operating Expenses and Capital Expenditures with respect thereto, as set forth in the related Reserve Evaluation Report, and less (without duplication) all amounts projected to be applied to the discharge of any Production Payment and to the unearned balance of any advance payment received under any contract to be performed relating to such Proved Reserves.

"GAAP" shall mean generally accepted accounting principles in Canada applied on a basis consistent with those which, in accordance with the last sentence of Section 1.02(a) hereof, are to be used in making the calculations for purposes of determining compliance with this Agreement.

"Governmental Authority" shall mean any federal, state, municipal, provincial, local, territorial, or other governmental subdivision, department, commission, board, bureau, agency, regulatory authority, instrumentality, judicial or administrative body, domestic or foreign, having jurisdiction where the Company or any Subsidiary conducts any business or has Property and the actions of which could reasonably be expected to result in a Material Adverse Effect.

"Guarantee" shall mean a guarantee, an endorsement, a contingent agreement to purchase or to furnish funds for the payment or maintenance of, or otherwise to be or become contingently liable under or with respect to, the Indebtedness, other obligations, net worth, working capital or earnings of any Person or any production or revenues generated by (or any capital or other expenditures incurred in connection with the acquisition and exploitation of, exploration for, development of or production from) any hydrocarbon reserves, or a guarantee of the payment of dividends or other distributions upon the stock or equity interests of any Person, or an agreement to purchase, sell or lease (as lessee or lessor) Property, products, materials, supplies or services primarily for the purpose of enabling a debtor to make payment of such debtor's obligations or an agreement to assure a creditor against loss, and including, without limitation, causing a bank, surety company or other financial institution or similar entity to issue a letter of credit, surety bond or other similar instrument for the benefit of another Person, but excluding endorsements for collection or deposit in the ordinary course of business. The terms "Guarantee" and "Guaranteed" used as a verb shall have a correlative meaning.

"Guaranteed Obligations" shall have the meaning assigned to such term in Section 6.01 hereof.

"Hazardous Material" shall mean, collectively, (a) any petroleum or petroleum products, flammable explosives, radioactive materials, asbestos in any form that is or could become friable, urea formaldehyde foam insulation, and transformers or other equipment that contain dielectric fluid containing polychlorinated biphenyls (PCB's), (b) any chemicals or other materials or substances which are now or hereafter become defined as or included in the definition of "hazardous substances", "hazardous wastes", "hazardous materials", "extremely hazardous wastes", "restricted hazardous wastes", "toxic substances", "toxic pollutants", "contaminants", "pollutants" or words of similar import under any Environmental Law and (c) any other chemical or other material or substance, exposure to which is now or hereafter prohibited, limited or regulated under any Environmental Law.

"Hedging Agreement" means any Commodity Hedging Agreement, Currency Exchange Agreement or Interest Rate Protection Agreement.

"Hydrocarbon Properties" shall mean interests which one or more of the Obligors have from time to time in hydrocarbon reserves (i) from which hydrocarbons may be severed or extracted in commercially feasible quantities, (ii) which have been designated by the Company for inclusion in the Borrowing Base and given value by the Banks in the most recent determination or redetermination of the Borrowing Base, as applicable, and (iii) which have been subjected to the Mortgages as required hereunder in favor of the Administrative Agent for the benefit of the Banks pursuant to the Security Documents.

"Income Tax Act (Canada)" shall mean the Income Tax Act (Canada), as amended from time to time.

"Indebtedness" shall mean, for any Person and without duplication: (a) obligations created, issued or incurred by such Person for borrowed money (whether by loan, the issuance and sale of debt securities or the sale of Property to another Person subject to an understanding or agreement, contingent or otherwise, to purchase or repurchase the same or similar Property from such Person); (b) obligations of such Person to pay the deferred purchase or acquisition price of Property or services, other than trade accounts payable (other than for borrowed money) arising, and accrued expenses incurred, in the ordinary course of business so long as such trade accounts payable are payable within 90 days of the date the respective goods are delivered or the respective services are rendered; (c) obligations of others secured by a Lien on the Property of such Person, whether or not the respective obligations so secured has been assumed by such Person, provided that (i) the amount to be included as "Indebtedness" shall be the amount reasonably estimated by the Company and indicated on each certificate delivered pursuant to Section 9.01(b) (or prior to the date of the delivery of the first such certificate pursuant to Section 9.01(b), the amount indicated by the Company to the Administrative Agent on the Closing Date) and (ii) if no such estimate is provided, the amount included as Indebtedness shall be the entire amount of such obligations; (d) obligations of such Person in respect of letters of credit, surety bonds or similar instruments issued or accepted by banks, surety companies and other financial institutions for account of such Person; (e) Capital Lease Obligations of such Person; (f) obligations of such Person in respect of obligations of the types specified in other clauses of this definition as a general partner or joint venturer of any partnership or joint venture (other than in respect of obligations incurred in the ordinary course of business); (g) upon the failure of such Person to perform or fulfill any warranties or guaranties of, or similar obligations relating to, production or payment contained in any Non-Recourse Debt, the maximum amount of the obligation of such Person in respect of such warranties, guaranties or similar obligations; (h) the unearned balance of any advance payment received by such Person under any contract to be performed in excess of U.S.$1,000,000 (or its equivalent in another currency) in the aggregate resulting from transactions in the ordinary course of such Person's business; and (i) Indebtedness of others Guaranteed by such Person. In no event shall Indebtedness include obligations or liabilities pursuant to the NPI.

"Indebtedness to EBITDA Ratio" shall mean, for any period, the ratio of (a) Indebtedness (other than Subordinated Indebtedness owing to the Trust) of the Company and the Restricted Subsidiaries for such period on a consolidated basis to (b) EBITDA of the Company and the Restricted Subsidiaries for such period.

"Indebtedness to Equity Ratio" shall mean, at any date, the ratio of (a) Indebtedness of the Company and the Restricted Subsidiaries outstanding at such date (including, for the avoidance of doubt, all Subordinated Indebtedness owing to the Trust) (excluding any Indebtedness maturing in less than one year from the date of calculation thereof other than Indebtedness described in clause (a) of the definition thereof) on a consolidated basis to (b) Tangible Net Worth.

"Indemnified Taxes" shall mean Taxes other than Excluded Taxes.

"Independent Petroleum Engineer" shall mean (a) McDaniel & Associates or (b) such other firm of independent petroleum engineers expert in the matters required to be performed in connection with the preparation and delivery of a Reserve Evaluation Report and proposed by the Company from time to time and reasonably satisfactory to the Administrative Agent.

"Insurance Date" shall have the meaning assigned to that term in section 2.10(b).

"Interest Coverage Ratio" shall mean, for any period, the ratio of (a) EBITDA for such period to (b) Interest Expense (other than Interest Expense relating to Subordinated Indebtedness owing to the Trust) for such period.

"Interest Expense" shall mean, for any period, interest expense for the Company and the Restricted Subsidiaries for such period (determined on a consolidated basis without duplication in accordance with GAAP) including, without limitation, the following: all interest in respect of Indebtedness accrued or capitalized during such period (whether or not actually paid during such period) (other than interest paid in common stock of the Company) and the net amounts payable (or minus the net amounts receivable) under Interest Rate Protection Agreements of such Persons accrued during such period (whether or not actually paid or received during such period), but excluding the non-cash amortization of deferred debt issuance costs and original issue discount for such period and the interest expense attributable to Dollar-Denominated Production Payments of the Company and the Restricted Subsidiaries in existence on the Effective Date for such period. References in this definition (whether in the singular or the plural) to Subsidiaries, Restricted Subsidiaries and Unrestricted Subsidiaries shall, for purposes of calculating Interest Expense for a period or part of a period ending prior to the date of this Agreement, be deemed to refer to corporations or other entities that would have been "Subsidiaries", "Restricted Subsidiaries" or "Unrestricted Subsidiaries" (as the case may be) had this Agreement been in effect on the first day of such period.

"Interest Period" shall mean, (a) with respect to any Eurodollar Loan or Eurocanadian Loan, each period commencing on the date such Eurodollar Loan or Eurocanadian Loan is made or the last day of the next preceding Interest Period for such Loan and ending on the numerically corresponding day in the first, second, third or sixth calendar month thereafter, as the Company may select as provided in Section 4.05 hereof, except that each Interest Period that commences on the last Business Day of a calendar month (or on any day for which there is no numerically corresponding day in the appropriate subsequent calendar month) shall end on the last Business Day of the appropriate subsequent calendar month. Notwithstanding the foregoing: (i) if any Interest Period would otherwise end after the Commitment Termination Date, such Interest Period shall end on the Commitment Termination Date; (ii) each Interest Period that would otherwise end on a day which is not a Business Day shall end on the next succeeding Business Day (or if the next succeeding Business Day falls in the next succeeding calendar month, on the next preceding Business Day); and (iii) notwithstanding clause (i) above, no Interest Period shall have a duration of less than one month and, if the Interest Period for any Eurodollar Loan or Eurocanadian Loan would otherwise be a shorter period, such Loan shall not be available as a Eurodollar Loan or Eurocanadian Loan hereunder for such period; and (b) with respect to any BA Loan, each period commencing on the date such BA Loan is made or Converted from a Eurocanadian Loan or the last day of the next preceding Interest Period for such BA Loan and ending 30, 60, 90 or 180 days thereafter, as the Company may select as provided in Section 4.05 hereof. Notwithstanding the foregoing, no Interest Period shall mature on a date after the Commitment Termination Date.

"Interest Rate Protection Agreement" shall mean, for any Person, an interest rate swap, cap or collar agreement or similar arrangement between such Person and one or more financial institutions or other entities providing for the transfer or mitigation of interest risks, either generally or under specific contingencies.

"Investment" shall mean, for any Person: (a) the acquisition (whether for cash, Property, services or securities or otherwise) of capital stock, bonds, notes, debentures, partnership or other ownership interests or other securities of any other Person or any agreement to make any such acquisition (including, without limitation, any "short sale" or any sale of any securities at a time when such securities are not owned by the Person entering into such short sale); (b) the making of any deposit with, or advance, loan or other extension of credit to, any other Person (including the purchase of Property from another Person subject to an understanding or agreement, contingent or otherwise, to resell such Property to such Person, but excluding any such deposit, advance, loan or extension of credit having a term not exceeding 90 days representing the purchase price of inventory or supplies sold by such Person in the ordinary course of business); (c) the entering into of any Guarantee of, or other contingent obligation with respect to, Indebtedness or other liability of any other Person and (without duplication) any amount committed to be advanced, lent or extended to such Person; or (d) the entering into of any Interest Rate Protection Agreement or Commodity Hedging Agreement. The definition of "Investment" shall not include expenditures made to acquire interests in joint ventures, unit interests, royalty interests, working interests and similar interests, in each case relating to oil and gas properties and plants, facilities, pipelines and equipment reasonably related thereto.

"Issuing Bank" shall mean WestLB as the issuer of Letters of Credit under Section 2.03(b) hereof, together with its successors and assigns in such capacity.

"Letter of Credit" shall have the meaning assigned to such term in Section 2.03(a) hereof.

"Letter of Credit Documents" shall mean, with respect to any Letter of Credit, collectively, any application therefor and any other agreements, instruments, guarantees or other documents (whether general in application or applicable only to such Letter of Credit) governing or providing for (a) the rights and obligations of the parties concerned or at risk with respect to such Letter of Credit or (b) any collateral security for any of such obligations, each as the same may be modified and supplemented and in effect from time to time.

"Letter of Credit Interest" in connection with any Letter of Credit, shall mean, for each Bank and the Issuing Bank, such Bank's participation interest (or, in the case of the Issuing Bank, the Issuing Bank's retained interest, if any) in the Issuing Bank's liability under Letters of Credit and such Bank's rights and interests in Reimbursement Obligations and fees, interest and other amounts payable in connection with Letters of Credit and Reimbursement Obligations.

"Letter of Credit Liability" shall mean, without duplication, at any time and in respect of any Letter of Credit, the Equivalent Amount in U.S. Dollars of the sum of (a) the undrawn and uncancelled face amount of such Letter of Credit plus (b) the aggregate unpaid principal amount of all Reimbursement Obligations of the Company at such time due and payable in respect of all drawings made under such Letter of Credit. For purposes of this Agreement, a Bank (other than the Issuing Bank) shall be deemed to hold a Letter of Credit Liability in an amount equal to its participation interest in the related Letter of Credit under Section 2.03 hereof.

"LIBOR Reference Bank" shall mean WestLB, Canadian Imperial Bank of Commerce and Société Générale or such other banks of recognized standing as may be appointed as a LIBOR Reference Bank in substitution for a then-existing LIBOR Reference Bank by the Company and reasonably acceptable to the Administrative Agent.

"Lien" shall mean, with respect to any Property, any mortgage, lien, pledge, charge, security interest or encumbrance of any kind in respect of such Property, but does not include a right of set-off created in the ordinary course of business unless such right of set-off is created for the purposes of securing obligations created, issued or incurred for borrowed money. For purposes of this Agreement and the other Loan Documents, a Person shall be deemed to own subject to a Lien any Property that it has acquired or holds subject to the interest of a vendor or lessor under any conditional sale agreement, capital lease or other title retention agreement (other than an operating lease) relating to such Property.

"Loan Documents" shall mean this Agreement, the Notes, the Letter of Credit Documents, the Bankers' Acceptances, the Subordination Agreement and the Security Documents.

"Loans" shall mean the loans provided for by Section 2.01(a) hereof.

"Majority Banks" shall mean Banks having greater than 50% of the aggregate amount of the Commitments, or if the Commitments shall have been terminated, Banks holding greater than 50% of the sum of the aggregate unpaid principal amount of the sum of (a) the Loans, (b) the Letter of Credit Liabilities and (c) the Bankers' Acceptance Liabilities.

"Margin Stock" shall mean "margin stock" within the meaning of Regulations U and X.

"Material Adverse Effect" shall mean a material adverse effect on (a) the Property, business, operations, financial condition, prospects, liabilities or capitalization of the Company and its Restricted Subsidiaries taken as a whole, (b) the Property, business, operations, financial condition, prospects, liabilities or capitalization of an Unrestricted Subsidiary that could reasonably be expected to have a material adverse effect on the Property, business, operations, financial condition, prospects, liabilities or capitalization of the Company and its Restricted Subsidiaries taken as a whole, (c) the ability of the Company or any material Restricted Subsidiary to perform its respective obligations under any of the Loan Documents to which it is a party, (d) the validity or enforceability of any of the Loan Documents, (e) the right and remedies of any Bank and the Administrative Agent under any of the Loan Documents, as the case may be (other than any such material adverse effect resulting from the failure of the Administrative Agent or any Bank to take actions to maintain such rights or remedies and other than as those rights and remedies are subject to the qualifications contained in the legal opinions delivered pursuant to Section 7.01(c) hereof), or (f) the timely payment of the principal of or interest on the Loans, Reimbursement Obligations, Bankers' Acceptances or other amounts payable in connection therewith.

"Material Documents" shall mean the Trust Indenture, the NPI Agreement, the Administration Agreement, any Note Indenture, the payment provisions of the Capital Stock of any of the Company or its Restricted Subsidiaries and the Subordinated Indebtedness.

"Maturity Date" shall mean the date on which a Bankers' Acceptance is payable.

"Mortgage(s)" shall mean a fixed and floating charge debenture or similar document executed by the Company in favor of the Administrative Agent or a security trustee for the benefit of the Banks, in each case substantially in the form of Exhibit C hereto and providing for a floating and unregistered fixed charge covering all of the assets of the Company, as the same shall be modified and supplemented and in effect from time to time.

"Mortgaged Properties" shall mean Hydrocarbon Properties which are subject to the Liens created hereunder and under the Security Documents.

"Net Available Proceeds" shall mean:

(a) in the case of any Disposition by the Company or a Restricted Subsidiary, the amount of Net Cash Payments received in connection with such Disposition; and

(b) in the case of any Casualty Event with respect to any Property of the Company or any of its Restricted Subsidiaries, the aggregate amount of proceeds of insurance, condemnation awards and other compensation received by the Company and its Restricted Subsidiaries in respect of such Casualty Event (excluding proceeds of business interruption insurance) net of (i) reasonable expenses incurred by the Company and its Restricted Subsidiaries in connection therewith and (ii) contractually required repayments of Indebtedness to the extent secured by a Lien on such Property and any income and transfer taxes payable by the Company or any of its Restricted Subsidiaries in respect of such Casualty Event.

"Net Cash Payments" shall mean, with respect to any Disposition, the aggregate amount of all cash payments, and the fair market value of any non-cash consideration, received by the Company and its Restricted Subsidiaries directly or indirectly in connection with such Disposition; provided that (a) Net Cash Payments shall be net of (i) the amount of any legal, title and recording tax expenses, commissions and other fees and expenses paid by the Company and its Restricted Subsidiaries in connection with such Disposition and (ii) any federal, state, provincial and local income or other taxes estimated to be payable by the Company and its Restricted Subsidiaries as a result of such Disposition (but only to the extent that (x) such estimated taxes are in fact paid to the relevant federal, state, provincial or local Governmental Authority within three months of date of such Disposition or placed in escrow for the payment of such taxes or (y) the amount of such estimated taxes is less than U.S.$1,000,000 (or its equivalent in another currency converted at the applicable exchange rate as of the date of such Disposition) and the payment of such taxes is being contested in good faith and by appropriate proceedings), (b) Net Cash Payments shall not include any cash payment (or portion thereof) received in any fiscal year of the Company in respect of such Disposition to the extent that such cash payment (or portion thereof), together with all cash payments with respect to other Dispositions therefore received in such fiscal year, does not exceed U.S.$500,000 (or its equivalent in another currency converted at the applicable exchange rate as of the date of such Disposition) and (c) Net Cash Payments shall be net of any repayments by the Company or any of its Restricted Subsidiaries of Indebtedness to the extent that (i) such Indebtedness is secured by a Lien on the Property that is the subject of such Disposition and (ii) such Indebtedness is to be repaid as a condition to the Disposition of such Property.

"Net Proceeds" shall mean, in respect of any Bankers' Acceptance, the amount obtained by applying the Bankers' Acceptance Rate plus the BA Fee Rate to the face amount of such Bankers' Acceptance in accordance with the formula set forth in Exhibit F hereto.

"New Wholly-Owned Subsidiary" shall have the meaning assigned to such term in Section 9.08 hereof.

"Non-Recourse Debt" shall mean any Indebtedness of any Unrestricted Subsidiary, in each case in respect of which the recourse of the holder or holders thereof is to such Unrestricted Subsidiary and/or one or more of its Subsidiaries (which is an Unrestricted Subsidiary) and/or any other Person (other than the Company and/or any Restricted Subsidiary) and the terms and conditions of the non-recourse provisions of which are reasonably acceptable to the Majority Banks.

"Note Indenture" shall mean any note indenture entered into after the date hereof between the Company and a trustee on behalf of the noteholders thereunder, as contemplated pursuant to the Harvest Trust Indenture as a note indenture referenced thereunder.

"Notes" shall mean the promissory notes provided for by Section 2.08(a) hereof and any promissory notes delivered in substitution or exchange therefor, in each case as the same shall be modified and supplemented and in effect from time to time.

"NPI" shall mean the net profit interest payable by the Company to the Trust pursuant to the NPI Agreement.

"NPI Agreement" shall mean the Amended and Restated Net Profit Interest Agreement dated July 10, 2002 between the Company and the Trustee (for and on behalf of the Trust) as amended and restated from time to time.

"Operating Expenses" shall mean, for any period, the sum of the following for the Company and its Restricted Subsidiaries (determined on a consolidated basis in accordance with GAAP) to the extent accrued or paid during such period (without duplication): (i) lease operating expenses and (ii) all other expenses that would be included as operating expenses in accordance with GAAP.

"Other Taxes" means any and all present or future stamp or documentary taxes or any other excise or property taxes, charges or similar levies arising from any payment made hereunder to the Administrative Agent, any Bank or the Issuing Bank or from the execution, delivery or enforcement of, or otherwise with respect to, this Agreement, but in all events not including any Excluded Taxes.

"Permitted Investments" shall mean: (a) direct obligations of Canada or the United States of America, or of any agency of either thereof, or obligations guaranteed as to principal and interest by Canada, or the United States of America or by any agency of either thereof, in either case maturing not more than 90 days from the date of acquisition thereof; (b) certificates of deposit issued or bankers' acceptances issued by any Bank or any other bank or trust company organized under the laws of Canada or any province thereof or the United States of America or any state thereof and having capital, surplus and undivided profits of at least U.S.$500,000,000 (or the Equivalent Amount), maturing not more than 90 days from the date of acquisition thereof; (c) commercial paper rated A-1 or better or P-1, R-1 low or A-1 or better by Standard & Poor's Ratings Group, a division of McGraw-Hill, Inc., Moody's Investors Service, Inc., Dominion Bond Rating Service Limited or Canada Bond Rating Service, respectively, maturing not more than 90 days from the date of acquisition thereof; and (d) commercial paper rated A-2 or better (but less than A-1) or P-2 or better (but less than P-1) by Standard and Poor's Rating Group or Moody's Investors Services, Inc. respectively, maturing not more than 30 days from the date of acquisition thereof.

"Permitted Liens" means those Liens permitted pursuant to Section 9.06 hereof.

"Person" shall mean any individual, corporation, company, voluntary association, partnership, joint venture, trust, unincorporated organization or government (or any agency, instrumentality or political subdivision thereof).

"Post-Default Rate" shall mean, in respect of any principal of any Loan, any Reimbursement Obligation or any other amount under this Agreement, any Note or any other Loan Document that is not paid when due (whether at stated maturity, by acceleration, by optional or mandatory prepayment or otherwise), a rate per annum during the period from and including the due date to but excluding the date on which such amount is paid in full equal to 2% plus the Base Rate as in effect from time to time plus the Applicable Margin for Base Rate Loans (provided that, if the amount so in default is principal of a BA Loan, Canadian Base Rate Loan, Eurodollar Loan or a Eurocanadian Loan and the due date thereof is a day other than the last day of the Interest Period therefor, the "Post-Default Rate" for such principal shall be, for the period from and including such due date to but excluding the last day of the Interest Period, 2% plus the interest rate for such Loan as provided in Section 3.02(a) hereof and, thereafter, the Canadian Base Rate as in effect from time to time plus the Applicable Margin for Canadian Base Rate Loans plus 2%).

"Present Value of Reserves" shall mean, on any date, estimated net cash flow expressed in U.S. Dollars (after development expenses and production taxes) in respect of Proved Reserves attributable to Hydrocarbon Properties calculated in accordance with the provisions of Section 1.03.

"Prime Rate" shall mean the rate of interest per annum publicly announced from time to time by WestLB as its prime rate in effect at its office in New York City for commercial loans in U.S. Dollars.

"Principal Amount" shall mean, for a Bankers' Acceptance, the face amount thereof, for a BA Loan, the principal amount thereof determined in accordance with Section 2.11(h) hereof, and for any other Loans, the outstanding principal amount thereof.

"Production Payments" shall mean, collectively, Dollar-Denominated Production Payments and Volumetric Production Payments.

"Property" shall mean any right or interest in or to property of any kind whatsoever, whether real, personal or mixed and whether tangible or intangible.

"Proved Reserves" shall mean reserves (to the extent of the net interest of the Company and its Restricted Subsidiaries therein) comprised of quantities of hydrocarbons that geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing conditions, provided that such reserves are recoverable from (a) existing wells, whether from completion intervals currently open and producing to market, or completion intervals currently open but not currently producing or zones behind casing of existing wells, or (b) new wells on undrilled acreage. Proved Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain to be productive when drilled. Other undrilled units may also be credited with Proved Reserves where continuity of production from existing productive formations can be demonstrated with reasonable certainty. For purposes of determining whether any Hydrocarbon Properties of any Obligor contain Proved Reserves, the Banks and the Obligors agree that the most recent Reserve Evaluation Report or other internal reserve reports prepared by the Company shall be determinative.

"Quarterly Dates" shall mean the last day of March, June, September and December in each year, the first of which shall be the first such day after the date of this Agreement; provided that if any such day is not a Business Day, then such Quarterly Date shall be the next succeeding Business Day.

"Regulation A" and "Regulation D" shall mean, respectively, Regulations A and D of the Board of Governors of the Federal Reserve System (or any successor), as the same may be modified and supplemented and in effect from time to time.

"Regulatory Change" shall mean, with respect to any Bank, any change after the date of this Agreement in federal, state, provincial or foreign law or regulations (including, without limitation, Regulation D) or the adoption or making after such date of any interpretation, directive or request applying to a class of banks including such Bank of or under any federal, state, provincial or foreign law or regulations (whether or not having the force of law and whether or not failure to comply therewith would be unlawful) by any court or governmental or monetary authority charged with the interpretation or administration thereof.

"Reimbursement Obligations" shall mean, at any time, the obligations of the Company then outstanding, or that may thereafter arise in respect of all Letters of Credit then outstanding, to reimburse amounts paid by the Issuing Bank in respect of any drawings under a Letter of Credit.

"Release" shall mean any release, spill, emission, leaking, pumping, injection, deposit, disposal, discharge, dispersal, leaching or migration into the indoor or outdoor environment, including, without limitation, the movement of Hazardous Materials through ambient air, soil, surface water, ground water, wetlands, land or subsurface strata.

"Report Delivery Date" shall mean, with respect to any Reserve Evaluation Report, the date which is (a) 60 days following each December 31, with respect to any Determination Date falling on December 31 and (b) 60 days following each June 30, with respect to any Determination Date falling on June 30.

"Reserve Evaluation Report" shall mean an unsuperseded report that (a) is (i) prepared, in the case of the report required to be delivered by the Company pursuant to Section 9.01(e) hereof in connection with a Determination Date with respect to December 31 of each year, by the Independent Petroleum Engineer on the basis of assumptions provided by the Administrative Agent (which are consistent with those applied by the Administrative Agent for similar production loans for similarly situated companies) (including projected hydrocarbon price assumptions) and projections which the Company believes in good faith to be reasonable or, in the case of the report required to be delivered by the Company pursuant to Section 9.01(e) hereof in connection with each other Determination Date, by the Independent Petroleum Engineer based on the report delivered with respect to the immediately preceding December 31, as adjusted by the Independent Petroleum Engineer for reserve additions and production information from such December 31 as provided to the Independent Petroleum Engineer by the Company and (ii) reasonably satisfactory in form and substance to the Majority Banks (including as to assumptions) and (b) is prepared on the basis of findings and material data as of a date not more than 90 days prior to the effective date of such report, (i) identifies the Hydrocarbon Properties covered thereby, (ii) as to each of the Hydrocarbon Properties, sets forth (A) the Proved Reserves attributable to such Hydrocarbon Property, (B) the total amount of such Proved Reserves attributable to such Hydrocarbon Property that, in the opinion of the preparer of such report, the Company and its Restricted Subsidiaries have the right to produce for their own account in the current and each succeeding calendar year, (C) a projection of the rate of production and the Future Net Revenues of the Company and its Restricted Subsidiaries (including as additional information the data and assumptions used to determine such Future Net Revenues) from such Proved Reserves for the current and each succeeding calendar year, (D) the quantity and type of hydrocarbons recoverable from such Proved Reserves in the current and each succeeding calendar year, (E) an estimate of the projected revenues and expenses attributable to such Proved Reserves in the current and each succeeding calendar year, and (F) any reports or evaluations prepared by the Company or any of its Subsidiaries regarding the expediency of any change in methods of treatment or operation of all or any wells drilled to produce any of such Proved Reserves that are producing or capable of producing hydrocarbons, any new drilling or development, any method of secondary recovery by repressuring or otherwise, or any other action with respect to such Proved Reserves, the decision as to which may increase or reduce the quantity of hydrocarbons ultimately recoverable, or the rate of production thereof and (c) reconciles (i) the total amount of Proved Reserves attributable to each Hydrocarbon Property and (ii) any material changes in Operating Expenses or Capital

Expenditures contained in such Reserve Evaluation Report with the information contained in the immediately preceding Reserve Evaluation Report, if any.

"Reserve Requirement" shall mean, for any Interest Period for any Eurodollar Loan or Eurocanadian Loan, the average maximum rate at which reserves (including, without limitation, any marginal, supplemental or emergency reserves) are required to be maintained during such Interest Period under Regulation D by member banks of the Federal Reserve System in New York City with deposits exceeding one billion U.S. Dollars against "Eurocurrency liabilities" (as such term is used in Regulation D). Without limiting the effect of the foregoing, the Reserve Requirement shall include any other reserves required to be maintained by such member banks by reason of any Regulatory Change with respect to (i) any category of liabilities that includes deposits by reference to which the Eurodollar Base Rate is to be determined as provided in the definition of "Eurodollar Base Rate" or "Eurocanadian Base Rate", respectively, in this Section 1.01 or (ii) any category of extensions of credit or other assets that includes Eurodollar Loans or Eurocanadian Loans, respectively.

"Restricted Subsidiary" shall mean any Subsidiary of the Company other than an Unrestricted Subsidiary.

"Security Documents" shall mean, collectively, the Mortgages, and all Personal Property Security Act and other filings required by this Agreement or the Mortgages to be filed with respect to the security interests in real and personal Property and fixtures created pursuant to the Mortgages.

"Stamping Fee" shall mean, in respect of any Bankers' Acceptance or BA Loan, the fee payable by the Company described in Section 2.11(c) hereof.

"Subordinated Indebtedness" shall mean any Indebtedness of any of the Obligors (including, without limitation, all Indebtedness issued to the Trust by the Company, its predecessor or any other Obligor) (i) which is unsecured, (ii) for which any Obligor is directly and primarily liable, and (iii) which is subordinated to the obligations of the respective Obligors to pay principal of and interest on the Loans, Reimbursement Obligations and Notes hereunder on terms and pursuant to documentation containing terms substantially in the form of Exhibit E and otherwise in form and substance satisfactory to the Majority Banks (provided that any Subordinated Indebtedness issued by any Obligor and subject to the Subordination Agreement shall be deemed to be in form and substance satisfactory to the Majority Banks), and any extensions or renewals thereof, but excluding any increases in the outstanding amount thereof if, in the case of any Subordinated Indebtedness payable to any Person other than the Trust, following such increases, on a pro forma basis (assuming that such Subordinated Indebtedness has been issued at the beginning of the period, if applicable, contemplated by each of the subsections of Section 9.10) the Company would not be in compliance with its obligations pursuant to Section 9.10.

"Subordinated Notes" shall mean promissory notes issued by the Company pursuant to the Note Indenture from time to time.

"Subordination Agreement" shall mean the Subordination Agreement dated as of the date hereof among the Trustee (for and on behalf of the Trust), the Administrative Agent for itself and as agent for the Banks and the Obligors, as amended or amended and restated from time to time.

"Subsidiary" shall mean, for any Person, any corporation, partnership or other entity of which at least a majority of the securities or other ownership interests having by the terms thereof ordinary voting power to elect a majority of the board of directors or other persons performing similar functions of such corporation, partnership or other entity (irrespective of whether or not at the time securities or other ownership interests of any other class or classes of such corporation, partnership or other entity shall have or might have voting power by reason of the happening of any contingency) is at the time directly or indirectly owned or controlled by such Person or one or more Subsidiaries of such Person or by such Person and one or more Subsidiaries of such Person.

"Supermajority Banks" shall mean Banks having at least 66⅔% of the aggregate amount of the Commitments, or if the Commitments shall have been terminated, Banks holding at least 66⅔% of the sum of the aggregate unpaid principal amount of the Loans, the Letter of Credit Liabilities and the Bankers' Acceptance Liabilities.

"Tangible Net Worth" shall mean, as at any date for any Person, the sum for such Person (determined on a consolidated basis without duplication in accordance with GAAP as of the date of its most recent financial statement) of the following, expressed in U.S. Dollars:

(a) the amount of capital stock, plus

(b) the amount of surplus and retained earnings (or, in the case of a surplus or retained earnings deficit, minus the amount of such deficit), minus

(c) the sum of the following: cost of treasury shares and the book value of all assets which should be classified as intangibles (without duplication of deductions in respect of items already deducted in arriving at surplus and retained earnings) but in any event including goodwill, minority interests, research and development costs, trademarks, trade names, copyrights, patents and franchises, unamortized debt discount and expense, all accounting reserves, plus

(d) the amount of noncash writedowns of long-lived assets in compliance with GAAP guidelines or Alberta Securities Commission rules or regulations;

plus any increase occurring during the period from the date of the Company's most recent financial statements to the date of determination as a result of any Equity Issuance by the Company. Additionally, for purposes of calculating the Indebtedness to Equity Ratio only, Tangible Net Worth shall include the NPI.

"Taxes" shall mean all taxes, levies, imposts, stamp taxes, duties, charges to tax, fees, deductions, withholdings, royalties, charges, compulsory loans or restrictions or conditions resulting in a charge which are imposed, levied, collected, withheld or assessed by any political subdivision or taxing authority as of the date of this Agreement or at any time in the future together with interest thereon and penalties with respect thereto, if any, and any payments of principal, interest, charges, fees or other amounts made on or in respect thereof, including without limitation production and severance taxes and windfall profit taxes, and "Tax" and "Taxation" shall be construed accordingly provided that "Taxes" shall exclude taxes imposed on or measured by the overall net income or capital of a Person.

"Trust" shall mean Harvest Energy Trust, an open-ended, unincorporated investment trust established under the laws of the Province of Alberta.

"Trust Indenture" shall mean the amended and restated trust indenture dated September 27, 2002 between the Trustee and the Company as such indenture may be further amended by supplemental indentures from time to time.

"Trustee" means Valiant Trust Company, or its successor as trustee of the Trust.

"Type" shall have the meaning assigned to such term in Section 1.04 hereof.

"U.S. Dollar Letter of Credit" shall mean a Letter of Credit denominated in U.S. Dollars.

"U.S. Dollars" and "U.S.$" shall mean lawful money of the United States of America.

"Unrestricted Properties" shall mean, at any time of determination, the Hydrocarbon Properties of the Company and its Subsidiaries that (i) are not Mortgaged Properties and do not contain Proved Reserves or (ii) have not been given any value in the Borrowing Base as most recently determined prior to such time of determination.

"Unrestricted Subsidiary" shall mean such Subsidiaries of the Company (other than Subsidiary Guarantors) as may be designated by the Company as "Unrestricted Subsidiaries" as provided in Section 1.05 hereof.

"Usage Ratio" shall mean as of any date the ratio of (a) the Principal Amount of all Loans and Letter of Credit Liabilities outstanding on such date to (b) the Borrowing Base on such date.

"Volumetric Production Payments" shall mean production payment obligations of the Company or any of its Restricted Subsidiaries which are payable from a specified share of production from specific Properties, together with all undertakings and obligations in connection therewith.

"Voting Stock" shall mean, with respect to any Person, securities of any class or classes of Capital Stock in such Person entitling the holders thereof (whether at all times or only so long as no senior class of stock has voting power by reason of any contingency) to vote in the election of members of the Board of Directors or other governing body of such Person.

"WestLB" shall mean WestLB AG, New York Branch.

"Wholly Owned Subsidiary" shall mean, with respect to any Person, any corporation, partnership or other entity of which all of the equity securities or other ownership interests (other than, in the case of a corporation, directors' qualifying shares) are directly or indirectly owned or controlled by such Person or one or more Wholly Owned Subsidiaries of such Person or by such Person and one or more Wholly Owned Subsidiaries of such Person.

1.02 Accounting Terms and Determinations.

(a) Except as otherwise expressly provided herein, all accounting terms used herein shall be interpreted, and all financial statements and certificates and reports as to financial matters required to be delivered to the Banks hereunder shall (unless otherwise disclosed to the Banks in writing at the time of delivery thereof in the manner described in subsection (b) below) be prepared, in accordance with GAAP applied on a basis consistent with those used in the preparation of the latest financial statements furnished to the Banks hereunder (which, prior to the delivery of the first financial statements under Section 9.01 hereof, shall mean the unaudited pro-forma consolidated financial statements of the Trust as at July 10, 2002 and for the six months ended June 30, 2002 referred to in Section 8.02 hereof). All calculations made for the purposes of determining compliance with this Agreement shall (except as otherwise expressly provided herein) be made by application of GAAP applied on a basis consistent with those used in the preparation of the latest annual or quarterly financial statements furnished to the Banks pursuant to Section 9.01 hereof (or, prior to the delivery of the first financial statements under Section 9.01 hereof, used in the preparation of the unaudited pro-forma consolidated financial statements of the Trust as at July 10, 2002 and for the six months ended June 30, 2002 referred to in Section 8.02 hereof) unless (i) the Company objects to the Banks in writing to determining such compliance on such basis at the time of delivery of such financial statements to the Banks or (ii) the Majority Banks shall object to the Company (through the Administrative Agent) in writing to so determining such compliance within 30 days after such delivery of such financial statements, in either of which events such calculations shall be made on a basis consistent with those used in the preparation of the latest financial statements as to which such objection shall not have been made (which, if objection is made in respect of the first financial statements delivered under Section 9.01 hereof, shall mean the financial statements referred to in Section 8.02 hereof).

(b) At the request of the Majority Banks, the Company shall deliver to the Banks (i) a description in reasonable detail of any material variation between the application of accounting principles employed in the preparation of such statement and the application of accounting principles employed in the preparation of the next preceding annual or quarterly financial statements as to which no objection has been made in accordance with the last sentence of subsection (a) above and (ii) reasonable estimates of the difference between such statements arising as a consequence thereof.

(c) The Company will not, without the prior written consent of the Administrative Agent, change the last day of its fiscal year from December 31 of each year, or the last days of the first three fiscal quarters in each of its fiscal years from March 31, June 30 and September 30 of each year, respectively.

1.03 Borrowing Base.

(a) Reserve Evaluation Reports. The Company has furnished to the Administrative Agent and the Banks a Reserve Evaluation Report dated August 1, 2002. On or before each Report Delivery Date, the Company shall furnish to the Administrative Agent and the Banks an updated Reserve Evaluation Report.

(b) Borrowing Base. (i) During the period commencing on the date hereof and ending on such date as the first redetermination of the Borrowing Base shall become effective as provided below in this Section 1.03(b), the Borrowing Base shall be U.S.$38,000,000 (subject in each case to any adjustments and redeterminations provided for by Sections 1.03(c), 1.03(d), 1.03(e), 2.10 and 9.22 hereof) which amount has been determined on the basis of the Reserve Evaluation Report referred to in the first sentence of Section 1.03(a) hereof (with such adjustments to the rates, factors, values, estimates, assumptions and computations set forth in such Reserve Evaluation Report as were acceptable to the initial Banks party hereto). As promptly as reasonably practicable after its receipt of the Reserve Evaluation Report furnished to it pursuant to the second sentence of Section 1.03(a) hereof, the Administrative Agent (in consultation with the Supermajority Banks) shall endeavor to redetermine the Borrowing Base on the basis of such Reserve Evaluation Report in the manner provided in this clause (b), notify the Banks of such redetermination and, if such redetermination is approved by the Supermajority Banks, notify the Company of the Borrowing Base as so redetermined (or, if the Administrative Agent's redetermination is not approved, notify the Company of the Borrowing Base as redetermined by the Supermajority Banks) and such redetermined Borrowing Base shall become effective on the Determination Date next following each Report Delivery Date and shall remain effective until again redetermined as provided in this Section 1.03(b) (subject to any adjustments and redeterminations provided for by Sections 1.03(c), 1.03(d) and 1.03(e) hereof, reductions pursuant to Section 2.10(b), (c) and (d) and Section 9.22 hereof). The determination by the Administrative Agent (and as approved or redetermined by the Supermajority Banks), of the Borrowing Base for any Determination Period shall be made on the basis of customary loan parameters of the Banks for production loans to similarly situated companies which shall include the Present Value of Reserves attributable to Hydrocarbon Properties as set forth in the applicable Reserve Evaluation Report for such Determination Period, subject, however, to such adjustments as the Administrative Agent, with the concurrence of the Supermajority Banks, may make in its and their sole discretion to the rates (including without limitation discount rates), factors, values, assumptions, prices and costs set forth in such Reserve Evaluation Report and any other relevant information or factors, including without limitation, any additional Indebtedness (other than Subordinated Indebtedness) or other obligations that have been incurred or that the Company or its Restricted Subsidiaries intend to incur that the Supermajority Banks may reasonably deem appropriate. The parties to the Agreement acknowledge that no Properties of the Obligors shall be included in the Borrowing Base unless they are subject to the Lien of the Mortgage.

(ii) As used herein, "Borrowing Base" means the amount specified in the first sentence of this Section 1.03(b) as redetermined from time to time as provided in the second sentence of this Section 1.03(b) and subject to adjustments, redeterminations and principles provided in Sections 1.03(c), 1.03(d), 1.03(e), 2.10 and 9.22 hereof.

(c) Material Change. The Company agrees to notify the Administrative Agent promptly of any material change of which the Company or any of the Restricted

Subsidiaries is aware which reduces or may result in a reduction of the Borrowing Base by more than 10%.

(d) Redetermination. If so requested by the Supermajority Banks or the Company at any time after any change in commodity prices, applicable laws, contracts, material reserve additions, drilling results or the Properties as a result of acquisitions or Dispositions or the pricing parameters that the Banks apply to similar production loans for similarly situated companies, that are reasonably expected to result in a change of the Borrowing Base by more than 5% (provided that each of the Supermajority Banks (collectively) and the Company may each only make one such request in any calendar year) the Administrative Agent shall, as promptly as reasonably practicable after the receipt of such request, endeavor to redetermine (in consultation with the Supermajority Banks) the Borrowing Base as then in effect on the basis of the then most recent Reserve Evaluation Report (subject, however, to such additional adjustments to the rates, factors, values, estimates, assumptions and computations as set forth therein as the Administrative Agent, with the concurrence of the Supermajority Banks, may determine to be appropriate in accordance with their current parameters for similar production loans for similarly situated companies) and any other relevant information and factors, including, without limitation, any additional Indebtedness or other obligations that have been or are reasonably anticipated to be incurred by the Company and its Restricted Subsidiaries and any Hydrocarbon Properties (and assets relating thereto) acquired by the Company and its Restricted Subsidiaries (which are not subject to any Lien other than Liens created under the Security Documents or Permitted Liens) that the Supermajority Banks may deem appropriate and as otherwise provided in Section 1.03(b) hereof, provided that no Hydrocarbon Properties acquired by any Subsidiary of the Company shall be included in the calculation of the Borrowing Base unless such Subsidiary is an Obligor under this Agreement. As promptly as reasonably following its redetermination of the Borrowing Base, the Administrative Agent shall notify the Banks of such redetermination and, if such redetermination is approved by the Supermajority Banks, notify the Company in writing of the Borrowing Base as so redetermined (and in any event not later than the Determination Date with respect to such redetermination) and such redetermined Borrowing Base shall become effective immediately upon delivery to the Company of such notice of redetermination.

(e) Determinations, Etc. Notwithstanding any other provision of this Agreement, all determinations and redeterminations and adjustments by the Administrative Agent (and any determinations and decisions by the Supermajority Banks or Majority Banks in connection therewith, or in connection with the provisions of Section 2.10 or 9.22, including any thereof approving or disapproving a proposed redetermination or redetermination by the Administrative Agent or effecting any adjustment to any element included in a Reserve Evaluation Report or the determination or redetermination of the Borrowing Base) shall be made on a reasonable basis, in good faith and in a manner reasonably consistent with their loan parameters for similar production loans for similarly situated companies and consistent with the basis on which the initial Borrowing Base was determined to be acceptable to the Banks (but after giving effect to changes in facts and circumstances occurring after the date of such initial determination including, but not limited to, reserves and production, operating expenses and economic assumptions with respect to price of hydrocarbons and inflation), and any such determination, redetermination or adjustment shall consider any other relevant information or factors, including without limitation, any additional Indebtedness (other than Subordinated

Indebtedness) or other obligations that have been incurred or that the Company and its Restricted Subsidiaries intend or expect to incur that the Majority Banks may deem appropriate, provided that no Hydrocarbon Properties acquired by any Subsidiary of the Company shall be included in the calculation of the Borrowing Base unless such Subsidiary is an Obligor under this Agreement.

1.04 Types of Loans. Loans hereunder are distinguished by "Type". The "Type" of a Loan refers to whether such Loan is a BA Loan, a Base Rate Loan, a Canadian Base Rate Loan, a Eurocanadian Loan or a Eurodollar Loan, each of which constitutes a Type.

1.05 Designation of Subsidiaries as Restricted or Unrestricted Subsidiaries. By delivery to the Administrative Agent of a new Schedule II hereto and with the approval of the Majority Banks, the Company may designate a Restricted Subsidiary (other than a Subsidiary Guarantor) to be an Unrestricted Subsidiary or an Unrestricted Subsidiary to be a Restricted Subsidiary; provided that the Company may, without such approval, designate (by notice to the Administrative Agent which shall promptly notify the Banks) a corporation or other entity that is formed or acquired as a direct or indirect Subsidiary of the Company after the date hereof (no part of the business or assets of which was owned by the Company or a Restricted Subsidiary prior to the date of such formation or acquisition and included in the Borrowing Base or used in connection with the exploration, exploitation, transportation or marketing of hydrocarbons from properties included in the Borrowing Base) to be an Unrestricted Subsidiary on or prior to the date of such formation or acquisition if, after giving effect thereto, the Company would be in compliance with its obligations with respect to such Subsidiary as an Unrestricted Subsidiary under Section 9.17 hereof and no other Default shall have occurred and be continuing.

SECTION 2.
COMMITMENTS, LOANS, NOTES AND PREPAYMENTS.

2.01 Loans.

(a) Each Bank severally agrees, in accordance with the terms and conditions of this Agreement, to make one or more loans to the Company in U.S. Dollars or Canadian Dollars during the period from and including the Effective Date to and including the Commitment Termination Date, in an aggregate amount (expressed as the Equivalent Amount of U.S. Dollars) up to but not exceeding the lesser of (x) the Commitment of such Bank and (y) an amount equal to such Bank's Commitment Percentage multiplied by the then effective Borrowing Base; provided that (i) except during a Deficiency Cure Period, in no event shall the aggregate Principal Amount of all Loans (with the Principal Amount of Canadian Loans expressed as an Equivalent Amount in U.S. Dollars), together with the aggregate amount of all Letter of Credit Liabilities (with the Canadian Letter of Credit Liabilities expressed as an Equivalent Amount in U.S. Dollars) and the Equivalent Amount in U.S. Dollars of all Bankers' Acceptance Liabilities of the Company, exceed the lesser of (x) the aggregate amount of the Commitments as in effect from time to time, and (y) the then effective Borrowing Base and (ii) the Company may not borrow Loans or obtain Letters of Credit or Bankers' Acceptances under this Agreement at any time while a Borrowing Base Deficiency exists. The aggregate of the Commitments of the Banks on the date hereof is U.S.$60,000,000.

(b) Subject to the terms and conditions of this Agreement, during the period from and including the Effective Date to but not including the Commitment Termination Date, the Company may request the issuance of Bankers' Acceptances pursuant to Section 2.11 hereof and repay such Bankers' Acceptances and may borrow, repay and reborrow the Loans, and may, subject to Section 4.04 hereof Continue Loans of one Type as Loans of the same Type or Convert Loans of one Type to Loans of another Type (as provided in Section 2.09 hereof); provided that no more than five separate Interest Periods in respect of BA Loans, Eurodollar Loans or Eurocanadian Loans may be outstanding at any one time and no more than three separate tranches of Bankers' Acceptances with different Maturity Dates may be outstanding at any one time.

(c) Except during a Deficiency Cure Period, the aggregate amount of Letter of Credit Liabilities outstanding under this Agreement shall not at the time of issuance of any Letter of Credit exceed the least of (A) the Equivalent Amount of C$7,500,000 minus the face amount of any letters of credit secured by a Lien permitted by Section 9.06(f)(ii), (B) the aggregate of the Commitments and (C) the then effective Borrowing Base.

2.02 Borrowings.

(a) Loans. The Company shall give the Administrative Agent (which shall promptly notify the Banks) notice of each borrowing hereunder as provided in Section 4.05 hereof. Not later than 1:00 p.m. New York time on the date specified for each borrowing hereunder, each Bank shall make available the amount of the Loan or Loans to be made by it on such date to the Administrative Agent, at an account specified by the Administrative Agent maintained by the Administrative Agent with WestLB, in immediately available funds, for account of the Company. The amount so received by the Administrative Agent shall, subject to the terms and conditions of this Agreement, be made available to the Company by depositing the same, in immediately available funds, in an account of the Company designated by the Company in writing. Notwithstanding any provision of this Agreement to the contrary, Eurocanadian Loans, Canadian Base Rate Loans and BA Loans may only be denominated in Canadian Dollars and Eurodollar Loans and Base Rate Loans may only be denominated in U.S. Dollars.

(b) Usage Certificate. At the time of each such notice of borrowing hereunder or the request for the issuance of a Letter of Credit or Bankers' Acceptance, the Company shall deliver a certificate of the chief financial officer, the controller, the treasurer or an assistant treasurer of the Company, in the form of Exhibit D hereto.

2.03 Letters of Credit.

(a) Issuance. Subject to the terms and conditions of this Agreement, the Commitments may be utilized, upon the request of the Company, in addition to the Loans provided for by Section 2.01(a) hereof and the Bankers' Acceptances provided for by Section 2.11 hereof, for the issuance by the Issuing Bank of letters of credit (collectively, "Letters of Credit") in Canadian Dollars or U.S. Dollars for account of the Company, provided that in no event, except during a Deficiency Cure Period, shall (i) the aggregate amount of all Letter of Credit Liabilities, together with the aggregate Principal Amount of the Loans and the aggregate amount of all Bankers' Acceptances (with the amounts of any Canadian Loans, Canadian Letter of Credit Liabilities and Bankers' Acceptance Liabilities (collectively, "Canadian Dollar Obligations") outstanding in Canadian Dollars expressed as an Equivalent Amount in U.S. Dollars), exceed the lesser of (A) the aggregate of the Commitments and (B) the then effective Borrowing Base, (ii) the outstanding aggregate amount of all Letter of Credit Liabilities, at the time of the issuance of any Letter of Credit, exceed the Equivalent Amount in U.S. Dollars of C$7,500,000 minus the face amount of any letters of credit secured by a Lien permitted by Section 9.06(f)(ii) and (iii) the expiration date of any Letter of Credit extend beyond the earlier of the date which is five Business Days prior to the Commitment Termination Date and the date 12 months following the issuance of such Letter of Credit. The Issuing Bank shall be deemed to hold a Letter of Credit Liability in an amount equal to its retained interest in the related Letter of Credit after giving effect to the acquisition by the Banks other than the Issuing Bank of their participation interests under this Section 2.03.

(b) Letters of Credit Generally. The following additional provisions shall apply to Letters of Credit:

(i) The Company shall give the Administrative Agent at least three Business Days' irrevocable prior notice (effective upon receipt) specifying the Business Day (which shall be no later than 30 days preceding the Commitment Termination Date) each Letter of Credit that the Company is requesting to be issued, the beneficiary, the payment currency for the Letter of Credit and the account party or parties therefor and describing in reasonable detail the proposed terms of such Letter of Credit (including the beneficiary thereof and the currency of such Letter of Credit) and the nature of the obligations proposed to be supported thereby. Each such notice shall be irrevocable and binding on the Company. Upon receipt of any such notice, the Administrative Agent shall on the same day advise the Issuing Bank and each Bank of the contents thereof.

(ii) On each day during the period commencing with the issuance by any Issuing Bank of any Letter of Credit and until such Letter of Credit shall have expired or been terminated, each Bank's Commitment shall be deemed to be utilized for all purposes of this Agreement in an amount equal to such Bank's Commitment Percentage of the Equivalent Amount in U.S. Dollars of the then undrawn face amount of such Letter of Credit. Each Bank (other than the Issuing Bank) agrees that, upon the issuance of any Letter of Credit hereunder, it shall automatically acquire a participation in such Issuing Bank's liability under such Letter of Credit in an amount equal to such Bank's applicable Commitment Percentage of such liability, and each such Bank (other than the Issuing Bank) thereby shall absolutely, unconditionally and irrevocably assume, as primary obligor and not as surety, and shall be unconditionally obligated to the Issuing Bank to pay and discharge when due, its Commitment Percentage of the Issuing Bank's liability under such Letter of Credit.

(iii) Upon receipt from the beneficiary of any Letter of Credit of any demand for payment under such Letter of Credit, the Issuing Bank shall promptly notify the Company and each Bank (in each case through the Administrative Agent) of the amount to be paid by the Issuing Bank and the currency of payment as a result of such demand, the date on which payment is to be made by the Issuing Bank to such beneficiary in respect of such demand and the amount required by each Bank to reimburse the Issuing

Bank, specifying such Bank's Commitment Percentage of the amount of the related demand for payment. The amount of such payment shall be deemed to be a Base Rate Loan to the Company if made in U.S. Dollars and a Canadian Base Rate Loan to the Company if made in Canadian Dollars.

(iv) In respect of any Letter of Credit, each Bank having a Letter of Credit Liability with respect to such Letter of Credit (other than the Issuing Bank) shall, upon demand by the Administrative Agent under clause (iv) above, pay to the Administrative Agent for the account of the Issuing Bank at an account specified by the Issuing Bank maintained with the Administrative Agent and in immediately available funds, the amount in the relevant currency of such Bank's Commitment Percentage of any payment under such Letter of Credit upon notice by the Issuing Bank (through the Administrative Agent) to such Bank requesting such payment and specifying such amount. Such Bank's obligation to make such payments to the Administrative Agent for account of the Issuing Bank under this clause (iv), and the Issuing Bank's right to receive the same, shall be absolute and unconditional and shall not be affected by any circumstance whatsoever, including, without limitation, (x) the failure of any other Bank to make its payment under this clause (iv), the financial condition of the Company or any other Obligor (or any other account party), the existence of any Default or (y) the termination of the Commitments. Each such payment to the Issuing Bank shall be made without any offset, abatement, withholding or reduction whatsoever. If such Bank shall default in its obligation to make any such payment to the Administrative Agent for the account of the Issuing Bank, for so long as such default shall continue the Administrative Agent shall at the request of the Issuing Bank withhold from any payments received by the Administrative Agent under this Agreement or any Note for account of such Bank the amount so in default and the Administrative Agent shall pay the same to the Issuing Bank in satisfaction of such defaulted obligation.

(v) The Company agrees to pay to the Administrative Agent for account of each Bank in respect of each Letter of Credit issued for the Company an issuance fee in an amount equal to the Applicable Margin for Eurodollar Loans per annum of the daily average Equivalent Amount in U.S. Dollars, of the undrawn face amount of such Letter of Credit for the period from and including the date of issuance of such Letter of Credit to and including the date such Letter of Credit is drawn in full, expires or is terminated (such fee to be non-refundable, to be paid in arrears on each Quarterly Date and on the Commitment Termination Date and to be calculated, for any day, after giving effect to any payments made under such Letter of Credit on such day). The Administrative Agent shall pay to each Bank (other than the Issuing Bank), from time to time at reasonable intervals (but in any event at least quarterly), but only to the extent actually received from the Company, an amount equal to such Bank's Commitment Percentage of all such fees in respect of each Letter of Credit (including any such fee in respect of any period of any renewal or extension thereof). In addition, the Company agrees to pay to the Administrative Agent for account of the Issuing Bank on the issuance date, a fronting fee in respect of each Letter of Credit in an amount equal to 1/8 of 1% of the face amount of such Letter of Credit plus all commissions, charges, costs and expenses in the amounts customarily charged by such Issuing Bank from time to time in like circumstances with respect to the issuance of each Letter of Credit and drawings and other transactions relating thereto.

(vi) Promptly following the end of each calendar month, the Issuing Bank shall deliver (through the Administrative Agent) to each Bank and the Company notice describing the aggregate Equivalent Amount in U.S. Dollars of all Letters of Credit, as applicable, outstanding at the end of such month. Upon the request of any Bank from time to time, the Issuing Bank shall deliver any other information in its possession reasonably requested by the Bank with respect to each Letter of Credit then outstanding and issued by the Issuing Bank.

(vii) The issuance of each Letter of Credit by the Issuing Bank shall, in addition to the conditions precedent set forth in Section 7 hereof, be subject to the conditions precedent that (A) such Letter of Credit shall be in such form, contain such terms and support such transactions as shall be satisfactory to such Issuing Bank consistent with its then current practices and procedures with respect to letters of credit of the same type and (B) the Company shall have executed and delivered such applications, agreements and other instruments relating to such Letter of Credit as the Issuing Bank shall have reasonably requested consistent with its then current practices and procedures with respect to letters of credit of the same type, provided that in the event of any conflict between any such application, agreement or other instrument and the provisions of this Agreement or any Security Document, the provisions of this Agreement and the Security Documents shall control.

(viii) In connection with any Letter of Credit, to the extent that any Bank fails to pay any amount required to be paid pursuant to clause (v) of this Section 2.03(b) on the due date therefor, such Bank shall pay interest to the Issuing Bank (through the Administrative Agent) on such amount from and including such due date to but excluding the date such payment is made (A) in the case of Letters of Credit payable in U.S. Dollars, during the period from and including such due date to but excluding the date three Business Days thereafter, at a rate per annum equal to the Federal Funds Effective Rate (as in effect from time to time) and thereafter, at a rate per annum equal to the Base Rate (as in effect from time to time) plus 2% and (B) in the case of Letters of Credit payable in Canadian Dollars, during the period from and including such due date to but excluding the date three Business Days thereafter, at a rate per annum equal to the Canadian Base Rate, and thereafter at a rate per annum equal to the Canadian Base Rate plus 2%.

(ix) Without the prior written consent of the Issuing Bank, no Letter of Credit shall be issued in face amount of less than U.S.$100,000 or the Equivalent Amount in Canadian Dollars (or multiples of U.S.$100,000 in excess thereof).

As between the Company and the Issuing Bank, the Company assumes all risks for the acts and omissions of, or misuse of, the Letters of Credit by the respective beneficiaries of such Letter of Credit. The Company hereby indemnifies and holds harmless each Bank, the Issuing Bank and the Administrative Agent from and against any and all claims and damages, losses, liabilities, costs or expenses which such Bank, the Issuing Bank or the Administrative Agent may incur (or which may be claimed against such Bank, the Issuing Bank or the Administrative Agent by any Person whatsoever) by reason of or in connection with (A) any loss or expense incurred by such Bank or the Issuing Bank as a result of the Company's failure to honor or fulfill, before the date specified for the issuance of any Letter of Credit, the applicable conditions set forth in Section 7 or this Section 2.03 if the Letter of Credit is not issued on that date because of that failure; and (B) the execution, delivery, issuance or transfer of or payment or refusal to pay by the Issuing Bank under any Letter of Credit; provided that the Company shall not be required to indemnify any Bank, the Issuing Bank or the Administrative Agent for any claims, damages, losses, liabilities, costs or expenses to the extent, but only to the extent, caused by (x) the willful misconduct or gross negligence of the Issuing Bank in determining whether a request presented under any Letter of Credit complied with the terms of such Letter of Credit or (y) the Issuing Bank's failure to pay under any Letter of Credit after the presentation to it of a request strictly complying with the terms and conditions of such Letter of Credit. Nothing in this Section 2.03 is intended to limit the other obligations of the Company, any Bank, the Issuing Bank or the Administrative Agent under this Agreement.

2.04 Changes of Commitments. (a) The aggregate amount of the Commitments shall be automatically reduced to zero on the Commitment Termination Date.

(b) The Company shall have the right at any time or from time to time (i) so long as no Loans, Letter of Credit Liabilities or Bankers' Acceptance Liabilities are outstanding, to terminate the Commitments and (ii) to reduce the Commitments in part up to the aggregate unused amount of the Commitments; provided that (x) the Company shall give notice of each such termination or reduction as provided in Section 4.05 hereof and (y) each partial reduction shall be in an aggregate amount at least equal to U.S.$1,000,000 or in multiples of U.S.$500,000 in excess thereof.

(c) The Company shall notify the Administrative Agent of any election to terminate or reduce the Commitments under paragraph (b) of this Section at least three (3) Business Days prior to the effective date of such termination or reduction, specifying such election and the effective date thereof. Promptly following receipt of any notice, the Administrative Agent shall advise the Banks of the contents thereof. Each notice delivered by the Company pursuant to this Section shall be irrevocable; provided that a notice of termination of the Commitments delivered by the Company may state that such notice is conditioned upon the effectiveness of other credit facilities, in which case such notice may be revoked by the Company (by notice to the Administrative Agent on or prior to the specified effective date) if such condition is not satisfied. Any termination or reduction of the Commitments shall be permanent. Each reduction of the Commitments shall be made ratably among the Banks in accordance with their respective Commitments.

2.05 Commitment Fee. The Company shall pay to the Administrative Agent for account of each Bank a commitment fee for each day at a rate per annum equal to the Applicable Commitment Fee Rate times such Bank's Commitment Percentage share of the Borrowing Base less the aggregate Principal Amount of all Loans, Letter of Credit Liabilities and Bankers' Acceptance Liabilities (with any amounts outstanding in Canadian Dollars being expressed as an Equivalent Amount in U.S. Dollars) outstanding on such day for the period from and including the Effective Date to but not including the earlier of the date such Bank's

Commitment is terminated and the Commitment Termination Date. Accrued Commitment fees shall be payable in arrears on each Quarterly Date and on the earlier of the date the Commitments are terminated and the Commitment Termination Date.

2.06 Lending Offices. The Loans of each Type made by each Bank shall be made and maintained at such Bank's Applicable Lending Office for Loans of such Type.

2.07 Several Obligations; Remedies Independent. With respect to any Loan, Letter of Credit or Bankers' Acceptance, the failure of any Bank to make any Loan or provide proceeds in respect of a Letter of Credit or Bankers' Acceptance to be made by it on the date specified therefor shall not relieve any other Bank of its obligation to make its Loan or provide such proceeds on such date, but neither any Bank nor the Administrative Agent shall be responsible for the failure of any other Bank to make a Loan or provide such proceeds to be made or provided by such other Bank, and no Bank shall have any obligation to the Administrative Agent or any other Bank for the failure by such other Bank to make any Loan or provide such proceeds required to be made or provided by such Bank. The amounts payable by the Company at any time hereunder, under the Notes and under any Bankers' Acceptances to each Bank shall be a separate and independent debt, and each Bank shall be entitled to protect and enforce its rights arising out of this Agreement, the Notes, the Bankers' Acceptances and the other Loan Documents, and it shall not be necessary for any other Bank or the Administrative Agent to consent to, or be joined as an additional party in, any proceedings for such purposes.

2.08 Notes. (a) The Loans made by each Bank shall be evidenced by a single promissory note of the Company substantially in the form of Exhibit A hereto, dated the date hereof, payable to such Bank in a Principal Amount equal to the amount of its Commitment as originally in effect and otherwise duly completed.

(b) The date, amount, Type, interest rate and duration of Interest Period (if applicable) of each Loan made by each Bank to the Company, and each payment made on account of the principal thereof, shall be recorded by such Bank on its books and, prior to any transfer of the Note evidencing the Loans held by it, endorsed by such Bank on the schedule attached to such Note or any continuation thereof; provided that the failure of such Bank to make any such recordation or endorsement shall not affect the obligations of the Company to make a payment when due of any amount owing hereunder or under such Note in respect of the Loans evidenced by such Note.

(c) No Bank shall be entitled to have its Notes subdivided, by exchange for promissory notes of lesser denominations or otherwise, except in connection with a permitted assignment of all or any portion of such Bank's Commitment, Loans and Note pursuant to Section 12.06(b) hereof.

2.09 Optional Prepayments and Conversions or Continuations of Loans. Subject to Section 4.04 hereof, the Company shall have the right to prepay Loans, or to Convert Loans of one Type into Loans of another Type, or Continue Loans of one Type as Loans of the same Type, at any time or from time to time, provided that: (i) the Company shall give the Administrative Agent notice of each such prepayment, Conversion or Continuation as provided in Section 4.05 hereof (and, upon the date specified in any such notice of prepayment, the amount to be prepaid shall become due and payable hereunder) and (ii) BA Loans and Bankers' Acceptances may be prepaid or Converted only on the last day of an Interest Period or on the Maturity Date, as applicable, for such BA Loans or Bankers' Acceptances as applicable. Notwithstanding the foregoing, and without limiting the rights and remedies of the Banks under Section 10 hereof, in the event that any Event of Default shall have occurred and be continuing, the Administrative Agent may (and at the request of the Majority Banks shall) by notice to the Company suspend the right of the Company to Convert any Loan into a Eurodollar Loan or Eurocanadian Loan, or to Continue any Loan as a Eurodollar Loan or Eurocanadian Loan, in which event all Eurodollar Loans and Eurocanadian Loans shall be Converted to (on the last day(s) of the respective Interest Periods therefor) or Continued as, as the case may be, Canadian Base Rate Loans.

2.10 Mandatory Prepayments and Reductions of Commitments.

(a) Borrowing Base. The Administrative Agent shall notify the Company (in a "Deficiency Notice") any time the Borrowing Base as then in effect is less than the sum of (i) the aggregate Principal Amount of the Loans and Letter of Credit Liabilities outstanding at such time (the amount of such difference being called herein the "Borrowing Base Deficiency") and within 30 days after the date of delivery of the Deficiency Notice the Company shall notify the Administrative Agent of the Company's intentions with respect to compliance with the procedures set forth in this Section 2.10(a). As specified in such notice from the Company, the Company shall (within 30 days after the date of the Deficiency Notice) (the "Deficiency Cure Period") prepay, or provide cover in accordance with Section 2.10(f) hereof, the aggregate Principal Amount of all Loans, Bankers' Acceptance Liabilities and Letter of Credit Liabilities outstanding at such time, in an amount sufficient to eliminate such Borrowing Base Deficiency.

(b) Casualty Events. Upon the date (the "Insurance Date") 30 days following the receipt by the Company or any of its Restricted Subsidiaries of the proceeds of insurance, condemnation award or other compensation, in each case in excess of U.S.$500,000 (or its equivalent for other currencies, calculated as of the date such proceeds are received) in respect of any Casualty Event, affecting any Hydrocarbon Property other than Unrestricted Properties of the Company or any Restricted Subsidiary, the Company shall repay the Loans (and/or provide cover for the Letter of Credit Liabilities and Bankers' Acceptance Liabilities as specified in clause (f) below), and if such Casualty Event or series of related Casualty Events shall result in the receipt by the Company or any of its Restricted Subsidiaries of Net Available Proceeds in excess of U.S.$2,000,000 (or its equivalent amount in other currencies, calculated as of the date such proceeds are received) in any Determination Period, the Supermajority Banks, in their sole discretion based on their review of such Casualty Event, may reduce the Borrowing Base, such reduction in any event not to be in an aggregate amount in excess of 100% of the Net Available Proceeds of such Casualty Event, or such lesser amount as is specified in a written notice from the Supermajority Banks, such prepayment and reduction to be effected in each case in the manner and to the extent specified in clause (e) of this Section 2.10. Nothing in this clause (b) shall be deemed to limit any obligation of the Company and any of its Restricted Subsidiaries pursuant to any of the Security Documents to remit to a collateral or similar account maintained by the Administrative Agent the proceeds of insurance, condemnation award or other compensation received in respect of any Casualty Event.

(c) Sale of Assets. Without limiting the obligation of the Obligors to obtain the consent of the Majority Banks pursuant to Section 9.05 hereof to any Disposition not otherwise permitted hereunder, no later than five Business Days prior to the occurrence of any Disposition expected to result in Net Available Proceeds in excess of U.S.$1,000,000 (or its equivalent amount in other currencies, calculated as of the date such proceeds are received), the Company, on behalf of the applicable Obligor will deliver to the Banks a statement, certified by the chief financial officer or treasurer of the Company, in form and detail satisfactory to the Administrative Agent, of the estimated amount of the Net Available Proceeds of such Disposition and, if (i) the Net Available Proceeds of such Disposition is in excess of U.S.$2,500,000 (or its equivalent amount in other currencies, calculated as of the date such proceeds are received), in respect of (A) assets which have been given value in determining the Borrowing Base or (B) assets which have not been given value in determining the Borrowing Base but which are directly related to exploration, production or transportation of hydrocarbons or (ii) the Net Available Proceeds of such Disposition together with the aggregate of all other such Dispositions by any Obligor within any six-month period (including as a result of any Casualty Event) of Hydrocarbon Property or other hydrocarbon Property is in excess of U.S.$5,000,000 (or its equivalent amount in other currencies, calculated as of the date such proceeds are received), then the Supermajority Banks, based on their review of the statement referred to in this Section 2.10(c) may reduce the Borrowing Base in an aggregate amount determined in their sole discretion. If a Borrowing Base Deficiency results from such reduction, then the Company shall, notwithstanding Section 2.10(a) to the contrary, immediately prepay the Loans (and/or provide cover for the Letter of Credit Liabilities and Bankers' Acceptance Liabilities) with the Net Available Proceeds to cure such deficiency. The Administrative Agent shall endeavor to advise the Company within 15 days following receipt of any such statement of the proposed redetermined Borrowing Base that the Administrative Agent will recommend to the Banks, provided that the Administrative Agent shall have no liability for failure to so advise the Company.

(d) Application. Prepayments and reductions of Commitments or the Borrowing Base, if applicable, as the case may be, described in the above clauses of this Section 2.10 shall be effected as follows: the Commitments or the Borrowing Base, as the case may be, shall be automatically reduced by an amount equal to the amount specified in such clauses (and to the extent that, after giving effect to such reduction, the aggregate Principal Amount of the Loans, together with the aggregate amount of all relevant Letter of Credit Liabilities and Bankers' Acceptance Liabilities, would exceed the Commitments or the then effective Borrowing Base, as applicable, the Company shall first, prepay Base Rate Loans and Canadian Base Rate Loans, second, prepay Eurodollar Loans and Eurocanadian Loans, ratably, and third, provide cover for such Letter of Credit Liabilities and Banker's Acceptance Liabilities with respect to such Commitments or the Borrowing Base, as applicable, as specified in clause (f) below, in an aggregate amount equal to such excess).

(e) Cover for Letter of Credit Liabilities and Bankers' Acceptance Liabilities. In the event that the Company shall be required pursuant to this Section 2.10, or pursuant to Section 3.01 hereof, to provide cover for Letter of Credit Liabilities, BA Loans and Bankers' Acceptance Liabilities, the Company shall effect the same by paying to the Administrative Agent immediately available funds in an amount equal to the required amount, which funds shall be retained by the Administrative Agent as collateral security in the first instance pro rata for the

Letter of Credit Liabilities, BA Loans and Bankers' Acceptance Liabilities) until such time as the Letters of Credit shall have been terminated, all of the Letter of Credit Liabilities have been paid in full, the Bankers' Acceptances shall have matured and all of the Bankers' Acceptance Liabilities and BA Loans have been paid in full.

(f) Excess Resulting from Exchange Rate Change. (i) Subject to Section 2.10(f)(ii) hereof, any time that, following one or more fluctuations in the exchange rate of the U.S. Dollar against the Canadian Dollar, the sum of the Equivalent Amount in U.S. Dollars of the aggregate principal amount of Canadian Dollar Liabilities outstanding at such time plus the aggregate Principal Amount of U.S. Dollar denominated Loans and Letter of Credit Liabilities outstanding at such time (the amount of such sum being called herein the "Aggregate Borrowings") exceeds by an amount equal to or in excess of 3% for a period of more than five consecutive Business Days (or 5% on any Business Day) of the lesser of (x) the aggregate amount of the Commitments of the Banks on such date and (y) the then effective Borrowing Base, the Company shall promptly after receipt of notice from the Administrative Agent and, in any case, within 10 days after receipt of such notice, either (A) prepay the Loans (except BA Loans) (and/or provide cover for the Canadian Letter of Credit Liabilities, BA Loans and the Bankers' Acceptance Liabilities as specified in clause (f) above) in an amount (such amount being called herein the "Exchange Rate Deficiency") necessary to reduce the Aggregate Borrowings to an amount equal to or less than the lesser of (x) the aggregate amount of the Commitments of the Banks on such date and (y) the then effective Borrowing Base or (B) maintain or cause to be maintained with the Administrative Agent deposits of U.S. Dollars in an amount equal to the Exchange Rate Deficiency, such deposits to be maintained in such form and upon such terms as are acceptable to the Administrative Agent. Without in any way limiting the forgoing provisions, the Administrative Agent shall on each Acceptance Date, Maturity Date, Quarterly Date, Determination Date and on the date of any borrowing hereunder make any necessary exchange rate calculations to determine whether any such Exchange Rate Deficiency exists on such date and, if such Exchange Rate Deficiency exists on such date, it shall so notify the Company.

(ii) Notwithstanding Section 2.10(f)(i), the Majority Banks shall be entitled, in their sole discretion, to require that the Company, at the Company's option, (A) make the payments or prepayments or maintain the deposits required to be maintained under Section 2.10(f)(i) or (B) fully cover, to the reasonable satisfaction of the Majority Banks, the Exchange Rate Deficiency and assign the benefit of all interest rate hedging contracts to the Administrative Agent, for the benefit of the Banks, in any case where an Exchange Rate Deficiency exists.

2.11 Bankers' Acceptances. Subject to the terms and conditions of this Agreement, the Commitments may be utilized, upon the request of the Company, in addition to the Loans provided for by Section 2.01 hereof and the issuance of Letters of Credit provided for by Section 2.03 hereof, for the acceptance by the Banks of Bankers' Acceptances issued by the Company, provided that, except during a Deficiency Cure Period, in no event shall (i) the aggregate amount of all Bankers' Acceptance Liabilities (expressed as the Equivalent Amount of U.S. Dollars), together with the aggregate Principal Amount of the Loans and the aggregate amount of all Letter of Credit Liabilities (with amounts of any Canadian Loans or Canadian Letter of Credit Liabilities outstanding in Canadian Dollars expressed as an Equivalent Amount in U.S. Dollars) exceed the lesser of (A) the aggregate of the Commitments and (B) the then effective Borrowing Base and (ii) any Bankers' Acceptances have maturities of less than 30 days or more than 180 days from the Acceptance Date (and shall in no event mature on a date after the Commitment Termination Date). The following additional provisions shall apply to Bankers' Acceptances:

(a) The Company shall deliver to each Bank bills of exchange, executed in blank by its authorized signatory in sufficient quantity and thereafter shall, from time to time upon request from the Administrative Agent, deliver to each Bank further quantities of such bills of exchange, so executed, and each Bank shall hold the bills of exchange in safekeeping.

(b) When the Company wishes to make a borrowing by way of Bankers' Acceptances, the Company shall give the Administrative Agent prior written notice with respect to the issuance of the Bankers' Acceptances (such written notice a "Bankers' Acceptance Request") by not later than 1:00 p.m. Toronto time, two Business Days' prior to the Acceptance Date. Each Bankers' Acceptance Request shall be irrevocable and binding on the Company. The Company shall indemnify each Bank against any loss or expense incurred by such Bank as a result of any failure by the Company to fulfill or honor before the date specified as the Acceptance Date, the applicable conditions set forth in Section 7, if, as a result of such failure the requested Bankers' Acceptance is not made on such date. Unless otherwise agreed among the Administrative Agent and the Banks, the Equivalent Amount in U.S. Dollars of the aggregate amount of all Bankers' Acceptances issued on any Acceptance Date hereunder shall be accepted pro rata by all Banks relative to their respective Commitment Percentage, rounded, upwards or downwards, as the case may be, to the nearest U.S.$100,000. Upon receipt of a Bankers' Acceptance Request, the Administrative Agent shall advise each Bank of the contents thereof.

(c) Unless the Company has notified the Administrative Agent in the Bankers' Acceptance Request that the Company intends to arrange the sale of the Bankers' Acceptances which are the subject of such Bankers' Acceptance Request (a "Borrower Arrangement"), on the Acceptance Date at 10:30 a.m. Toronto time, the Administrative Agent shall determine the Bankers' Acceptance Rate based upon the average of the bankers' acceptance rates of each of the Accepting Lenders. That Bankers' Acceptance Rate will be the discount rate used by each of the Accepting Lenders and, not later than 2:00 p.m. Toronto time, each such Accepting Lender shall accept and purchase its share of the Bankers' Acceptances that are issued and shall make available to the Administrative Agent, in accordance with Section 2.02 hereof, the Net Proceeds of the purchase of Bankers' Acceptances on such day by such Bank calculated in accordance with Exhibit H. The Administrative Agent shall transfer to the Company the Net Proceeds of the Bankers' Acceptances and shall notify the Company and each such Bank by telex, facsimile or telephone (if by telephone, to be confirmed subsequently in writing) of the details of the issue.

On the Acceptance Date, the Company shall pay each Accepting Lender and each Bank providing a BA Loan (in accordance with Section 2.11(h) hereof) a Stamping Fee with respect to each Bankers' Acceptance and each BA Loan.

For each Bankers' Acceptance or BA Loan, the Stamping Fee payable by the Company shall be the product obtained by multiplying:

(i) the applicable BA Fee Rate specified in the definition of Applicable Margin in effect from time to time; by

(ii) the Principal Amount of that Bankers' Acceptance or BA Loan;

and prorating that product for the number of days in the term from and including the Acceptance Date to but not including the Maturity Date of that Bankers' Acceptance or the Interest Period for the BA Loan, as the case may be, on the basis of a year of 365 days.

(d) Before giving value to the Administrative Agent for the account of the Company (or in the case of a Borrower Arrangement, before delivering the Bankers' Acceptance to or at the direction of the Company), on the Acceptance Date each Accepting Lender shall, and is hereby authorized by the Company to, accept the Bankers' Acceptances by inserting the appropriate face amount, Acceptance Date and Maturity Date in accordance with the Bankers' Acceptance Request relating thereto and affixing its acceptance thereto and shall purchase the same or make them available for sale in accordance with the Borrower Arrangement. Each such Bank shall promptly send after the Maturity Date thereof, to the Company, each original cancelled Bankers' Acceptance it has accepted and purchased as provided above.

Each Accepting Lender may at any time and from time to time hold, sell, rediscount or otherwise dispose of any or all Bankers' Acceptances accepted and purchased by it.

(e) On each day during the period commencing with the issuance by the Company of any Bankers' Acceptance and until such Bankers' Acceptance Liability shall have been paid by the Company, the Commitment of each Accepting Lender that is able to extend credit by way of Bankers' Acceptances shall be deemed to be utilized for all purposes of this Agreement in an amount equal to the Equivalent Amount in U.S. Dollars of the Principal Amount of such Bankers' Acceptance.

The Commitment of any Bank providing a BA Loan rather than a Bankers' Acceptance shall be deemed utilized during this period in an amount equal to its Commitment Percentage of the Equivalent Amount in U.S. Dollars of the total amount of Bankers' Acceptances in each Bankers' Acceptance Request.

(f) The Company agrees to pay on the Maturity Date for each Bankers' Acceptance, to the Administrative Agent for account of each Accepting Lender an amount equal to the Bankers' Acceptance Liability for such Bankers' Acceptance.

The Company hereby waives presentment for payment of Bankers' Acceptances by the Accepting Lenders and any defense to payment of amounts due to an Accepting Lender in respect of a Bankers' Acceptance which might exist by reason of such Bankers' Acceptance being held at maturity by the Accepting Lender which accepted it and agrees not to claim from the Banks any days of grace for the payment at maturity of Bankers' Acceptances.

(g) In the event the Company fails to notify the Administrative Agent in writing not later than 1:00 p.m. Toronto time on the Business Day prior to any Maturity Date that the Company intends to pay with its own funds the Bankers' Acceptance Liabilities due on such Maturity Date or fails to make such payment, the Company shall be deemed, for all purposes to have given the Administrative Agent notice of a borrowing of a Canadian Base Rate Loan for an amount equal to the Principal Amount of such Bankers' Acceptance; provided that:

(i) the Maturity Date for such Bankers' Acceptances shall be considered to be the date of such borrowing:

(ii) the proceeds of such Canadian Base Rate Loan shall be used to pay the amount of the Bankers' Acceptance Liability due on such Maturity Date;

(iii) on such Maturity Date, the amount of such Canadian Base Rate Loan shall first be directly applied to the Principal Amount of the Bankers' Acceptance due on such date;

(iv) if after giving effect to such Canadian Base Rate Loan, a Borrowing Base Deficiency would exist, the Administrative Agent shall so advise the Company and the Company shall advise the Administrative Agent on the Maturity Date of the manner in which it intends to comply with the provisions of Section 2.10(a);

(v) each Bank which has made a maturing BA Loan (in accordance with Section 2.11(h) hereof) shall continue to extend credit to the Company by way of a Canadian Base Rate Loan (without further advance of funds to the Company) in the Principal Amount equal to its Commitment Percentage of the total amount of credit requested to be extended by Bankers' Acceptances when the BA Loan was made; and

(vi) the Administrative Agent shall promptly and in any event within 3 Business Days following the Maturity Date of such Bankers' Acceptances, notify the Company in writing of the making of such Canadian Base Rate Loan pursuant to this Section 2.11(g).

(h) If, in the sole judgment of a Bank, such Bank is unable, as a result of applicable law or customary market practice, to extend credit by way of Bankers' Acceptance in accordance with this Agreement, such Bank shall give notice to such effect to the Administrative Agent and the Company prior to 1:00 p.m. (Toronto time) on the date of the requested credit extension (which notice may, if so stated therein, remain in effect with respect to subsequent requests for extension of credit by way of Bankers' Acceptance until revoked by notice to the Administrative Agent and the Company) and shall make available to the Administrative Agent, in accordance with Section 2.02 hereof prior to 2:00 p.m. (Toronto time) on the date of such requested credit extension a Canadian Dollar loan (a "BA Loan") in the Principal Amount equal to such Bank's Commitment Percentage of the total amount of credit requested to be extended by way of Bankers' Acceptances. The Stamping Fee for that BA Loan shall be calculated on that Principal Amount. Such BA Loan shall have the same term as the Bankers' Acceptances for which it is a substitute and shall bear interest throughout the Interest Period applicable to that BA Loan at a rate per annum equal to the Bankers' Acceptance Rate for such Bankers' Acceptances. The amount of the proceeds of that BA Loan to be disbursed to the Company on the Acceptance Date shall be the same amount as if that Bank had accepted and purchased its Commitment Percentage of the requested Bankers' Acceptances at a discount from the Principal Amount of that Bankers' Acceptance calculated at a discount rate per annum equal to the Bankers' Acceptance Rate for the term of such Bankers' Acceptances in the same manner that Net Proceeds are calculated but excluding the BA Fee Rate component of that calculation. For greater certainty, the amount to be made available by each such Bank on any date in respect of a BA Loan made by it on such date and, notwithstanding the Principal Amount of that BA Loan, the amount of that BA Loan that interest will be calculated on, shall be the same as the amount that such Bank would have been required to make available to the Company as its Commitment Percentage of the total amount of credit requested to be extended pursuant to the related Bankers' Acceptance Request before deducting the Stamping Fee had such Bank been able to extend credit by way of Bankers' Acceptance on such date. Such Bank shall deduct the Stamping Fee from that amount.

(i) The Company may, if it so notifies the Administrative Agent in the applicable Bankers' Acceptance Request, arrange the sale of any particular issuance of Bankers' Acceptances to be accepted by the Banks hereunder. To that end, on the Acceptance Date:

(i) the Company shall obtain quotations from prospective purchasers regarding the sale of the Bankers' Acceptances to be accepted by the Banks, and shall, on or before 11:00 a.m. (Toronto time) on such date, provide each Bank (through the Administrative Agent) with all necessary information required by such Bank to enable such Bank to determine the Bankers' Acceptance discount rate applicable to such issue, together with the identity of and the face amount of Bankers' Acceptances to be purchased by each of the purchaser(s) of the Bankers' Acceptances accepted by such Bank. In obtaining such quotes, the Company shall offer each Bank the right to bid on the Bankers' Acceptances accepted by it. The Banks and the Administrative Agent shall not be responsible for any losses occasioned by the failure of the Company to comply with its obligations under this paragraph and shall not be required to purchase any Bankers' Acceptances on such Acceptance Date if the Company has requested a Borrower Arrangement; and

(ii) on receipt from the Company of the information referred to in paragraph (i), the Administrative Agent shall promptly notify each Bank of:

(A) the Bankers' Acceptance discount rate to be applicable to such issue;

(B) the minimum proceeds to be received by such Bank on the sale of the Bankers' Acceptances accepted by such Bank, based upon such Bankers' Acceptance discount rate obtained by the Company for each such Bank; and

(C) the Stamping Fee payable to such Bank in connection with such issue.

(j) The issuance by an Accepting Lender of each Bankers' Acceptance shall, in addition to the conditions precedent set forth in Section 7 hereof, be subject to the conditions precedent that the Company shall have executed and delivered all Bankers' Acceptance Documents as the Accepting Lender shall have reasonably requested consistent with its then current practices and procedures, provided that in the event of any conflict between any such Bankers' Acceptance Documents and the provisions of this Agreement or any Security Document, the provisions of this Agreement and the Security Documents shall control.

(k) If a Bank determines in good faith, which determination shall be final, conclusive and binding upon the Company, and notifies the Company that, by reason of circumstances affecting the money market:

(i) there is no market for Bankers' Acceptances; or

(ii) the demand for Bankers' Acceptances is insufficient to allow the sale or trading of the Bankers' Acceptances created and purchased hereunder;

then:

(iii) the right of the Company to request Bankers' Acceptances or a BA Loan from that Bank shall be suspended until such Bank determines that the circumstances causing such suspension no longer exist and such Bank so notifies the Company; and

(iv) any Bankers' Acceptance Request which is outstanding shall be cancelled and the Bankers' Acceptances or BA Loan requested therein shall not be made.

(l) It is the intention of the Administrative Agent, the Banks and the Company that, pursuant to the Depository Bills and Notes Act ("DBNA"), all Bankers' Acceptances accepted by the Banks under this Agreement shall be issued in the form of a "depository bill" (as defined in the DBNA), deposited with the Canadian Depository for Securities Ltd. and made payable to CDS & Co. In order to give effect to the foregoing, the Administrative Agent shall, subject to the approval of the Company and the Banks, establish and notify the Company and the Banks of any procedure, consistent with the terms of this Agreement and the requirements of the DBNA, as is reasonably necessary to accomplish such intention, including, without limitation:

(i) any instrument held by the Administrative Agent or a Bank for the purposes of Bankers' Acceptances shall have marked prominently and legibly on its face and within its text, at or before the time of issue, the words "This is a depository bill subject to the Depository Bills and Notes Act (Canada)";

(ii) any reference to the authentication of the Bankers' Acceptances will be removed; and

(iii) any reference to "bearer" will be removed and no Bankers' Acceptance shall be marked with any words prohibiting negotiation, transfer or assignment of it or of an interest in it.

SECTION 3.
PAYMENTS OF PRINCIPAL AND INTEREST

3.01 Repayment of Loans.

The Company hereby promises to pay to the Administrative Agent for the account of each Bank the entire outstanding Principal Amount of such Bank's Loans (or with respect to BA Loans, the amount made available by the applicable Bank to the Company as determined in accordance with Section 2.11(h) hereof), and each Loan shall mature, on the Commitment Termination Date. All Bankers' Acceptance Liabilities and Letter of Credit Liabilities shall also be payable to the Administrative Agent for the account of each Bank on the Commitment Termination Date. In addition, if following any reduction in the Commitments, the aggregate Principal Amount of the Loans, together with the aggregate amount of all Letter of Credit Liabilities and all Bankers' Acceptance Liabilities (with the amounts of any Canadian Dollar Obligations expressed as an Equivalent Amount in U.S. Dollars) shall exceed the Commitments, the Company shall first, prepay Loans (except BA Loans) and second, provide cover for Letter of Credit Liabilities, BA Loans and Bankers' Acceptance Liabilities with respect to the Commitments as specified in Section 2.10(f) above, in an aggregate amount equal to such excess.

3.02 Interest. (a) The Company hereby promises to pay to the Administrative Agent for the account of each Bank interest on the unpaid Principal Amount of each Loan made by such Bank for the period from and including the date of such Loan to but excluding the date such Loan shall be paid in full, at the following rates per annum:

(i) during such periods as such Loan is a Base Rate Loan, the Base Rate (as in effect from time to time) plus the Applicable Margin;

(ii) during such periods as such Loan is a Canadian Base Rate Loan, the Canadian Base Rate (as in effect from time to time) plus the Applicable Margin;

(iii) during such periods as such Loan is a Eurodollar Loan, for each Interest Period relating thereto, the Eurodollar Rate for such Loan for such Interest Period plus the Applicable Margin;

(iv) during such periods as such Loan is a Eurocanadian Loan, for each Interest Period relating thereto, the Eurocanadian Rate for such Loan for such Interest Period plus the Applicable Margin; and

(v) during such periods as such Loan is a BA Loan, for each Interest Period relating thereto, the Bankers' Acceptance Rate for such Loan for such Interest Period.

Notwithstanding the foregoing, the Company hereby promises to pay to the Administrative Agent for account of each Bank interest at the applicable Post-Default Rate on any principal of any Loan made by such Bank, on any Reimbursement Obligation held by such Bank and on any other amount payable by the Company hereunder or under the Note held by such Bank to or for account of such Bank, which shall not be paid in full when due (whether at stated maturity, by acceleration, by mandatory prepayment or otherwise), for the period from and including the due date thereof to but excluding the date the same is paid in full.

(b) Accrued interest on each Loan shall be payable (i) quarterly on the Quarterly Dates for Base Rate Loans and Canadian Base Rate Loans, (ii) at the end of each Interest Period for Eurodollar Loans, Eurocanadian Loans and BA Loans and (iii) in the case of any Loan, upon the payment or prepayment thereof (but only on the Principal Amount so paid or prepaid), except that interest payable at the Post-Default Rate shall be payable from time to time on demand. In connection with each Loan, promptly after the determination of any interest rate provided for herein or any change therein, the Administrative Agent shall give notice thereof to the Banks and to the Company, but failure to do so on a timely basis or at all shall not affect the Company's obligation to pay interest for any period at the applicable rate determined by the Administrative Agent.

3.03 Currency. Borrowings of Loans and other extensions of credit hereunder including Bankers' Acceptances and Letters of Credit and any payments in respect thereof (other than direct reimbursements paid to the Issuing Bank) are payable by the Company in the currency in which the same are denominated.

SECTION 4.
PAYMENTS; PRO RATA TREATMENT; COMPUTATIONS; ETC.

4.01 Payments. (a) Except to the extent otherwise provided herein, all payments of principal, interest, Reimbursement Obligations, in respect of Bankers' Acceptances and other amounts to be made by the Company under this Agreement and the Notes, and, except to the extent otherwise provided therein, all payments to be made by the Obligors under any other Loan Document, shall be made in the currency in which the same are denominated, in immediately available funds, without deduction, set-off or counterclaim, to the Administrative Agent at an account in New York, New York specified by the Administrative Agent, not later than 1:00 p.m. New York time on the date on which such payment shall become due (each such payment made after such time on such due date to be deemed to have been made on the next succeeding Business Day).

(b) Any Bank for whose account any such payment is to be made may (but shall not be obligated to) debit the amount of any such payment that is not made by such time (other than any payment not made due to a failure by the Administrative Agent to forward any such payment to such Bank) to any ordinary deposit account of the Company with such Bank (with notice to the Company and the Administrative Agent), provided that such Bank's failure to give such notice shall not affect the validity thereof.

(c) In connection with making each payment in respect of each Loan, Letter of Credit or Bankers' Acceptance, the Company shall, at the time of making each payment under this Agreement or any Note for the account of any Bank, specify to the Administrative Agent (which shall so notify the intended recipient(s) thereof) the Loans, Reimbursement Obligations, Bankers' Acceptance Liabilities or other amounts payable by the Company hereunder to which such payment is to be applied (and in the event that the Company fails to so specify, or if an Event of Default has occurred and is continuing, the Administrative Agent may distribute such payment to the Banks for application in such manner as it or the Majority Banks, and subject to Section 4.02 hereof, may determine to be appropriate).

(d) Except to the extent otherwise provided in the last sentence of the first paragraph of Section 2.03(c)(v) hereof, each payment received by the Administrative Agent under this Agreement, any Note or any Bankers' Acceptance for account of any Bank shall be paid by the Administrative Agent promptly to such Bank, in immediately available funds, for account of such Bank's Applicable Lending Office for the Loan or other obligation in respect of which such payment is made.

(e) Except as provided in clause (a)(ii) of the definition of Interest Period, if the due date of any payment under this Agreement or any Note would otherwise fall on a day that is not a Business Day, such date shall be extended to the next succeeding Business Day, and interest shall be payable for any principal so extended for the period of such extension.

4.02 Pro Rata Treatment. Except to the extent otherwise provided herein: (a) each borrowing of Loans from the Banks under Section 2.01 hereof or acceptance of Bankers' Acceptances under Section 2.11 hereof shall be made from the Banks, each payment of commitment fee under Section 2.05 hereof in respect of Commitments shall be made for account of the Banks, and each termination or reduction of the amount of the Commitments under Section 2.04 hereof shall be applied to the respective Commitments of the Banks, pro rata according to the amounts of their respective Commitments; (b) the making, Conversion and Continuation of Loans of a particular Type (including by way of requests for the issuance of Bankers' Acceptances) (other than Conversions provided for by Section 5.04 hereof) shall be made pro rata among the Banks according to the amounts of their respective Commitments (in the case of the making of Loans or issuing of Bankers' Acceptances) or their respective Loans (in the case of Conversions and Continuations); (c) except as otherwise provided in Section 5.04 hereof, the Interest Period of each BA Loan or the Maturity Date for each Bankers' Acceptance, as the case may be, shall be coterminous, and Eurodollar Loans and Eurocanadian Loans having the same Interest Period shall be allocated pro rata among the Banks according to the amounts of their respective Commitments; (d) each payment or prepayment of principal of Loans or Bankers' Acceptances by the Company shall be made for the account of the Banks pro rata in accordance with the respective unpaid Principal Amounts of the Loans or Bankers' Acceptances held by them; provided that if immediately prior to giving effect to any such payment in respect of any Loans or Bankers' Acceptances the outstanding Principal Amount of the Loans or

Bankers' Acceptances shall not be held by the relevant Banks pro rata in accordance with their respective Commitments in effect at the time such Loans or Bankers' Acceptance were made (whether by reason of a failure of a Bank to make a Loan or provide a Bankers' Acceptance hereunder in the circumstances described in the second paragraph of Section 12.04 hereof or otherwise), then such payment shall be applied to the Loans or Bankers' Acceptances, as the case may be, in such manner as shall result, as nearly as is practicable, in the outstanding Principal Amount of the Loans or Bankers' Acceptances being held by such Banks pro rata in accordance with their respective Commitments; and (e) each payment of interest on Loans or Bankers' Acceptances by the Company shall be made for account of the relevant Banks pro rata in accordance with the amounts of interest on such Loans or Bankers' Acceptances then due and payable to the respective Banks.

4.03 Computations. Interest on Eurodollar Loans, Eurocanadian Loans and commitment fees and letter of credit fees shall be computed on the basis of a year of 360 days and actual days elapsed (including the first day but, except as otherwise provided in Section 2.03(c)(vii) excluding the last day) occurring in the period for which that interest and those fees are payable. Bankers' Acceptance Rates, interest on BA Loans and Stamping Fees shall be computed on the basis of a year of 365 days and actual days elapsed (including the first day but excluding the last day) occurring during the period for which such interest or fees are payable. Interest on Base Rate Loans, Canadian Base Rate Loans and Reimbursement Obligations shall be computed on the basis of a year of 365 or 366 days, as the case may be, and actual days elapsed (including the first day but excluding the last day) occurring in the period for which such interest and fees are payable. Notwithstanding the foregoing, for each day that the Base Rate is calculated by reference to the Federal Funds Effective Rate, interest on Base Rate Loans and Reimbursement Obligations shall be computed on the basis of a year of 360 days and actual days elapsed.

4.04 Minimum Amounts. Except for mandatory prepayments made pursuant to Section 2.10 hereof and Conversions or prepayments made pursuant to Section 5.04 hereof, each borrowing (other than by way of a Letter of Credit), Conversion, Continuation and partial prepayment of principal of Loans shall be in an aggregate amount at least equal to the Equivalent Amount of C$1,000,000 or in multiples of the Equivalent Amount of C$1,000,000 or U.S.$1,000,000 in excess thereof (borrowings, Conversions or prepayments of or into Loans of different Types or, in the case of BA Loans, Eurodollar Loans or Eurocanadian Loans, having different Interest Periods at the same time hereunder to be deemed separate borrowings, Conversions and prepayments for purposes of the foregoing, one for each Type or Interest Period).

4.05 Certain Notices. Notices by the Company to the Administrative Agent of terminations or reductions of the Commitments and of borrowings and optional prepayments of Loans and Conversions and Continuations of Loans or Types of Loans and of the duration of Interest Periods shall be irrevocable and shall be effective only if received by the Administrative Agent not later than 11:00 a.m. New York time, on the number of Business Days prior to the date of the relevant termination, reduction, borrowing, Conversion, Continuation or prepayment or the first day of such Interest Period specified below:

Notice	Number of Business Days Prior
Termination or reduction of Commitments; borrowings or prepayments of, Conversions of or into, Continuations as, or duration of Interest Period for, BA Loans or acceptance of Bankers' Acceptances	2
Borrowing or prepayment of or Conversion into Base Rate Loans or Canadian Base Rate Loans	1
Borrowing or prepayment of, Conversions into, Continuations as, or duration of Interest Period for, Eurodollar Loans or Eurocanadian Loans	3
Request for issuance or Continuation of Letters of Credit	3

Each such notice of termination or reduction shall specify the amount of the Commitments to be terminated or reduced. Each such notice of borrowing, Conversion, Continuation or optional prepayment shall specify the Loans to be borrowed, Converted, Continued or prepaid and the amount (subject to Section 4.04 hereof) and Type of each Loan to be borrowed, Converted, Continued or prepaid and the date of borrowing, Conversion, Continuation or optional prepayment (which shall be a Business Day) and, if applicable, the relevant Interest Period. Each such notice of the duration of an Interest Period shall specify the Loans to which such Interest Period is to relate. The Administrative Agent shall promptly notify the Banks of the contents of each such notice. In the event that the Company fails to select the Type of Loan, or the duration of any Interest Period for any BA Loan, Eurodollar Loan or Eurocanadian Loan, within the time period and otherwise as provided in this Section 4.05, such Loan will be automatically Converted into a Base Rate Loan, in the case of a Eurodollar Loan, or into a Canadian Base Rate Loan in the case of a BA Loan or Eurocanadian Loan on the last day of the then current Interest Period for such Loan or (if outstanding as a Base Rate Loan or Canadian Base Rate Loan) will remain as a Base Rate Loan or Canadian Base Rate Loan, as applicable, or (if not then outstanding) will be made as, a Base Rate Loan or Canadian Base Rate Loan.

4.06 Non-Receipt of Funds by the Administrative Agent. Unless the Administrative Agent shall have been notified by a Bank or the Company (the "Payor") prior to the date on which the Payor is to make payment to the Administrative Agent of (in the case of a Bank) the proceeds of a Loan to be made by such Bank, or a Bankers' Acceptance to be purchased by such Bank or a Bank's Commitment Percentage of (x) any payment made by the Issuing Bank under a Letter of Credit or (y) a participation in a Letter of Credit drawing to be acquired by such Bank, hereunder or (in the case of the Company) a payment to the Administrative Agent for account of one or more of the Banks hereunder (such payment being herein called the "Required Payment"), which notice shall be effective upon receipt, that the Payor does not intend to make the Required Payment to the Administrative Agent, the Administrative Agent may assume that the Required Payment has been made and may, in reliance upon such assumption (but shall not be required to), make the amount thereof available to the intended recipient(s) on such date; and, if the Payor has not in fact made the Required Payment to the Administrative Agent, the recipient(s) of such payment shall, on demand, repay to the Administrative Agent the amount so made available together with interest thereon in respect of each day during the period commencing on the date (the "Advance Date") such amount was so made available by the Administrative Agent until the date the Administrative Agent recovers such amount if such amount relates to a Loan, at a rate per annum equal to the Federal Funds Effective Rate for such day and, if such recipient(s) shall fail promptly to make such payment, the Administrative Agent shall be entitled to recover such amount, on demand, from the Payor, together with interest as aforesaid, provided that if neither the recipient(s) nor the Payor shall return the Required Payment to the Administrative Agent within three Business Days of the Advance Date, then, retroactively to the Advance Date, the Payor and the recipient(s) shall each be obligated to pay interest on the Required Payment as follows:

(i) if the Required Payment shall represent a payment to be made by the Company to the Banks, the Company and the recipient(s) shall each be obligated retroactively to the Advance Date to pay interest in respect of the Required Payment at the Post-Default Rate (and, in case the recipient(s) shall return the Required Payment to the Administrative Agent, without limiting the obligation of the Company under Section 3.02 hereof to pay interest to such recipient(s) at the Post-Default Rate in respect of the Required Payment) and

(ii) if the Required Payment shall represent a payment to be made by a Bank to the Company, the Payor and the Company shall each be obligated retroactively to the Advance Date to pay interest in respect of the Required Payment at the rate of interest provided for such Required Payment pursuant to Section 3.02 hereof (and, in case the Company shall return the Required Payment to the Administrative Agent, without limiting any claim the Company may have against the Payor in respect of the Required Payment);

provided that the Administrative Agent shall only be entitled to retain interest in respect of a Required Payment pursuant to clause (i) or (ii) above from either the Payor or the recipient.

4.07 Sharing of Payments, Etc. (a) Each of the Obligors agrees that, in addition to (and without limitation of) any right of set-off, banker's lien or counterclaim a Bank may otherwise have, each Bank shall be entitled, at its option, to offset balances held by it for account of such Obligor at any of its offices, in U.S. Dollars or in any other currency, against any principal of or interest on any of such Bank's Loans, Reimbursement Obligations, Bankers' Acceptance or any other amount payable to such Bank hereunder, that is not paid when due (regardless of whether such balances are then due to the Company), in which case it shall promptly notify such Obligor (through the Company) and the Administrative Agent thereof, provided that such Bank's failure to give such notice shall not affect the validity thereof.

(b) If any Bank shall obtain from any Obligor payment of any principal of or interest on any Loan, Letter of Credit Liability or Bankers' Acceptance owing to it or payment of any other amount under this Agreement or any other Loan Document through the exercise of any right of set-off, banker's lien or counterclaim or similar right or otherwise (other than from the Administrative Agent as provided herein), and, as a result of such payment, such Bank shall have received a greater percentage of the principal of or interest on the Loans, Letter of Credit Liabilities, Bankers' Acceptances or such other amounts then due hereunder or thereunder by such Obligor to such Bank than the percentage received by any other Bank, it shall promptly purchase from such other Banks participations in (or, if and to the extent specified by such Bank, direct interests in) the Loans, Letter of Credit Liabilities, Bankers' Acceptances or such other amounts, respectively, owing to such other Banks (or in interest due thereon, as the case may be) in such amounts, and make such other adjustments from time to time as shall be equitable, to the end that all the Banks shall share the benefit of such excess payment (net of any expenses that may be incurred by such Bank in obtaining or preserving such excess payment) pro rata in accordance with the unpaid principal of and/or interest on the Loans, Letter of Credit Liabilities, Bankers' Acceptances or such other amounts, respectively, owing to each of the Banks, provided that if at the time of such payment the outstanding Principal Amount of the Loans shall not be held by the Banks pro rata in accordance with their respective Commitments in effect at the time such Loans were made (whether by reason of a failure of a Bank to make a Loan hereunder in the circumstances described in the second paragraph of Section 12.04 hereof or otherwise), then such purchases of participations and/or direct interests shall be made in such manner as will result, as nearly as is practicable, in the outstanding Principal Amount of the Loans being held by the Banks pro rata according to the amounts of such Commitments. To such end all the Banks shall make appropriate adjustments among themselves (by the resale of participations sold or otherwise) if such payment is rescinded or must otherwise be restored.

(c) The Obligors agree that any Bank so purchasing such a participation (or direct interest) may exercise all rights of set-off, banker's lien, counterclaim or similar rights with respect to such participation as fully as if such Bank were a direct holder of Loans or other amounts (as the case may be) owing to such Bank in the amount of such participation.

(d) Nothing contained herein shall require any Bank to exercise any such right or shall affect the right of any Bank to exercise, and retain the benefits of exercising, any such right with respect to any other indebtedness or obligation of any Obligor. If, under any applicable bankruptcy, insolvency or other similar law, any Bank receives a secured claim in lieu of a set-off to which this Section 4.07 applies, such Bank shall, to the extent practicable, exercise its rights in respect of such secured claim in a manner consistent with the rights of the Banks entitled under this Section 4.07 to share in the benefits of any recovery on such secured claim.

4.08 Interest Act (Canada); Judgment Interest Act (Alberta). (a) For purposes of the Interest Act (Canada), whenever any interest or fee under this Agreement is calculated using a rate based on a year of 360 days or 365 days, the annual rate of interest to which such rate is equivalent is, (x) the applicable rate based on a year of 360 days or 365 days, as the case may be, (y) multiplied by the actual number of days in the calendar year in which the period for which such interest or fee is payable (or compounded) ends, and (z) divided by 360 or 365 as the case may be.

(b) The principle of deemed reinvestment of interest shall not apply to any interest calculation under this Agreement, and the rates of interest stipulated in this Agreement are intended to be nominal rates and not effective rates or yields.

(c) To the extent permitted by law, Section 8 of the Interest Act (Canada) is hereby waived and shall not apply to the Loan Documents.

(d) To the extent permitted by law, any provision of the Judgment Interest Act (Alberta) and the Interest Act (Canada) which restricts the rate of interest on any judgment debt shall be inapplicable to this Agreement and is hereby waived by each Obligor.

4.09 Maximum Rate Permitted by Law. Under no circumstances shall a Bank be entitled to receive nor shall it in fact receive a payment or partial payment of interest, fees or other amounts under this Agreement at a rate that is prohibited by applicable law. Accordingly, notwithstanding anything herein or elsewhere contained, if and to the extent that under any circumstances, the "effective annual rate of interest" (as defined in Section 347 of the Criminal Code (Canada)) received or to be received by a Bank (determined in accordance with such section) on any amount of "credit advanced" (as defined in that section) pursuant to this Agreement or any agreement or arrangement collateral hereto entered into in consequence or implementation hereof would, but for this Section 4.09, be a rate that is prohibited by applicable law, then the effective annual rate of interest, as so determined, received or to be received by the Bank on such amount of credit advanced shall be and be deemed to be adjusted to a rate that is one whole percentage point less than the lowest effective annual rate of interest that is so prohibited (the "adjusted rate"); and, if a Bank has received a payment or partial payment which would, but for this Section 4.09, be so prohibited then any amount or amounts so received by such Bank in excess of the adjusted rate shall comprise and be deemed to have comprised the credit to be applied (together with interest thereon at the adjusted rate from the date of receipt of any such amount by such Bank to the date of its application as hereinafter provided) to subsequent payment on accounts of interest, fees or other amounts due to such Bank at the adjusted rate.

SECTION 5.
YIELD PROTECTION, ETC.

5.01 Additional Costs. (a) The Company shall pay directly to each Bank from time to time, as and by way of additional interest on the Indebtedness hereunder (to the extent such characterization as interest is permitted by applicable law), such amounts as such Bank may determine to be necessary to compensate such Bank for any costs that such Bank determines are attributable to its making or maintaining of any Eurodollar Loans or Eurocanadian Loans or its obligation to make any Eurodollar Loans or Eurocanadian Loans hereunder, or any reduction in any amount receivable by such Bank hereunder in respect of any of such Loans or such obligation (such increases in costs and reductions in amounts receivable being herein called

"Additional Costs"), resulting from any Regulatory Change after the date hereof or, with respect to any financial institution that becomes a Bank hereunder after the date hereof, after the date on which such financial institution becomes a Bank hereunder (including any Regulatory Change after such applicable date with retroactive effect) that:

(i) changes the basis of taxation of any amounts payable to such Bank under this Agreement or its Notes in respect of any of such extensions of credit (other than Excluded Taxes); or

(ii) imposes or modifies any reserve, special deposit or similar requirements (other than the Reserve Requirement utilized in the determination of the Eurodollar Rate or Eurocanadian Rate for such Loan) relating to any extensions of credit or other assets of, or any deposits with or other liabilities of, such Bank (including, without limitation, any of such Loans or any deposits referred to in the definition of "Eurodollar Base Rate" or "Eurocanadian Base Rate" in Section 1.01 hereof), or any commitment of such Bank (including, without limitation, the Commitments of such Bank hereunder); or

(iii) imposes any other condition affecting this Agreement or its Note (or any of such extensions of credit or liabilities) or its Commitment.

If any Bank requests compensation from the Company under this Section 5.01(a), the Company may, by notice to such Bank (with a copy to the Administrative Agent), suspend the obligation of such Bank thereafter to make or Continue Eurodollar Loans or Eurocanadian Loans, or to Convert Base Rate Loans into Eurodollar Loans or to Convert Bankers' Acceptances into Eurocanadian Loans, until the Regulatory Change giving rise to such request ceases to be in effect (in which case the provisions of Section 5.04 hereof shall be applicable), provided that such suspension shall not affect the right of such Bank to receive the compensation so requested.

(b) Without limiting the effect of the provisions of paragraph (a) of this Section 5.01, in the event that, by reason of any Regulatory Change after the date hereof or with respect to any financial institution that becomes a Bank hereunder after the date hereof, after the date on which such financial institution becomes a Bank hereunder (including any Regulatory Change after such applicable date with retroactive effect) any Bank either (i) incurs Additional Costs based on or measured by the excess above a specified level of the amount of a category of deposits or other liabilities of such Bank that includes deposits by reference to which the interest rate on Eurodollar Loans or Eurocanadian Loans is determined as provided in this Agreement or a category of extensions of credit or other assets of such Bank that includes Eurodollar Loans or Eurocanadian Loans or (ii) becomes subject to restrictions on the amount of such a category of liabilities or assets that it may hold, then, if such Bank so elects by notice to the Company (with a copy to the Administrative Agent), the obligation of such Bank to make or Continue, or to Convert Base Rate Loans into, Eurodollar Loans or Eurocanadian Loans hereunder shall be suspended until such Regulatory Change ceases to be in effect (in which case the provisions of Section 5.04 hereof shall be applicable).

(c) Without limiting the effect of the foregoing provisions of this Section 5.01 (but without duplication), the Company shall pay directly, as and by way of additional interest on the Indebtedness hereunder (to the extent such characterization as interest is permitted by applicable law), to each Bank from time to time on request such amounts as such Bank may determine to be necessary to compensate such Bank (or, without duplication, the bank holding company of which such Bank is a subsidiary) for (i) any costs that it determines are attributable to the maintenance by such Bank (or any Applicable Lending Office or such bank holding company), pursuant to any law or regulation or any interpretation, directive or request (whether or not having the force of law and whether or not failure to comply therewith would be unlawful) of any court or governmental or monetary authority (A) following any Regulatory Change after the date hereof or, with respect to any financial institution that becomes a Bank hereunder after the date hereof, after the date on which such financial institution becomes a Bank hereunder (including any Regulatory Change after such applicable date with retroactive effect) or (B) implementing after the date hereof any risk-based capital guideline or other requirement (whether or not having the force of law and whether or not the failure to comply therewith would be unlawful) heretofore or hereafter issued by any government or governmental or supervisory authority implementing at the national level the Basel Accord (including, without limitation, the Final Risk-Based Capital Guidelines of the Board of Governors of the Federal Reserve System (12 C.F.R. Part 208, Appendix A; 12 C.F.R. Part 225, Appendix A) and the Final Risk-Based Capital Guidelines of the Office of the Comptroller of the Currency (12 C.F.R. Part 3, Appendix A) and the January 2001 Guidelines issued by the Office of the Superintendent of Financial Institutions of Canada entitled "Capital Adequacy Requirements" (or any guidelines issued in replacement thereof)), of capital in respect of its Commitment or Loans (such compensation to include, without limitation, an amount equal to any reduction of the rate of return on the Commitment or Loans of such Bank (or any Applicable Lending Office or such bank holding company) to a level below that which such Bank (or any Applicable Lending Office or such bank holding company) could have achieved but for such law, regulation, interpretation, directive or request); and (ii) any reduction in amounts payable to it hereunder (other than a reduction resulting from a higher rate of Excluded Taxes) or any payment required to be made or return that is foregone on or calculated with reference to any amount received or receivable by such Bank under this Agreement as a result of a Regulatory Change after the date hereof or, with respect to any financial institution that becomes a Bank hereunder after the date hereof, after the date on which such financial institution becomes a Bank hereunder (including any Regulatory Change after such applicable date with retroactive effect).

For purposes of this Section 5.01(c) and Section 5.06 hereof, "Basel Accord" shall mean the proposals for risk-based capital framework described by the Basel Committee on Banking Regulations and Supervisory Practices in its paper entitled "International Convergence of Capital Measurement and Capital Standards" dated July 1988, as amended, modified and supplemented and in effect from time to time or any replacement thereof.

(d) Each Bank shall notify the Company of any event occurring after the date of this Agreement entitling such Bank to compensation under paragraph (a) or (c) of this Section 5.01 or Sections 5.06 and 5.07 as promptly as practicable, but in any event within 60 days, after such Bank obtains actual knowledge thereof; provided that (i) if any Bank fails to give such notice within 60 days of such an event, such Bank shall, with respect to compensation payable pursuant to this Section 5.01 or Sections 5.06 and 5.07 in respect of any costs resulting from such event, only be entitled to payment under this Section 5.01 or Sections 5.06 and 5.07 for costs incurred from and after the date 60 days prior to the date that such Bank does give such notice and (ii) each Bank will designate a different Applicable Lending Office for the Loans of such Bank affected by such event if such designation will avoid the need for, or reduce the amount of, such compensation and will not, in the sole opinion of such Bank, be disadvantageous to such Bank. Each Bank will furnish to the Company a certificate setting forth the basis and amount of each request by such Bank for compensation under paragraph (a) or (c) of this Section 5.01 or Section 5.06 or 5.07. Determinations and allocations by any Bank for purposes of this Section 5.01 of the effect of any Regulatory Change pursuant to paragraph (a) or (b) of this Section 5.01, or of the effect of capital maintained pursuant to paragraph (c) of this Section 5.01, on its costs or rate of return of maintaining Loans or its obligation to make Loans, or on amounts receivable by it in respect of Loans, and of the amounts required to compensate such Bank under this Section 5.01, shall be conclusive in the absence of manifest error, provided that each Bank shall, to the extent contractually permitted, treat the Company in a manner consistent with other similarly situated borrowers of such Bank.

5.02 Limitation on Types of Loans. Anything herein to the contrary notwithstanding, if, on or prior to the determination of the BA Rate, Eurodollar Base Rate or Eurocanadian Base Rate for any Interest Period:

(i) the Administrative Agent determines, which determination shall be conclusive, that quotations of interest rates for the relevant deposits referred to in the definition of "Eurodollar Base Rate" or "Eurocanadian Base Rate" in Section 1.01 hereof are not being provided in the relevant amounts or for the relevant maturities for purposes of determining rates of interest for Eurodollar Loans or Eurocanadian Loans as provided herein; or

(ii) the Majority Banks determine, which determination shall be conclusive, and notify the Administrative Agent that the relevant rates of interest referred to in the definition of "Eurodollar Base Rate" or "Eurocanadian Base Rate" in Section 1.01 hereof upon the basis of which the rate of interest for Eurodollar Loans or Eurocanadian Loans for such Interest Period is to be determined are not likely to be adequate to cover the cost to such Banks of making or maintaining Eurodollar Loans or Eurocanadian Loans for such Interest Period;

then the Administrative Agent shall give the Company and each Bank prompt notice thereof and, so long as such condition remains in effect, such Banks shall be under no obligation to make additional Eurodollar Loans or Eurocanadian Loans, to Continue Eurodollar Loans or Eurocanadian Loans or to Convert Base Rate Loans into Eurodollar Loans or to Convert BA Loans, Canadian Base Rate Loans or Bankers' Acceptances into Eurocanadian Loans, as applicable in each case, and the Company shall, on the last day(s) of the then current Interest Period(s) for the outstanding Eurodollar Loans and Eurocanadian Loans, either prepay such Loans or Convert such Loans into Base Rate Loans in accordance with Section 2.09 hereof.

5.03 Illegality. Notwithstanding any other provision of this Agreement, in the event that it becomes unlawful for any Bank or its Applicable Lending Office to honor its obligation to make or maintain Eurodollar Loans or Eurocanadian Loans, then such Bank shall promptly notify the Company thereof (with a copy to the Administrative Agent) and such Bank's obligation to make or Continue, or to Convert Loans of any other Type into Eurodollar Loans or Eurocanadian Loans, as the case may be, shall be suspended until such time as such Bank may again make and maintain Eurodollar Loans or Eurocanadian Loans, as the case may be (in which case the provisions of Section 5.04 hereof shall be applicable).

5.04 Treatment of Affected Extensions of Credit. If the obligation of any Bank to make Eurodollar Loans or Eurocanadian Loans or to Continue, or to Convert Base Rate Loans into Eurodollar Loans or to Convert Bankers' Acceptances (and the related BA Loans) or Canadian Base Rate Loans into Eurocanadian Loans shall be suspended pursuant to Section 5.01, 5.02 or 5.03 hereof, such Bank's Eurodollar Loans or Eurocanadian Loans, as applicable, shall be automatically Converted into Base Rate Loans or Canadian Base Rate Loans, respectively, on the last day(s) of the then current Interest Period(s) for Eurodollar Loans or Eurocanadian Loans, as applicable (or, in the case of a Conversion required by Section 5.01(b) or 5.03 hereof, on such earlier date as such Bank may specify to the Company, with a copy to the Administrative Agent) and, unless and until such Bank gives notice as provided below that the circumstances specified in Section 5.01 or 5.03 hereof that gave rise to such Conversion no longer exist:

(a) to the extent that such Bank's Eurodollar Loans and Eurocanadian Loans have been so Converted, all payments and prepayments of principal that would otherwise be applied to such Bank's Eurodollar Loans and Eurocanadian Loans shall be applied instead to its Base Rate Loans or Canadian Base Rate Loans, respectively; and

(b) all Loans that would otherwise be made or Continued by such Bank as Eurodollar Loans or Eurocanadian Loans shall be made or Continued instead as Base Rate Loans or Canadian Base Rate Loans, respectively, and all Base Rate Loans and Canadian Base Rate Loans of such Bank that would otherwise be Converted into Eurodollar Loans or Eurocanadian Loans shall remain as Base Rate Loans or Canadian Base Rate Loans, respectively.

If such Bank gives notice to the Company, with a copy to the Administrative Agent that the circumstances specified in Section 5.01, 5.02 or 5.03 hereof that gave rise to the Conversion of such Bank's Eurodollar Loans or Eurocanadian Loans pursuant to this Section 5.04 no longer exist (which such Bank agrees to do promptly upon such circumstances ceasing to exist) at a time when Eurodollar Loans or Eurocanadian Loans made by other Banks are outstanding, such Bank's Loans shall be Converted or such Bank and the Company shall take such other actions, to the extent necessary so that, after giving effect thereto, all Loans and other credit utilizations held by such Bank and by the other Banks are held pro rata (as to Principal Amounts, Types and Interest Periods) in accordance with their respective Commitments.

5.05 Compensation. The Company shall pay to the Administrative Agent for the account of each Bank, upon the request of such Bank through the Administrative Agent, such amount or amounts, as and by way of additional interest on the Indebtedness hereunder (to the extent such characterization as interest is permitted by applicable law), as shall be sufficient (in the reasonable opinion of such Bank) to compensate it for any loss, cost or expense that such Bank determines is attributable to:

(i) any payment, mandatory or optional prepayment or Conversion of a BA Loan, Bankers' Acceptance, Eurodollar Loan or Eurocanadian Loan made by such Bank for any reason (including, without limitation, the acceleration of the Loans pursuant to Section 10 hereof) on a date other than the last day of an Interest Period for such Loan; or

(ii) any failure by the Company for any reason (including, without limitation, the failure of any of the conditions precedent specified in Section 7 hereof to be satisfied) to borrow or optionally prepay a BA Loan, Eurodollar Loan or Eurocanadian Loan from such Bank on the date for such borrowing specified in the relevant notice of borrowing or prepayment given pursuant to Section 2.02 or 2.09 hereof, respectively.

A certificate of any Bank submitted to the Company as to the amount necessary to so compensate the Bank shall be conclusive evidence, absent manifest error, of the amount due from the Company to such Bank.

Without limiting the effect of the preceding sentence, such compensation shall include an amount equal to the excess, if any, of (A) the amount of interest that otherwise would have accrued on the Principal Amount so paid, prepaid or Converted or not borrowed for the period from the date of such payment, prepayment, Conversion or failure to borrow to the last day of the then current Interest Period for such Loan (or, in the case of a failure to borrow, the Interest Period for such Loan that would have commenced on the date specified for such borrowing) at the applicable rate of interest for such Loan provided for herein over (B) the amount of interest that otherwise would have accrued on such Principal Amount at a rate per annum equal to the BA Rate for BA Loans plus the Applicable Margin, or equal to the interest component of the amount such Bank would have bid in the London interbank market for U.S. Dollar deposits (or Canadian Dollar deposits for Eurocanadian Loans) of leading banks in amounts comparable to such Principal Amount and with maturities comparable to such period (as reasonably determined by such Bank).

5.06 Additional Costs in Respect of Letters of Credit and Bankers Acceptances. Without limiting the obligations of the Company under Section 5.01 hereof (but without duplication), if as a result of any Regulatory Change after the date hereof, or with respect to financial institution that becomes a Bank hereunder after the date hereof, the date on which such financial institution becomes a Bank hereunder (including any Regulatory Change after such applicable date with retroactive effect) or any risk-based capital guideline or other requirement heretofore or hereafter issued by any government or governmental or supervisory authority implementing at the national level the Basel Accord there shall be imposed, modified or deemed applicable any tax, reserve, special deposit, capital adequacy or similar requirement against or with respect to or measured by reference to Letters of Credit issued or to be issued hereunder and the result shall be to increase the cost to the Issuing Bank of issuing (or of any Bank of purchasing participations in) or maintaining its obligation hereunder to issue (or purchase participations in) any Letter of Credit hereunder or reduce any amount receivable by the Issuing Bank or any Bank hereunder in respect of any Letter of Credit (which increases in cost, or reductions in amount receivable, shall be the result of the Issuing Bank or such Bank's or Banks' reasonable allocation of the aggregate of such increases or reductions resulting from such event), then, upon demand by the Issuing Bank or such Bank or Banks (through the Administrative Agent), the Company shall pay immediately to the Administrative Agent for account of the Issuing Bank or such Bank or Banks, from time to time as specified by the Issuing Bank or such Bank or Banks (through the Administrative Agent), as and by way of additional interest on the Indebtedness hereunder (to the extent such characterization as interest is permitted by applicable law), such additional amounts as shall be sufficient to compensate the Issuing Bank or such Bank or Banks (through the Administrative Agent) for such increased costs or reductions in amount. A statement as to such increased costs or reductions in amount incurred by the Issuing Bank or any such Bank or Banks, submitted by the Issuing Bank or such Bank or Banks to the Company, shall be conclusive in the absence of manifest error as to the amount thereof.

5.07 Taxes; Loans and Reimbursement Obligations. (a) Any and all payments by or on account of any obligation of the Company or any Subsidiary Guarantor to the Banks hereunder shall be made free and clear of and without deduction or withholding for any Indemnified Taxes or Other Taxes; provided that if the Company or any Subsidiary Guarantor shall be required to deduct or withhold any Indemnified Taxes or Other Taxes from such payments to the Banks, then (i) the sum payable shall be increased, as and by way of additional interest on the Indebtedness hereunder (to the extent such characterization as interest is permitted by applicable law), as necessary so that after making all required deductions or withholdings (including deductions or withholdings applicable to additional sums payable under this Section) the Administrative Agent, Bank or Issuing Bank (as the case may be) receives an amount equal to the sum it would have received had no such deductions or withholdings been made, (ii) the Company or such Subsidiary Guarantor shall make such deductions or withholdings and (iii) the Company or such Subsidiary Guarantor shall pay the full amount deducted or withheld (including the full amount of any deduction or withholding from any additional sums payable under this Section 5.07(a)) to the relevant Governmental Authority in accordance with applicable law.

(b) In addition, the Company or the applicable Subsidiary Guarantor shall pay any Other Taxes to the relevant Governmental Authority in accordance with applicable law.

(c) The Company shall indemnify the Administrative Agent, each Bank and the Issuing Bank, within 10 days after written demand therefor, for the full amount of any Indemnified Taxes or Other Taxes paid by the Administrative Agent, such Bank or the Issuing Bank, as the case may be, on or with respect to any payment by or on account of any obligation of the Company or any Subsidiary Guarantor hereunder (including Indemnified Taxes or Other Taxes imposed or asserted on or attributable to amounts payable under this Section) and any penalties, interest and reasonable expenses arising therefrom or with respect thereto (other than such penalties, interest or expenses arising through the negligence or willful misconduct of the Administrative Agent, such Bank or the Issuing Bank), whether or not such Indemnified Taxes or Other Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority. A certificate as to the amount of such payment or liability delivered to the Company by a Bank or the Issuing Bank, or by the Administrative Agent on its own behalf or on behalf of a Bank or the Issuing Bank, shall be conclusive absent manifest error.

(d) As soon as practicable after any payment of Indemnified Taxes or Other Taxes by the Company or any Subsidiary Guarantor to a Governmental Authority, the Company shall deliver to the Administrative Agent the original or a certified copy of a receipt issued by such Governmental Authority evidencing such payment, a copy of the return reporting such payment or other evidence of such payment reasonably satisfactory to the Administrative Agent.

(e) Any Foreign Lender that is entitled to an exemption from or reduction of withholding tax under the law of the jurisdiction in which an Obligor is located, or any treaty to which such jurisdiction is a party, with respect to payments under this Agreement shall deliver to such Obligor (with a copy to the Administrative Agent) such properly completed and executed documentation as reasonably required to comply with applicable law and reasonably requested by such Obligor as will permit such payments to be made without withholding or at a reduced rate or as will permit such Obligor to recover amounts on account of such payments. If any withholding taxes are imposed on or with respect to any payment on or under this Agreement, as a result of which the Company is required to make any additional payment to any Foreign Lender under this Section 5.07, and if such Foreign Lender is entitled to a cash refund from the authorities that imposed such withholding taxes which is both identifiable and quantifiable by such Foreign Lender as being attributable to the imposition of such withholding taxes (a "Tax Refund"), and such Tax Refund may be obtained without increased liability to such Foreign Lender, such Foreign Lender shall reimburse the Company such amount as such Foreign Lender shall determine acting in good faith to be attributable to the Tax Refund, together with any interest received thereon (attributable to such additional payment) as will leave such Foreign Lender after the reimbursement in the same position as it would have been if the additional payment had not been required; provided that, if any Tax Refund reimbursed by a Foreign Lender to the Company is subsequently disallowed, the Company shall repay such Foreign Lender such amount (together with interest and any applicable penalty payable by such Foreign Lender to the relevant taxing authority) promptly after receipt of notice by such Foreign Lender of such disallowance. The Company agrees to reimburse each such Foreign Lender for such Foreign Lender's reasonable out-of-pocket expenses, if any, incurred in complying with any request hereunder and agrees that all costs incurred by such Foreign Lender in respect of this Section 5.07(e) may be deducted from the amount of any reimbursement to the Company in respect of any Tax Refund pursuant to this Section 5.07(e).

(f) Notwithstanding any other provision of this Section 5.07, the Company shall not be required to indemnify the Administrative Agent, any Bank or Issuing Bank:

(i) to the extent of any withholding tax imposed by reason of a failure of the Administrative Agent, such Bank or the Issuing Bank, as the case may be, to comply with any certification, information, documentation or other reporting requirement if compliance is required by applicable law, administrative practice or an applicable treaty as a precondition to exemption from, or reduction in the rate of deduction or withholding of, such withholding taxes (provided that any such certification, information, documentation or other reporting requirement required by administrative practice is generally followed by other similarly situated financial institutions), including, without limitation, any failure to comply with the requirement to provide documentation in accordance with Section 5.07(e); or

(ii) to the extent that any withholding tax for which it would otherwise be entitled to indemnity hereunder arises in circumstances where it is a Subsidiary or Affiliate of a bank that is a bank listed in Schedule II or III of the *Bank Act* (Canada) but is not the lender providing Loans and having a Commitment hereunder, or if it is a Subsidiary or Affiliate of a bank which if it was the Bank lending hereunder would result in a reduced rate of deduction or withholding applicable pursuant to an applicable tax treaty with Canada, in which case indemnity shall be limited to such reduced rate of deduction or withholding; provided that WestLB shall be entitled to the indemnity for such withholding taxes following the establishment by it of a bank listed on Schedule II or III of the *Bank Act* (Canada) for such period of time as it is using commercially reasonable efforts to transfer its Commitments hereunder to such bank.

5.08 Replacement of Banks. If any Bank requests compensation under Sections 5.01 or 5.06 or if Section 5.03 becomes applicable to any Bank, then the Company may, at its sole expense and effort, upon notice to such Bank and the Administrative Agent, require such Bank to assign and delegate, without recourse (in accordance with and subject to the restrictions, including required consents, contained in Section 12.06), all of its interests, rights and obligations under this Agreement to an assignee that assumes those obligations (which assignee may be another Bank); provided that (i) such Bank receives payment from the assignee or from the Company of an amount equal to the obligations owing to such Bank (to the extent of the outstanding principal, accrued interest and fees included in those obligations), together with any additional amounts due pursuant to Section 5.01 or 5.06 (in the case of all other amounts so included) and (ii) in the case of any such assignment resulting from a claim for compensation under Section 5.01 or 5.06, such assignment will result in a reduction in such compensation or payments. A Bank shall not be required to make any such assignment and delegation if, as a result of a waiver by such Bank of its right under Section 5.01, 5.03 or 5.06, as applicable, the circumstances entitling the Company to require such assignment and delegation have ceased to apply or if a Bank determines, in its sole discretion, that such transfer would result in additional costs not indemnified by the Company and notifies the Company of such additional costs together with a reasonably detailed description of such additional costs; provided that if the Company subsequently determines to indemnify such Bank for such costs, such Bank shall be required to make such assignment.

SECTION 6.
GUARANTEE.

6.01 Guarantee. The Subsidiary Guarantors hereby jointly and severally guarantee to each Bank, the Issuing Bank and the Administrative Agent and their respective successors and assigns the prompt payment in full when due (whether at stated maturity, by acceleration or otherwise) of the principal of and interest on the Loans made by the Banks to, Bankers Acceptance Liabilities of the Company to, and the Notes held by each Bank and Reimbursement Obligations in respect of Letters of Credit of, the Company and all other amounts from time to time owing to the Banks, the Issuing Bank or the Administrative Agent by the Company under this Agreement, under the Notes and by any Obligor under any of the other Loan Documents to which such Obligor is a party, in each case strictly in accordance with the terms thereof (such obligations being herein collectively called the "Guaranteed Obligations"). The Subsidiary Guarantors hereby further jointly and severally agree that if the Company shall fail to pay in full when due (whether at stated maturity, by acceleration or otherwise) any of the Guaranteed Obligations, the Subsidiary Guarantors will promptly pay the same, without any demand or notice whatsoever, and that in the case of any extension of time of payment or renewal of any of the Guaranteed Obligations, the same will be promptly paid in full when due (whether at extended maturity, by acceleration or otherwise) in accordance with the terms of such extension or renewal.

6.02 Obligations Unconditional. The obligations of the Subsidiary Guarantors under Section 6.01 hereof are absolute and unconditional, joint and several, irrespective of the value, genuineness, validity, regularity or enforceability of the obligations of the Company under this Agreement, the Notes or any other agreement or instrument referred to herein or therein, or any substitution, release or exchange of any other guarantee of or security for any of the Guaranteed Obligations, and, to the fullest extent permitted by applicable law, irrespective of any other circumstance whatsoever which might otherwise constitute a legal or equitable discharge or defense of a surety or guarantor, it being the intent of this Section 6.02 that the obligations of the Subsidiary Guarantors hereunder shall be absolute and unconditional, joint and several, under any and all circumstances. Without limiting the generality of the foregoing, it is agreed that the occurrence of any one or more of the following shall not alter or impair the liability of the Subsidiary Guarantors hereunder which shall remain absolute and unconditional as described above:

(i) at any time or from time to time, without notice to the Subsidiary Guarantors, the time for any performance of or compliance with any of the Guaranteed Obligations shall be extended, or such performance or compliance shall be waived;

(ii) any of the acts mentioned in any of the provisions of this Agreement or the Notes or any other agreement or instrument referred to herein or therein shall be done or omitted;

(iii) the maturity of any of the Guaranteed Obligations shall be accelerated, or any of the Guaranteed Obligations shall be modified, supplemented or amended in any respect, or any right under this Agreement or the Notes or any other agreement or instrument referred to herein or therein shall be waived or any other guarantee of any of the Guaranteed Obligations or any security therefor shall be released or exchanged in whole or in part or otherwise dealt with; or

(iv) any Lien granted to, or in favor of, the Administrative Agent or any Bank as security for any of the Guaranteed Obligations shall fail to be perfected.

Each of the Subsidiary Guarantors hereby expressly waive diligence, presentment, demand of payment, protest and all notices whatsoever, and any requirement that the Administrative Agent or any Bank exhaust any right, power or remedy or proceed against the Company and the other Subsidiary Guarantors under this Agreement or the Notes or any other agreement or instrument referred to herein or therein, or against any other Person under any other guarantee of, or security for, any of the Guaranteed Obligations. Each Subsidiary Guarantor agrees that its obligations pursuant to this Section 6 shall not be affected by any assignment or participation entered into by any Bank pursuant to Section 12.06 hereof.

6.03 Reinstatement. The obligations of the Subsidiary Guarantors under this Section 6 shall be automatically reinstated if and to the extent that for any reason any payment by or on behalf of the Company in respect of the Guaranteed Obligations is rescinded or must be otherwise restored by any holder of any of the Guaranteed Obligations, whether as a result of any proceedings in bankruptcy or reorganization or otherwise and the Subsidiary Guarantors jointly and severally agree that they will indemnify the Administrative Agent and each Bank on demand for all reasonable costs and expenses (including, without limitation, fees of counsel) incurred by the Administrative Agent or such Bank in connection with such rescission or restoration, including any such costs and expenses incurred in defending against any claim alleging that such payment constituted a preference, fraudulent transfer or similar payment under any bankruptcy, insolvency or similar law.

6.04 Subrogation.. Until all Loans and Letter of Credit Liabilities have been paid in full and the Commitments have been terminated, each Subsidiary Guarantor hereby waives all rights of subrogation or contribution, whether arising by contract or operation of law or otherwise by reason of any payment by it pursuant to the provisions of this Section 6.

6.05 Remedies. The Subsidiary Guarantors jointly and severally agree that, as between the Subsidiary Guarantors and the Banks, the obligations of the Company under this Agreement and the Notes may be declared to be forthwith due and payable as provided in Section 10 hereof (and shall be deemed to have become automatically due and payable in the circumstances provided in said Section 10) for purposes of Section 6.01 hereof notwithstanding any stay, injunction or other prohibition preventing such declaration (or such obligations from becoming automatically due and payable) as against the Company and that, in the event of such declaration (or such obligations being deemed to have become automatically due and payable), such obligations (whether or not due and payable by the Company) shall forthwith become due and payable by the Subsidiary Guarantors for purposes of said Section 6.01.

6.06 Continuing Guarantee. The guarantee in this Section 6 is a continuing guarantee, and shall apply to all Guaranteed Obligations whenever arising.

6.07 Instrument for the Payment of Money. Each Subsidiary Guarantor hereby acknowledges that the guarantee in this Section 6 constitutes an instrument for the payment of money, and consents and agrees that any Bank, the Issuing Bank or the Administrative Agent, at its sole option, in the event of a dispute by such Subsidiary Guarantor in the payment of any moneys due hereunder, shall have the right to bring motion-action under New York CPLR Section 3213.

6.08 Rights of Contribution. The Subsidiary Guarantors hereby agree, as between themselves, that if any Subsidiary Guarantor shall become an Excess Funding Guarantor (as defined below) by reason of the payment by such Subsidiary Guarantor of any Guaranteed Obligations, each other Subsidiary Guarantor shall, on demand of such Excess Funding Guarantor (but subject to the next sentence), pay to such Excess Funding Guarantor an amount equal to such Subsidiary Guarantor's Pro Rata Share (as defined below and determined, for this purpose, without reference to the Properties, debts and liabilities of such Excess Funding Guarantor) of the Excess Payment (as defined below) in respect of such Guaranteed Obligations. The payment obligation of a Subsidiary Guarantor to any Excess Funding Guarantor under this Section 6.08 shall be subordinate and subject in right of payment to the prior payment in full of the obligations of such Subsidiary Guarantor under the other provisions of this Section 6 and such Excess Funding Guarantor shall not exercise any right or remedy with respect to such excess until payment and satisfaction in full of all of such obligations.

For purposes of this Section 6.08, (i) "Excess Funding Guarantor" shall mean, in respect of any Guaranteed Obligations, a Subsidiary Guarantor that has paid an amount in excess of its Pro Rata Share of such Guaranteed Obligations, (ii) "Excess Payment" shall mean, in respect of any Guaranteed Obligations, the amount paid by an Excess Funding Guarantor in excess of its Pro Rata Share of such Guaranteed Obligations and (iii) "Pro Rata Share" shall mean, for any Subsidiary Guarantor, the ratio (expressed as a percentage) of (x) the amount by which the aggregate present fair saleable value of all Properties of such Subsidiary Guarantor (excluding any shares of stock of any other Subsidiary Guarantor) exceeds the amount of all the debts and liabilities of such Subsidiary Guarantor (including contingent, subordinated, unmatured and unliquidated liabilities, but excluding the obligations of such Subsidiary Guarantor hereunder and any obligations of any other Subsidiary Guarantor that have been Guaranteed by such Subsidiary Guarantor) to (y) the amount by which the aggregate fair saleable value of all Properties of all of the Subsidiary Guarantors exceeds the amount of all the debts and liabilities (including contingent, subordinated, unmatured and unliquidated liabilities, but excluding the obligations of the Company and the Subsidiary Guarantors hereunder and under the other Loan Documents) of all of the Subsidiary Guarantors, determined (A) with respect to any Subsidiary Guarantor that is a party hereto on the date of this Agreement, as of the date of this Agreement, and (B) with respect to any other Subsidiary Guarantor, as of the date such Subsidiary Guarantor becomes a Subsidiary Guarantor hereunder.

6.09 General Limitation on Guarantee Obligations In any action or proceeding involving any state corporate law, or any state or Federal bankruptcy, insolvency, reorganization or other law affecting the rights of creditors generally, if the obligations of any Subsidiary Guarantor under Section 6.01 hereof would otherwise, taking into account the provisions of Section 6.08 hereof, be held or determined to be void, invalid or unenforceable, or subordinated to the claims of any other creditors, on account of the amount of its liability under said Section 6.01, then, notwithstanding any other provision hereof to the contrary, the amount of such liability shall, without any further action by such Subsidiary Guarantor, any Bank, the Issuing Bank, the Administrative Agent or any other Person, be automatically limited and reduced to the highest amount that is valid and enforceable and not subordinated to the claims of other creditors as determined in such action or proceeding.

SECTION 7.
CONDITIONS PRECEDENT.

7.01 Conditions to Effectiveness. The effectiveness of this Credit Agreement is subject to the receipt by the Administrative Agent of the following documents and evidence, each of which shall be satisfactory to in both form and substance:

(a) Corporate Documents. The following documents, each certified as indicated below:

(i) a copy of the articles and by-laws, as amended and in effect, of the Company certified as of a recent date by the Registrar of Corporations of Alberta, and a certificate from such Registrar of Corporations of Alberta dated as of a recent date as to the continuing existence of the Company;

(ii) a certificate of the Secretary or an Assistant Secretary of the Company, dated the date hereof and certifying (A) that the charter documents of the Company have not been amended since the date of the resolutions specified in the following clause (B), (B) that attached thereto is a true and complete copy of resolutions duly adopted by the board of directors of the Company authorizing the execution, delivery and performance of the Loan Documents and the extensions of credit hereunder, and that such resolutions have not been modified, rescinded or amended and are in full force and effect, (C) that the charter of the Company has not been amended since the date of their certification pursuant to the foregoing clause (i), and (D) as to the incumbency and specimen signature of each officer of the Company executing the Loan Documents and each other document to be delivered by the Company from time to time in connection therewith (and the Administrative Agent and each Bank may conclusively rely on such certificate until it receives notice in writing to the contrary from the Company); and

(iii) a certificate of another officer of the Company as to the incumbency and specimen signature of the secretary or assistant secretary, as the case may be, of the Company.

(b) Officer's Certificate. A certificate of a senior officer of the Company, dated the date hereof, to the effect set forth in the first sentence of Section 7.02 hereof.

(c) Opinions of Counsel. An opinion, dated the date hereof, of (i) Burnet, Duckworth & Palmer LLP, Canadian counsel of the Company, substantially in the form of Exhibit B hereto and covering such other matters as the Administrative Agent, the Issuing Bank or any Bank may reasonably request (and the Company hereby instructs such counsel to deliver such opinion to the Banks and the Administrative Agent), in form and substance satisfactory to the Administrative Agent and its counsel and (ii) Latham & Watkins, special counsel of the Banks.

(d) Notes. The Notes, duly executed and delivered, in form and substance satisfactory to the Administrative Agent and its counsel.

(e) Security Documents. The Security Documents (other than the Mortgages), each duly executed and delivered by the parties thereto, in form and substance satisfactory to the Administrative Agent and its counsel.

(f) Mortgages. One or more Mortgages covering all real and personal property of the Company located in the Province of Alberta, in each case duly executed and delivered by the Company in recordable form (in such number of copies as the Administrative Agent shall have requested), each of which shall be executed (and, where appropriate, acknowledged) by Persons satisfactory to the Administrative Agent and each of which shall be in form and substance satisfactory to special Canadian counsel to the Banks.

(g) Loan Documents. Each other Loan Document, duly executed and delivered by the parties thereto, in form and substance satisfactory to the Administrative Agent and its counsel.

(h) Title to Hydrocarbon Properties. Evidence satisfactory to the Administrative Agent and special Canadian counsel to the Banks that the Company owns the Hydrocarbon Properties subject to the fixed charge of the Mortgage free and clear of any Lien (other than Permitted Liens), which evidence may include title opinions with respect to such Hydrocarbon Properties.

(i) Environmental. All phase I evaluations or similar evaluations performed with respect to Hydrocarbon Properties.

(j) Governmental Approvals. Evidence satisfactory to the Administrative Agent that all governmental and third-party consents and approvals necessary in connection with the financing hereunder and the Loan Documents and the other transactions contemplated hereby and thereby have been obtained (without the imposition of any conditions) and are in full force and effect; all applicable waiting periods have expired without any action being taken by any competent authority; and no law or regulation is applicable (in the reasonable judgment of the Supermajority Lenders) that restrains, prevents or imposes materially adverse conditions upon the financing hereunder or thereunder, or any security therefor or any of the other transactions contemplated hereby or thereby.

(k) Notice of Borrowing. A notice of borrowing as provided in Section 4.05, signed by a senior officer of the Company.

(l) Reserve Evaluation Report. A Reserve Evaluation Report dated as of August 1, 2002, from McDaniel & Associates or another independent engineering firm acceptable to the Administrative Agent detailing future cash flows, capital expenditures, net profits after taxes and all other charges and expenses, in form and substance satisfactory to the Administrative Agent. The Administrative Agent acknowledges that it has received such report and that it is in form and substance satisfactory.

(m) Insurance Certificates. Certificates of insurance evidencing the existence of all insurance required to be maintained by the Obligors pursuant to Section 9.04 hereof and the designation of the Administrative Agent, as agent, as the loss payee thereunder in respect of all insurance covering Hydrocarbon Properties. In addition, the Company shall have delivered a certificate of the chief financial officer or treasurer of the Company setting forth the insurance obtained by it in accordance with the requirements set forth in Section 9.04 and stating that such insurance is in full force and effect and that all premiums then due and payable thereon have been paid.

(n) Commodity Hedging Agreement. One or more Commodity Hedging Agreements, duly executed and delivered by the parties thereto and in form and substance acceptable to the Administrative Agent which shall comply with the requirements of Section 9.03(i) hereof (together with a schedule prepared by the Company indicating the volume of hydrocarbons subject to such Commodity Hedging Agreements by calendar quarter.

(o) Release of Charges. Evidence satisfactory to the Administrative Agent and the Banks of the release and discharge of security granted to the Bank of Nova Scotia and the National Bank of Canada (or an undertaking to do so), including, without limitation, Personal Property Security Act registrations.

(p) CT Corporation. Evidence satisfactory to the Administrative Agent and the Banks that CT Corporation shall have accepted agency for service of process pursuant to Section 12.15 hereof.

(q) Other Documents. Such other documents as the Administrative Agent, any Bank, the Issuing Bank or special New York counsel to WestLB may reasonably request.

The effectiveness of this Agreement is also subject to (i) the simultaneous closing of the purchase by the Company of the Anadarko Canada Corporation's Hayter and West Provost Areas (as described in the Agreement of Purchase and Sale dated August 1, 2002 between the Company and Anadarko Canada Corporation), provided that no conditions precedent under such agreement shall have been waived and the purchase price thereunder shall not have been increased since August 1, 2002 other than pursuant to adjustments specified in such agreement and (ii) concurrently with the initial borrowing hereunder, the payment by the Company of such fees as the Company shall have agreed to pay or deliver to any Bank or the Administrative Agent in connection herewith, including, without limitation, the reasonable fees and expenses of Latham & Watkins, special New York counsel to WestLB, and Macleod Dixon LLP, special Canadian counsel to WestLB, in connection with the negotiation, preparation, execution and delivery of this Agreement and the Notes and the other Loan Documents and the extensions of credit hereunder.

7.02 Effectiveness and Subsequent Extensions of Credit.

The effectiveness of this Agreement and the obligation of the Banks to make any Loans or otherwise extend credit to the Company upon the occasion of each borrowing or other extension of credit hereunder is subject to the further conditions precedent that, both immediately prior to the making of such Loans or other extension of credit and also after giving effect thereto and to the intended use thereof: (i) no Default shall have occurred and be continuing; (ii) the representations and warranties made by each Obligor in Section 8 hereof and in each of the other Loan Documents to which it is a party, shall be true and complete on and as of the date of the making of such Loans or other extension of credit with the same force and effect as if made on and as of such date (or, if any such representation or warranty is expressly stated to have been made as of a specific date, as of such specific date); (iii) no event or events with respect to the Company or any of its Subsidiaries shall have occurred which alone or in the aggregate could have a Material Adverse Effect; (iv) the Equivalent Amount in U.S. Dollars of the aggregate Principal Amount of Loans, Bankers' Acceptance Liabilities and Letter of Credit Liabilities shall not exceed the Borrowing Base as determined pursuant to Sections 1.03 and 2.10 hereof. Each Notice of Borrowing or request for the issuance of a Letter of Credit or Bankers' Acceptances by the Company hereunder shall constitute a certification by the Company and each other Obligor to the effect set forth in the preceding sentences (both as of the date of such notice or request and, unless the Company otherwise notifies the Administrative Agent prior to the date of such borrowing or issuance, as of the date of such borrowing or issuance).

SECTION 8.
REPRESENTATIONS AND WARRANTIES.

Each Obligor represents and warrants to the Banks, the Issuing Bank and the Administrative Agent that:

8.01 Corporate Existence. The Company and each other Obligor: (a) is a corporation, partnership or other entity duly incorporated or formed, validly existing and in good standing under the laws of the jurisdiction of its organization or formation; (b) has all requisite corporate, partnership or other applicable entity power, and has all material governmental licenses, authorizations, consents and approvals necessary to own its assets and carry on its business as now being or as proposed to be conducted; and (c) is qualified to do business and is in good standing in all jurisdictions in which the nature of the business conducted by it makes such qualification necessary and where failure so to qualify could reasonably be expected to have a Material Adverse Effect.

8.02 Financial Condition. The Company has heretofore furnished to each of the Banks the Unaudited Pro-Forma Consolidated financial statements of the Trust and its Consolidated Subsidiaries as at July 10, 2002 and for the six months ended June 30, 2002. All such financial statements fairly present the pro-forma consolidated financial condition of the Trust and its Consolidated Subsidiaries as at said date in accordance with GAAP. Neither the Trust nor any of its Subsidiaries has on the date hereof any material contingent liabilities, liabilities for taxes, unusual forward or long-term commitments or unrealized or anticipated losses from any unfavorable commitments, except as referred to or reflected or provided for in its financial statements most recently delivered (including the notes thereto). Since June 30, 2002 there has been no material adverse change in the consolidated financial condition, operations, business or prospects taken as a whole of the Trust and its Consolidated Subsidiaries from that set forth in said financial statements as at said date.

8.03 Litigation. Except as disclosed to the Banks in writing prior to the date of this Agreement (or, prior to the date of any subsequent affirmation or repetition of this representation and warranty, as applicable) , there are no legal or arbitral proceedings, or any proceedings by or before any Governmental Authority, now pending or (to the knowledge of the Company or any of its Subsidiaries) threatened against the Company or any of its Subsidiaries which, if adversely determined could reasonably be expected to have a Material Adverse Effect.

8.04 No Breach. None of the execution and delivery of this Agreement and the Notes and the other Loan Documents to which such Obligor is a party, the consummation of the transactions herein and therein contemplated or compliance with the terms and provisions hereof and thereof will conflict with or result in a breach of, or require any consent under, the charter or by-laws or other constitutive document of such Obligor, or any applicable law or regulation, or any order, writ, injunction or decree of any Governmental Authority, or any agreement or instrument to which the Company or any of its Restricted Subsidiaries is a party or by which any of them or any of their Property is bound or to which any of them is subject, or constitute a default under any such agreement or instrument, or (except for Liens created pursuant to the Security Documents and the other Loan Documents) result in the creation or imposition of any Lien upon any Property of the Company or any of its Restricted Subsidiaries pursuant to the terms of any such agreement or instrument, except for any such breach of applicable law, regulation, order, injunction or decree of any Governmental Authority or default under such agreement or instrument that would not have a Material Adverse Effect.

8.05 Action. Each Obligor has all necessary corporate, partnership or other applicable entity power, capacity, authority and legal right to execute, deliver and perform its obligations under each of the Loan Documents to which it is or is intended to be a party; the execution, delivery and performance by each Obligor of each of the Loan Documents to which it is or is intended to be a party have been duly authorized by all necessary corporate, partnership or other applicable entity action on its part (including, without limitation, any required shareholder approvals); and this Agreement has been duly and validly executed and delivered by each Obligor and constitutes, and each of the Notes and the other Loan Documents to which it is a party when executed and delivered by such Obligor (in the case of the Notes, for value) will constitute, its legal, valid and binding obligation, enforceable against such Obligor in accordance with its terms, except as such enforceability may be limited by (a) bankruptcy, insolvency, reorganization, moratorium or similar laws of general applicability affecting the enforcement of creditors' rights and (b) the application of general principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at law).

8.06 Approvals. No authorizations, approvals or consents of, and no filings or registrations with, any Governmental Authority, or any securities exchange, are necessary for the execution, delivery or performance by any Obligor of the Loan Documents to which it is a party or for the legality, validity or enforceability hereof or thereof, except for filings and recordings in respect of the Liens created pursuant to the Security Documents.

8.07 Use of Credit. Neither the Company nor any of its Subsidiaries is engaged principally, or as one of its important activities, in the business of extending credit for the purpose, whether immediate, incidental or ultimate, of buying or carrying Margin Stock, and no part of the proceeds of any extension of credit hereunder will be used to buy or carry any Margin Stock.

8.08 Taxes. As and when required by applicable law, the Company and its Subsidiaries have filed either directly or indirectly through the Company all Canadian federal income tax returns, as applicable, required to be filed pursuant to the Income Tax Act (Canada) and all other material tax returns that are required to be filed by them in any Canadian or foreign jurisdiction and have paid either directly or indirectly through the Company all taxes due pursuant to such returns or pursuant to any assessment received by the Company or any of its Subsidiaries. The charges, accruals and reserves on the books of the Company and its Subsidiaries in respect of taxes and other governmental charges are, in the opinion of such Obligor, adequate. No Obligor has given or been requested to give a waiver of the statute of limitations relating to the payment of federal, provincial, local and foreign taxes or other impositions.

8.09 Compliance with Laws and Agreements. Each of the Company and its Subsidiaries is in compliance with all laws, regulations and orders of any Governmental Authority applicable to it or its Property and all indentures, agreements and other instruments binding upon it or its Property, except where the failure to do so, individually or in the aggregate, could not reasonably be expected to result in a Material Adverse Effect. No Default has occurred and is continuing.

8.10 Environmental Matters. (a) Each of the Company and its Restricted Subsidiaries has obtained all environmental, health and safety permits, licenses and other authorizations required under all Environmental Laws to carry on its business as now being or as proposed to be conducted, except to the extent failure to have any such permit, license or authorization would not have a Material Adverse Effect. Each of such permits, licenses and authorizations is in full force and effect and each of the Company and its Restricted Subsidiaries is in compliance with the terms and conditions thereof, and is also in compliance with all other limitations, restrictions, conditions, standards, prohibitions, requirements, obligations, schedules and timetables contained in any applicable Environmental Law or in any regulation, code, plan, order, decree, judgment, injunction, notice or demand letter issued, entered, promulgated or approved thereunder, except to the extent failure to comply therewith would not have a Material Adverse Effect.

(b) No notice, notification, demand, request for information, citation, summons or order has been issued, no complaint has been filed, no penalty has been assessed and no investigation or review is pending or threatened by any governmental or other entity with respect to any alleged failure by the Company or any of its Restricted Subsidiaries to have any environmental, health or safety permit, license or other authorization required under any Environmental Law in connection with the conduct of the business of the Company or any of its Restricted Subsidiaries or with respect to any generation, treatment, storage, recycling, transportation, discharge or disposal, or any Release of any Hazardous Materials generated by the Company or any of its Restricted Subsidiaries and which in any case could reasonably be expected to have a Material Adverse Effect.

(c) Except as set forth on Schedule IV (or, after the date hereof, as disclosed to the Administrative Agent in writing), neither the Company nor any of its Subsidiaries owns, operates or leases a treatment, storage or disposal facility requiring a permit under any Canadian federal, provincial or local statute; and

(i) to the knowledge of the Company after due inquiry in accordance with standard hydrocarbon industry practice, no polychlorinated biphenyls (PCB's) are or have been present at any site or facility now or previously owned, operated or leased by the Company or any of its Subsidiaries;

(ii) to the knowledge of the Company after due inquiry in accordance with standard hydrocarbon industry practice, no asbestos or asbestos-containing materials is or has been present at any site or facility now or previously owned, operated or leased by the Company or any of its Subsidiaries;

(iii) to the knowledge of the Company after due inquiry in accordance with standard hydrocarbon industry practice, there are no underground storage tanks or surface impoundments for Hazardous Materials, active or abandoned, at any site or facility now or previously owned, operated or leased by the Company or any of its Subsidiaries which could reasonably be expected to have a Material Adverse Effect (provided that all such tanks or impoundments which could not reasonably be expected to have a Material Adverse Effect have been set forth on Schedule IV or, if acquired after the date hereof, have been disclosed to the Administrative Agent in writing);

(iv) to the knowledge of the Company after due inquiry in accordance with standard hydrocarbon industry practice, no Hazardous Materials have been Released at, on or under any site or facility now or previously owned, operated or leased by the Company or any of its Subsidiaries in a reportable quantity established by statute, ordinance, rule, regulation or order which could reasonably be expected to have a Material Adverse Effect (provided that all such Releases which could not reasonably be expected to have a Material Adverse Effect have been set forth on Schedule IV or, if such Release occurs after the date hereof, have been disclosed to the Administrative Agent in writing); and

(v) to the knowledge of the Company after due inquiry in accordance with standard hydrocarbon industry practice, no Hazardous Materials have been otherwise Released at, on or under any site or facility now or previously owned, operated or leased by the Company or any of its Subsidiaries that would have a Material Adverse Effect.

(d) No oral or written notification of a Release of a Hazardous Material has been filed by or on behalf of the Company or any of its Restricted Subsidiaries and no site or facility now or, to the knowledge of the Company, previously owned, operated or leased by the Company or any of its Restricted Subsidiaries is listed or proposed by any Governmental Authority as a site requiring investigation or clean-up and which in any case could reasonably be expected to have a Material Adverse Effect.

(e) As of the date hereof, no Liens have arisen and remain outstanding under or pursuant to any Environmental Laws on any site or facility owned, operated or leased by the Company or any of its Restricted Subsidiaries, and no government action has been taken or is in process that could subject any such site or facility to Liens under or pursuant to any Environmental Laws and neither the Company nor any of its Restricted Subsidiaries would be required to place any notice or restriction relating to the presence of Hazardous Materials at any site or facility owned by it in any deed to the real property on which such site or facility is located. Upon each subsequent affirmation or repetition of this representation and warranty, no Liens have arisen and remain outstanding under or pursuant to any Environmental Laws on any site or facility owned, operated or leased by the Company or any of its Restricted Subsidiaries that could reasonably be expected to result in a Material Adverse Effect, and no government action has been taken or is in process that could subject any such site or facility to Liens under or pursuant to any Environmental Laws which could reasonably be expected to result in a Material Adverse Effect and neither the Company nor any of its Restricted Subsidiaries would be required to place any notice or restriction relating to the presence of Hazardous Materials at any site or facility owned by it in any deed to the real property on which such site or facility is located.

(f) There have been no environmental investigations, studies, audits, tests, reviews or other analyses conducted by or that are in the possession of the Company or any of its Subsidiaries in relation to any site or facility now or previously owned, operated or leased by the Company or any of its Restricted Subsidiaries which have not been made available to the Banks.

8.11 Subsidiaries, Etc. (a) Set forth in Part A of Schedule II hereto is a complete and correct list, as of the date of this Agreement, of all of the Subsidiaries of the Company, together with, for each such Subsidiary, (i) the jurisdiction of organization of such Subsidiary, (ii) each Person holding ownership interests in such Subsidiary, (iii) the nature of the ownership interests held by each such Person and the percentage of ownership of such Subsidiary represented by such ownership interests and (iv) indicating whether each such Subsidiary is a Restricted Subsidiary or an Unrestricted Subsidiary. Except as disclosed in Part A of Schedule II hereto, (x) each of the Company and its Subsidiaries owns, free and clear of Liens (other than Liens created pursuant to the Security Documents), and has the unencumbered right to vote, all outstanding ownership interests in each Person shown to be held by it in Part A of Schedule II hereto, (y) all of the issued and outstanding capital stock of each such Person organized as a corporation is validly issued, fully paid and nonassessable and (z) there are no outstanding Equity Rights with respect to such Person.

(b) Set forth in Part B of Schedule II hereto is a complete and correct list, as of the date of this Agreement, of all Investments (other than Investments disclosed in Part A of said Schedule II hereto, other than Permitted Investments and Investments having a value less than U.S.$25,000 held by the Company or any of its Subsidiaries in any Person and, for each such Investment, (x) the identity of the Person or Persons holding such Investment and (y) the nature of such Investment. Except as disclosed in Part B of Schedule II hereto, each of the Company and its Subsidiaries owns, free and clear of all Liens (other than Liens created pursuant to the Security Documents, Liens arising by operation of law, Liens indicated in any title opinions delivered by the Company pursuant to Section 7.01(h) and Liens permitted pursuant to Section 9.06(b) and (j) (and Section 9.06(o), (p) and (q) if created after the date hereof)), all such Investments.

(c) None of the Restricted Subsidiaries of the Company is, on the date hereof, subject to any indenture, agreement, instrument or other arrangement of the type described in the last sentence of Section 9.15 hereof.

8.12 True and Complete Disclosure. The information, reports, financial statements, exhibits and schedules furnished in writing to the Administrative Agent, the Issuing Bank or any Bank in connection with the negotiation, preparation or delivery of this Agreement and the other Loan Documents or included herein or therein or delivered pursuant hereto or thereto and prepared by or on behalf of the Obligors (or, when prepared by any other Person, to the knowledge of the Company) when taken as a whole do not contain any untrue statement of material fact or omit to state any material fact necessary to make the statements herein or therein, in light of the circumstances under which they were made, not misleading. All written information furnished after the date hereof by the Obligors to the Administrative Agent, the Issuing Bank or the Banks in connection with this Agreement and the other Loan Documents and the transactions contemplated hereby and thereby when prepared by or on behalf of the Obligors will be, (or, when prepared by any other person to the knowledge of the Company will be) true, complete and accurate in every material respect, or (in the case of projections) based on reasonable estimates, on the date as of which such information is stated or certified. There is no fact known to any Obligor that could reasonably be expected to have a Material Adverse Effect that has not been disclosed herein, in the other Loan Documents or in a report, financial statement, exhibit, schedule, disclosure letter or other writing furnished to the Banks for use in connection with the transactions contemplated hereby or thereby.

8.13 Title to Properties. The Company and each of its Restricted Subsidiaries has good and indefeasible title to the Properties shown to be owned by it on its most recent financial statements, free and clear of all Liens (other than Permitted Liens).

8.14 Capitalization. Schedule III sets forth the authorized capital stock of the Company and each Subsidiary and the amount of such capital stock issued and outstanding.

8.15 Insurance. The Company and its Subsidiaries maintain insurance with financially sound and reputable third party insurers of a character usually maintained by Persons engaged in the same or similar businesses, against loss, damage and liability of the kinds and in the amounts customarily maintained by such Persons. All such insurance is in full force and effect and all premiums due and payable on such insurance has been paid.

SECTION 9.
COVENANTS OF THE OBLIGORS.

Each Obligor covenants and agrees with the Banks, the Issuing Bank and the Administrative Agent that, so long as any Commitment, Loan, Bankers' Acceptance or Letter of Credit Liability is outstanding and until payment in full of all amounts payable by the Company hereunder:

9.01 Financial Statements, Etc. The Company shall (for itself and on behalf of each of the other Obligors) deliver to the Administrative Agent (with sufficient copies for each Bank) and, in the case of clause (f) only, to the Trustee:

(a) within 30 days after the Effective Date, a balance sheet of the Company dated as of the end of the most recent calendar month preceding the Effective Date, accompanied by a certificate of a senior financial officer of the Company, which certificate shall state that the balance sheet has been prepared in accordance with GAAP (subject to normal year-end audit adjustments);

(b) as soon as available and in any event within 60 days after the end of each quarterly fiscal period of each fiscal year of the Trust, consolidated and consolidating statements of income, retained earnings and cash flow of the Trust and its Consolidated Subsidiaries for such period and for the period from the beginning of the respective fiscal year to the end of such period, and the related consolidated and consolidating balance sheets of the Trust and its Consolidated Subsidiaries as at the end of such period, setting forth in each case in comparative form the corresponding consolidated and consolidating figures for the corresponding period in the preceding fiscal year, accompanied by (i) a certificate of a senior financial officer of the Company, which certificate shall state that said consolidated financial statements fairly present the consolidated financial condition and results of operations of the Trust and its Consolidated Subsidiaries, and said consolidating financial statements reconcile to the consolidated financial statements of the Trust and its Consolidated Subsidiaries, and that such consolidated financial statements have been prepared in accordance with GAAP, as at the end of, and for, such period (subject to normal year-end audit adjustments), (ii) the Trust's quarterly report for such period and (iii) a certificate of a senior officer of the Company setting forth the valuation of Indebtedness included in clause (c) of the definition of Indebtedness;

(c) as soon as available and in any event within 140 days after the end of each fiscal year of the Trust, consolidated and consolidating statements of income, retained earnings and cash flow of the Trust and its Consolidated Subsidiaries for such fiscal year and the related consolidated and, consolidating balance sheets of the Trust and its Consolidated Subsidiaries as at the end of such fiscal year, setting forth in each case in comparative form the corresponding consolidated and consolidating figures for the preceding fiscal year, and accompanied (i) in the case of said consolidated statements and balance sheet of the Trust, by an opinion thereon of independent certified public accountants of recognized national standing, which opinion shall state that said consolidated financial statements fairly present the consolidated financial position and results of operations of the Trust and its Consolidated Subsidiaries as at the end of, and for, such fiscal year in accordance with generally accepted accounting principles, (ii) in the case of said consolidating statements and balance sheet, by a certificate of a senior financial officer of the Trust, which certificate shall state that said consolidating financial statements reconcile to the consolidated financial statements of the Trust and its Consolidated Subsidiaries, and that such consolidated financial statements have been prepared in accordance with GAAP, as at the end of, and for, such fiscal year and (iii) in each case, the annual report of the Trust;

(d) following a public offering of equity securities by the Trust, copies of all financial statements, reports and proxy statements mailed to the shareholders of such entity promptly upon the mailing thereof;

(e) on or before each Report Delivery Date, the applicable Reserve Evaluation Report;

(f) promptly after the Company or any of its Restricted Subsidiaries knows or has reason to believe that any Default has occurred, a notice of such Default describing the same in reasonable detail and, together with such notice or as soon thereafter as possible, a description of the action that the Company or any of its Restricted Subsidiaries has taken or proposes to take with respect thereto;

(g) within 30 days after the end of each fiscal quarter of the Company, a report detailing production of hydrocarbons by the Company and its Restricted Subsidiaries during such quarter, and containing such information as the Administrative Agent may reasonably request; and

(h) from time to time such other information regarding the financial condition, operations, business, prospects or Properties of the Company or any of its Subsidiaries as any Bank or the Administrative Agent may reasonably request.

The Company will furnish to the Administrative Agent (with sufficient copies for each Bank), at the time it furnishes each set of financial statements pursuant to paragraph (b) or (c) above, a certificate of a senior financial officer of the Company (i) to the effect that no Default has occurred and is continuing (or, if any Default has occurred and is continuing, describing the same in reasonable detail and describing the action that the Company has taken or proposes to take with respect thereto), (ii) setting forth in reasonable detail the computations necessary to determine whether the Company is in compliance with Sections 9.07(a)(xi), 9.08(g), 9.09, 9.10, 9.11 and 9.16 hereof as of the end of the respective quarterly fiscal period or fiscal year, which computations in respect of Sections 9.09, 9.10, 9.11 and 9.16 shall be in accordance with GAAP and (iii) setting forth the volume of hydrocarbons subject to Commodity Hedging Agreements by calendar quarter.

9.02 Litigation. The Company will promptly give to the Administrative Agent notice of all legal or arbitral proceedings, and of all proceedings by or before any Governmental Agency, and any material development in respect of such legal or other proceedings, affecting the Company or any of its Subsidiaries, except proceedings which, if adversely determined, would not have a Material Adverse Effect. Without limiting the generality of the foregoing, the Company will give to the Administrative Agent notice of the assertion of any Environmental Claim by any Person against, or with respect to the activities of, the Company or any of its Subsidiaries and notice of any alleged violation of or non-compliance with any Environmental Laws or any permits, licenses or authorizations, other than any Environmental Claim or alleged violation which, if adversely determined, would not have a Material Adverse Effect.

9.03 Existence, Etc. The Company will, and will cause each of its Restricted Subsidiaries to:

(a) preserve and maintain its legal existence and all of its material rights, privileges, licenses and franchises (provided that nothing in this Section 9.03 shall prohibit any transaction expressly permitted under Section 9.05 hereof);

(b) comply with the requirements of all applicable laws, rules, regulations and orders of Governmental Authorities (including Environmental Laws) if failure to comply with such requirements could reasonably be expected to have a Material Adverse Effect;

(c) pay and discharge all Taxes imposed on it or on its income or profits or on any of its Property prior to the date on which penalties attach thereto, except for any such Tax the payment of which is being contested in good faith and by proper proceedings and against which adequate reserves are being maintained in accordance with GAAP;

(d) pay and discharge all trade debt and royalties when due and payable;

(e) maintain or cause the maintenance all of its Properties used or useful in its business in good working order and condition and in compliance with applicable laws and insurance requirements (ordinary wear and tear excepted) and maintain and operate (or to the extent that the Company or one of its Restricted Subsidiaries is not the operator of any Hydrocarbon Properties, use its reasonable commercial efforts to cause the operator thereof to do so) its Hydrocarbon Properties in accordance with prudent industry standards;

(f) keep adequate records and books of account, in which complete entries will be made in accordance with GAAP;

(g) permit representatives of any Bank or the Administrative Agent, during normal business hours, to examine, copy and make extracts from its books and records, to inspect any of its Properties, and to discuss its business and affairs with its officers, all to the extent reasonably requested by such Bank or the Administrative Agent (as the case may be). If any such inspection is to be conducted at the site of any operational assets of an Obligor, such inspection shall be conducted at the sole risk and, prior to the occurrence and continuance of a Default, cost of the inspecting Persons and must be conducted subject to the reasonable safety policies and procedures of the Obligor, if it is the operator thereof, or of any third party operator;

(h) promptly obtain from time to time at its own expense and at all times maintain in full force and effect without any material modification or amendment, all such governmental licenses, authorizations, registrations, consents, permits and approvals as may be required for the Company or its Restricted Subsidiaries to (a) comply with its obligations, and preserve its rights under, each of the Loan Documents and (b) maintain the existence, priority and perfection of the Liens purported to be created under the Security Documents; and

(i) at all times prior to the Commitment Termination Date, maintain Commodity Hedging Agreements in effect from time to time with counterparties acceptable to the Administrative Agent with respect to not less than 66 2/3% of its anticipated production of oil and gas for a period of 18 months from the Effective Date.

9.04 Insurance. The Company will, and will cause each of its Restricted Subsidiaries (including without limitation the Subsidiary Guarantors) to, keep insured by financially sound and reputable insurers all Property of a character usually insured by Persons engaged in the same or similar businesses similarly situated against loss or damage of the kinds and in the amounts customarily insured against by such corporations and carry such other insurance as is usually carried by such Persons or as is required by law.

9.05 Prohibition of Fundamental Changes; Disposition of Assets. The Company will not, nor will it permit any of its Restricted Subsidiaries to, enter into any transaction of merger or consolidation or amalgamation, or liquidate, wind up or dissolve itself (or suffer any liquidation or dissolution). The Company will not, nor will it permit any of its Restricted Subsidiaries to, acquire any business or Property (other than Hydrocarbon Properties and related assets) from, or Capital Stock (other than the Capital Stock of Persons engaged in the acquisition and exploitation of, or the exploration for or development or production of, hydrocarbon reserves and activities reasonably related thereto) of, or be a party to any acquisition of, any Person except for purchases of inventory and other Property to be sold or used in the ordinary course of business and Investments permitted under Section 9.08 hereof. The Company will not, and will not permit any of its Restricted Subsidiaries to, convey, sell, lease, transfer or otherwise dispose of, in one transaction or a series of transactions, any part of its business or Property (including by way of disposition of the Capital Stock of a Restricted Subsidiary), whether now owned or hereafter acquired including, without limitation, receivables and leasehold interests, but excluding (i) obsolete or worn-out Property, tools or equipment no longer used or useful in its business so long as the amount thereof sold in any single fiscal year by the Company and its Restricted Subsidiaries shall not have an aggregate fair market value in excess of U.S.$2,000,000 (or its equivalent in other currencies), (ii) any hydrocarbons produced or sold in the ordinary course of business and on ordinary business terms (which shall include all hydrocarbons sold pursuant to the Anadarko Crude Contract) excluding any sale or lease of interests in hydrocarbons in the ground, (iii) on and after the date hereof, any other Properties of the Company and its Restricted Subsidiaries (other than Unrestricted Properties), including any such disposition by way of disposition of the Capital Stock of any Restricted Subsidiary provided that the aggregate fair market value of such other Properties (including such Capital Stock) conveyed, sold, leased, transferred or otherwise disposed of on or after the date hereof shall not exceed U.S.$1,000,000 (or its equivalent in other currencies) during any Determination Period, provided further that such conveyance, sale, lease, transfer or other disposition shall not include any accounts receivable or inventory of the Company or any of its Restricted Subsidiaries other than such accounts, receivable or inventory, (x) incidental to the sale of Hydrocarbon Properties and (y) created or produced from such Hydrocarbon Properties on or after the effective date of any such conveyance, sale, lease, transfer or other disposition of such Hydrocarbon Properties, (iv) the expiration of leases covering Hydrocarbon Properties, (v) Unrestricted Properties, (vi) sales or dispositions of Hydrocarbon Properties (and related tangibles) resulting from any pooling or unitization entered into in the ordinary course of business when, in the reasonable judgment of the Company, it is necessary to do so in order to facilitate the orderly exploration, development or operation of such Hydrocarbon Properties, (vii) Dispositions of any business or Property from one Obligor to another, (viii) Dispositions permitted by Section 9.06, and (ix) the sale of the Capital Stock of Unrestricted Subsidiaries. Notwithstanding the foregoing provisions of this Section 9.05:

(a) any Restricted Subsidiary of the Company may be merged or consolidated with or into: (i) the Company if the Company shall be the continuing or surviving corporation or (ii) any other such Restricted Subsidiary; provided that if any such transaction shall be between a Subsidiary Guarantor and a Restricted Subsidiary not a Subsidiary Guarantor, and such Subsidiary Guarantor is not the continuing or surviving corporation, then the continuing or surviving corporation shall have assumed all of the obligations of such Subsidiary Guarantor hereunder;

(b) any Restricted Subsidiary of the Company may sell, lease, transfer or otherwise dispose of any or all of its Property (upon voluntary liquidation or otherwise) to the Company or a Wholly Owned Subsidiary of the Company which is a Restricted Subsidiary; provided that if any such sale is by a Subsidiary Guarantor to a Restricted Subsidiary of the Company not a Subsidiary Guarantor, then such Restricted Subsidiary shall have assumed all of the obligations of such Subsidiary Guarantor hereunder; and

(c) the Company or any Restricted Subsidiary of the Company may merge or consolidate with any other Person if (i) in the case of a merger or consolidation of the Company, the Company is the surviving corporation and, in any other case, the surviving corporation is a Wholly Owned Subsidiary of the Company which is a Restricted Subsidiary and (ii) after giving effect thereto no Default would exist hereunder.

9.06 Limitation on Liens. The Company will not, nor will it permit any of its Restricted Subsidiaries to, create, incur, assume or suffer to exist any Lien upon any of their Property, whether now owned or hereafter acquired, except:

(a) Liens created pursuant to the Security Documents;

(b) Liens in existence on the date hereof and listed on Schedule I hereto;

(c) Liens imposed by any Governmental Authority for taxes, assessments, charges or levies not yet due or which are being contested in good faith and by appropriate proceedings if, unless the amount thereof is not material with respect to it or its financial condition, adequate reserves with respect thereto are maintained on the books of the Company or the affected Subsidiaries, as the case may be, in accordance with GAAP;

(d) Liens, privileges or charges imposed by law, such as statutory liens and deemed trusts, workers' compensation, unemployment insurance, pension and employment law carriers', warehousemen's, mechanics', materialmen's, repairmen's or other like Liens arising in the ordinary course of business which are not overdue for a period of more than 45 days or which are being contested in good faith and by appropriate proceedings and Liens securing judgments (but only to the extent, for an amount and for a period not resulting in an Event of Default under Section 10(h) hereof);

(e) pledges or deposits under worker's compensation, unemployment insurance and other social security or similar legislation;

(f) (i) deposits to secure the performance of bids, trade contracts (other than for borrowed money), leases, statutory obligations, surety, stay, appeal and indemnity bonds, performance bonds and other obligations of a like nature incurred in the ordinary course of business and (ii) deposits to secure letters of credit permitted pursuant to Section 9.07(a)(v);

(g) easements, rights-of-way, restrictions and other similar encumbrances incurred in the ordinary course of business and encumbrances consisting of zoning restrictions, easements, licenses, restrictions on the use of Property, or minor imperfections in title thereto which, in the aggregate, are not material in amount, and which do not in any case materially detract from the value of the Property subject thereto or interfere with the ordinary conduct of the business of the Company or any of its Restricted Subsidiaries;

(h) Liens (provided that with respect to the Obligors such Liens consist only of floating charges on real property and security interests in personal property) on Property of any corporation or other entity which becomes a Restricted Subsidiary of the Company after the date of this Agreement, provided that such Liens are in existence at the time such corporation becomes a Restricted Subsidiary of the Company and were not created in anticipation or contemplation thereof;

(i) Liens upon real and/or tangible personal Property acquired after the date hereof (by purchase, construction or otherwise) by the Company or any of its Restricted Subsidiaries, each of which Liens existed on such Property before the time of its acquisition and was not created in anticipation or contemplation thereof, and provided that such Lien will not spread to cover any other Property of the Company or any such Restricted Subsidiary;

(j) Liens created pursuant to any Hedging Agreement, provided that the aggregate value of the obligation secured by all such Liens shall not exceed the value of the obligations pursuant to Hedging Agreements entered into prior to the date hereof (and replacements thereof required pursuant to Section 9.03(i)) plus U.S.$2,500,000 (or the equivalent amount in other currencies) in the aggregate at any one time outstanding and no such Liens shall extend to any Hydrocarbon Properties;

(k) undetermined or inchoate Liens arising in the ordinary course of and incidental to construction, maintenance or current operations of any Obligor which relate to obligations which are not overdue or which are being contested in good faith and by appropriate proceedings and for which appropriate reserves have been established in accordance with GAAP;

(l) Liens incurred or created in the ordinary course of business and in accordance with sound industry practice in respect of the exploration, development or operation of Hydrocarbon Properties, or related production or processing facilities in which such Person has an interest, or for the transmission of hydrocarbons as security in favor of any other Person conducting the exploration, development, operation or transmission of the Property to which such Liens relate, for the applicable Obligor's portion of the costs and expenses of such exploration, development, operation or transmission, provided that such Liens are not overdue or are being contested in good faith and by appropriate proceedings and for which appropriate reserves have been established in accordance with GAAP;

(m) the Lien or any right of distress reserved in or exercisable under any real property lease for rent or otherwise to effect compliance with the terms of such lease in respect of which the rent or other obligations is not at the time overdue or which is being contested in good faith and by appropriate proceedings and for which appropriate reserves have been established in accordance with GAAP;

(n) overriding royalty interests, net profit interests, reversionary interests and carried interests in respect of Hydrocarbon Properties of any Obligor that are in existence at the time any such Hydrocarbon Properties are acquired by such Obligor or come into existence within six months following the date of the acquisition of such Hydrocarbon Properties;

(o) farmout interests entered into in the ordinary course of business on standard industry terms, provided that the value of such interest in the aggregate with all other farmout interests following the date hereof as set forth in the most recent Reserve

Evaluation Report prior to the granting of such farmout interests shall not exceed U.S.$2,500,000 (or its equivalent in other currencies);

(p) Liens for Indebtedness permitted pursuant to Section 9.07(a)(xi)(A) and (B);

(q) Liens on the Property of any Obligor which are not otherwise permitted above if the indebtedness, liabilities or other obligations secured are incurred in the ordinary course of business and in any event the aggregate amount of such indebtedness, liabilities or other obligations so incurred and secured by such Lien against the Property of any Obligor are not, at any time, in the aggregate in excess of U.S.$5,000,000 (or its equivalent in other currencies);

(r) any extension, renewal or replacement of the foregoing, provided that the Liens permitted hereunder shall not be spread to cover any additional Indebtedness or Property (other than a substitution of like Property); and

(s) any right of first refusal or similar agreement with respect to any Properties provided such right is on ordinary business terms and provides for the receipt of value for the Properties subject to such right in an amount not substantially less than the fair market value of such Properties.

9.07 Indebtedness. (a) The Company will not, nor will it permit any of the Restricted Subsidiaries to, create, incur or suffer to exist any Indebtedness except:

(i) Indebtedness to the Administrative Agent, the Issuing Bank and the Banks hereunder or under any Loan Document;

(ii) Subordinated Indebtedness, provided that following the incurrence of any Subordinated Indebtedness payable to any Person other than the Trust, on a pro forma basis (assuming that such Subordinated Indebtedness has been issued at the beginning of the period, if applicable, contemplated by each of the subsections of Section 9.10) the Company shall be in compliance with its obligations pursuant to Section 9.10;

(iii) Indebtedness of Restricted Subsidiaries of the Company to the Company or to other Restricted Subsidiaries of the Company or of the Company to Restricted Subsidiaries that is subordinated to the obligations of the Obligors to the applicable Banks under the Loan Documents;

(iv) Indebtedness incurred under working capital facilities to the extent supported by a Letter of Credit;

(v) unsecured Indebtedness extended by suppliers, or letters of credit opened for the benefit of suppliers, on normal trade terms in connection with purchases of goods and services in the ordinary course of business, provided that the reimbursement obligation under such letters of credit in an amount not in excess of C$7,500,000 (or its Equivalent Amount) minus the face amount of Letters of Credit outstanding hereunder may be secured by a Lien permitted pursuant to Section 9.06(f)(ii);

(vi) Indebtedness in respect of taxes, assessments or governmental charges, and Indebtedness in respect of claims for labor, materials or supplies incurred in the ordinary course of business to the extent that payment thereof shall not be overdue for a period of more than 45 days;

(vii) Indebtedness of the Company to the Trust which has been subordinated to Indebtedness under the Loan Documents and Indebtedness pursuant to the NPI;

(viii) Indebtedness pursuant to Hedging Agreements permitted to be entered into in accordance with the terms hereof;

(ix) Indebtedness of a Restricted Subsidiary in existence at the time such Subsidiary becomes a Restricted Subsidiary, provided that such Indebtedness was not incurred in contemplation of such Subsidiary becoming a Restricted Subsidiary;

(x) Indebtedness of a Restricted Subsidiary to an Unrestricted Subsidiary provided that the obligations of the Restricted Subsidiary to the Unrestricted Subsidiary are subordinated to the obligations of such Restricted Subsidiary to the Banks under the Loan Documents and the Unrestricted Subsidiary provides a security interest in such Indebtedness to the Banks as security for the obligations of such Restricted Subsidiary under the Loan Documents; and

(xi) additional Indebtedness of the Company and its Restricted Subsidiaries in an aggregate amount up to but not exceeding U.S.$4,000,000 (or its equivalent in other currencies) at any one time outstanding, which may include (A) Indebtedness in an aggregate amount up to but not exceeding U.S.$2,000,000 (or its equivalent in other currencies) at any one time outstanding secured by purchase money security interests used for the acquisition of new assets not included in the Borrowing Base and which are not acquired in replacement of assets included in the Borrowing Base and (B) Capital Lease Obligations in an aggregate amount up to but not exceeding U.S.$2,000,000 (or its equivalent in other currencies) at any one time outstanding used for the acquisition of new assets not included in the Borrowing Base and which are not acquired in replacement of assets included in the Borrowing Base.

(b) The Company will not permit any of the Unrestricted Subsidiaries to create, incur or suffer to exist any Indebtedness except Non-Recourse Debt.

9.08 Investments. The Company will not, nor will it permit any of its Restricted Subsidiaries to, make or permit to remain outstanding any Investments except:

(a) Investments outstanding on the date hereof and identified in Schedule II Part B hereto;

(b) operating deposit accounts with banks;

(c) Permitted Investments;

(d) Investments by the Company and its Restricted Subsidiaries in capital stock of Restricted Subsidiaries, in Indebtedness of the Company or any of its Restricted Subsidiaries or in Indebtedness of other Subsidiaries permitted pursuant to Section 6.08 or 9.07(a)(iii) hereof;

(e) Investments in the Capital Stock of any Wholly-Owned Subsidiary of the Company formed or acquired by the Company or any of its other Wholly-Owned Subsidiaries (other than Unrestricted Subsidiaries) after the date hereof (a "New Wholly-Owned Subsidiary"), provided that (i) such New Wholly-Owned Subsidiary is maintained as a separate Subsidiary of the Company (unless the Majority Banks consent to the merger of such New Wholly-Owned Subsidiary into the Company or into another Wholly-Owned Subsidiary of the Company, except that no such consent shall be required to merge such New Wholly-Owned Subsidiary into another Wholly-Owned Subsidiary of the Company established solely for the purpose of facilitating the acquisition of such New Wholly-Owned Subsidiary (which Wholly-Owned Subsidiary, following such merger, shall have no assets other than the assets of such New Wholly-Owned Subsidiary)), (ii) such New Wholly-Owned Subsidiary is engaged principally in the business of the acquisition and exploitation of, exploration for and/or development, production, processing, marketing, gathering and sales of oil, gas or other hydrocarbons, (iii) immediately following the consummation of each such Investment, such New Wholly-Owned Subsidiary shall have no Indebtedness other than Non-Recourse Debt (provided such Indebtedness may have full recourse to the assets of such Wholly-Owned Subsidiary or any Unrestricted Subsidiary) and, if applicable, Indebtedness hereunder and (iv) the Company complies with Section 9.16 hereof with respect to such New Wholly-Owned Subsidiary immediately following the consummation of such Investment by the Company;

(f) Hedging Agreements entered into by the Company and its Restricted Subsidiaries in the ordinary course of business and not for speculation purposes;

(g) loans and advances to employees in the ordinary course of the business of the Obligors as presently conducted in an aggregate principal amount not to exceed U.S.$500,000 (or the equivalent in other currencies) at any time outstanding;

(h) Investments made with the proceeds of net income attributable to any Unrestricted Subsidiary by such Unrestricted Subsidiary or another Unrestricted Subsidiary;

(i) Investments made for the acquisition, exploration or development of undivided interests in Hydrocarbon Properties and tangibles relating thereto; and

(j) to the extent not included in the foregoing clauses (a) through (i), additional Investments up to but not exceeding U.S.$2,000,000 (or the equivalent in other currencies) in the aggregate; provided that any cash dividends received by the Company or any Restricted Subsidiary from an Unrestricted Subsidiary, up to the amount of the Investments in such Unrestricted Subsidiary, shall reduce pro tanto the aggregate amount of the Investments in such Unrestricted Subsidiary for purposes of calculating compliance with such U.S.$2,000,000 limitation.

9.09 Distributions. The Company shall not, and shall not permit any of its Restricted Subsidiaries to make any Distribution except:

(a) with respect to the NPI or Subordinated Indebtedness;

(b) with respect to the Capital Stock of any Restricted Subsidiary, only as permitted by the payment provisions governing such Capital Stock; and

(c) any Distribution by one Restricted Subsidiary to another Restricted Subsidiary.

Notwithstanding the foregoing, no Distribution shall be made at any time when a Default, Event of Default or Borrowing Base Deficiency exists, or would exist or be reasonably expected to exist upon making such Distribution.

9.10 Financial Covenants. (a) The Company will not permit the Interest Coverage Ratio, as of the end of any fiscal quarter of the Company, for the immediately preceding four consecutive fiscal quarters (provided that in the case of the first, second and third fiscal quarters ending after the Closing Date, EBITDA for the one, two or three fiscal quarters then ended, respectively, shall be annualized for the purposes of calculating such ratio), treated for this purpose as a single accounting period, to be less than 2.0:1.0.

(b) The Company will not permit the Indebtedness to EBITDA Ratio, as of the end of any fiscal quarter of the Company, for the immediately preceding four consecutive fiscal quarters (provided that in the case of the first, second and third fiscal quarters ending after the Closing Date, EBITDA for the one, two or three fiscal quarters then ended, respectively, shall be annualized for the purposes of calculating such ratio), treated for this purpose as a single accounting period, to be greater than 4.0:1.0.

(c) The Company will not permit the Fixed Charge Coverage Ratio as of the end of any fiscal quarter of the Company for the immediately preceding four consecutive fiscal quarters (provided that in the case of the first, second and third fiscal quarters ending after the Closing Date, EBITDA for the one, two or three fiscal quarters then ended, respectively, shall be annualized for the purposes of calculating such ratio), treated for this purpose as a single accounting period, to be less than 1.25:1.0.

(d) At all times following the date which is three months after the date hereof, the Company shall have a maximum Indebtedness to Equity Ratio of 3:1.

9.11 Working Capital. The Company will not permit the current assets of the Company and its Restricted Subsidiaries (determined on a consolidated basis in accordance with GAAP) to be equal to or less than the current liabilities of the Company and its Restricted Subsidiaries (so determined). For purposes hereof, the terms "current assets" and "current liabilities" shall have the respective meanings assigned to them by GAAP, provided that in any event there shall be (i) included in current assets the aggregate amount of the unused

Commitments (but only to the extent such unused Commitments could then be utilized as provided in Section 7.02), (ii) excluded from current liabilities all Indebtedness hereunder (iii) excluded from current liabilities all Subordinated Indebtedness to the Trust and all other Indebtedness having a maturity not earlier than the date which is three months following the Commitment Termination Date and (iv) excluded from current liabilities hereunder the current portion of any gas balancing liabilities.

9.12 Lines of Business. The Company will not, nor will it permit any of its Restricted Subsidiaries to, engage to any substantial extent in any line or lines of business activity other than the business of the acquisition, exploration, development, gathering, production (excluding refining, but including for the avoidance of doubt any customary field processing with respect to the Company's or its Restricted Subsidiaries' own production) , processing, marketing or sale of hydrocarbons or products derived from any of the foregoing and transactions reasonably associated therewith.

9.13 Transactions with Affiliates. Except as expressly permitted by this Agreement, the Company will not, and will not permit any Restricted Subsidiaries to, directly or indirectly: (a) make any Investment in an Affiliate; (b) transfer, sell, lease, assign or otherwise dispose of any Property to an Affiliate; (c) merge into or consolidate with or purchase or acquire Property from an Affiliate; or (d) enter into any other transaction directly or indirectly with or for the benefit of an Affiliate (including, without limitation, Guarantees and assumptions of obligations of an Affiliate); provided that (w) the Company may sell a Direct Royalty to the Trust pursuant to a Direct Royalties Sale Agreement, and may make payments to the Trust which are not otherwise in contravention of this Agreement or any other Loan Document, and which are subordinated in accordance with the Subordination Agreement; (x) the Trust may sell the NPI or any part of the NPI to the Company in connection with a disposition of Property by the Company not otherwise in contravention of this Agreement to release such NPI from such disposed Properties; (y) any Affiliate who is an individual may serve as a director, officer or employee of any of the Company and its Subsidiaries and receive reasonable compensation for his or her services in such capacity; and (z) any of the Company and its Restricted Subsidiaries may enter into transactions with Affiliates (other than extensions of credit to Affiliates) in the ordinary course of business if the monetary or business consideration arising therefrom would be substantially as advantageous to the Company and its Restricted Subsidiaries as the monetary or business consideration which would obtain in a comparable transaction with a Person not an Affiliate.

9.14 Use of Proceeds. The Obligors will use the proceeds of the Loans hereunder and will use Letters of Credit and Bankers' Acceptances issued hereunder solely for the acquisition of Anadarko Canada Corporation's Hayter and West Provost Areas (as described in the Agreement of Purchase and Sale, dated August 1, 2002) and for general corporate purposes (in each case, in compliance with all applicable legal and regulatory requirements); provided that none of the Administrative Agent, the Issuing Bank nor any Bank shall have any responsibility as to the use of any of such proceeds.

9.15 Certain Obligations Respecting Subsidiaries. Except as permitted by Section 9.05 hereof, the Company will, and will cause each of its Restricted Subsidiaries to, take such action from time to time as shall be necessary to ensure that the Company and each of its

Restricted Subsidiaries at all times own (subject only to the Lien of the Security Documents) at least the same percentage of the issued and outstanding shares of each class of stock of each of such Restricted Subsidiaries the stock of which is subject to the Lien of the Security Documents as is owned on the date hereof or, in the case of New Wholly-Owned Subsidiaries which are Restricted Subsidiaries created or acquired after the date hereof (other than any Wholly-Owned Subsidiaries of such Persons), the stock of which are required to be subject to the Lien of the Security Documents, 100% of each class of stock of each of such Subsidiaries (each of the Subsidiaries referred to above being herein called, a "Pledged Subsidiary"). Without limiting the generality of the foregoing and except as permitted by Section 9.05, none of the Company and its Restricted Subsidiaries will sell, transfer or otherwise dispose of any shares of stock in any Pledged Subsidiary owned by it, nor permit any Pledged Subsidiary to issue any shares of stock of any class whatsoever to any Person (other than to the Company or another Obligor). In the event that any such additional shares of stock are issued by any Pledged Subsidiary, the respective Obligor agrees forthwith to deliver to the Administrative Agent pursuant to the Security Documents the certificates evidencing such shares of stock, accompanied by undated stock powers executed in blank and shall take such other action as the Administrative Agent shall request to perfect the security interest created therein pursuant to the Security Documents. The Company will not and will not permit any of its Restricted Subsidiaries to enter into any indenture, agreement, instrument or other arrangement (other than this Agreement and the other Loan Documents) that, directly or indirectly, prohibits or restrains, or has the effect of prohibiting or restraining, or imposes (i) conditions upon the incurrence or payment of Indebtedness of the Company and its Restricted Subsidiaries, or the declaration or payment of dividends to the Company or any of its Restricted Subsidiaries or (ii) any other conditions or terms that, in the case of this clause (ii) only, could reasonably be expected to have a Material Adverse Effect.

9.16 Additional Subsidiary Guarantors.

The Company will take such action, and will cause each of its Subsidiaries to take such action, including without limitation the action specified below in this Section 9.16 from time to time as shall be necessary to ensure that each of such Subsidiaries (other than Unrestricted Subsidiaries) with Tangible Net Worth of more than 5% of the Tangible Net Worth of the Company and its Consolidated Subsidiaries determined on a consolidated basis in accordance with GAAP is a Subsidiary Guarantor hereunder and an Obligor hereunder. Each Subsidiary of the Company that is required to become a Subsidiary Guarantor after the date hereof shall execute such instruments and agreements, in form and substance satisfactory to, and as required by the Administrative Agent to acknowledge that such Subsidiary has all of the obligations of a Subsidiary Guarantor pursuant to this Agreement and the Subordination Agreement and to confirm that the Security Documents constitute a Lien on its Properties free of any other encumbrances except those described in Section 9.06.

9.17 Unrestricted Subsidiaries. The Company:

(a) will cause the management, business and affairs of each of the Company and its Subsidiaries to be conducted in such a manner (including, without limitation, by keeping separate books of account, furnishing separate financial statements of Unrestricted Subsidiaries to creditors and potential creditors thereof and by not permitting Properties of the Company and its respective Subsidiaries to be commingled) so that each Unrestricted Subsidiary that is a corporation will be treated as a corporate entity separate and distinct from the Company and the Restricted Subsidiaries;

(b) will not, and will not permit any of the Restricted Subsidiaries to, incur, assume, Guarantee or be or become liable for any Indebtedness or other obligations of any of the Unrestricted Subsidiaries; and

(c) will not permit any Unrestricted Subsidiary to hold any capital stock of or other ownership interest in, or any Indebtedness of, any Restricted Subsidiary.

9.18 Limitations on Sale and Leaseback Transactions. The Company will not, nor will it permit any of its Restricted Subsidiaries to, enter into, renew or extend any transaction or series of related transactions pursuant to which the Company or any such Restricted Subsidiary sells or transfers any Property in connection with the leasing, or the release against installment payments, or as part of an arrangement involving the leasing or resale against installment payments, of such Property to the seller or transferor ("Sale and Leaseback Transaction").

9.19 Environmental Matters.

(a) The Company will and will cause each of its Subsidiaries to comply in all material respects with all Environmental Laws now or hereafter applicable to the Company or its Subsidiaries, and shall obtain, at or prior to the time required by applicable Environmental Laws, all environmental, health and safety permits, licenses and other authorizations necessary for its operations and maintain such authorizations in full force and effect, except to the extent failure to have any such permit, license or authorization could not reasonably be expected to have a Material Adverse Effect.

(b) The Company will and will cause each of its Subsidiaries to promptly furnish to the Administrative Agent all requests for information, notices of claim, demand letters, and other notifications, received by the Company or its Subsidiaries, to the effect that, in connection with its ownership or use of any of its Properties or the conduct of any of its business, it may be potentially responsible in any material amount with respect to any investigation or clean-up of Hazardous Material at any location.

9.20 No Action to Affect Security Documents. Except for transactions expressly permitted hereby, the Company shall not, nor shall it permit its Subsidiaries to, do anything to adversely affect the priority of the Security Documents given or to be given in respect of the obligations of the Company hereunder.

9.21 Further Assurances. Each Obligor shall, after notice thereof from the Administrative Agent, do all such further acts and things and execute and deliver all such further documents as shall be reasonably requested by the Administrative Agent in order to give effect to this Agreement and the Security Documents and shall cause the same to be registered wherever, in the opinion of the Administrative Agent, such registration may be required or advisable to preserve, perfect or validate or continue the perfected status (as required to constitute a Mortgage hereunder) of any deemed or other Lien granted pursuant to a Security

Document or to enable each Bank to exercise and enforce its rights hereunder with respect to such deemed or other Lien.

9.22 Title Defects. The Company shall, promptly upon becoming aware of the existence of any title defect or any encumbrance (other than Permitted Liens) affecting any Hydrocarbon Property which has been given material value in the most recent Reserve Evaluation Report (other than title defects which do not materially and adversely impact the value of such Hydrocarbon Property), give the Administrative Agent prompt written notice of such title defect or encumbrance, and in such case, the Company shall or shall cause the applicable Subsidiary to undertake to take all steps necessary to cure such title defect or discharge such encumbrance; provided that if the Company or the applicable Subsidiary is unable or unwilling to cure such title defect or discharge such encumbrance to the reasonable satisfaction of the Administrative Agent within 60 days following the date on which the Company shall have given the notice referred to in this Section 9.22, then the remedy of the Administrative Agent and the Banks shall be to cause the Borrowing Base to be reduced by an amount equal to the value (or such portion thereof which has been impaired) assigned such Hydrocarbon Property in the most recent Borrowing Base which reductions may lead to the provisions of Section 2.10(a) becoming applicable and actions taken by the Administrative Agent and the Banks in that regard; provided that if the Administrative Agent and the Banks redetermine the Borrowing Base and such title defect or series of defects has caused a reduction in the Borrowing Base that results in a Borrowing Base Deficiency in excess of U.S.$10,000,000, the Banks shall have all the rights set forth in Section 10 hereof.

9.23 Management Contract Prohibition. The Company shall not be or become, and shall not permit any Restricted Subsidiary to be or become, a party to any agreement providing for its directorship or any management functions to be conducted by or delegated to any Person other than the directors, officers or employees of the Company or any Restricted Subsidiary.

9.24 Material Documents. The Company shall not, and shall not permit any Restricted Subsidiary to, amend or agree to any amendment to any of the Material Documents or waive the benefit of any provisions thereof if such amendment or waiver individually or in the aggregate could reasonably be expected to have a Material Adverse Effect (including any amendment or waiver which increases or accelerates the NPI, or which changes the manner of calculation or the payment dates of the NPI); provided that the Company or any Restricted Subsidiary may enter into any such amendment or waiver of Subordinated Indebtedness that does not shorten the maturity of such Subordinated Indebtedness, modify any subordination provision thereof or grant any security interest or collateral interest in respect thereof.

SECTION 10.
EVENTS OF DEFAULT.

If one or more of the following events (herein called "Events of Default") shall occur and be continuing:

(a) The Company shall default in the payment when due (whether at stated maturity or upon mandatory prepayment) of any principal of or interest on any Loan, any

Bankers' Acceptance Liability or Reimbursement Obligation, any fee or any other amount payable by it hereunder or under any other Loan Document or the Fee Letter, and such failure shall continue unremedied for a period of three Business Days (other than any default in a payment due on the Commitment Termination Date, which shall be an immediate Event of Default upon such failure); or

(b) The Company or any of its Restricted Subsidiaries shall default in the payment when due of any principal of or interest on any of its other Indebtedness aggregating U.S.$1,000,000 or more (or the equivalent in any other currency), or in the payment when due of U.S.$500,000 or more (or the equivalent in any other currency) under any Hedging Agreement; or any event specified in any note, agreement, indenture or other document evidencing or relating to any such Indebtedness or any event specified in any such Hedging Agreement shall occur if the effect of such event is to cause, or (with the giving of any notice or the lapse of time or both) to permit the holder or holders of such Indebtedness (or a trustee or agent on behalf of such holder or holders) to cause, such Indebtedness to become due, or to be prepaid in full (whether by redemption, purchase, offer to purchase or otherwise), prior to its stated maturity in an amount aggregating U.S.$1,000,000 or more (or the equivalent in any other currency) or to have the interest rate thereon reset to a level so that securities evidencing such Indebtedness trade at a level specified in relation to the par value thereof; or

(c) Any representation, warranty or certification made or deemed made herein or in any other Loan Document (or in any modification or supplement hereto or thereto) by any Obligor, or any certificate furnished to any Bank, the Issuing Bank or the Administrative Agent pursuant to the provisions hereof or thereof, shall prove to have been false or misleading as of the time made or furnished in any material respect and such representation or warranty, if capable of cure, remains uncured for 30 or more days following any Obligor's knowledge thereof; or

(d) Any Obligor shall default in the performance of any of its obligations under any of Sections 9.05, 9.06, 9.07, 9.08, 9.09, 9.10, 9.11, 9.12, 9.14, 9.15 (other than the delivery of certificates), 9.22 (but only with respect to the proviso in the last sentence thereof), 9.23 or 9.24 hereof; or any Obligor shall default in the performance of any of its other obligations in this Agreement or any other Loan Document and such default shall continue unremedied for a period of 30 days after notice thereof to the Company by the Administrative Agent or any Bank (through the Administrative Agent); or

(e) The Company or any of its Restricted Subsidiaries shall admit in writing its inability to, or be generally unable to, pay its debts as such debts become due; or

(f) Except as permitted by Section 9.05 the Company or any of its Restricted Subsidiaries shall (i) apply for or consent to the appointment of, or the taking of possession by, a receiver, custodian, trustee, examiner or liquidator of itself or of all or a substantial part of its Property, (ii) make a general assignment for the benefit of its creditors, (iii) commence a voluntary case under the Bankruptcy and Insolvency Act (Canada) or any similar bankruptcy or insolvency law, (iv) file a petition or take any other action seeking to take advantage of any other law relating to bankruptcy, insolvency, reorganization relating to the relief of debtors, liquidation, dissolution, arrangement relating to the relief of debtors or winding-up, or composition or readjustment of debts, (v) fail to controvert in a timely and appropriate manner, or acquiesce in writing to, any petition or any other action filed against it in an involuntary case under the Bankruptcy and Insolvency Act (Canada) or any similar bankruptcy or insolvency law in Canada or its jurisdiction of organization or where any material assets are located, (vi) threaten or take any corporate action for the purpose of effecting any of the foregoing or fail to act in defence therefor or (vii) do the equivalent of any of the foregoing under the laws of Canada; or

(g) Except as permitted by Section 9.05, a proceeding or case shall be commenced, without the application or consent of the Company or any of its Restricted Subsidiaries, in any court of competent jurisdiction, seeking (i) its reorganization, liquidation, dissolution or winding-up, or the composition or readjustment of its debts, (ii) the appointment of a receiver, custodian, trustee, examiner, liquidator or the like of the Company or such Restricted Subsidiary or of all or any substantial part of its Property, (iii) similar relief in respect of the Company or such Restricted Subsidiary under any law relating to bankruptcy, insolvency, reorganization, winding-up, or composition or adjustment of debts, and such proceeding or case shall continue undismissed, or an order, judgment or decree approving or ordering any of the foregoing shall be entered and continue unstayed and in effect, for a period of 60 or more days; or an order for relief against the Company or such Restricted Subsidiary shall be entered in an involuntary case under the Bankruptcy and Insolvency Act (Canada) or any similar foreign bankruptcy or insolvency law in Canada or its jurisdiction of organization or where any material assets are located or (iv) the equivalent of any of the foregoing under the laws of Canada; or

(h) A final judgment or judgments for the payment of money in excess of U.S.$1,000,000 in the aggregate (or the equivalent in any other currency) shall be rendered by a one or more courts, administrative tribunals or other bodies having jurisdiction against the Company or any of its Restricted Subsidiaries and the same shall not be discharged (or provision shall not be made for such discharge), or a stay of execution thereof shall not be procured, within 60 days from the date of entry thereof and the Company or the relevant Restricted Subsidiary shall not, within said period of 60 days, or such longer period during which execution of the same shall have been stayed, appeal therefrom and cause the execution thereof to be stayed during such appeal; or

(i) Any Property of any Obligor is seized pursuant to legal process and not bonded, discharged or released within 30 days, and material value has been ascribed to such property in the most recent Reserve Evaluation Report; or

(j) Any Governmental Authority shall take any action to condemn, seize, nationalize or appropriate any portion of the Property of any Obligor (either with or without payment of compensation) used in the exploration or development of properties and the fair market value of such Property constitutes greater than 5% of the then-current Borrowing Base; or

(k) The Liens created by the Security Documents shall at any time not constitute a valid Lien perfected as required hereunder on the collateral intended to be covered thereby (to the extent perfection by filing, registration, recordation or possession is required herein or therein) in favor of the Banks, specified to be benefited by such Security Document, free and clear of all other Liens (other than Permitted Liens), or, except for expiration, termination or satisfaction of the obligations thereunder in accordance with its terms, any of the Security Documents shall for whatever reason be terminated or cease to be in full force and effect, or the enforceability thereof shall be contested by any Obligor and provided such termination, cessation, invalidity or imperfection is not attributable to an action of the Administration Agent; provided that the Obligors shall use all reasonable commercial efforts to cure such termination, cessation, invalidity or imperfection promptly upon being notified thereof by the Administrative Agent; or

(l) Except as permitted by Section 9.05, a Change of Control occurs and the Majority Banks have not consented to the same within 30 days of such Change of Control;

THEREUPON: (1) in the case of an Event of Default other than one referred to in clause (f) or (g) of this Section 10 with respect to any Obligor, the Administrative Agent may and, upon request of the Majority Banks, shall, by notice to the Company, terminate the Commitments and/or declare the Principal Amount then outstanding of, and the accrued interest on, the Loans, the Reimbursement Obligations, the Bankers' Acceptances and all other amounts payable by the Obligors hereunder and under the Notes to be forthwith due and payable, whereupon such amounts shall be immediately due and payable without presentment, demand, protest or other formalities of any kind, all of which are hereby expressly waived by each Obligor; and (2) in the case of the occurrence of an Event of Default referred to in clause (f) or (g) of this Section 10 with respect to any Obligor, the Commitments shall automatically be terminated and the Principal Amount then outstanding of, and the accrued interest on, the Loans, the Reimbursement Obligations, the Bankers' Acceptances and all other amounts payable by the Obligors hereunder and under the Notes shall automatically become immediately due and payable without presentment, demand, protest or other formalities of any kind, all of which are hereby expressly waived by each Obligor.

In addition, upon the occurrence and during the continuance of any Event of Default (if the Administrative Agent has declared the Principal Amount then outstanding of, and accrued interest on, the Loans and all other amounts payable by the Company hereunder and under the Notes to be due and payable), the Obligors agree that they shall, if requested by the Administrative Agent or the Majority Banks through the Administrative Agent (and, in the case of any Event of Default referred to in clause (f) or (g) of this Section 10 with respect to any Obligor, forthwith, without any demand or the taking of any other action by the Administrative Agent or such Banks) provide cover for the Letter of Credit Liabilities, BA Loans and the Bankers' Acceptances by paying to the Administrative Agent in immediately available funds an amount equal to the then aggregate undrawn face amount of all Letters of Credit and the Principal Amount of all BA Loans and Bankers' Acceptances, which funds shall be held by the Administrative Agent, as collateral security in the first instance for the Letter of Credit Liabilities.

SECTION 11.
THE ADMINISTRATIVE AGENT.

11.01 Appointment, Powers and Immunities. Each Bank hereby irrevocably appoints and authorizes the Administrative Agent to act as its agent hereunder and under the other Loan Documents with such powers as are specifically delegated to such Administrative Agent by the terms of this Agreement and of the other Loan Documents, to which such Administrative Agent is a party, together with such other powers as are reasonably incidental thereto. The Administrative Agent (which term as used in this sentence and in Section 11.05 and the first sentence of Section 11.06 hereof shall include reference to its Affiliates and its own and its Affiliates' officers, directors, employees and agents): (a) shall have no duties or responsibilities (including fiduciary or implied duties) except those expressly set forth in this Agreement and in the other Loan Documents, to which such Administrative Agent is a party, and shall not by reason of this Agreement or any other Loan Document be a trustee for any Bank; (b) shall not be responsible to the Banks for any recitals, statements, representations or warranties contained in this Agreement or in any other Loan Document, or in any certificate or other document referred to or provided for in, or received by any of them under, this Agreement or any other Loan Document, or for the value, validity, effectiveness, genuineness, enforceability or sufficiency of any collateral security provided for by any of the Security Documents, or of this Agreement, any Note or any other Loan Document or any other document referred to or provided for herein or therein, or for any failure by the Company, any other Obligor or any other Person to perform any of its obligations hereunder or thereunder; (c) shall not be required to initiate or conduct any litigation or collection proceedings hereunder or under any other Loan Document; (d) shall not be responsible for any action taken or omitted to be taken by it hereunder or under any other Loan Document or under any other document or instrument referred to or provided for herein or therein or in connection herewith or therewith, except for its own gross negligence or willful misconduct and (e) shall not have any duty to take any discretionary action or exercise any discretionary powers, except discretionary rights or powers expressly contemplated by this Agreement and the other Loan Documents that the Administrative Agent is required to exercise following its receipt of written instructions from the Banks, the Majority Banks or the Supermajority Banks, as the case may be, in accordance with the provisions of this Agreement and the other Loan Documents. The Administrative Agent may employ agents and attorneys-in-fact and shall not be responsible for the negligence or misconduct of any such agents or attorneys-in-fact selected by it in good faith. The Administrative Agent may deem and treat the payee of any Note as the holder thereof for all purposes hereof unless and until a notice of the assignment or transfer thereof shall have been filed with the Administrative Agent, together with the consent of the Company to such assignment or transfer (to the extent provided in Section 12.06(b) hereof).

11.02 Reliance by Administrative Agent. The Administrative Agent shall be entitled to rely upon any certification, notice or other communication (including, without limitation, any thereof by telephone, telecopy, telex, telegram or cable) believed by it to be genuine and correct and to have been signed or sent by or on behalf of the proper Person or Persons, and upon advice and statements of legal counsel, independent accountants and other experts selected by the Administrative Agent. As to any matters not expressly provided for by this Agreement or any other Loan Document, the Administrative Agent shall in all cases be fully protected in acting, or in refraining from acting, hereunder or thereunder in accordance with instructions given by the Majority Banks, and any action taken or failure to act pursuant thereto shall be binding on all of the Banks.

11.03 Defaults. The Administrative Agent shall not be deemed to have knowledge or notice of the occurrence of a Default (other than the non-payment of principal of or interest on Loans, Reimbursement Obligations or of commitment fees) unless the Administrative Agent has received notice from a Bank or any Obligor specifying such Default and stating that such notice is a "Notice of Default". In the event that the Administrative Agent receives such a notice of the occurrence of a Default, the Administrative Agent shall give prompt notice thereof to the Banks. The Administrative Agent shall (subject to Section 11.07 hereof) take such action with respect to such Default as shall be directed by the Majority Banks, provided that, unless and until the Administrative Agent shall have received such directions, the Administrative Agent may (but shall not be obligated to) take such action, or refrain from taking such action, with respect to such Default as it shall deem advisable in the best interest of the Banks, except to the extent that this Agreement expressly requires that such action be taken, or not be taken, only with the consent or upon the authorization of the Majority Banks or all of the Banks, as the case may be.

11.04 Rights as a Bank. The Bank serving as Administrative Agent hereunder shall have the same rights and powers in its capacity as a Bank as any other Bank and may exercise the same as though it were not the Administrative Agent, and such Bank and its Affiliates may accept deposits from, lend money to and generally engage in any kind of business with the Company or any Subsidiary or Affiliate thereof as if it were not the Administrative Agent hereunder.

11.05 Indemnification. The Banks agree to indemnify the Administrative Agent (to the extent not reimbursed under Sections 12.03 and 12.07 hereof, but without limiting the obligations of the Obligors under said Sections 12.03 and 12.07), ratably in accordance with the aggregate principal amount of the Loans, Bankers' Acceptances and Reimbursement Obligations held by the Banks (or, if no Loans, Bankers' Acceptances or Reimbursement Obligations are at the time outstanding, ratably in accordance with their respective Commitments or, if no Loans, Bankers' Acceptances, Reimbursement Obligations or Commitments are at the time outstanding or in effect, ratably in accordance with their respective Commitments as most recently in effect) for any and all liabilities, obligations, losses, damages, penalties, actions, judgments, suits, costs, expenses or disbursements of any kind and nature whatsoever that may be imposed on, incurred by or asserted against the Administrative Agent (including by any Bank) arising out of or by reason of any investigation in or in any way relating to or arising out of this Agreement or any other Loan Document or any other documents contemplated by or referred to herein or therein or the transactions contemplated hereby or thereby (including, without limitation, the costs and expenses that the Obligors are obligated to pay under Sections 12.03 and 12.07 hereof, but excluding, unless a Default has occurred and is continuing, normal administrative costs and expenses incident to the performance of its agency duties hereunder) or the enforcement of any of the terms hereof or thereof or of any such other documents, provided that no Bank shall be liable for any of the foregoing to the extent they arise from the gross negligence or willful misconduct of the party to be indemnified.

11.06 Non-Reliance on Agent and Other Banks. Each Bank agrees that it has, independently and without reliance on the Administrative Agent or any other Bank, and based on such documents and information as it has deemed appropriate, made its own credit analysis of the Company and its Subsidiaries and decision to enter into this Agreement and that it will, independently and without reliance upon the Administrative Agent or any other Bank, and based on such documents and information as it shall deem appropriate at the time, continue to make its own analysis and decisions in taking or not taking action under this Agreement. The Administrative Agent shall not be required to keep itself informed as to the performance or observance by any Obligor of this Agreement or any of the other Loan Documents or any other document referred to or provided for herein or therein or to inspect the Properties or books of the Company or any of its Subsidiaries. Except for notices, reports and other documents and information expressly required to be furnished to the Banks by the Administrative Agent hereunder, the Administrative Agent shall not have any duty or responsibility to provide any Bank with any credit or other information concerning the affairs, financial condition or business of the Company or any of its Subsidiaries (or any of their Affiliates) that may come into the possession of the Administrative Agent or any of its affiliates.

11.07 Failure to Act. Except for action expressly required of the Administrative Agent hereunder and under the other Loan Documents, the Administrative Agent shall in all cases be fully justified in failing or refusing to act hereunder and thereunder unless it shall receive further assurances to its satisfaction from the Banks of their indemnification obligations under Section 11.05 hereof against any and all liability and expense that may be incurred by it by reason of taking or continuing to take any such action.

11.08 Resignation or Removal of Agent. Subject to the appointment and acceptance of a successor Administrative Agent as provided below, the Administrative Agent may resign at any time by giving notice thereof to the Banks and the Company, and the Administrative Agent may be removed at any time with or without cause by the Majority Banks. Upon any such resignation or removal, the Majority Banks shall have the right to appoint a successor Administrative Agent. If no successor Administrative Agent shall have been so appointed by the Majority Banks and shall have accepted such appointment within 30 days after the retiring Administrative Agent's giving of notice of resignation or the Majority Banks' removal of the retiring Administrative Agent, then the retiring Administrative Agent may, on behalf of the Banks, appoint a successor Administrative Agent, that shall be a bank which has an office in New York, New York with a combined capital and surplus of at least U.S.$1,000,000,000. Upon the acceptance of any appointment as Administrative Agent hereunder by a successor Administrative Agent, such successor Administrative Agent shall thereupon succeed to and become vested with all the rights, powers, privileges and duties of the retiring Administrative Agent, and such retiring Administrative Agent shall be discharged from its duties and obligations hereunder. After any retiring Administrative Agent's resignation or removal hereunder as Administrative Agent, the provisions of this Section 11 shall continue in effect for its benefit in respect of any actions taken or omitted to be taken by it while it was acting as Administrative Agent. Without the prior written consent of the Company, no Bank may become Administrative Agent hereunder unless it holds not less than U.S.$15,000,000 of the aggregate Commitments (or 25% of the aggregate Commitments, at any time that the aggregate Commitments are less than U.S.$45,000,000) at the time it becomes the Administrative Agent.

11.09 Consents under Other Loan Documents. The Administrative Agent may, with the prior consent of the Majority Banks (but not otherwise) consent to any modification, supplement or waiver under any of the Loan Documents other than this Agreement, to which the Administrative Agent is a party, provided that without the prior consent of each Bank, the Administrative Agent shall not (except as provided herein or in the Security Documents to which the Administrative Agent is a party) release any collateral or otherwise terminate any Lien under any Loan Document providing for collateral security, or agree to additional obligations being secured by such collateral security (unless the Lien for such additional obligations shall be junior to the Lien in favor of the other obligations secured by such Loan Document), except that no such consent shall be required, and the Administrative Agent is hereby authorized, to release any Lien covering Property which is the subject of a disposition of Property permitted hereunder.

11.10 Collateral Sub-Agents. Each Bank by its execution and delivery of this Agreement agrees that, in the event it shall hold any Permitted Investments referred to therein, such Permitted Investments shall be held in the name and under the control of such Bank, and such Bank shall hold such Permitted Investments as a collateral sub-agent for the Administrative Agent thereunder. The Company by its execution and delivery of this Agreement hereby consents to the foregoing.

11.11 Dealings With the Administrative Agent. In the absence of written notice or any actual knowledge of a lack of authority of the Administrative Agent to act for and on behalf of the Banks in respect of any matter hereunder or under the Loan Documents, the Obligors shall be entitled to conclusively assume that any certificate, directive or other writing of the Administrative Agent in connection with such matter has been duly authorized by the Banks in accordance with this Agreement.

SECTION 12.
MISCELLANEOUS.

12.01 Waiver. No failure on the part of the Administrative Agent or any Bank to exercise and no delay in exercising, and no course of dealing with respect to, any right, power or privilege under this Agreement or any Note shall operate as a waiver thereof, nor shall any single or partial exercise of any right, power or privilege under this Agreement or any Note preclude any other or further exercise thereof or the exercise of any other right, power or privilege. The remedies provided herein are cumulative and not exclusive of any remedies provided by law.

12.02 Notices. All notices, requests and other communications provided for herein and under the Security Documents (including, without limitation, any modifications of, or waivers or consents under, this Agreement) shall be given or made by telecopy or other writing and telecopied, mailed or delivered to the intended recipient:

(a) in the case of any Obligor, at the "Address for Notices" specified below the name of such Obligor on the signature pages hereof;

(b) in the case of the Administrative Agent, at the "Address for Notices" specified below its name on the signature pages hereof;

(c) in the case of the Issuing Bank, at the "Address for Notices" specified below the name of the Issuing Bank on the signature pages hereof; and

(d) in the case of any Bank, at its address (or telecopy number) set forth in its Administrative Questionnaire;

or, as to any party, at such other address as shall be designated by such party in a notice to the Company and the Administrative Agent given in accordance with this Section 12.02. Except as otherwise provided in this Agreement, all such communications shall be deemed to have been duly given when transmitted by telecopier (and receipt is electronically confirmed), personally delivered or, in the case of a mailed notice, upon receipt, in each case given or addressed as aforesaid.

12.03 Expenses. The Obligors hereby jointly and severally agree to pay or reimburse each of the Banks and the Administrative Agent for paying: (a) all reasonable and documented out-of-pocket costs and expenses of the Administrative Agent (including, without limitation, the reasonable fees and expenses of Latham & Watkins, special New York counsel to WestLB, and Macleod Dixon LLP, special Canadian counsel to WestLB, but excluding the fees and expenses of Computershare Trust Company of Canada), in connection with (A) the negotiation, preparation, execution and delivery of this Agreement and the other Loan Documents and the extensions of credit hereunder (provided that in no event shall the foregoing include any costs or expenses in respect of in-house counsel or advisors of the Administrative Agent or of any Bank or Participant) and (B) any modification, supplement or waiver of any of the terms of this Agreement or any of the other Loan Documents; (b) all reasonable out-of-pocket costs and expenses of the Banks and the Administrative Agent (including, without limitation, reasonable counsel fees and expenses) in connection with (i) any Default and any enforcement or collection proceedings resulting therefrom or in connection with the negotiation of any restructuring or "work-out" (whether or not consummated), or the obligations of the Obligors hereunder and (ii) the enforcement of this Section 12.03 or Section 12.07; and (c) all transfer, stamp, documentary or other similar taxes, assessments or charges levied by any governmental or revenue authority in respect of this Agreement or any of the other Loan Documents or any other document referred to herein or therein and all costs, expenses, taxes, assessments and other charges incurred in connection with any filing, registration, recording or perfection of any security interest contemplated by any Loan Document or any other document referred to therein; provided that in no event shall the Obligors be responsible for paying any amounts or costs incurred pursuant to this clause (c) as a result of the gross negligence or willful misconduct of the Administrative Agent or any Bank.

12.04 Amendments, Etc. Except as otherwise expressly provided in this Agreement, any provision of this Agreement may be modified or supplemented only by an instrument in writing signed by the Obligors, the Administrative Agent and the Supermajority Banks (and if such amendment relates in any way to the rights or obligations of the Issuing Bank or any Letter of Credit, the Issuing Bank) and any provision of this Agreement may be waived by the Supermajority Banks (and if such amendment relates in any way to any Letter of Credit, the Issuing Bank); provided that no modification, supplement or waiver shall, unless by an instrument signed by all of the Banks or by the Administrative Agent acting with the consent of all of the Banks whose rights or interests are affected thereby: (i) increase, or extend the term of any of the Commitments, or extend the time or waive any requirement for the reduction or termination of any of the Commitments, (ii) extend the date fixed for the payment of principal of or interest on the Loans, the Reimbursement Obligations or any fee hereunder, (iii) reduce the amount of any such payment of principal, (iv) reduce the rate at which interest is payable thereon or any fee is payable hereunder, (v) alter the rights or obligations of the Obligors to prepay Loans, (vi) alter the terms of this Section 12.04 or (vii) modify the definition of the term "Majority Banks" or "Supermajority Banks" or modify in any other manner the number or percentage of the Banks required to make any determinations or waive any rights hereunder or waive or modify any provision hereof, any modification or supplement of this Agreement that increases any of the obligations or reduces or impairs any of the rights of, or otherwise adversely affects the interests of, the Administrative Agent or an Issuing Bank under this Agreement or any of the other Loan Documents shall require the consent of the Administrative Agent or such Issuing Bank (as the case may be).

Anything in this Agreement to the contrary notwithstanding, if:

(x) at a time when the conditions precedent set forth in Section 7 hereof to any Loans or other extension of credit hereunder are, in the opinion of the Majority Banks satisfied, any Bank shall fail to fulfill its obligations to make the Loan to be made by it; or

(y) any Bank shall fail to pay to the Administrative Agent for the account of the Issuing Bank the amount of such Bank's Commitment Percentage of the Commitments of any payment under a Letter of Credit pursuant to Section 2.03(b)(v) hereof;

then, for so long as such failure shall continue, such Bank shall (unless the Majority Banks, determined, in either case, as if such Bank were not a "Bank" hereunder, shall otherwise consent in writing) be deemed for all purposes relating to amendments, modifications, waivers or consents under this Agreement or any of the other Loan Documents (including, without limitation, under this Section 12.04 and under Section 11.09 hereof) to have no Loans, Letter of Credit Liabilities, Bankers' Acceptances or Commitments, shall not be treated as a "Bank" hereunder when performing the computation of Majority Banks or Supermajority Banks, as the case may be, and shall have no rights under the preceding paragraph of this Section 12.04 or under Section 11.09 hereof; provided that any action taken by the other Banks with respect to the matters referred to in the preceding paragraph shall not be effective as against such Bank.

Anything in this Agreement to the contrary notwithstanding, the Administrative Agent, acting reasonably and following discussion with the Company, may modify any and all of the terms, structure, amount or pricing of the credit facilities provided for in this Agreement if the Administrative Agent determines, acting reasonably that such modifications are necessary in order to achieve a "successful syndication" of such credit facilities as described in the Fee Letter.

12.05 <u>Successors and Assigns</u>. This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and permitted assigns.

12.06 Assignments and Participations.

(a) No Obligor may assign any of its rights or obligations hereunder or under the Notes without the prior consent of the Majority Banks and the Administrative Agent.

(b) Each Bank may assign and, so long as no Default shall have occurred and be continuing, if demanded by the Company (following a demand by such Bank pursuant to Section 5.01 or 5.06 hereof or notice by such Bank pursuant to Section 5.03 hereof) upon at least five Business Days' notice to such Lender and the Administrative Agent, shall, assign any of its Loans, its Note, its Commitment and its Letter of Credit Interest (but only with the consent of, in the case of an outstanding Commitment, the Administrative Agent and, in the case of a Commitment or a Letter of Credit Interest in connection with Letters of Credit, the Issuing Bank); provided that

(i) no such consent by the Administrative Agent shall be required in the case of any assignment to another Bank;

(ii) any such partial assignment (other than to another Bank) shall be in an amount at least equal to U.S.$5,000,000 and; provided that in each case unless a Bank is assigning all of its Loans, Bankers' Acceptances, Letter of Credit Interests and Commitments, the assigning Bank shall maintain a Commitment of not less than U.S.$5,000,000; and provided that except with the Company's prior written consent, the Administrative Agent shall at all times maintain a Commitment of not less than U.S.$15,000,000 (or 25% of the aggregate Commitments at any time that the aggregate Commitments are less than U.S.$45,000,000);

(iii) each such permitted assignment by a Bank of its Loans, Note, Commitment, Bankers' Acceptances or Letter of Credit Interest shall be made in such manner so that the same portion of its Loans, Note, Commitment, Bankers' Acceptances and Letter of Credit Interest is assigned to the respective assignee;

(iv) each such assignment made as a result of a demand by the Company pursuant to this Section 12.06(b) shall be arranged by the Company after consultation with the Administrative Agent and shall be either an assignment of all of the rights and obligations of the assigning Bank under this Agreement or an assignment of a portion of such rights and obligations made concurrently with another such assignment or other such assignments that together cover all of the rights and obligations of the assigning Bank under this Agreement; and

(v) no Bank shall be obligated to make any such assignment as a result of a demand by the Borrower pursuant to this Section 12.06(b) unless and until such Bank shall have received one or more payments from either the Company or one or more assignees in an aggregate amount at least equal to the aggregate outstanding principal amount of the Loans, Bankers' Acceptances and Reimbursement Obligations owing to such Bank (or that such Reimbursement Obligations have been irrevocably assumed by the assignee Bank), together with accrued interest thereon to the date of payment of such principal amount and all other amounts payable to such Bank under this Agreement.

Upon execution and delivery by the assignee to the Company, the Administrative Agent and the Issuing Bank, to the extent required above, of an instrument in writing pursuant to which such assignee agrees to become a "Bank" hereunder (if not already a Bank) having the Commitment, Loans and, if applicable, the Letter of Credit Interest specified in such instrument, and upon consent thereto by the Administrative Agent as provided in this Section 12.06(b) and the Issuing Bank, the assignee shall have, to the extent of such assignment (unless provided in such assignment with the consent of the Administrative Agent and the Issuing Bank), the obligations, rights and benefits of a Bank hereunder holding the Commitment, Loans and, if applicable, the Letter of Credit Interest (or portions thereof) assigned to it (in addition to the Commitment, Loans and Letter of Credit Interest theretofore held by such assignee) and the assigning Bank shall, to the extent of such assignment, be released from the Commitment, Loans and Letter of Credit Interest (or portion thereof) so assigned. Any Bankers' Acceptances specified in such instrument shall remain the liability and obligation of the Banks hereunder holding such Bankers' Acceptances and such Bank shall be entitled to all of the rights, titles and benefits arising out of this Agreement with respect to such Bankers' Acceptances (including reimbursement rights); provided, however, that the assignee shall indemnify such Bank and hold such Bank harmless from and against any losses or costs paid or incurred by such Bank in connection with such Bankers' Acceptances (other than losses or costs which arise out of the gross negligence or willful misconduct of such Bank). Upon each such assignment the assigning Bank shall pay the Administrative Agent an assignment fee of U.S.$3,000.

(c) Each Bank may sell or agree to sell to one or more other Persons (a "Participant") a participation in all or any portion of its rights and obligations under this Agreement (including, without limitation, all or any portion of its Commitment and the Loans, Bankers' Acceptances and/or Letter of Credit Interest held by it). In the event of any such participation by a Bank of participating interests to a Participant, such Bank's obligations under this Agreement shall remain unchanged, such Bank shall remain solely responsible for the performance thereof and the Obligors shall continue to deal solely and directly with such "Bank" for all purposes hereunder and such Participant shall not have any other rights or benefits under this Agreement, any Note, any Bankers' Acceptance or any other Loan Document, except as provided in Section 4.07(c) hereof (the Participant's rights against such Bank in respect of such participation to be those set forth in the agreements executed by such Bank in favor of the Participant). All amounts payable by the Obligors to any Bank under Section 5 hereof in respect of Loans, Bankers' Acceptances, Letter of Credit Interests and its Commitment, shall be determined as if such Bank had not sold or agreed to sell any participations in such Loans, Bankers' Acceptances, Letter of Credit Interest and Commitment, and as if such Bank were funding each of such Loans, Bankers' Acceptances, Letter of Credit Interests and Commitment in the same way that it is funding the portion of such Loans, Bankers' Acceptances, Letter of Credit Interests and Commitment in which no participations have been sold. In no event shall a Bank that sells a participation agree with the Participant to take or refrain from taking any action hereunder or under any other Loan Document except that such Bank may agree with the Participant that it will not, without the consent of the Participant, agree to any of the following (to the extent the rights or interest of the Participant are adversely affected thereby): (A) increase or extend the term, or extend the time or waive any requirement for the reduction or termination, of such Bank's Commitment, (B) extend the date fixed for the payment of principal of or interest on the related Loan or Loans, Bankers' Acceptance Liabilities, Reimbursement Obligations or any portion of any fee hereunder, (C) reduce the amount of any such payment of principal, (D) reduce the rate at which interest is payable thereon, or any fee hereunder payable to the Participant, to a level below the rate at which the Participant is entitled to receive such interest or fee, (E) alter the rights or obligations of the Company to prepay the related Loans or (F) consent to any other modification, supplement or waiver hereof or of any of the other Loan Documents to the extent that the same, under Section 11.09 or 12.04 hereof, requires the consent of each Bank.

(d) In addition to the assignments and participations permitted under the foregoing provisions of this Section 12.06, including, without limitation, Section 12.06(c) hereof, any Bank may assign and pledge all or any portion of its Loans and its Notes to any Federal Reserve Bank as collateral security pursuant to Regulation A and any Operating Circular issued by such Federal Reserve Bank. No such assignment shall release the assigning Bank from its obligations hereunder.

(e) A Bank may furnish any information concerning the Company or any of its Subsidiaries in the possession of such Bank from time to time to assignees and participants (including prospective assignees and participants), subject, however, to the provisions of Section 12.13(b) hereof.

(f) Anything in this Section 12.06 to the contrary notwithstanding, no Bank may assign or participate any interest in any Loan or Reimbursement Obligation held by it hereunder to the Obligors or any of their Affiliates or Subsidiaries without the prior written consent of each Bank.

(g) The Administrative Agent shall provide copies to the Company from time to time (and promptly following any request from the Company for such copies) of the Administrative Questionnaire as completed by each Bank.

12.07 Indemnification. The Company and each other Obligor hereby jointly and severally agrees (i) to indemnify the Administrative Agent, each Bank and the Issuing Bank and their respective directors, officers, employees, attorneys and agents from, and hold each of them harmless against, any and all losses, liabilities, claims, damages or expenses incurred by any of them (including, without limitation, any and all losses, liabilities, claims, damages or expenses incurred by the Administrative Agent, any Bank or the Issuing Bank, whether or not the Administrative Agent, any Bank or the Issuing Bank is a party thereto) (collectively, "Damages") arising out of or by reason of any investigation or litigation or other proceedings (including any threatened investigation or litigation or other proceedings) relating to the extensions of credit hereunder or any actual or proposed use by the Company or any other Obligor of the proceeds of any of the extensions of credit hereunder, including, without limitation, the reasonable fees and disbursements of counsel incurred in connection with any such investigation or litigation or other proceedings (but excluding any such losses, liabilities, claims, damages or expenses incurred by reason of the gross negligence, bad faith or willful misconduct of the Person to be indemnified) and (ii) not to assert any claim against the Administrative Agent, any Bank, the Issuing Bank, any of their affiliates, or any of their respective directors, officers, employees, attorneys and agents, on any theory of liability, for special, indirect, consequential or punitive damages arising out of or otherwise relating to any of the transactions contemplated herein or in any other Loan Document; provided that the Company or any other Obligor may enforce the obligations, if applicable, of the Banks and the Issuing

Bank hereunder. Without limiting the generality of the foregoing, Company and the other Obligors will indemnify the Administrative Agent, each Bank and the Issuing Bank from, and hold the Administrative Agent, each Bank and the Issuing Bank harmless against, any losses, liabilities, claims, damages or expenses described in the preceding sentence (but excluding, as provided in the preceding sentence, any loss, liability, claim, damage or expense incurred by reason of the gross negligence, bad faith or willful misconduct of the Person to be indemnified) arising under any Environmental Law as a result of the past, present or future operations of the Company or any of its Subsidiaries (or any predecessor in interest to the Company or any of its Subsidiaries), or the past, present or future condition of any site or facility owned, operated or leased by the Company or any of its Subsidiaries (or any such predecessor in interest), or any Release or threatened Release of any Hazardous Materials from any such site or facility, including any such Release or threatened Release which shall occur during any period when the Administrative Agent or any Bank shall be in possession of any such site or facility following the exercise by the Administrative Agent or any Bank of any of its rights and remedies hereunder or under any of the Security Documents other than any Release caused by the gross negligence, bad faith or willful misconduct of the Administrative Agent or any Bank or any agent, security agent or receiver acting on behalf of the Administrative Agent or any Bank.

12.08 Survival. The obligations of the Obligors under Sections 2.03, 5.01, 5.05, 5.06, 5.07, 12.03 and 12.07 hereof, the obligations of the Subsidiary Guarantors under Section 6.03 hereof and the obligations of the Banks under Section 11.05 hereof shall survive the repayment of the Loans, Bankers' Acceptances and Reimbursement Obligations and the termination of the Commitments. In addition, each representation and warranty made, or deemed to be made by a notice of any extension of credit (whether by means of a Loan, Bankers' Acceptance or a Letter of Credit), herein or pursuant hereto shall survive the making of such representation and warranty, and no Bank shall be deemed to have waived, by reason of making any extension of credit hereunder (whether by means of a Loan, Bankers' Acceptance or a Letter of Credit), any Default which may arise by reason of such representation or warranty proving to have been false or misleading, notwithstanding that such Bank or the Administrative Agent may have had notice or knowledge or reason to believe that such representation or warranty was false or misleading at the time such extension of credit was made.

12.09 Captions. The table of contents and captions and section headings appearing herein are included solely for convenience of reference and are not intended to affect the interpretation of any provision of this Agreement.

12.10 Counterparts. This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one and the same instrument and any of the parties hereto may execute this Agreement by signing any such counterpart.

12.11 Governing Law; Submission to Jurisdiction. This Agreement and the Notes shall be governed by, and construed in accordance with, the law of the State of New York. Each Obligor hereby submits to the nonexclusive jurisdiction of the United States District Court for the Southern District of New York and of any New York state court sitting in New York City for the purposes of all legal proceedings arising out of or relating to this Agreement or the transactions contemplated hereby. Each Obligor irrevocably waives, to the fullest extent permitted by applicable law, any objection which it may now or hereafter have to the laying of the venue of any such proceeding brought in such a court and any claim that any such proceeding brought in such a court has been brought in an inconvenient forum.

12.12 Waiver of Jury Trial. **EACH OF THE OBLIGORS, THE ADMINISTRATIVE AGENT, THE BANKS AND THE ISSUING BANK HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.**

12.13 Treatment of Certain Information.

(a) Each of the Banks and the Administrative Agent agrees (on behalf of itself and each of its affiliates, directors, officers, employees and representatives) to use reasonable precautions to keep confidential, in accordance with their customary procedures for handling confidential information of the same nature and in accordance with safe and sound banking practices, any non-public information supplied by any Obligor or any of its Subsidiaries pursuant to this Agreement, provided that nothing herein shall limit the disclosure of any such information (i) to the extent required by statute, rule, regulation or judicial process, (ii) to counsel for any of the Banks or Administrative Agent, (iii) to bank examiners, auditors or accountants, (iv) to the Administrative Agent or any other Bank, (v) in connection with any litigation in respect of the Loan Documents to which any one or more of the Banks or the Administrative Agent is a party, (vi) to a Subsidiary or Affiliate of such Bank as provided in clause (a) above or (vii) to any assignee or participant (or prospective assignee or participant).

(b) In the event a Bank or the Administrative Agent is required to disclose confidential information pursuant to this Section 12.13, it shall only disclose such information as it is legally required to disclose or it would customarily disclose under similar circumstances to any Governmental Authority and shall use reasonable efforts to obtain confidential treatment for any information so disclosed. In addition, it shall promptly provide notice of the requirement to the Company setting out the requirements and circumstances surrounding the required disclosure and any other information it deems relevant so that the Company may take any appropriate steps to protect such confidential information.

12.14 Judgment Currency. This is an international loan transaction in which the specification of Canadian Dollars or U.S. Dollars is of the essence, and the stipulated currency shall in each instance be the Currency of account and payment in all instances. A payment obligation in one currency hereunder (the "Original Currency") shall not be discharged by an amount paid in another currency (the "Other Currency"), whether pursuant to any judgment expressed in or converted into any Other Currency or in another place except to the extent that such tender or recovery results in the effective receipt by the payee of the full amount of the Original Currency payable by it under this Agreement. If for the purpose of obtaining judgment in any court it is necessary to convert a sum due hereunder in the Original Currency into the Other Currency, the rate of exchange that shall be applied shall be that at which in accordance with normal banking procedures the Administrative Agent could purchase Original Currency with the Other Currency on the Business Day next preceding the day on which such judgment is rendered. The obligation of each Obligor in respect of any such sum due from it to the

Administrative Agent or any Bank hereunder or under any other Loan Document (in this Section 12.14 called an "Entitled Person") shall, notwithstanding the rate of exchange actually applied in rendering such judgment, be discharged only to the extent that on the Business Day following receipt by such Entitled Person of any sum adjudged to be due hereunder in the Other Currency such Entitled Person may in accordance with normal banking procedures purchase and transfer the Original Currency to Toronto with the amount of the judgment currency so adjudged to be due; and each Obligor hereby, as a separate obligation and notwithstanding any such judgment, agrees jointly and severally to indemnify such Entitled Person against, and to pay such Entitled Person on demand, in the Original Currency, the amount (if any) by which the sum originally due to such Entitled Person in the Original Currency hereunder exceeds the amount of the Original Currency so purchased and transferred.

12.15 <u>Agent for Service of Process</u>. THE COMPANY AND EACH OBLIGOR HEREBY IRREVOCABLY DESIGNATES, APPOINTS AND EMPOWERS CT CORPORATION SYSTEM AS ITS DESIGNEE, APPOINTEE AND AGENT TO RECEIVE, ACCEPT AND ACKNOWLEDGE FOR AND ON ITS BEHALF, AND IN RESPECT OF ITS PROPERTY, SERVICE OF ANY AND ALL LEGAL PROCESS, SUMMONS, NOTICES AND DOCUMENTS WHICH MAY BE SERVED IN ANY ACTION OR PROCEEDING. IF FOR ANY REASON SUCH DESIGNEE, APPOINTEE AND AGENT SHALL CEASE TO BE AVAILABLE TO ACT AS SUCH, THE COMPANY AND EACH OBLIGOR, AGREES TO DESIGNATE A NEW DESIGNEE, APPOINTEE AND AGENT IN NEW YORK CITY ON THE TERMS AND FOR THE PURPOSES OF THIS PROVISION SATISFACTORY TO THE ADMINISTRATIVE AGENT. EACH OF THE COMPANY, THE OBLIGORS AND THE ADMINISTRATIVE AGENT IRREVOCABLY CONSENTS TO THE SERVICE OF PROCESS OUT OF ANY OF THE AFOREMENTIONED COURTS IN ANY SUCH ACTION OR PROCEEDING BY THE MAILING OF COPIES THEREOF BY REGISTERED OR CERTIFIED MAIL, POSTAGE PREPAID TO THE ADMINISTRATIVE AGENT AND THE COMPANY AT ITS RESPECTIVE ADDRESS REFERRED TO IN SECTION 12.02.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed and delivered as of the day and year first above written.

HARVEST OPERATIONS CORP.

By: *(signed) "David Rain"*
Name: David Rain
Title: Corporate Secretary

Address for Notices:

2400, 500 – 4th Avenue S.W.
Calgary, Alberta
T2P 2V6
Canada

Attention: Bruce Chernoff

Telecopier No.: (403) 266-1438
Telephone No.: (403) 920-0128

WESTLB AG, NEW YORK BRANCH,
as Administrative Agent

By: *(signed) "Roderick L. Fraser*
Name: Roderick L. Fraser
Title: Managing Director

By: *(signed) "Michael D. Peist"*
Name: Michael D. Peist
Title: Director

Address for Notices:

1211 Avenue of the Americas
New York, New York 10036
United States of America

Attention: Transaction Management

WESTLB AG, NEW YORK BRANCH,
as Issuing Bank

By: *(signed) "Roderick L. Fraser"*
Name: Roderick L. Fraser
Title: Managing Director

By: (signed) "Michael D. Peist"
Name: Michael D. Peist
Title: Director

Address for Notices:

1211 Avenue of the Americas
New York, New York 10036
United States of America

Attention: Transaction Management

BANKS

WESTLB AG, NEW YORK BRANCH

By: *(signed) "Roderick L. Fraser"*
Name: Roderick L. Fraser
Title: Managing Director

By: (signed) "Michael D. Peist"
Name: Michael D. Peist
Title: Director

Address for Notices:

1211 Avenue of the Americas
New York, New York 10036
United States of America

Attention: Transaction Management

ANNEX I

Banks and Commitments

Banks	Commitments
WestLB AG, New York Branch	$60,000,000

SCHEDULE I

Liens

1. **PHH Vehicle Management Services Inc.**
   Leased vehicles together with all attachments, accessions, appurtenances, accessories or replacement parts, and all proceeds thereof.

2. **Anadarko Canada Corporation**
   As outlined in Article 16 of the September 6, 2002 Crude Oil Purchase Agreement between Anadarko Canada Corporation ("Anadarko") and the Borrower, the Borrower granted a lien, charge and security interest to Anadarko with respect to:

(a) the interest of the Borrower in the "Assets" (as defined in the August 1, 2002 Purchase & Sale Agreement between Anadarko and the Borrower) and all proceeds of production derived therefrom:

(b) all present and after-acquired personal property; and

(c) the proceeds of sale of the Borrower's production of the liquid hydrocarbon to be delivered by the Borrower to Anadarko under that agreement.

The lien, charge and security interest is stated under the agreement to be subordinate and postponed to any of the Borrower's "Indebtedness for Borrowed Money" (as defined in that agreement).

SCHEDULE II

Subsidiaries and Investments

None.

Capitalization

	Authorized	Issued	Outstanding	Amount
Common Shares	Unlimited	1	1	$1.00
First Preferred Shares	Unlimited	None	None	Nil

SCHEDULE IV

Environmental Matters

Type	Description	Area	Field	Location	AEUB Approval # or License #
Natural gas processing facility	Gas Plant	Hayter/Provost	West Provost	16-31-37-2 W4	5261
Oil Battery		Hayter/Provost	East Hayter	8-35-40-1 W4	1987-1109
Oil Battery		Thompson	Metiskow	5-22-39-6 W4M	1997-690
Oil Battery		Thompson	David North	15-26-40-3 W4M	C0369
Oil Battery		Hayter/Provost	North Hayter	1-34-40-1 W4	CP1308
Oil Battery		Thompson	Bellshill	11-5-41-12 W4M	FS05507
Oil Battery		Thompson	Thompson Lake	4-2-41-11 W4M	FS05579
Oil Battery		Hayter/Provost	West Provost	3-15-38-3 W4	MS4820
Well	Injection/Disposal Well	Hayter/Provost	East Hayter	13C-36-40-1W4/2	212072
Well	Injection/Disposal Well	Hayter/Provost	East Hayter	15D-35-40-1W4	202792
Well	Injection/Disposal Well	Hayter/Provost	East Hayter	9B-24-40-1W4/2	153453
Well	Injection/Disposal Well	Hayter/Provost	North Hayter	2D-34-40-1W4	84427
Well	Injection/Disposal Well	Hayter/Provost	North Hayter	5C-34-40-1W4	255554
Well	Injection/Disposal Well	Hayter/Provost	North Hayter	8C-34-40-1W4/2	78738
Well	Injection/Disposal Well	Hayter/Provost	North Hayter	8-3-41-1W4	82949
Well	Injection/Disposal Well	Hayter/Provost	West Provost	10A2-15-38-3W4	202856
Well	Injection/Disposal Well	Hayter/Provost	West Provost	12A2-10-38-3W4	2099317
Well	Injection/Disposal Well	Hayter/Provost	West Provost	14A-15-38-3W4	152923
Well	Injection/Disposal Well	Hayter/Provost	West Provost	14C-15-38-3W4	135468
Well	Injection/Disposal Well	Hayter/Provost	West Provost	15C-15-38-3W4	186646
Well	Injection/Disposal Well	Hayter/Provost	West Provost	2A-15-38-3W4	152900
Well	Injection/Disposal Well	Hayter/Provost	West Provost	3C-10-38-3W4	188391
Well	Injection/Disposal Well	Hayter/Provost	West Provost	4A-15-38-3W4	152903
Well	Injection/Disposal Well	Hayter/Provost	West Provost	4B-10-38-3W4	102729
Well	Injection/Disposal Well	Hayter/Provost	West Provost	5D-10-38-3W4	156496
Well	Injection/Disposal Well	Hayter/Provost	West Provost	9B-15-38-3W4	186569
Well	Injection/Disposal Well	Thompson	Bellshill	100/8-5-41-12 W4M	A0107699
Well	Injection/Disposal Well	Thompson	Bellshill	100/9-5-41-12 W4M	A0151457
Well	Injection/Disposal Well	Thompson	Bellshill	100/8-7-41-12 W4M	A0101859
Well	Injection/Disposal Well	Thompson	David North	100/2-26-40-3 W4M	A0101273
Well	Injection/Disposal Well	Thompson	David North	102/12-26-40-3 W4M	A0103159
Well	Injection/Disposal Well	Thompson	David North	102/2-26-40-3 W4M	A0172903
Well	Injection/Disposal Well	Thompson	David North	102/11-26-40-3 W4M	A0103157
Well	Injection/Disposal Well	Thompson	David North	100/3-26-40-3 W4M	A0101272
Well	Injection/Disposal Well	Thompson	David North	102/15-26-40-3 W4M	A009963
Well	Injection/Disposal Well	Thompson	David North	102/9-27-40-3 W4M	A0171631
Well	Injection/Disposal Well	Thompson	David North	103/9-26-40-3 W4M	A0172332
Well	Injection/Disposal Well	Thompson	David North	103/16-27-40-3 W4M	A0172330
Well	Injection/Disposal Well	Thompson	David North	100/1-26-40-3 W4M	A0178411
Well	Injection/Disposal Well	Thompson	David North	105/8-26-40-3 W4M	A0189079
Well	Injection/Disposal Well	Thompson	David North	102/8-26-40-3 W4M	A0103158

Well	Injection/Disposal Well	Thompson	David North	102/9-26-40-3 W4M	A010360
Well	Injection/Disposal Well	Thompson	David North	104/8-26-40-3 W4M	189091
Well	Injection/Disposal Well	Thompson	David North	104/10-26-40-3 W4M	171634
Well	Injection/Disposal Well	Thompson	David North	100/9-27-40-3 W4M	58218
Well	Injection/Disposal Well	Thompson	David North	100/15-26-40-3 W4M	A0053258
Well	Injection/Disposal Well	Thompson	Metiskow	100/2-22-39-6 W4M	A0193414
Well	Injection/Disposal Well	Thompson	Metiskow	102/6-22-39-6 W4M	A0191824
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C3/3-36-40-11 W4M	158777
Well	Injection/Disposal Well	Thompson	Thompson Lake	104/8-25-40-11 W4M	158774
Well	Injection/Disposal Well	Thompson	Thompson Lake	100/3-36-40-11 W4M	152442
Well	Injection/Disposal Well	Thompson	Thompson Lake	1A0/6-36-40-11 W4M	153188
Well	Injection/Disposal Well	Thompson	Thompson Lake	100/13-35-40-11 W4M	A0170296
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C0/13-35-40-11 W4M	A0152781
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C0/10-34-40-11 W4M	A0152773
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C0/9-34-40-11 W4M	A0152775
Well	Injection/Disposal Well	Thompson	Thompson Lake	104/15-34-40-11 W4M	A0158372
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C0/8-2-41-11 W4M	A0152805
Well	Injection/Disposal Well	Thompson	Thompson Lake	1B0/10-2-41-11 W4M	A0152801
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C0/3-1-41-11 W4M	A0153761
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C2/3-2-41-11 W4M	A0152764
Well	Injection/Disposal Well	Thompson	Thompson Lake	1A0/4-2-41-11 W4M	A0152765
Well	Injection/Disposal Well	Thompson	Thompson Lake	100/3-2-41-11 W4M	170293
Well	Injection/Disposal Well	Thompson	Thompson Lake	100/8-3-41-11 W4M	A0152044
Well	Injection/Disposal Well	Thompson	Thompson Lake	102/4-2-41-11 W4M	170294
Well	Injection/Disposal Well	Thompson	Thompson Lake	102/5-2-41-11 W4M	A0156725
Well	Injection/Disposal Well	Thompson	Thompson Lake	100/11-2-41-11 W4M	A0171800
Well	Injection/Disposal Well	Thompson	Thompson Lake	1B2/10-2-41-11 W4M	A0170150
Underground Storage Facility	Flare Knock-Out	Hayter/Provost	Hayter	3-25-40-1 W4M	
Underground Storage Facility	Floor Drain	Hayter/Provost	Hayter	3-25-40-1 W4M	
Underground Storage Facility	Floor Drain	Hayter/Provost	Hayter	1-34-40-1 W4M	
Underground Storage Facility	Floor Drain	Hayter/Provost	Hayter	3-25-40-1 W4M	
Underground Storage Facility	Flare Knock-Out	Hayter/Provost	Hayter	3-25-40-1 W4M	
Underground Storage Facility	Flare Knock-Out	Hayter/Provost	Hayter	2-25-40-1 W4M	
Underground Storage Facility	Floor Drain	Hayter/Provost	Hayter	1-34-40-1 W4M	
Underground Storage Facility	Water Tank Trays	Hayter/Provost	West Provost	3-15-38-3 W4M	
Underground Storage Facility	Oil Tank Trays	Hayter/Provost	West Provost	3-15-38-3 W4M	
Underground Storage Facility	Process Bldg Trays	Hayter/Provost	West Provost	3-15-38-3 W4M	
Underground Storage Facility	Blowdown	Hayter/Provost	Bodo	14-7-39-1 W4M	
Underground Storage Facility	Separator Blowdown	Hayter/Provost	Bodo	6-11-38-3 W4M	
Underground Storage Facility	Produced Water	Hayter/Provost	Bodo	6-10-38-2 W4M	
Underground Storage Facility	Separator Blowdown	Hayter/Provost	Bodo	7-15-38-3 W4M	
Underground Storage Facility	Separator Blowdown	Hayter/Provost	Bodo	6-16-38-3 W4M	
Underground Storage Facility	Separator Blowdown	Hayter/Provost	Bodo	7-13-38-3 W4M	

Underground Storage Facility	Separator Drain	Hayter/Provost	Bodo	6-14-38-3 W4M
Underground Storage Facility	Waste Oil	Hayter/Provost	Bodo	16-31-37-2 W4M
Underground Storage Facility	Scrubber Drain	Hayter/Provost	Bodo	16-31-37-2 W4M
Underground Storage Facility	Dehy Drain	Hayter/Provost	Bodo	16-31-37-2 W4M
Underground Storage Facility	Produced Water	Hayter/Provost	Bodo	8-15-38-2 W4M
Underground Storage Facility	Produced Water	Hayter/Provost	Bodo	15-11-38-2 W4M
Underground Storage Facility	Produced Water	Hayter/Provost	Bodo	7-12-38-2 W4M
Underground Storage Facility	Flare Knock-Out	Thompson	Bellshill	11-5-41-12 W4M
Underground Storage Facility	Flare Knock-Out	Thompson	Bellshill	11-5-41-12 W4M
Underground Storage Facility	Separator Drain	Thompson	Bellshill	11-5-41-12 W4M
Underground Storage Facility	Injection Bldg Drain	Thompson	Thompson Lake	4-2-41-11 W4M
Underground Storage Facility	FKO Bldg Drain	Thompson	Thompson Lake	4-2-41-11 W4M
Underground Storage Facility	Dehy Drain	Thompson	Thompson Lake	4-2-41-11 W4M
Underground Storage Facility	Header Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Header Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	FWKO Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	FWKO Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Treater Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Treater Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Cut Shack Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Cut Shack Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	VRU Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Injection Bldg Drain	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Injection Bldg Drain	Thompson	David North	15-26-40-3 W4M
Underground Storage Facility	Injection Bldg	Thompson	David North	15-26-40-3 W4M
Underground Storage Facility	VRU Bldg	Thompson	David North	15-26-40-3 W4M
Underground Storage Facility	Old Injection Bldg	Thompson	David North	15-26-40-3 W4M
Underground Storage Facility	Header Bldg	Thompson	David North	15-26-40-3 W4M
Underground Storage Facility	Treater Bldg	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Oil	Thompson	Bellshill	11-5-41-12 W4M
Aboveground Storage Facility	Oil	Thompson	Bellshill	11-5-41-12 W4M
Aboveground Storage Facility	Oil	Thompson	Bellshill	11-5-41-12 W4M
Aboveground Storage Facility	Slop Oil	Thompson	Bellshill	11-5-41-12 W4M
Aboveground Storage Facility	Produced Water	Thompson	Bellshill	11-5-41-12 W4M
Aboveground Storage Facility	Produced Water	Thompson	Bellshill	11-5-41-12 W4M

Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Pop Tank	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Sweet Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Pop Tank	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Waste Tank	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Oil	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Oil	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Produced Water	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Produced Water	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Emulsion	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Emulsion	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Pop Tank	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Oil	Thompson	David North	15-26-40-3 W4M
Aboveground Storage	Oil	Thompson	David North	15-26-40-3 W4M

Facility

Aboveground Storage Facility	Oil	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Oil	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Produced Water	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Produced Water	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Produced Water	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Slop Oil	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Slop Oil	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Oil	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Oil	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Oil	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Treater 1	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Treater 2	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	FWKO 1	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	FWKO 2	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Settling	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Test Tank	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Desand	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Truck Tank	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Slop Oil 1	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Slop Oil 2	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Slop Oil 3	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Production	Hayter/Provost	North Hayter	1B2-34-40-1 W4M
Aboveground Storage Facility	Production	Hayter/Provost	North Hayter	9-34-40-1 W4M
Aboveground Storage Facility	Production	Hayter/Provost	North Hayter	16-5-41-1 W4M
Aboveground Storage Facility	Production	Hayter/Provost	North Hayter	1-3-41-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Oil	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Production	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Recycle	Hayter/Provost	East Hayter	8-35-40-1 W4M

Aboveground Storage Facility	Test Tank	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Desand	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Test Tank	Hayter/Provost	East Hayter	3A-25-40-1 W4M
Aboveground Storage Facility	Test Tank	Hayter/Provost	East Hayter	3B-25-40-1 W4M
Aboveground Storage Facility	Test Tank	Hayter/Provost	East Hayter	2A-25-40-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Production-Oil	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Sales-Oil	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Sales-Oil	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Desand	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Production-Oil	Hayter/Provost	West Provost	4A-10-38-3 W4M
Aboveground Storage Facility	Production-Oil	Hayter/Provost	West Provost	14B-10-38-3 W4M
Aboveground Storage Facility	Production-Oil	Hayter/Provost	West Provost	6B-15-38-3 W4M
Aboveground Storage Facility	Slop Tank 1	Hayter/Provost	West Provost	12A-10-38-3 W4M
Aboveground Storage Facility	Slop Tank 2	Hayter/Provost	West Provost	12A-10-38-3 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	16-31-37-2 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	14D-12-38-3 W4M

EXHIBIT A

FORM OF NOTE

Date: [________________]

U.S.$[______________] New York, New York

FOR VALUE RECEIVED, the undersigned, Harvest Operations Corp., a corporation organized under the laws of the Province of Alberta, Canada ("Harvest"), promises to pay to the order of WestLB AG, New York Branch as Administrative Agent (the "Administrative Agent"), for the ratable benefit of [______________] ("Bank") on the Commitment Termination Date as defined in the Credit Agreement, hereinafter referred to, in the currency in which the Loans, Bankers' Acceptances Liabilities and Letter of Credit Liabilities and any payments in respect thereof under the Credit Agreement are denominated and in immediately available funds, the principal amount of U.S.$[______________], or, if less, the aggregate unpaid principal amount of all the Loans, Bankers' Acceptance Liabilities and Letter of Credit Liabilities and any payments in respect thereof made by the Administrative Agent for the account of the Bank to Harvest pursuant to the Credit Agreement, and to pay interest at such office, in like money, from the date hereof on the unpaid principal amount of such Loans, Bankers' Acceptances Liabilities and Letter of Credit Liabilities and any payments in respect thereof from time to time outstanding at the rates and on the dates specified in the Credit Agreement.

The Administrative Agent is authorized for the ratable benefit of the Bank to record, on the schedule annexed hereto and made a part hereof or on other appropriate records of the Administrative Agent, the date and amount of each Loan, Bankers' Acceptances Liability and Letter of Credit Liability and any payments in respect thereof made by the Administrative Agent, each continuation thereof, the interest rate from time to time on each Loan, Bankers' Acceptances Liability and Letter of Credit Liability and any payments in respect thereof and the date and amount of each payment or prepayment of principal thereof. Any such recordation shall constitute prima facie evidence of the accuracy of the information so recorded, provided that the failure of the Administrative Agent to make any such recordation (or any error in such recordation) shall not affect the obligations of Harvest hereunder or under the Credit Agreement in respect of the Loans, Bankers' Acceptances Liabilities and Letter of Credit Liabilities and any payments in respect thereof.

This Note is one of the Notes referred to in the Credit Agreement dated as of November [12], 2002 (as amended, supplemented or otherwise modified and in effect from time to time, the "Credit Agreement") among Harvest, the Subsidiary Guarantors party thereto and the Administrative Agent, and is entitled to the benefits thereof. Capitalized terms used herein without definition have the meanings assigned to them in the Credit Agreement.

This Note is subject to optional and mandatory prepayment as provided in the Credit Agreement.

Upon the occurrence of the Commitment Termination Date, the Administrative Agent shall have all of the remedies specified in the Credit Agreement. Harvest hereby waives presentment, demand, protest and all notices of any kind.

In case an Event of Default (as defined in the Credit Agreement) shall occur and be continuing, the principal of and accrued interest on this Note may be declared to be due and payable in the manner and with the effect provided in the Credit Agreement.

THIS NOTE AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES UNDER THIS NOTE SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

HARVEST OPERATIONS CORP.

By: ___________________________________

Name:

Title:

Schedule to
Note

Sample Summary Sheet
for Harvest Operations Corp.
Under the Credit Agreement

Loan Amount and Currency	Type	Date of Loan	Termination Date/Interest Rate and Other Loan Variables

EXHIBIT B

Exhibit Not Attached

EXHIBIT C

Exhibit Not Attached

EXHIBIT D

FORM OF USAGE CERTIFICATE

[Date]

WestLB AG, New York Branch
as Administrative Agent
1211 Avenue of the Americas
New York, New York 10036

Re: Harvest Operations Corp. Credit Agreement

Ladies and Gentlemen:

This certificate is hereby delivered pursuant to Section 2.02(b) of the Credit Agreement dated as of November __, 2002 (the "Credit Agreement") among Harvest Operations Corp., each Subsidiary of the Company that becomes a Subsidiary Guarantor, the Banks from time to time party thereto, WestLB AG, New York Branch, as Issuing Bank and WestLB AG, New York Branch, as Administrative Agent. Capitalized terms used herein and not otherwise defined shall have the meanings set forth in the Credit Agreement.

On the date hereof, we have delivered to you a [notice of borrowing] [request for issuance of a [Letter of Credit] [Bankers' Acceptance]]. After giving effect to such [borrowing] [issuance], the Usage Ratio will be [_______], which has been calculated as follows: [*insert details of calculation*].

I further certify that I am the [chief financial officer] [controller] [treasurer] [assistant treasurer] of the Company.

____
Name:

EXHIBIT E

Exhibit Not Attached

EXHIBIT F

CALCULATION OF NET PROCEEDS
OF BANKERS' ACCEPTANCE

The Net Proceeds of any Bankers' Acceptance shall be equal to the following formula:

Net Proceeds =

$$\frac{\text{Principal Amount of Bankers' Acceptance}}{100} \times \text{Price}$$

Price =

$$\frac{100}{1 + \frac{\text{Bankers' Acceptance Rate + BA Fee Rate}}{100} \times \frac{\text{Term}}{365}}$$

The Price of any Bankers' Acceptance shall be rounded to nearest 1/1000 of 1%.

14

04 MAR -9 AM 7:21

ADMINISTRATION AGREEMENT

between

VALIANT TRUST COMPANY

(the "Trustee")

and

HARVEST OPERATIONS CORP.

(the "Administrator")

Dated September 27, 2002

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ADMINISTRATION AGREEMENT

This Administration Agreement is made effective the 27th day of September, 2002 between VALIANT TRUST COMPANY, (the "Trustee") and HARVEST OPERATIONS CORP., an Alberta corporation (the "Administrator").

WHEREAS the Trustee wishes to retain the Administrator to provide certain administrative and advisory services in connection with the Trust and the Units (as defined herein);

AND WHEREAS the Administrator is willing to provide administrative and advisory services on the terms and conditions hereinafter set out;

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the mutual covenants herein contained and other good and valuable consideration receipt of which is hereby acknowledged by each of the parties hereto, the parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definition

In this Agreement, unless the context otherwise requires, the following terms shall have the following respective meanings:

(a) "affiliate" shall have the meaning ascribed to that term in the *Securities Act* (Alberta) as at the date hereof;

(b) "associate" shall have the meaning ascribed to that term in the *Securities Act* (Alberta) as at the date hereof;

(c) "Business Day" means a day, other than a Saturday, Sunday or statutory holiday, when banks are generally open in the city of Calgary, Alberta, for the transaction of banking business;

(d) "person" means an individual, partnership, corporation, business trust, joint stock company, trust, unincorporated association, joint venture or other entity or organization of whatever nature;

(e) "Transfer Agent" means the transfer agent from time to time for the Units;

(f) "Trust" means Harvest Energy Trust, a trust governed by the Trust Indenture;

(g) "Trust Fund" has the meaning set out in the Trust Indenture;

(h) "Trust Indenture" means the amended and restated indenture dated September 27, 2002 by which the Trust is governed;

(i) "Unitholders" means the holders of Units in the Trust; and

(j) "Units" means trust units of the Trust.

1.2 Additional Definitions

Unless the context otherwise requires, capitalized terms used in this Agreement without definition that are defined in the Trust Indenture shall have the meaning ascribed thereto in the Trust Indenture.

1.3 Interpretation

In this Agreement, except as otherwise expressly provided:

(a) "this Agreement" means this agreement, as amended and in effect from time to time;

(b) any reference in this Agreement to a designated "Article", "section", "subsection", "schedule" or other subdivision is a reference to the designated Article, Section, subsection, schedule or other subdivision of this Agreement;

(c) the recitals hereto are incorporated into and form part of this Agreement;

(d) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section, subsection, schedule or other subdivision of this Agreement;

(e) the division of this Agreement into Articles, Sections, subsections, schedules and other subdivisions and the provision of headings are for convenience of reference only and shall not affect the interpretation of the provisions to which they relate or of any other provisions hereof;

(f) words importing the singular number only shall include the plural and vice versa and words importing the use of any gender shall include any other gender, the word "or" is not exclusive and the word "including" is not limiting 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;

(g) all dollar amounts are stated and are to be paid in lawful currency of Canada;

(h) where the time for doing an act falls or expires on a day which is not a business day, the time for doing such act is extended to the next business day; and

(i) any reference to a statute includes and is a reference to such statute and to the regulations made pursuant thereto in effect on the date of this Agreement unless otherwise specifically provided.

1.4 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Province of Alberta and the federal laws of Canada applicable therein and the courts of such province shall have non-exclusive jurisdiction over any dispute hereunder, to which jurisdiction the parties attorn.

1.5 References to Acts Performed by the Trust

For greater certainty, where any reference is made in this Agreement to an act to be or not to be performed by the Trust, such reference shall be construed and applied for all purposes as if it referred to an act to be or not to be performed by the Trustee on behalf of the Trust.

1.6 Liability of Trustee and Unitholders

The parties hereto acknowledge that the Trustee is entering into this Agreement solely in its capacity as Trustee and the obligations of the Trustee hereunder shall not be personally binding upon the Trustee, or any of the Unitholders or any annuitant under a plan of which a Unitholder is a trustee or carrier (an "annuitant") and that any recourse against the Trust, the Trustee, any Unitholder or annuitant in any manner in respect of any indebtedness, obligation or liability of the Trustee arising hereunder or arising in connection herewith or from the matters to which this Agreement relates, if any, including without limitation claims based on negligence or otherwise tortious behaviour, shall be limited to, and satisfied only out of, the Trust Fund.

ARTICLE 2
ADMINISTRATION OF THE TRUST

2.1 General Delegation of Authority

Subject to and in accordance with the terms, conditions and limitations of the Trust Indenture and to the other provisions of this Agreement, the Trustee hereby delegates to the Administrator, and the Administrator hereby accepts the delegation of the authority to perform the Trustee's duties under the Trust Indenture, and agrees to be responsible for the administration and management of all general and administrative affairs of the Trust in accordance with the provisions hereof. The exercise of powers by the Administrator shall not adversely affect the status of the Trust as a "unit trust" and a "mutual fund trust" for the purposes of the Tax Act.

2.2 Specific Delegation of Authority

It is acknowledged and agreed that in furtherance of its obligations under Section 2.1 to administer and manage the general and administrative affairs of the Trust, and not in limitation thereof; the Administrator will, subject to the direction of the Trustee:

(a) keep and maintain at its offices in Calgary, Alberta at all times books, records and accounts which shall contain particulars of operations, receipts, disbursements and investments relating to the Trust Fund and such books, records and accounts shall be kept pursuant to normal commercial practices that will permit the preparation of financial statements in accordance with Canadian generally accepted accounting principles which, as early as practicable, shall be in accordance with those required to be kept by a distributing corporation (as defined in the *Business Corporations Act* (Alberta)) (except that nothing herein shall be construed as requiring the books, records or documents of the Administrator to be audited) and in each case shall also be in accordance with those required to be kept by a reporting issuer under applicable securities legislation in Canada and those required of the Trust under the *Income Tax Act* (Canada) and the Income Tax Regulations applicable with respect thereto, all as amended from time to time;

(b) prepare all returns, filings and documents and make all determinations necessary for the discharge of the Trustee's obligations under Sections 16.2, 16.3, 16.5, 16.6 and 16.7 of the Trust Indenture;

(c) monitor the tax status of the Trust and provide information to the Trustee regarding the taxable portions of distributions;

(d) prepare and submit all income tax returns and filings to the Trustee in sufficient time prior to the dates upon which they must be filed so that the Trustee has a reasonable opportunity to review them, approve them, execute them and return them to the Administrator; and arrange for their filing within the time required by applicable tax law;

(e) provide advice with respect to the Trust's obligations as a reporting issuer and ensure compliance by the Trust with continuous disclosure obligations under applicable securities legislation including the preparation and filing of reports and other documents with all applicable regulatory authorities;

(f) provide investor relations services to the Trust including assisting with communications with Unitholders;

(g) at the request and under the direction of the Trustee, call and hold all annual and/or special meetings of the Unitholders pursuant to Article 10 of the Trust Indenture, prepare all materials (including notices of meetings and information circulars) in respect thereof and submit all such materials to the Trustee in sufficient time prior to the dates upon which they must be mailed, filed or otherwise relied upon so that the Trustee has a reasonable opportunity to review them, approve them, execute them and return them to the Administrator for filing or mailing or otherwise;

(h) provide, for performing its obligations hereunder, office space, equipment and personnel including all accounting, clerical, secretarial, corporate and administrative services as may be reasonably necessary to perform its obligations hereunder;

(i) provide or cause to be provided such audit, accounting, engineering, legal, insurance and other professional services as are reasonably required or desirable for the purposes of the Trust including, without limitation, administration of the Direct Royalties, from time to time and provide or cause to be provided such legal, engineering, financial and other advice and analysis as the Trustee may require or desire to permit it to make informed decisions in connection with the discharge by it of its responsibilities as Trustee, to the extent such advice and analysis can be reasonably provided or arranged by the Administrator;

(j) provide assistance in negotiating the terms of any financing required by the Trust or otherwise in connection with the Trust Fund;

(k) take all actions reasonably necessary in connection with, or in relation to, those matters referred to in Section 7.4 of the Trust Indenture;

(l) take all actions reasonably necessary in connection with, or in relation to, all matters relating to the redemption of Units pursuant to the Trust Indenture;

(m) take all actions reasonably necessary in connection with, or in relation to, the voting rights on any investments in the Trust Fund or any Subsequent Investments;

(n) take all actions reasonably necessary in connection with, or in relation to, directly or indirectly, the borrowing of money from or incurring indebtedness by the Trust to any person and in connection therewith, to cause the Trust to guarantee, indemnify or act as a surety with respect to payment or performance of any indebtedness, liabilities or obligation of any kind of any person, including, without limitation, the Administrator and any subsidiary (as defined in the *Securities Act* (Alberta) of the Trust; to enter into any other obligations on behalf of the Trust; or enter into any subordination agreement on behalf of the Trust or any other person, and to assign, charge, pledge, hypothecate, convey, transfer, mortgage, subordinate, and grant any security interest, mortgage or encumbrance over or with respect to all or any of the Trust Fund or to subordinate the interests of the Trust in the Trust Fund to any other person;

(o) take all actions reasonably necessary in connection with, or in relation to, the guarantee by the Trust of obligations of the Administrator or any other affiliate of the Trust pursuant to any debt for borrowed money or obligations resulting or arising from hedging instruments incurred by the Administrator or any such affiliate, as the case may be, and pledging securities issued by the Administrator or the affiliate, as the case may be, as security for such guarantee provided that such guarantee is incidental to the Trust's direct or indirect investment in the Administrator or any such affiliate or the business and affairs (existing or proposed) of the Administrator or any such affiliate, and each such guarantee entered into by the Trustee shall be binding upon, and enforceable in accordance with its terms against, the Trust;

(p) take all actions reasonably necessary in connection with, or in relation to, the Trust providing indemnities for the directors and officers of the Administrator and any affiliates;

(q) provide or cause to be provided to the Trustee any services reasonably necessary for the Trustee to be able to consider any future acquisitions or divestitures by the Trustee of any portion of the Trust Fund, including Direct Royalties;

(r) provide advice to the Trustee with respect to determining the timing and terms of future offerings of Units, if any;

(s) administer all of the records and documents relating to the Trust Fund other than maintenance of a register of Unitholders;

(t) provide advice and, at the request and under the direction of the Trustee, direction to the Transfer Agent;

(u) take all actions reasonably necessary in connection with, or in relation to, those matters referred to in Sections 7.1(b) and 8.1 of the Trust Indenture;

(v) determine, from time to time, all amounts required to be determined pursuant to Article 5 of the Trust Indenture, including the amounts available for distribution to Unitholders, and arrange for payment thereof to the Unitholders in accordance with Article 5 of the Trust Indenture;

(w) provide advice and assistance to the Trustee with respect to the performance of the obligations of the Trust and the enforcement of the rights of the Trust under all agreements entered into by the Trust;

(x) monitor the status of the Units as eligible investments for registered retirement savings plans, registered retirement income funds, and deferred profit sharing plans (all within the meaning of the Tax Act) and immediately provide the Trustee with written notice when the Administrator reasonably foresees that such Units may cease to have such status, or, if not reasonably foreseen, when the Units cease to have such status;

(y) in the event that withholding taxes are exigible on any distributions or redemption amounts distributed under the Trust Indenture or any other agreement, the Administrator shall withhold the withholding taxes required and shall promptly remit such taxes to the appropriate taxing authority. In the event that withholding taxes are exigible on any distributions or redemption amounts distributed under the Trust Indenture or any other agreement and the Administrator is, or was, unable to withhold taxes from a particular distribution to a Unitholder or has not otherwise withheld taxes on past distributions to a Unitholder, the Administrator shall be permitted to withhold amounts from other distributions to satisfy the Administrator's withholding tax obligations;

(z) provide such additional administrative and support services pertaining to the Trust, the Trust Fund and the Units and matters incidental thereto as may be reasonably requested by the Trustee from time to time;

(aa) administer all matters relating to the Direct Royalties and the Trust, including: (i) determining the total amounts owing to Unitholders and arranging cash distributions; (ii) providing Unitholders with periodic reports on the NPI, the Direct Royalties and the Properties; and (iii) providing Unitholders with financial reports and tax information relating to the Properties, the NPI and the Direct Royalties;

(bb) provide management services for the economic and efficient exploitation of the Properties and the Direct Royalties;

(cc) take all actions reasonably necessary in connection with, or in relation to, the Capital Fund (as defined in the Trust Indenture); and

(dd) recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for the Trust.

2.3 Restrictions on Delegation of Authority

Notwithstanding any other provisions of this Agreement, the Trustee shall not and is not hereby delegating to the Administrator any authority to manage the following affairs of the Trust:

(a) the issue, certification, countersigning, transfer, exchange and cancellation of certificates representing Units;

(b) the maintenance of a register of Unitholders;

(c) the delivery of distributions to Unitholders, although the calculation of distributions shall be made by the Administrator and approved by the board of directors of the Administrator and submitted by the Administrator to the Trustee for distribution to the Unitholders;

(d) the mailing of notices, financial statements and reports to Unitholders pursuant to Sections 14.1, 16.2 and 16.3 of the Trust Indenture, although the Administrator shall be responsible for the preparation or causing the preparation of such notices, financial statements and reports;

(e) the provision of a basic list of registered Unitholders (as defined in the Trust Indenture) to Unitholders in accordance with the procedures outlined in the Trust Indenture;

(f) the amendment or waiver of the performance or breach of any term or provision of this Agreement or the NPI Agreement on behalf of the Trust;

(g) the renewal or termination of this Agreement on behalf of the Trust; and

(h) any matter which requires the approval of the Unitholders under the terms of the Trust Indenture.

2.4 Power and Authorities of the Administrator

Subject to any direction of the Trustee from time to time, the Administrator shall have full right, power and authority to do and refrain from doing all such things as are necessary or appropriate in order to discharge its duties hereunder. In particular, and without limiting the generality of the foregoing, the Administrator shall have full right, power and authority to execute and deliver all contracts, leases, licences and other documents and agreements, to make applications and filings with governmental and regulatory authorities and to take such other actions as the Administrator considers appropriate in connection with the Trust in the name of and on behalf of the Trust and no person shall be required to determine the authority of the Administrator to give any undertaking or enter into any commitment on behalf of the Trust, provided that the Administrator shall not have the authority to commit to any transaction which would require the approval of the Unitholders in accordance with the Trust Indenture or take any action required to be taken by the Trustee under the Trust Indenture or take any action requiring approval of the Trustee without such approval having been given.

2.5 Distributions to Unitholders

In connection with determining the amounts payable from time to time to Unitholders and arranging for distribution to them, it is understood and agreed that the Administrator shall determine from time to time the amounts available for distribution to Unitholders and shall provide a written statement thereof to the Trustee prior to the date on which such distribution must be made and shall cause such amount to be paid by the Transfer Agent on behalf of the Trust following the declaration by the Trustee that such amounts are due and payable by the Trust pursuant to Article 5 of the Trust Indenture; provided however that the Administrator shall not be obligated to make any such payment unless the Administrator has monies of the Trust available to make such distribution.

2.6 Annual Certificate

The Administrator shall deliver to the Trustee within 60 days after the end of each calendar year and at any other time upon the demand of the Trustee, a certificate signed by a senior officer of the Administrator stating that:

(a) the Administrator has complied with all of its duties contained in this Agreement relating to the management of the general and administrative affairs of the Trust, which, if not complied with, would, with the giving of notice, lapse of time or otherwise, constitute a default of the Administrator under this Agreement or, if there has been a failure so to comply, giving particulars thereof; and

(b) as at the end of such year or other time period requested by the Trustee, the Units were eligible investments for registered retirement savings plan, registered retirement income funds and deferred profit sharing plans (all within the meaning of the Tax Act).

ARTICLE 3
PAYMENT OF EXPENSES

3.1 Payment of Expenses

The Administrator shall pay for and shall bear all outlays and expenses to third parties incurred by the Administrator in the administration of the affairs of the Trust and the performance by the Administrator of its duties hereunder (including costs and expenses incurred in calling and convening meetings of Unitholders, in reporting to Unitholders and in making distributions to Unitholders), and shall not seek reimbursement from the Trust for any of such outlays and expenses.

3.2 No Fee

The Administrator shall not be entitled to the payment of a fee for the services provided by the Administrator to the Trust under this Agreement.

3.3 Remuneration and Expenses of the Trustee

The Administrator shall pay the remuneration and expenses of the Trustee as provided in Section 7.6 of the Trust Indenture.

ARTICLE 4
CONDUCT OF THE ADMINISTRATOR

4.1 Administrator's Acknowledgement

The Administrator acknowledges and agrees that it has received a copy of the Trust Indenture and is familiar with and understands the duties of the Administrator and the Trustee thereunder, including those which are being delegated to the Administrator under this Agreement. The Administrator agrees to comply in all respects with the provisions of the Trust Indenture in the performance of its duties and obligations hereunder.

4.2 Standard of Care and Delegation

(a) In exercising its powers and discharging its duties under this Agreement, the Administrator shall act honestly and in good faith and exercise the degree of care, diligence and skill that a reasonably prudent oil and natural gas industry advisor and administrator would exercise in comparable circumstances. The Administrator's objective in exercising its powers and discharging its duties hereunder shall be to maximize the income distributable to the Unitholders to the extent consistent with long-term growth in the value of the Trust. In pursuing such objective, the Administrator will employ prudent oil and natural gas business practices. All of the Administrator's activities in relation to this Agreement and the Trust will be conducted in accordance with applicable laws with a view to the best interests of the Unitholders and the Trust.

(b) The Administrator may delegate specific aspects of its obligations hereunder to any person, including any of its affiliates or associates and including the Transfer Agent, provided that:

(i) such delegation shall not relieve the Administrator of any of its obligations under this Agreement and provided that the Administrator shall not delegate any of its obligations hereunder to manage and administer the affairs of the Trust unless the Administrator shall have notified the Trustee of the name of the person or persons to which delegation is to be made and the terms and conditions thereof and the Trustee has provided prior written consent to such delegation; and

(ii) the Administrator shall not in any manner, directly or indirectly, be liable or held to account for the activities or inactivities of any person to which any such obligations may have been delegated provided that in making such specific delegation, the Administrator acted in accordance with subsection 4.2(a).

4.3 Liability

The Administrator shall not be liable, answerable or accountable to the Trust for:

(a) any loss or damage resulting from, incidental to or relating to the provision of the services provided for hereunder, including any exercise or refusal to exercise a discretion, any mistake or error of judgment or any act or omission believed by the Administrator to be within the scope of authority conferred on it by this Agreement, unless such loss or damage resulted from a breach by the Administrator of the standard of care set forth in Section 4.2(a); or

(b) any reasonable reliance by the Administrator in performing its obligations hereunder on:

(i) statements of fact of other persons (any of which may be persons with which the Administrator is affiliated or associated) who are reasonably considered by the Administrator to be knowledgeable of such facts; or

(ii) the opinion or advice of or information obtained from any solicitor, auditor, valuer, engineer, surveyor, appraiser or other expert who is reasonably considered by the Administrator to be a person on whom reliance should be had under the circumstances;

provided that in obtaining such statements of fact, opinions, advice or information, the Administrator acted in accordance with subsection 4.2(a).

4.4 No Liability for Advice

The Administrator shall not be liable, answerable or accountable for any loss or damage resulting from the advice given to the Trust by the Administrator or the exercise by the Administrator of a discretion or its refusal to exercise a discretion, provided that the Administrator acted in accordance with subsection 4.2(a) and the loss or damage suffered by the Trustee is not attributable to the Administrator's gross negligence, wilful default, bad faith or fraud.

4.5 Conflict of Interest

(a) To the extent there is a conflict of interest between the Administrator acting in that capacity and the Trust in respect of any matter, the Administrator shall resolve such conflicts, on a basis consistent with the objectives and funds of each group of interested parties and the time limitations on investment of such funds, all consistent with the duty of the Administrator to deal fairly and in good faith with each group or persons.

(b) In the event that the interests of the Administrator are in conflict with those of the Trust or the Unitholders, the Administrator shall make decisions acting in good faith, having regard to the best interests of the Unitholders and the Trust and in a manner that would not contravene its fiduciary obligations to Unitholders.

4.6 Confidentiality

Subject to Section 2.2, the Administrator shall not, without the prior written consent of the Trustee, disclose to any third party any information about the Trust acquired or developed pursuant to the performance of services under this Agreement except that consent shall not be required to the following disclosure:

(a) information disclosed as required by law or the regulations, rules or policies of any stock exchange on which any Units are listed or as may be required by the regulations or policies of any securities commission or other securities regulatory agency, governmental agency or other authority of competent jurisdiction and the requirements of any court; or

(b) information disclosed as necessary for the purposes of any debt or equity financing undertaken by the Trust; or

(c) information disclosed that the Administrator acting reasonably deems to be necessary to be disclosed on a confidential basis for the proper performance of its duties and obligations under this Agreement, including without limitation, disclosure of information to consultants and other third parties engaged by or assisting the Administrator in accordance with the terms of this Agreement in order to carry out the purposes of this Agreement.

The provisions of this Section 4.6 shall not merge upon the termination of this Agreement.

4.7 Indemnification of the Administrator

The Administrator and any person who, at the request of the Administrator, is serving or shall have served as a director, officer, employee, advisor, partner, consultant, agent or subcontractor of the Administrator shall be indemnified and saved harmless by the Trust against all losses (other than loss of profit), claims, damages, liabilities, obligations, costs and expenses (including judgments, fines, penalties, amounts paid in settlement and counsel and accountants' fees) of whatsoever kind or nature incurred by, borne by or asserted against any of such indemnified parties in any way arising from and related in any manner to the provision of services and the performance of obligations by the Administrator pursuant to this Agreement, unless such indemnified party is found liable for or guilty of fraud, wilful default or gross negligence. The foregoing right of indemnification shall not be exclusive of any other rights to which the Administrator or any person referred to in this Section 4.6 may be entitled as a matter of law or equity or which may be lawfully granted to him.

4.8 Indemnification of the Trust and the Trustee

The Trust, the Trustee and any person who, at the request of the Trustee, is serving or shall have served as an officer, employee, advisor, consultant, agent or subcontractor of the Trustee in respect of the Trust shall be indemnified and saved harmless by the Administrator against all losses, claims, damages, liabilities, obligations, costs and expenses (including judgments, fines, penalties, amounts paid in settlement and counsel and accountants' fees) of whatsoever kind or nature incurred by, borne by or asserted against any of such indemnified parties in any way arising from or related in any manner to the failure by the Administrator to discharge its duties and liabilities hereunder in accordance with the duty of loyalty and standard of care specified in Section 4.2(a), the breach by the Administrator of its obligations hereunder or the fraud, wilful default, negligence or bad faith of the Administrator or its employees in the provision of services or the performance of its obligations hereunder, unless such losses, claims, damages, liabilities, obligations, costs and expenses (including judgments, fines, penalties, amounts paid in settlement, and counsel and accountants fees) arise from the fraud, wilful default or negligence of such indemnified party. The foregoing right of indemnification shall not be exclusive of any rights to which the Trust, the Trustee or any person referred to in this Section 4.7 may be entitled as a matter of law or equity or which may be lawfully granted to him.

ARTICLE 5
TERM AND TERMINATION

5.1 Term

Subject to Section 5.4, this Agreement shall continue in force for a period of ten years from the date of this Agreement unless terminated earlier by the Trust, in its sole discretion, by notice in writing to the Administrator given at least 30 days prior to the effective date of termination which shall be stated in such notice and upon payment to the Administrator of any amounts required to be paid to it as provided for in Section 5.5.

5.2 Automatic Renewal

Subject to Section 5.4 and any earlier termination pursuant to Section 5.1, upon the expiry of the ten-year initial term of this Agreement provided pursuant to Section 5.1, the term of this Agreement shall be automatically renewed for a further term of three years subject to the Trust's right of earlier termination on the same basis as provided in Section 5.1 and subject to Section 5.4 and thereafter automatically for such additional three-year renewal terms upon the expiry of each preceding renewal term, all subject to Section 5.1 and Section 5.4.

5.3 Effect of Termination

Upon the effective date of termination of this Agreement, the Administrator shall:

(a) forthwith pay to the Trust, or to the order of the Trust, all monies collected and held for the Trust pursuant to this Agreement;

(b) as soon thereafter as is reasonably practicable, deliver to the Trust, or to the order of the Trust, a complete auditor's report including a statement showing all payments collected by it and a statement of all monies held by it during the period following the date of the last audited statement furnished to the Trust; and

(c) forthwith, to the extent that it is able, subject to any applicable legal and contractual restrictions, deliver to and, where applicable, transfer into the custody of the Trustee all property and documents of the Trust then in the custody of the Administrator.

5.4 Default

This Agreement shall be immediately terminable by written notice from the Administrator or the Trustee to the other, as the case may be, in the event that:

(a) the Trust terminates;

(b) the Administrator:

(i) institutes proceedings for it to be adjudicated a voluntary bankrupt, or consents to the filing of a bankruptcy proceeding against it;

(ii) files a petition or answer or consent seeking reorganization, readjustment, arrangement, composition or similar relief under any bankruptcy law;

(iii) consents to the appointment of a receiver, liquidator, Trustee or assignee in bankruptcy; or

(iv) makes an assignment for the benefit of its creditors generally;

(c) a court having jurisdiction enters a decree or order adjudging the Administrator a bankrupt or insolvent or for the appointment of a receiver, Trustee or assignee in bankruptcy;

(d) any proceeding with respect to the Administrator is commenced under the *Bankruptcy and Insolvency Act* (Canada) or the *Companies' Creditors' Arrangement Act* (Canada) or similar legislation relating to a compromise or arrangement with creditors or claimants; or

(e) control of the Administrator changes other than pursuant to actions taken by the Trust or Trustee, pursuant to a resolution passed by Unitholders.

5.5 Payment

Upon a written notice to terminate this Agreement being given pursuant to Section 5.1 or 5.4, the Trust shall either pay to the Administrator, before or at the time of the termination of this Agreement, all costs and expenses incurred or required to be incurred by the Administrator in terminating contracts the Administrator has entered into in the performance by the Administrator of its duties under this Agreement (less any amount owing by the Administrator to the Trust) or, at the election of the Trust, assume the obligations of the Administrator under such contracts or any of them.

5.6 Continuing Obligations

Notwithstanding termination of this Agreement, the parties hereto shall not be relieved from any obligations or liabilities arising prior to such termination.

ARTICLE 6
GENERAL

6.1 Access to Records

The Trust and the Administrator shall provide to the other full and free access to all records, documents and materials in its possession or control and relating to the Trust and the services to be provided by the Administrator hereunder. The Administrator shall retain or cause to be retained all books and records related to it and its obligations hereunder for a period of two years following termination of this Agreement, or such longer periods as required in accordance with income tax or other statutory requirements, during which period the Trust shall continue to have the access thereto described above.

6.2 Amendments

This Agreement shall not be amended or varied in its terms by oral agreement or by representations or otherwise except by instrument in writing executed by the duly authorized representatives of the parties hereto or their respective successors or assigns.

6.3 Assignment

This Agreement shall not be assigned by either party hereto without the prior written consent of the other party, which consent shall not be unreasonably withheld or refused, save and except that the Administrator may assign this Agreement to an affiliate or associate of the Administrator without the consent of the Trust if such affiliate or associate will agree, in writing, with the Trust to be bound by all of the provisions of this Agreement and to remain an affiliate or associate of the Administrator during the term of this Agreement.

6.4 Severability

The provisions of this Agreement are severable. In the event of the unenforceability or invalidity of any one or more of the provisions of this Agreement under applicable law, such unenforceability or invalidity shall not render any of the other terms, covenants, conditions or provisions hereof unenforceable or invalid.

6.5 Notice

All notices required or permitted herein under this Agreement shall be in writing and may be given by delivering such notice or mailing such notice by pre-paid registered mail or by facsimile transmission to the address set forth below. Any such notice or other communication shall, if delivered, be deemed to have been given or made and received on the date delivered (or the next business day if the day of delivery is not a business day), and if mailed, shall be deemed to have been given or made and received on the third business day following the day on which it was so mailed and if faxed (with confirmation received) shall be deemed to have been given or made and received on the day on which it was so faxed (or the next business day if the day of sending is not a business day). The parties hereto may give from time to time written notice of change of address in the manner aforesaid.

Valiant Trust Company
510, 550 - 6th Avenue S.W.
Calgary, Alberta T2P 0S2

Attention: Manager, Corporate Trust Department
Telecopier No.: (403) 233-2857

Harvest Operations Corp.
Suite 2400, 500 – 6th Avenue S.W
Calgary, Alberta T2P 0S2

Attention: Jacob Roorda, President
Telecopier No.: (403) 266-1438

6.6 Force Majeure

Delays in or failure of performance by a party hereto of a term or provision of this Agreement shall not constitute a default hereunder, and the obligations of a party shall be suspended during such time and to such extent that the performance of its obligations is prevented or delayed, in whole or in part, by force majeure, whenever, wherever and in respect of whomsoever such force majeure occurs.

For the purposes of this Agreement events of force majeure include strikes, lock-outs, industrial disturbance, storm, fire, flood, landslide, snowslide, earthquake, explosion, lightning, tempest, action of elements, interruption or delay in transportation including, without limitation, highway or railway closures, cessation or interruption of power supplies, acts of God, laws, rules and regulations of any government or any governmental or regulatory authority, unavoidable accidents, inability to obtain or delay in obtaining necessary permits or approvals from government or any governmental or regulatory authority, inability to obtain or delay in obtaining necessary materials, facilities and equipment in the open market, or any other cause whether similar or dissimilar to those specifically enumerated, to the extent that such cause and the effects thereof are beyond the reasonable control of the party, provided that a party's own lack of funds shall not be considered an event beyond a party's reasonable control.

6.7 Further Assurances

Each party hereto agrees to execute any and all documents and to perform such other acts as may be necessary or expedient to carry out the purposes of this Agreement and the transactions contemplated hereby.

6.8 Time of Essence

Time is of the essence in respect of this Agreement.

6.9 No Partnership

Nothing herein shall be construed as creating a partnership and no Party shall have any partnership rights or liabilities hereunder or in connection herewith.

6.10 Entire Agreement

This Agreement constitutes the entire agreement between the parties hereto, and supersedes all prior agreements, in respect of the subject matter hereof.

6.11 Enurement

This Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors (including additional or successor Trustee appointed pursuant to the Trust Indenture) and permitted assigns.

6.12 Counterparts

This Agreement may be executed in several counterparts, each of which when executed by any of the parties shall be deemed to be an original, and such counterparts shall together constitute one and the same instrument.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the date first above written.

VALIANT TRUST COMPANY

Per: (signed) "*Zinat H. Damji*"

Per: (signed) "*Cheryl Dahlager*"

HARVEST OPERATIONS CORP.

Per: (signed) "*Jacob Roorda*"

AGREL 04 MAR -9 AM 7:21

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Hayter and West Provost Areas, Alberta

THIS AGREEMENT made as of the 1st day of August, 2002.

BETWEEN:

ANADARKO CANADA CORPORATION, a body corporate, with offices in the City of Calgary, in the Province of Alberta ("**Vendor**")

- and -

COYOTE ENERGY INC., a body corporate, with offices in the City of Calgary, in the Province of Alberta ("**Purchaser**")

WHEREAS Vendor has agreed to sell and Purchaser has agreed to purchase certain oil and gas interests subject to and in accordance with the terms and conditions hereof;

NOW THEREFORE in consideration of the mutual covenants contained within this Agreement, the Parties covenant and agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement, including the recitals and schedules to this Agreement:

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

"**AFEs**" means the capital expenditures pursuant to the outstanding authorizations for expenditure set out in Schedule "C" arising as of and subsequent to the Effective Date for which the final accounting adjustments have not been completed and for which the Purchaser shall be responsible;

"**Affiliate**" means any corporation, partnership or legal entity which (a) controls directly or indirectly a party; (b) is controlled directly or indirectly by such party; or (c) is directly or indirectly controlled by a corporation, partnership or legal entity which directly or indirectly controls such party. A corporation will be deemed to be controlled by any such entity that owns or effectively controls, other than by way of security only, sufficient voting shares of that corporation whether directly or through the ownership of shares of another corporation that owns shares of that corporation or through other equity interests to elect the majority of its board of directors and control of a partnership means the ownership, directly or indirectly, of 50% or more of the voting rights in the partnership;

"**Assets**" means the Petroleum and Natural Gas Rights, the Tangibles and the Miscellaneous Interests;

"**Business Day**" means any day of the week except Saturday, Sunday and any statutory holiday in Alberta;

"**Certificate**" means a written certification of a matter or matters of fact which, if required from a corporation, shall be made by an officer of the corporation, on behalf of the corporation and not in any personal capacity;

"**Closing**" means the transfer by Vendor to Purchaser of beneficial ownership and risk of the Assets and the payment by Purchaser to Vendor of the purchase consideration and the completion of all matters incidental in accordance with the terms and conditions of this Agreement;

"**Closing Date**" means 10:00 a.m. on November 1, 2002, or such other time and date as may be agreed to in writing by the Parties;

"**Deposit**" means the sum of money set out in clause 2.4;

"**Dollar**" or "**$**" means a Canadian dollar;

"**Effective Date**" means 8:00 a.m. on June 1, 2002;

"**Field Facilities**" means the facility or facilities set out in Schedule "A" under that heading;

"**GST**" means the goods and services tax as provided for in the *Excise Tax Act*, R.S.C. 1985, c. E-15, as amended, or any successor or parallel provincial or federal legislation that imposes a tax on the recipient of goods or services supplied under this Agreement;

"**Lands**" means the lands set out in Schedule "A" under that heading;

"**Leased Substances**" means all Petroleum Substances or rights to Petroleum Substances which are granted, reserved or otherwise conferred by or under the Title Documents;

"**Material Title Defect**" means any defect or irregularity in Vendor's title to any of the Assets that has the effect of or may have the effect of reducing the value of the affected Asset(s) by at least twenty-five thousand dollars ($25,000.00), such defects or irregularities exclude Permitted Encumbrances and Preferential Rights;

"**Miscellaneous Interests**" means, subject to the exclusions and limitations provided in this definition, the Vendor's Interest in all property, assets and rights (other than the Petroleum and Natural Gas Rights and Tangibles) pertaining or ancillary to either the Petroleum and Natural Gas Rights or Tangibles to which Vendor is entitled including, but not limited to, the following:

(a) contracts and agreements relating to the Petroleum and Natural Gas Rights or Tangibles, including, without limitation, gas purchase contracts, operating agreements, processing agreements, transportation agreements, the Production and Marketing Contracts and agreements for the construction, ownership and operation of facilities;

(b) rights to enter upon, use or occupy the surface of the Lands for the purpose of gaining access to or otherwise using the Petroleum and Natural Gas Rights and the Tangibles, or either of them;

(c) Leased Substances produced from the Lands except those that are beyond the wellhead at the Effective Date or sale proceeds in respect of such Leased Substances if title has passed to the purchaser thereof;

(d) the Wells, including the wellbores and casing;

(e) all records, books, files, data, documents, licenses, permits or authorizations relating directly to the Petroleum and Natural Gas Rights or Tangibles and reservoir and environmental studies that relate solely to the Petroleum and Natural Gas Rights or Tangibles; and

(f) the Seismic Data; but

excluding any of the foregoing that pertain to Vendor's tax or financial records, economic evaluations, geophysical or geological data (with the exception of the Seismic Data);

"**Party**" means Vendor or Purchaser, and Parties means both of them;

"**Permitted Encumbrances**" means:

(a) any encumbrances, overriding royalties, liens, adverse claims, reductions in interest and other burdens set out in Schedule "A";

(b) agreements for the sale of Leased Substances, that are terminable on 30 days notice or less (without penalty);

(c) easements, rights of way, road use agreements, crossing agreements, servitudes and other similar rights in land including, without limitation, rights of way and servitudes for highways and other roads, railways, sewers, drains, gas and oil pipelines, gas and water mains, electric light, power, telephone, telegraph or cable television conduits, poles, wires or cables;

(d) the right reserved to or vested in any governmental or other public authority by the terms of any lease, licence, franchise, grant or permit or by any statutory provision to terminate any such lease, licence, franchise, grant or permit, or to require annual or other periodic payments as a condition of the continuance of them;

(e) rights of general application reserved to or vested in any governmental authority to levy taxes on Leased Substances or the income therefrom, and governmental requirements and limitations of general applications as to production rates or the operations of any property;

(f) the Production and Marketing Contracts and any agreements or plans relating to pooling or unitization which are binding on Vendor as well as agreements respecting the processing, treating or transmission of Leased Substances or the operation of Wells by contract field operators;

(g) liens incurred or created in the ordinary course of business as security in favour of the person who is conducting the development or operation of any of the Assets, for Vendor's proportionate share of the costs and expenses thereof;

(h) the reservations, limitations, provisos and conditions in any grants or transfers from the Crown of any of the Lands or interests in them and statutory exceptions to title;

(i) liens for taxes, assessments or governmental charges that are not due, or the validity of which is being contested in good faith by Vendor;

(j) mechanics', builders' or materialmen's liens in respect of services rendered or goods supplied for which payment is not due;

(k) provisions for penalties and forfeitures under agreements as a consequence of non-participation in operations; and

(l) any security held by any third party encumbering Vendor's interest in and to the Assets or any part or portion thereof, a discharge in respect of which Vendor delivers to Purchaser on or prior to the Closing Date in a form acceptable to Purchaser, acting reasonably, as contemplated in subclause 3.2(d) hereof;

"**Petroleum and Natural Gas Rights**" means the Vendor's Interest in and to the Title Documents and the Leased Substances and the rights granted in respect of the Title Documents and Leased Substances as set out in Schedule "A";

"**Petroleum Substances**" means any of crude oil, crude bitumen and products derived therefrom, synthetic crude oil, petroleum, natural gas, natural gas liquids, and any and all other substances related to any of the foregoing, whether liquid, solid or gaseous, and whether hydrocarbons or not, including without limitation, sulphur;

"**Preferential Right**" means a right of first refusal, preemptive right of purchase or similar right whereby any party, other than Vendor or Purchaser, has the right to acquire or purchase all or a portion of the Assets as a consequence of Vendor having agreed to sell the Assets to Purchaser in accordance herewith;

"**Prime Rate**" means an annual rate of interest equal to the annual rate of interest announced from time to time of the main branch of TD Canada Trust in Calgary, Alberta, as a reference rate then in effect for determining interest rates on Canadian dollar commercial loans provided that such rate shall be determined on the last day of each month and applied to the next succeeding month;

"**Production and Marketing Contracts**" means the agreements set out in Schedule "B";

"**Purchase Price**" means the sum of money first set out in clause 2.2 hereof;

"**Regulations**" means all statutes, laws, orders and regulations in effect from time to time and made by governments or governmental boards or agencies having jurisdiction over the Assets;

"**Seismic Data**" means one non-exclusive, non-transferable, licensed copy of Vendor's proprietary seismic data, including without limitation (provided it is available): (i) the SegP Survey on a 3.5 inch diskette; (ii) microfiche copies of the observer's reports, drilling reports and chaining reports; (iii) basic field data on a CD-ROM; all processed stack versions on a CD-ROM; and all notes, as specifically set out in Schedule "F";

"**Specific Conveyances**" means all conveyances, assignments, transfers, novations and other documents or instruments that are reasonably required or desirable to convey, assign and transfer the Assets to Purchaser and to novate Purchaser in the place and stead of Vendor with respect to the Assets and shall include, where applicable, Declarations of Special Operator for pipelines and/or wells;

"**Tangibles**" means the Vendor's Interest in:

(a) the Field Facilities; and

(b) in any and all tangible depreciable property and assets (other than the Field Facilities) which are located within or upon the Lands on the Effective Date and which are used or intended to be used in producing, processing, gathering, treating, measuring, making marketable or injecting Leased Substances or any of them or in connection with water injection or removal operations that pertain to the Petroleum and Natural Gas Rights, or are otherwise used or intended to be used in exploiting the Petroleum and Natural Gas Rights;

"**this Agreement", "herein", "hereto", "hereof**" and similar expressions mean and refer to this Agreement of Purchase and Sale and any agreement amending this Agreement of Purchase and Sale or any agreement or instrument which is supplemental or ancillary to this Agreement of Purchase and Sale;

"**Title Documents**" means, collectively, any and all leases (including leases to be granted by Vendor to Purchaser in respect of Vendor's fee simple lands, if any), reservations, permits, licenses, unit agreements, assignments, trust declarations, operating agreements, royalty agreements, gross overriding royalty agreements, participation agreements, farm-in agreements, sale and purchase agreements, pooling agreements and any other documents and agreements granting, reserving or otherwise conferring rights to: (i) explore for, drill for, produce, take, use or market Petroleum Substances; (ii) share in production of Petroleum Substances; (iii) share in the proceeds from, or measured or calculated by reference to the value or quantity of, Petroleum Substances which are produced; and (iv) acquire any of the rights described in items (i) to (iii) of this definition; including without limitation those, if any, set out in Schedule "A", but only to the extent that the foregoing items (i) through (iv) pertain to Petroleum Substances within, upon or under the Lands;

"**Vendor's Counsel**" means Macleod Dixon LLP;

"**Vendor's Interest**" means, in respect of a particular property, right or asset, the undivided interest of the Vendor in the Petroleum and Natural Gas Rights as described under the title "Vendor's Interest" in Schedule "A" and a corresponding interest in the Tangibles and Miscellaneous Interests;

"**Wells**" means all wells, regardless of status, including producing, shut-in, water source, observation, disposal, injection, capped, abandoned and suspended wells located on the Lands or lands pooled or unitized therewith, including but not limited to those under the title "Wells" on Schedule "A".

1.2 **Intentionally Deleted**

1.3 **Headings**

The insertion of headings in this Agreement is for convenience of reference only and shall not affect the construction or interpretation of this Agreement.

1.4 **Included Words and Gender**

When the context reasonably permits, words suggesting the singular shall be construed as the plural and vice versa and words suggesting gender or gender neutrality shall be construed as suggesting the masculine, feminine and neutral gender.

1.5 **Time**

In this Agreement all times are Mountain Standard Time or Daylight Saving Time, whichever is in effect pursuant to the *Daylight Saving Time Act* (Alberta).

1.6 **Conflicts**

If there is any conflict or inconsistency between a provision in the body of this Agreement and that contained in a schedule (except Schedule A) or a conveyance document, the provision in the body of this Agreement shall prevail. In the case of a conflict between a provision in the body of this Agreement and Schedule "A", Schedule "A" will prevail.

1.7 **Invalidity of Provisions**

If any of the provisions of this agreement should be determined to be invalid, illegal or unenforceable in any respect, the validity, legality or enforceability of the remaining provisions herein shall not in any way be affected or impaired by such determination.

1.8 **Knowledge or Awareness**

Where in this agreement a representation and warranty of the Vendor is made "to the best of its knowledge", "of which it has knowledge", or "to its knowledge", such knowledge is limited to matters within the actual knowledge of the officers or management employees having titles of "Director", "Manager" or "Vice President". "Actual knowledge" for purposes of this Agreement means information personally known after reasonable inquiry or review of Vendor's files or records, and does not include knowledge and awareness of any other person or constructive or imputed knowledge.

ARTICLE 2
PURCHASE AND SALE

2.1 **Agreement of Purchase and Sale**

(a) Subject to, and in accordance with the terms of this Agreement, Vendor hereby agrees to sell and Purchaser hereby agrees to purchase from Vendor the Assets, subject to the Permitted Encumbrances.

(b) Possession, beneficial ownership and risk of and title to the Assets shall pass to Purchaser as of the Closing Date.

2.2 **Purchase Price**

The consideration to be paid by Purchaser to Vendor for the Assets shall be $71,840,000.00 (the "Purchase Price") adjusted in accordance with Article 7 hereof. At Closing, Purchaser shall pay to Vendor the Purchase Price as adjusted in accordance with Article 7 less the Deposit (plus interest in accordance with clause 2.5).

2.3 **GST and Other Taxes**

(a) The parties acknowledge that, notwithstanding any other provision in this Agreement, the Purchase Price is exclusive of any GST or other taxes, fees, charges, levies or similar assessments that may be imposed by any governmental authority with respect to the subject transaction.

(b) The Purchaser acknowledges that it is responsible for paying any GST or other taxes (other than income taxes), fees, charges, levies or similar assessments which may be imposed by any governmental authority in respect of the subject transaction.

(c) The parties shall jointly elect at Closing pursuant to Section 167 of the *Excise Tax Act* (Canada) to have the provisions thereof concerning the acquisition of part of a business apply to the subject transaction and the Purchaser undertakes to file such election with the Canada Customs and Revenue Agency in a timely and proper fashion.

(d) The GST registration numbers for the parties are:

Vendor	-	871433199RT
Purchaser	-	863096665RT

The Purchaser agrees that it shall be solely liable and responsible for, and shall promptly indemnify and save the Vendor (including its directors, officers, employees and agents) harmless from and against, any and all direct or indirect losses suffered, sustained, paid or incurred by the Vendor by reason of any matter or thing arising out of, resulting from, attributable to or connected with the aforesaid GST election and any and all claims of the Canada Customs and Revenue Agency or other governmental authorities with respect to GST or any other taxes (other than income taxes), fees, charges, levies or similar assessments which may be imposed with respect to the subject transaction including, without limitation, any associated interest charges or penalties.

2.4 **Deposit**

Purchaser shall pay to Vendor's Counsel the amount of $5,000,000.00, which represents a deposit on the Assets (the "Deposit"). The Deposit will be held in escrow by Vendor's Counsel in an interest bearing account pursuant to an Escrow Agreement of even date among Vendor, Purchaser and Vendor's Counsel. If Closing occurs on the Closing Date, Vendor and Purchaser shall thereupon cause the Deposit and all interest thereon to be released to the Vendor, which amount will be applied towards the Purchase Price. If Closing does not occur on the Closing Date, the Deposit shall be governed by clauses 3.2 and 3.3.

If Closing does not occur and the Deposit is returned to Purchaser pursuant to clauses 3.2 or 3.3, Purchaser shall receive interest on the Deposit from the date the Deposit was received up to and including the date the Deposit is returned to the Purchaser. For purposes of this clause only, "interest" shall mean the interest which Vendor's Counsel receives on the Deposit. Vendor's Counsel shall provide evidence of such interest to Purchaser upon request.

2.5 **Interest**

At Closing, Purchaser shall pay to Vendor an amount equal to the interest that would have accrued on the Purchase Price less any Deposit at the Prime Rate plus one (1%) per cent, calculated daily and not compounded, from and including the Effective Date to and including the day prior to the Closing Date, which amount shall constitute an increase to the Purchase Price and shall be allocated to the Petroleum and Natural Gas Rights.

2.6 **Form of Payment**

All payments to be made at Closing shall be made by certified cheque or bank draft.

2.7 **Allocation of Purchase Price**

The parties shall allocate the Purchase Price as follows:

(a)	To Petroleum and Natural Gas Rights	$	57,472,000.00
(b)	To Tangibles	$	14,367,999.00
(c)	To Miscellaneous Interests	$	1.00
	TOTAL	$	71,840,000.00

In determining the Purchase Price, the Parties have taken into account Purchaser's assumption of responsibility for the future abandonment, reclamation costs and environmental responsibilities associated with the Assets and Vendor's release of responsibility therefor.

2.8 **Specific Conveyances**

Vendor shall prepare the Specific Conveyances at its cost, and will use reasonable efforts to prepare the Specific Conveyances and distribute them to the Purchaser prior to Closing. No Specific Conveyances will confer or impose upon a Party any greater right or obligation than contemplated in this Agreement. All Specific Conveyances that are prepared and circulated to Purchaser a reasonable time prior to the Closing Date shall be executed and delivered by the Parties at Closing. Prior and subsequent to the Closing Date, Vendor shall cooperate with Purchaser to secure execution of such documents by third parties, as required. Forthwith after Closing, Vendor shall circulate and at Purchaser's cost register, as the case may be, all Specific Conveyances that by their nature may be circulated or registered.

2.9 **Title Documents and Miscellaneous Interests**

Vendor shall deliver to Purchaser as soon as practicable after Closing and in any case no later than 10 Business Days after Closing: (i) copies of the Title Documents; and (ii) any other agreements and documents to which the Assets are subject and copies of contracts, agreements, records, books, documents, licenses, reports and data comprising Miscellaneous Interests which are now in the possession of Vendor or of which it gains possession prior to Closing provided that if Vendor retains any interest in any property to which such Title Documents and Miscellaneous Interests are applicable, Vendor may retain the original copy of such Title Documents and Miscellaneous Interests and provide a copy of same to the Purchaser.

2.10 **Governmental Security Deposits**

In the event that prior to or after the Closing Date a governmental authority or regulatory agency requires as a pre-requisite to or a condition of the transfer of any licence, permit or approval pertaining to the Assets, a security deposit or any kind of monetary payment, such amount shall be paid by the party whose actions, inactions or assets triggered the requirement to make the payment. Such party will make the payment as and when due.

2.11 **Intentionally Deleted**

ARTICLE 3
CLOSING

3.1 **Closing and Adjustments**

(a) The Closing shall take place at the offices of Vendor at 425 - 1st Street S.W. Calgary, Alberta on the Closing Date.

(b) On the Closing Date, Vendor and Purchaser shall, to the extent practicable, adjust and settle accounts pertaining to the Assets in the manner contemplated by Article 7.

3.2 **Purchaser's Conditions Precedent**

The obligation of Purchaser to purchase the Assets is subject to the following conditions precedent, which are for the exclusive benefit of Purchaser and may be waived by Purchaser:

(a) subject to clause 11.3, there has been no material damage to the Assets between the Effective Date and the Closing Date;

(b) the representations and warranties of Vendor shall be true and correct in all material respects when made and as of the Closing Date and a Certificate to that effect shall have been delivered by Vendor to Purchaser at Closing;

(c) all obligations of Vendor contained in this Agreement to be performed prior to or at Closing shall have been timely performed in all material respects and a Certificate to that effect shall have been delivered by Vendor to Purchaser at Closing;

(d) at or prior to Closing, Vendor shall deliver to Purchaser any releases and registrable discharges in a form acceptable to Purchaser acting reasonably of any adverse liens and encumbrances that are not Permitted Encumbrances and relate to security held against the Assets or any portion thereof;

(e) Vendor shall have obtained all necessary regulatory or governmental approvals required to permit the transaction to be completed;

(f) Vendor shall have obtained approval under the *Competition Act* and all applicable waiting periods shall have expired or been terminated;

(g) no Third Party action shall have been commenced or threatened, the subject of which is to block or stop this transaction or any part thereof;

(h) **intentionally deleted.**

If any one or more of the preceding conditions precedent is not satisfied or waived by Purchaser in the manner provided for herein for waiver at or before the Closing, Purchaser may rescind this Agreement by written notice to Vendor and, in such event, Vendor shall forthwith return the Deposit (plus accrued interest as described in clause 2.4) to Purchaser and Purchaser and Vendor shall be released and discharged from all obligations hereunder except as provided in clause 13.2.

3.3 **<u>Vendor's Conditions Precedent</u>**

The obligation of Vendor to sell the Assets is subject to the following conditions precedent, which are for the exclusive benefit of the Vendor and may be waived by Vendor:

(a) Purchaser shall have tendered to Vendor in the manner stipulated in this agreement the total consideration payable to Vendor;

(b) the representations and warranties of Purchaser shall be true and correct in all material respects when made and as of the Closing Date and a Certificate to that effect shall have been delivered by Purchaser to Vendor at Closing;

(c) all obligations of Purchaser contained in this Agreement to be performed prior to or at Closing shall have been timely performed in all material respects and a Certificate to that effect shall have been delivered by Purchaser to Vendor at Closing;

(d) Purchaser shall have obtained all necessary regulatory or governmental approvals required to permit the transaction to be completed;

(e) no Third Party action shall have been commenced or threatened, the subject of which is to block or stop this transaction or any part thereof; and

(f) Purchaser shall have obtained approval under the *Competition Act* and all applicable waiting periods shall have expired or been terminated.

If any one or more of the preceding conditions precedent is not satisfied or waived by Vendor in the manner provided for herein for waiver at or before Closing, Vendor may rescind this Agreement by written notice to Purchaser and, in such event, Vendor shall be entitled to retain the Deposit (plus accrued interest as described in clause 2.4) as liquidated damages and not as penalty and Purchaser and Vendor shall be released and discharged from all obligations hereunder except as provided in clause 13.2. Notwithstanding the foregoing, in the event Vendor elects to rescind the Agreement because condition precedents 3.3(e) and (f) is not satisfied or waived, Vendor will return the Deposit (plus accrued interest as described in clause 2.4) to the Purchaser.

3.4 **<u>Efforts to Fulfill Conditions Precedent</u>**

Purchaser and Vendor shall proceed diligently and in good faith and use all reasonable efforts to fulfill and assist in the fulfillment of the conditions precedent. If there is a condition precedent that is to be met prior to or at August 14, 2002 or the Closing Date, and if, by the time the condition precedent is to be met the Party for whose benefit the condition precedent exists fails to notify the other Party that the condition precedent has not been met, the condition precedent shall be deemed conclusively to have been met.

ARTICLE 4
REPRESENTATIONS AND WARRANTIES

4.1 Vendor's Representations

Purchaser acknowledges that it is purchasing the Assets on an "as is, where is" basis, without representation or warranty and without reliance on any information provided to or on behalf of Purchaser by Vendor, except for the following representations and warranties, which are made (unless otherwise indicated below in writing) by Vendor as of the date hereof and the Closing Date provided always that the following representations and warranties are made subject to the matters described in the Disclosure Statement in Schedule "G" and that the following representations and warranties will not limit in any manner or derogate from the provisions of clause 6.3 "Environmental Matters":

(a) Standing: it is a corporation duly incorporated and validly existing under the laws of its jurisdiction of incorporation and is authorized to carry on business in all jurisdictions in which the Assets are located;

(b) Requisite Authority: it has the corporate capacity, power and authority to execute and deliver this Agreement, to sell the Assets on the terms set out in this Agreement and to perform its obligations under this Agreement;

(c) No Conflict: the execution and delivery of this Agreement and the completion of the sale of the Assets in accordance with the terms of this Agreement do not and will not violate or conflict with any provision of:

  (i) the charter, bylaws or equivalent governing documents relating to it or any Regulations applicable to it; or

  (ii) any agreement or instrument to which it is a party or by which it is bound and of which it has knowledge or any judgment, decree or order applicable to it.

(d) Execution and Enforceability: as at the date hereof and the Closing Date, this Agreement and all documents executed and delivered pursuant to this Agreement are and will be duly authorized, executed and delivered by it and are legal, valid and binding obligations of it enforceable against it in accordance with their terms except to the extent limited by bankruptcy, insolvency, liquidation, reorganization, moratorium or other laws of general application affecting creditors' rights generally or by general equitable principles;

(e) Authorizations: no authorization or approval or other action by, or notice to or filing with, any governmental authority or regulatory body exercising jurisdiction over the Assets is required for the due execution, delivery and performance by it of this Agreement, other than authorizations, approvals or exemptions previously obtained and currently in force or regulatory consents or approvals to the transfer of well and pipeline licenses and permits and other similar licenses and permits available only after the Closing Date in the ordinary course;

(f) Encumbrances, No Cancellation or Reduction: it does not warrant title to the Assets but does warrant that other than Permitted Encumbrances, (i) Vendor has not alienated or encumbered or permitted the alienation or encumbrance of the Assets or any part or portion thereof, (ii) Vendor has not committed and is not aware of there having been committed any act or omission whereby the interest of the Vendor in and to the Assets or any part or portion thereof may be canceled or determined, (iii) the Assets are now free and clear of all liens, royalties, conversions, rights and other claims of third parties created by, through or under Vendor except as shown on Schedule "A" or of which Purchaser has actual knowledge without inquiry, and (iv) except as otherwise disclosed in Schedule "A", none of the Assets are subject to reduction by reference to payout of any well or otherwise pursuant to a right created by, through or under Vendor;

(g) **Intentionally deleted**;

(h) Knowledge of Default: in respect of those portions of the Assets where Vendor is Operator, and in respect of the other portions of the Assets to the best of its knowledge, it has not received any notice of and it is not in material default under any agreement pertaining to the Assets, which default has not been rectified or waived as of the date of this Agreement;

(i) Lawsuits and Claims: in respect of those portions of the Assets where it is Operator, and, in respect of other portions of the Assets to the best of its knowledge, no suit, action or other proceeding before any court or governmental agency has been commenced or, to the best of its knowledge, threatened against Vendor which might result in impairment or loss of the interest of the Vendor in and to the Assets or which might otherwise adversely affect the Assets;

(j) Payment of Royalties and Taxes: in respect of those portions of the Assets where Vendor is Operator and, in respect of other portions of the Assets to the best of its knowledge, and except for Permitted Encumbrances, all *ad valorem*, property, production, severance and similar taxes and assessments based on, or measured by, the ownership of the Assets or the production of Petroleum Substances from the Assets, or the receipt of proceeds from them, and all royalties and rentals pertaining to the Assets accruing prior to Effective Date, that are payable by it will be or will have been properly paid and discharged;

(k) Residency For Tax Purposes: it is not a non-resident of Canada within the meaning of section 116 of the *Income Tax Act* (Canada) and the interest of Vendor in and to the Assets does not constitute all or substantially all of the property of the Vendor;

(l) Take or Pay Obligations: it has no take or pay obligations relating to the Assets;

(m) **Intentionally Deleted**;

(n) Broker's Fees: it has not incurred any obligation or liability, contingent or otherwise, for broker's or finder's fees in respect of this Agreement or the transaction to be effected by it for which Purchaser shall have any liability or obligation;

(o) Sales Contracts: except for the Production and Marketing Contracts, it is not obligated to sell or deliver Petroleum Substances produced from the Lands to any person pursuant to agreements which cannot be terminated on 30 days' notice or less and it has not assigned or in any way restricted its right to receive the proceeds from the sale of Petroleum Substances produced from the Lands, except where Permitted Encumbrances would apply and except for the Production and Marketing Contracts, it has not pre-sold any Petroleum Substances beyond the wellhead at the Effective Date;

(p) Quiet Enjoyment: subject to the rents, covenants, conditions and stipulations in the Title Documents and any other agreements pertaining to the Assets and on the lessee's or holder's part thereunder to be paid, performed and observed, the Permitted Encumbrances and Material Title Defects waived by the Purchaser, Purchaser may enter into and upon, hold and enjoy the Lands for the residue of the respective terms of the Title Documents and all renewals or extensions thereof as to the interests hereunder assigned for Purchaser's own use and benefit without any interruption of or by Vendor or any other person whomsoever claiming by, through or under Vendor;

(q) Operations: all Assets operated by Vendor, while such Assets were operated by the Vendor, and to the best of its knowledge, those of the Assets operated by Third Parties were operated in accordance with good oil and gas industry practices and in material compliance with the Regulations in force and effect at the time of such operations, provided that nothing in this representation and warranty shall be construed as a statement by Vendor on any matter pertaining to the environmental status of the Assets, its compliance with environmental Regulations or to the presence or absence of environmental damage or contamination or other environmental problems or liabilities;

(r) Abandonment, Remediations, Reclamations: to the best of its knowledge all abandonments, remediations and reclamations of any of the Assets have been conducted in accordance with normal industry practice and in accordance with the Regulations, provided that nothing in this representation and warranty shall be construed as a statement by Vendor on any matter pertaining to the environmental status of the Assets, its compliance with environmental Regulations or to the presence or absence of environmental damage or contamination or other environmental problems or liabilities.

(s) Lease Operating Statements: it has prepared its lease operating statements in accordance with generally accepted accounting principles and are consistent with normal industry practice for the Assets; and

(t) AMIs: to the best of its knowledge, there are no Area of Mutual Interest ("AMIs") obligations affecting the Assets other than those AMIs disclosed in the data room managed by Waterous Securities Inc. on behalf of Vendor for the "2002 Heavy Oil and Natural Gas Property Offering".

4.2 **Limitation**

(a) Vendor makes no representations or warranties with respect to the Assets, except as contained in clause 4.1. Vendor disclaims any liability or responsibility for any representation or warranty (other than the representations and warranties made in clause 4.1) that may have been made or alleged to have been made and contained in any document or statement made or communicated to Purchaser including, but not limited to, any opinion, information or advice provided to Purchaser by any shareholder, director, officer, employee, agent, consultant or representative of Vendor in respect of:

(i) the quantity, quality or recoverability of Petroleum Substances within or under the Lands;

(ii) estimates of prices or future cash flows arising from the sale of Petroleum Substances produced from the Lands or estimates of other revenues attributable to the Assets or the availability or continued availability of transportation to sell those Petroleum Substances;

(iii) any engineering, geological or other interpretations or economic evaluations respecting the Assets; and

(iv) the quality, condition, fitness or suitability for purpose or merchantability of any of the Assets.

(b) Purchaser acknowledges it has made, and will continue prior to Closing Date to make, its own independent examination, investigation, analysis, evaluation and verification of the Assets, including Purchaser's own estimate and appraisal of the extent and value of the Petroleum Substances attributable to the Lands and it has relied solely on same as to its assessment of the condition (environmental or otherwise), quantum and value of the Assets;

(c) Except with respect to the representations and warranties in clause 4.1, Purchaser forever releases and discharges Vendor and its directors, officers, servants, agents and employees from any claims and all liability to Purchaser or Purchaser's assigns and successors, as a result of the use or reliance upon advice, information or materials pertaining to the Assets which was delivered or made available to Purchaser by Vendor or its directors, officers, servants, agents or employees prior to or pursuant to this Agreement, including, without limitation, any evaluations, projections, reports and interpretive or non-factual materials prepared by or for Vendor, or otherwise in Vendor's possession.

4.3 <u>**Purchaser's Representations**</u>

Purchaser makes the following representations and warranties to Vendor, which are made (unless otherwise indicated below in writing) as of the date hereof and the Closing Date:

(a) <u>Standing</u>: it is a corporation duly incorporated and validly existing under the laws of its jurisdiction of incorporation and is authorized to carry on business in all jurisdictions in which the Assets are located;

(b) <u>Requisite Authority</u>: it has the corporate capacity, power and authority to execute and deliver this Agreement and to purchase and pay for the Assets on the terms set out in this Agreement and to perform its other obligations under this Agreement;

(c) <u>No Conflict</u>: the execution and delivery of this Agreement and the completion of the purchase of the Assets in accordance with the terms of this Agreement do not and will not violate or conflict with any provision of:

(i) the charter, bylaws or equivalent governing documents relating to it or any Regulations applicable to it; or

(ii) any agreement or instrument to which it is a party or by which it is bound and of which it has knowledge or any judgment, decree or order applicable to it;

(d) Execution and Enforceability: as at the date hereof and the Closing Date, this Agreement and all documents executed and delivered pursuant to this Agreement are and will be duly authorized, executed and delivered by it and are legal, valid and binding obligations of it enforceable against it in accordance with their terms except to the extent limited by bankruptcy, insolvency, liquidation, reorganization, moratorium or other laws of general application affecting creditors' rights generally or by general equitable principles;

(e) Investment Canada Act: it is not a "non-Canadian" for the purposes of the *Investment Canada Act* (Canada);

(f) Authorizations: except under the *Competition Act,* no authorization or approval or other action by, or notice to or filing with, any governmental authority or regulatory body exercising jurisdiction over the Assets is required for the due execution, delivery and performance by it of this Agreement, other than authorizations, approvals or exemptions previously obtained and currently in force or regulatory consents or approvals to the transfer of well and pipeline licenses and permits and other similar licenses and permits available only after the Closing Date in the ordinary course;

(g) Purchaser as Principal: it is acquiring the Assets in its capacity as a principal and is not purchasing the Assets as agent for a third party or for the purpose of resale;

(h) AEUB License Transfer Requirements and Compliance: as of the date hereof and the Closing Date, (i) its Licensee Liability Rating, as determined by the AEUB prior to, or as a result of this transaction and the transfer of licenses contemplated herein, is and will be greater than one (1), (ii) it is not on "refer" status at the AEUB, and (iii) it is unaware of any other reason why the Well, Field Facilities or pipeline license transfers from Vendor to Purchaser will not be approved by the AEUB; and

(i) Financing: it will have at Closing sufficient cash, available lines of credit or other sources of immediately available funds to enable it to pay the Purchase Price to the Vendor at Closing.

ARTICLE 5
INDEMNITIES FOR
REPRESENTATIONS & WARRANTIES

5.1 Vendor's Indemnities for Representations and Warranties

Vendor shall be liable to Purchaser for and shall, in addition, indemnify Purchaser from and against, all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Purchaser which would not have been suffered, sustained, paid or incurred had all of the representations and warranties contained in clause 4.1 been accurate and truthful. Nothing in this clause 5.1 shall be construed so as to cause Vendor to be liable to or indemnify Purchaser (i) for any loss of profits or other consequential damages suffered by Purchaser or any punitive damages; (ii) any loss, cost claims, damages, expenses and liabilities that do not on an individual basis exceed $1,000,000; and (iii) any loss, cost claims, damages, expenses and liabilities that result from the actions or omissions of the Purchaser after the date of this Agreement.

5.2 **Limitation**

In no event shall the total of Vendor's liabilities and indemnities hereunder exceed the unadjusted Purchase Price. The provisions of clause 5.1 shall only be effective when the amount determined by the Parties to be recoverable from Vendor in the aggregate exceeds a deductible amount of five percent (5%) of the unadjusted Purchase Price, after which point Purchaser will be entitled to recovery from Vendor only with respect to an amount in excess of such deductible.

5.3 **Purchaser's Indemnities for Representations and Warranties**

Purchaser shall be liable to Vendor for and shall, in addition, indemnify Vendor from and against, all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor which would not have been suffered, sustained, paid or incurred had all of the representations and warranties contained in clause 4.3 been accurate and truthful, provided however that nothing in this clause 5.3 shall be construed so as to cause Purchaser to be liable to or indemnify Vendor in connection with any representation or warranty contained in clause 4.3 if and to the extent that Vendor did not rely upon such representation or warranty.

5.4 **Time Limitation**

No claim under this Article 5 shall be made or be enforceable by a Party unless notice of such claim, with reasonable particulars, is given by such Party to the Party against whom the claim is made within a period of one (1) year from the Closing Date.

ARTICLE 6
PURCHASER'S INDEMNITIES

6.1 **Purchaser's General Indemnity**

Purchaser shall:

(a) be liable to Vendor for all claims, liabilities, actions, proceedings, demands, losses, costs, damages (including legal costs on a solicitor/client basis) and expenses whatsoever which Vendor may suffer, sustain, pay or incur; and, in addition

(b) indemnify and save Vendor and its directors, officers, servants, agents and employees harmless from and against all claims, liabilities, actions, proceedings, demands, losses, costs, damages (including legal costs on a solicitor/client basis) and expenses whatsoever which may be brought against or suffered, sustained, paid or incurred by Vendor or its directors, officers, servants, agents or employees;

by reason of any matter or thing arising out of, resulting from, attributable to or connected with the Assets and occurring or accruing on or after the Closing Date, except any claims, liabilities, actions, proceedings, demands, losses, costs, damages (including legal costs on a solicitor/client basis) and expenses, to the extent that the same are caused by the gross negligence or willful or wanton misconduct of Vendor and except where such matter arose as a direct result of a breach of a representation and warranty in clause 4.1 that Purchaser has provided notice of to Vendor pursuant to clause 5.4, in which case the above indemnity will not apply.

6.2 **Abandonment and Reclamation**

Purchaser shall see to the timely performance of all abandonment and reclamation obligations pertaining to the Assets which in the absence of this Agreement would be the responsibility of Vendor, including, but not limited to, such obligations pertaining to any abandoned Wells for which the well license transfer has not been approved by the subject regulatory body. Purchaser shall be liable to Vendor and shall, in addition, indemnify Vendor from and against all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor should Purchaser fail to timely perform such obligations.

6.3 **Environmental Matters**

Notwithstanding the foregoing provisions of this clause, it is understood and agreed that Purchaser is acquiring the Assets on an "as is, where is" basis as of the Closing Date. Purchaser agrees that it has been or will be provided prior to the Closing Date with the right and opportunity to conduct due diligence investigations with respect to existing or potential environmental problems pertaining to the Assets; is familiar with the condition and use of the Assets; it can determine for itself whether the Assets are satisfactory from an environmental standpoint; and that it is not relying upon any representation or warranty from Vendor as to the condition, environmental or otherwise, of the Assets. Purchaser further agrees that on and after the Closing Date it shall:

(a) be solely liable and responsible for any and all losses, costs, damages (including legal costs on a solicitor/client basis) and expenses which Vendor may suffer, sustain, pay or incur; and, in addition

(b) indemnify and save Vendor and its directors, officers, servants, agents and employees harmless from and against any and all claims, liabilities, actions, proceedings, demands, losses, costs, damages (including legal costs on a solicitor/client basis) and expenses whatsoever which may be brought against or suffered by Vendor or its directors, officers, servants, agents or employees or which it may suffer, sustain, pay or incur;

by reason of any matter or thing arising out of, resulting from, attributable to or connected with any environmental damage or contamination or other environmental problems pertaining to the Assets, or any of them, whether occurring or accruing before, on or after the Effective Date and whether or not the subject regulatory body approves the license transfer for abandoned Wells including, without limitation, surface, underground, air, ground water or surface water contamination, damage from or removal of hazardous or toxic substances, spills of any nature whatsoever, clean-up, plugging, decommissioning, abandonment and reclamation (or failure to perform any or all of the foregoing) and the breach of applicable Regulations in effect at any time. Purchaser hereby releases Vendor from any environmental claims Purchaser may have against Vendor that in any way relate to, or are directly or indirectly caused by the Assets. Purchaser acknowledges and agrees that it shall not be entitled to any rights or remedies under the common law or statute pertaining to such damage, contamination or problems relative to Vendor including, without limitation, the right to name Vendor as a third party to any action including any action commenced by any person against Purchaser. Nothing herein contained shall prejudice any claims or remedies that

Vendor may have against Purchaser in relation to such claim or remedy outside this contract including rights and remedies under the common law and statute.

6.4 **Application To Other Documentation**

The liabilities and indemnities contained in Article 6 shall be deemed to apply to, and shall not merge in, any conveyances, transfers, assignments, novation agreements and other documents or instruments conveying the Assets to Purchaser or otherwise provided with respect to the transactions herein, despite the actual terms of such agreements, notwithstanding any rule of law, equity or statute to the contrary, and all such rules are hereby waived. Any claim by a Party must be made by notice to the other and include particulars of the claim and of the facts giving rise to it.

ARTICLE 7
OPERATING ADJUSTMENTS

7.1 **Adjustments**

(a) Five (5) Business Days before Closing Date, Vendor shall prepare and submit to Purchaser an interim statement of adjustments effective as of the Effective Date and prepared in accordance with this Article. Such statement will contain Vendor's good faith estimate of such adjustments and all reasonable applicable back-up. At Closing Date the Parties shall, to the extent practicable, adjust and settle accounts pertaining to the Assets. The Purchase Price shall be adjusted to reflect the adjustments and settlements shown on the interim statement of adjustments.

(b) Subject to subclauses (d), (e) and (f), all benefits and obligations of any kind and nature accruing payable, paid, received or receivable with respect to the Assets, prior to the Effective Date, including without limitation operating costs, capital costs, lease rentals, royalty obligations, GST, AFEs and the proceeds from the sale of production from the Lands that is beyond the wellhead prior to the Effective Date are for Vendor's account.

(c) Subject to subclauses (d), (e) and (f), all benefits and obligations of any kind and nature accruing payable, paid, received or receivable with respect to the Assets on and after the Effective Date, including without limitation operating costs, capital costs, lease rentals, royalty obligations, AFEs, GST and the proceeds from the sale of production from the Lands that is beyond the wellhead on and after the Effective Date are for Purchaser's account.

(d) The following provisions will apply to the apportionment of the revenues, costs, expenses and other relevant charges referred to in subclauses (b) and (c):

(i) all prepaid rentals and similar payments required to preserve any of the Title Documents, whether paid before or after the Effective Date for the Assets, shall be apportioned between Vendor and Purchaser on a per diem basis as of the Effective Date, unless and to the extent that such allocation is waived by Vendor;

(ii) operating, capital cost advances, AFEs and similar prepayments made by Vendor for the Assets prior to Closing Date and relating to benefits accruing after the Effective Date are the responsibility of Purchaser and an amount equal to such prepayments shall be credited to Vendor at Closing Date;

(iii) there will be no adjustments for Alberta Royalty Tax Credits;

(iv) Purchaser will be credited with an amount equal to the proceeds from the sale of production from the Lands from the Effective Date to Closing Date less all royalties, operating expenses, and overhead pertaining to the Assets from the Effective Date to Closing Date; and

(v) for further certainty, Vendor will provide Purchaser with actuals of crown royalties only.

(e) **Intentionally deleted**

(f) Notwithstanding any of the foregoing, accounting or adjustments resulting from joint venture or royalty audits for the Assets:

(i) relating to the period prior to Closing Date and for which audit queries are outstanding at Closing Date; or

(ii) that occur after Closing Date but not later than 2 years after Closing Date or for the applicable period in the governing operating agreements included in Miscellaneous Interests, whichever is later (in the case of joint venture audits), or 4 years after Closing Date (in the case of Crown royalty audits);

shall be made as they occur and payment for them shall be made within 30 days of each adjustment and shall be made by Purchaser to Vendor, or vice versa, as the case may be. The costs of any audit shall be the responsibility of the party initiating the audit.

(g) Disputed Payments and Interest on Overdue Payments

(i) If either party does not remit payment to the other party of an amount payable to such party in accordance with the terms of this agreement, then the non-paying party shall pay interest on such amount to the other party at the Prime Rate plus one percent calculated daily and not compounded from the date such payment was due until it is paid.

(ii) If either party disputes the correctness of an amount payable at or after Closing pursuant hereto, the payment shall nevertheless be made by the due date. To the extent that any disputed amount is subsequently determined not to have been payable, the party who has received it shall within fifteen (15) days from the date of such determination, pay such excess amount to the other party, together with interest at a rate equal to the Prime Rate plus one percent (1%) calculated daily and not compounded from the date of the overpayment until it is repaid. Each party shall retain complete records, pertinent to the subject matter of this agreement for a sufficient period of time to meet the requirements of this clause 7.1(g).

(h) Use of Joint Venture Billing Statements: To the extent possible, joint venture billing statements from operators of the Assets shall be used as a basis for adjustments pursuant to this clause. Costs, expenses and revenues shall be treated as having been incurred or having accrued in the month to which they are attributed in the joint venture billing statements unless it can be demonstrated that they were incurred or accrued in a different month.

(i) Tax Audits: If the amount of GST paid by the Purchaser pursuant to the provisions of this Agreement is subject to audit by the relevant governmental authorities, and it is determined by those authorities that an additional amount of GST should be assessed, the Purchaser shall be responsible for the payment of such additional amount including any related penalties.

7.2 **Intentionally Deleted**

7.3 **Intentionally Deleted**

ARTICLE 8
MAINTENANCE OF ASSETS

8.1 **Maintenance of Assets**

From the date of this Agreement until Closing Date, Vendor shall operate and maintain the Assets in a prudent manner in accordance with generally accepted oil and gas industry practices and in compliance with all material covenants and conditions contained in all agreements relating to the Assets.

8.2 **Consent of Transferee**

Notwithstanding clause 8.1, Vendor shall not, without the written consent of Purchaser, which consent shall not be unreasonably withheld by Purchaser and which, if provided, shall be provided in a timely manner:

(a) make any commitment or propose, initiate or authorize any capital expenditure with respect to the Assets of which Vendor's share is in excess of $10,000.00, except in case of an emergency or in respect of amounts which Vendor may be committed to expend or be deemed to authorize for expenditure without its consent;

(b) surrender or abandon any of the Assets;

(c) amend or terminate any Title Document or any other agreement or document to which the Assets are subject (including without limitation any employment contract relating to the Employees), or enter into any new agreement or commitment relating to the Assets; or

(d) sell, encumber or otherwise dispose of any of the Assets or any part or portion thereof excepting sales of the Leased Substances or any of them in the normal course of business.

Notwithstanding the foregoing, Vendor may assume such obligations or commitments and propose or initiate such operations or the exercise of any such right or option without the prior consent of Purchaser, if Vendor reasonably determines that such expenditures or actions are necessary for the protection of life, property, or income, in which case Vendor shall promptly notify Purchaser of such intentions or actions and Vendor's estimate of the costs and expenses associated therewith.

8.3 **Post-Closing Administration**

From Closing until Purchaser becomes the recognized holder of the Assets in the place of Vendor, the provisions of clauses 8.1 and 8.2 shall apply to the Assets and Vendor shall, to the extent its interest permits and, subject to the Title Documents and other agreements to which the Assets are subject:

(a) hold possession of the Assets on behalf of and in trust for Purchaser and receive and hold all proceeds, benefits and advantages accruing from the Assets for the benefit, use and ownership of Purchaser, with entitlement to commingle any of them with its own or any other assets;

(b) in a timely manner deliver to Purchaser all revenues, proceeds and other benefits received by Vendor for the Assets after deduction of any amounts owing by Purchaser to Vendor in respect of the Assets;

(c) in a timely manner deliver to Purchaser all third party notices and communications received by Vendor for the Assets;

(d) in a timely manner deliver to third parties all notices and communications as Purchaser may reasonably request and all monies and other items Purchaser reasonably provides for the Assets; and

(e) as agent of Purchaser, do and perform all acts and things, and execute and deliver all agreements, notices and other documents and instruments, that Purchaser reasonably requests for the purpose of facilitating the exercise of rights incidental to the ownership of the Assets.

Vendor shall not be liable to Purchaser for any loss or damage suffered by Purchaser in connection with the arrangement established by this clause 8.3, except to the extent that the loss or damage is caused by Vendor's gross negligence or its willful misconduct. Purchaser shall indemnify and save Vendor and its directors, officers, servants, agents and employees harmless from and against any liabilities, losses, costs, claims, demands, actions, proceedings and damages (including legal costs on a solicitor/client basis) which may be brought against or suffered by any of them arising out of the performance by Vendor of its obligations under this clause 8.3. An action or omission of Vendor or its directors, officers, servants, agents or employees shall not be regarded as gross negligence or willful misconduct to the extent it was done or omitted to be done in accordance with the instructions of or with the concurrence of Purchaser. Nothing in this clause 8.3 shall be construed as extending or restricting or limiting in any manner any of the other representations, warranties or other obligations of the parties under this Agreement.

The Vendor may retain or subsequently obtain from Purchaser copies or photocopies of any of the documents included in the Miscellaneous Interests that it considers necessary to enable it to comply with any laws or the requirements of any authority.

All costs incurred in connection with the operation of the Assets, for which Vendor is operator, after the Closing Date until Vendor is relieved of its responsibilities as operator, shall be reimbursed by Purchaser to Vendor.

8.4 **Purchaser's Post Closing Obligations**

(a) Subject to Article 7.1, on and after the Closing Date, Purchaser shall be liable for and shall discharge and satisfy as they become due all obligations in respect of the Assets and the Title Documents including, without limitation:

(i) the payment of all royalties under the Title Documents; and

(ii) any and all statutes, orders, writs, injunctions or decrees of any governmental agency relating to the Assets.

(b) Promptly after Closing, Purchaser will remove any signs which indicate Vendor's ownership or operation of the Assets. If Purchaser fails to remove such signs, Vendor will have the right to enter onto the Lands for the purpose of removing the signs and all costs relating thereto will be for the Purchaser's account. Except for such grace period for eliminating usage of signs bearing Vendor's name, Purchaser will have no right to use any logos, trademarks, or trade names belonging to Vendor or its Affiliates.

(c) Promptly after Closing, Purchaser will erect or install any signs (i) required by governmental agencies to indicate that Purchaser is the operator of the Assets; and (ii) notifying working interest owners, purchasers of Petroleum Substances, lessors, suppliers, contractors, governmental agencies or any other third party of Purchaser's interest in the Assets.

For further certainty the provisions of this clause will survive the Closing.

ARTICLE 9
PREFERENTIAL RIGHTS

9.1 **Preferential Rights**

Within five (5) days from the execution and delivery of this Agreement, Purchaser shall advise Vendor in writing of its bona fide allocations of value for Vendor's Interest in and to that portion of the Assets subject to Preferential Rights. The Parties will consult with respect to that value or allocation as appropriate in the circumstances. Any dispute between the Parties with respect to that value or allocation will be resolved by a single arbitrator pursuant to the *Arbitration Act* (Alberta). Vendor shall comply with the applicable provisions of such Preferential Right and shall, as quickly as possible, send notices to the third parties (and Purchaser, if applicable) holding such rights. Vendor shall notify Purchaser in writing forthwith upon each third party exercising or waiving a Preferential Right. If any such third party elects to exercise such a right, the definition of Assets shall be deemed to be amended to exclude those Assets in respect of which the right has been exercised, such Assets shall not be conveyed to Purchaser and the Purchase Price, the tax allocations and the GST shall be reduced accordingly.

ARTICLE 10
PRECLOSING INFORMATION

10.1 **Title Examination**

At all reasonable times from the date hereof until the Closing Date, and subject to the Title Documents, any limitations arising out of the Miscellaneous Interests, and the provisions of any confidentiality or other agreements, Vendor shall, if and as requested by Purchaser, make available to Purchaser and Purchaser's counsel in Vendor's offices in Calgary, information pertaining to the Assets to which Vendor has possession or to which it has access.

ARTICLE 11
TITLE DEFECTS, CASUALTY LOSS AND MATERIAL ENVIRONMENTAL DEFICIENCY

11.1 **Notice of Material Title Defects**

(a) No later than twelve (12) Business Days prior to the Closing Date, Purchaser shall give Vendor written notice of Material Title Defects ("Notice"). Such Notice shall include:

(i) a description of each Material Title Defect, in reasonable detail and the Assets directly affected thereby;

(ii) supporting documents reasonably necessary for Vendor to verify the existence of the alleged Material Title Defect;

(iii) the Purchaser's *bona fide* estimate of the amount of the unadjusted Purchase Price to be allocated to each of the Assets affected by the Material Title Defect;

(iv) the amount by which the Purchaser reasonably believes the portion of the unadjusted Purchase Price allocated to the affected Assets pursuant to clause 11.1(a) (iii) has been or will be reduced by the Material Title Defect ("Material Title Defect Amount") together with the computations and information upon which Purchaser's belief is based; and

(v) Purchaser's requirements for the curing or removal of same.

Failure by the Purchaser to include a Material Title Defect in the Notice shall be deemed to be waiver of such Material Title Defect for the purposes hereof.

(b) Prior to the Closing Date, Vendor shall diligently make all reasonable efforts to cure or remove all Material Title Defects which are contained in the Notice. In order to maximize the time available to cure such Material Title Defects, Purchaser shall notify Vendor of the existence of any Material Title Defects on an on-going basis as soon as reasonably possible after becoming aware of same. If Vendor is unable to cure or remove any Material Title Defects on or before the third Business Day prior to the Closing Date and at such date there remains Material Title Defects and the aggregate value of the Material Title Defect Amount is:

(i) five percent (5%) or less of the Purchase Price, Purchaser shall complete the purchase of all of the Assets on the Closing Date without any adjustment to the Purchase Price;

(ii) greater than five percent (5%) of the Purchase Price, Purchaser may, subject to a Party's right to terminate this Agreement pursuant to clause 11.1(b)(iii), elect to:

(A) with the agreement of Vendor, postpone Closing for an additional ten (10) Business Days, in which case Vendor shall diligently continue to make all reasonable efforts to cure or remove all Material Title Defects; or

(B) waive the uncured or unremoved Material Title Defects, in which case Purchaser shall complete the purchase of the Assets on the Closing Date without any adjustment to the Purchase Price; or

(C) not waive the uncured or unremoved Material Title Defects, in which case Purchaser shall purchase the Assets (including the Assets that are affected by the uncured or unremoved Material Title Defects) and the Purchase Price shall be decreased by the Material Title Defect Amount;

(iii) twenty percent (20%) or more of the Purchase Price, in addition to the elections set out in clauses 11.1(b)(ii), either Vendor or Purchaser may terminate this Agreement upon written notice to the other Party, in which case the Parties shall have no further obligation to each other hereunder, except for obligations arising pursuant to clause 13.2 and the Vendor shall forthwith return to Purchaser the Deposit plus interest accrued thereon;

(c) if at the end of the ten (10) day period referred to in clause 11.1(b)(ii)(A) there remains uncured or unremoved Material Title Defects and the aggregate value of the Assets affected thereby are:

(i) five percent (5%) or less of the Purchase Price, Purchaser shall complete the purchase of all of the Assets on the second (2^{nd}) Business Day following such tenth (10^{th}) day without an adjustment to the Purchase price; or

(ii) greater than five percent (5%) of the Purchase Price, Purchaser shall then proceed to purchase all of the Assets on the second (2^{nd}) Business Day following such tenth (10^{th}) Business Day in accordance with either clause 11.1(b)(ii)(B) or (C), subject to a Party's right to terminate this Agreement pursuant to clause 11.1(b)(iii) and in such event, the events described in clause 11.1(b)(ii)(B) or (C) or 11.1(b)(iii), as the case may be, shall occur; and

(d) any election under clause 11.1(b)(ii) or (iii) must be made by Purchaser on or before 4:00 p.m., Calgary time, on the second Business Day prior to Closing. Any election under clause 11.1(c)(ii) must be made on or before 4:00 p.m., Calgary time, on the first Business Day following the end of the ten day period referred to therein. Failure by Purchaser to give timely notice of an election under either of clauses 11.1(b)(ii) or (iii) or 11.1(c)(ii) above shall be deemed to be a waiver by Purchaser of the remaining Material Title Defects and Vendor and Purchaser shall close the transactions contemplated hereunder on the Closing Date or the revised Closing Date, as the case may be, in accordance with the terms hereof.

11.2 **Value Disputes**

If Vendor disagrees with the value allocated by Purchaser to the Material Title Defect Amount, the Parties shall forthwith meet in good faith to discuss the issue. If after such a meeting the issue has not been resolved or if a Party does not forthwith meet to discuss the same, the issue shall be resolved by a single arbitrator pursuant to the *Arbitration Act* (Alberta). The decision of the arbitrator shall take into account the likelihood that such defect or omission shall manifest and shall be final and shall not be subject to review. All costs of arbitration shall be borne by the Parties equally. Closing shall proceed based upon the Purchase Price payable in accordance with clause 2.2. Within five (5) Business Days from the date the decision of the arbitrator has been rendered, the Parties shall make an adjustment between themselves to reflect the decision of the arbitrator.

11.3 **Casualty Loss**

(a) If, after the date of this Agreement but prior to the Closing Date, any portion of the Assets is destroyed by fire or other casualty and the loss as a result of such individual casualty exceeds five percent (5%) of the unadjusted Purchase Price, Purchaser will nevertheless be required to close and Vendor will elect by written notice to Purchaser prior to Closing to either (i) to cause the Assets affected by any casualty to be repaired or restored to at least its condition prior to such casualty, at Vendor's sole cost, as promptly as reasonably practicable (which work may continue after the Closing Date), (ii) to indemnify Purchaser through a document reasonably acceptable to Vendor and Purchaser against any costs or expenses that Purchaser reasonably incurs to repair the Assets subject to any casualty; or (iii) to treat such casualty as a Material Title Defect with respect to the affected Assets under clause 11.1. In each case, Vendor will retain all rights to insurance and other claims against third parties with respect to the casualty or taking except to the extent the Parties otherwise agree in writing.

(b) If after the date of this Agreement but prior to the Closing Date, any portion of the Assets is destroyed by fire or other casualty and the loss as a result of such individual casualty is five percent (5%) or less of the unadjusted Purchase Price, Purchaser will nevertheless be required to Close and Vendor will, at Closing, pay to Purchaser all sums paid to Vendor by third parties by reason of such casualty and will assign, transfer and set over to Purchaser or subrogate Purchaser to all of Vendor's right, title and interest (if any) in insurance claims, unpaid awards, and other rights against third parties (other than Affiliates of Vendor and its and their directors, officers, employees and agents) arising out of the casualty.

(c) Notwithstanding subclause 11.3(a) if after the date of this Agreement but prior to the Closing Date, any portion of the Assets is destroyed by fire or other casualty and the loss as a result of such individual casualty is twenty percent (20%) or more of the Purchase Price, the Purchaser may elect to terminate this Agreement in accordance with clause 3.2.

11.4 **Intentionally Deleted**

ARTICLE 12
INTENTIONALLY DELETED

ARTICLE 13
GENERAL

13.1 Notices

(a) All notices, waivers and other communications permitted or required hereunder shall be in writing and shall be delivered as follows:

(i) by personal service on a party at the address of such party set out below, in which case the item so served shall be deemed to have been received by that party when personally served; or

(ii) by facsimile transmission to a party to the fax number of such party set out below, in which case the item so transmitted shall be deemed to have been received by that party when successfully transmitted by the party sending such facsimile transmission;

A party may from time to time change its address for service or its fax number or both by giving written notice of such change to the other party.

(b) For the purposes of this clause 13.1, the address for service of the Parties shall be as follows:

Vendor: Anadarko Canada Corporation
Box 2595, Station "M"
425 - 1st Street S.W.
Calgary, Alberta T2P 4V4

Attention: Acquisitions and Divestitures Team Leader
Telephone: (403) 231-0372
Facsimile: (403) 231-0043

Purchaser: Coyote Energy Inc.
1800, 500 – 4th Avenue S.W.
Calgary, Alberta T2P 2V6

Attention: Al Ralston
Telephone: (403) 232-1522
Facsimile: (403) 207-1522

13.2 Public Announcements

In the event that Closing does not occur, or until Closing has occurred, each Party shall keep confidential all information obtained from the other party in connection with the Assets and shall not release any information concerning this Agreement and the transactions herein provided for, without the prior written consent of the other Party, which consent shall not be unreasonably withheld. Nothing contained herein shall prevent a party at any time from furnishing information (i) to any governmental agency or regulatory authority or to the public if required by applicable law, provided that the Parties shall advise each other in advance of any public statement which they propose to make; (ii) in connection with obtaining consents or complying with preferential, pre-emptive or first purchase rights contained in Title Documents and any other agreements and documents to which the Assets are subject.

13.3 **Enurement**

This Agreement enures to the benefit of and is binding upon the Parties and their respective successors and permitted assigns.

13.4 **Assignment**

A Party may not assign its interest in this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld, provided however the Purchaser may, upon delivery of written notice, and delivery of a parental guarantee in form and substance satisfactory to the Vendor, acting reasonably, direct, assign and transfer all benefit under this Agreement and direct the conveyance and transfer of the Assets to any wholly owned subsidiary of Purchaser and such subsidiary will agree to be bound by the rights, duties, representations, warranties, covenants and obligations of Purchaser hereunder, provided however, that any such assignment will not relieve the Purchaser from any of its obligations hereunder.

13.5 **Time of Essence**

Time is of the essence in this Agreement.

13.6 **Governing Law**

This Agreement shall in all respects be governed by, interpreted and construed in accordance with the laws of the Province of Alberta and the laws of Canada applicable therein and shall in every regard be treated as a contract made in the Province of Alberta. The Parties irrevocably attorn to the exclusive jurisdiction of the courts of the Province of Alberta in respect of all matters arising out of this Agreement.

13.7 **Further Assurances**

Each Party will, from time to time and at all times after Closing, without further consideration, do such further acts and deliver all such further assurances, deeds and documents as shall be reasonably required in order to fully perform and carry out the terms of this Agreement.

13.8 **Waiver**

A waiver by either Party is not effective unless in writing and a waiver affects only the matter and its occurrence specifically identified in the writing granting the waiver and does not extend to any other matter or occurrence.

13.9 **No-Merger**

The covenants, representations, warranties and indemnities contained in this Agreement shall be deemed to be restated in any and all assignments, conveyances, transfers and other documents conveying the interests of Vendor in and to the Assets to Purchaser, subject to any and all time and other limitations contained in this Agreement. There shall not be any merger of any covenant, representation, warranty or indemnity in such assignments, conveyances, transfers and other documents notwithstanding any rule of law, equity or statute to the contrary and such rules are hereby waived.

13.10 **No Amendment Except in Writing**

No amendment shall be made to this Agreement unless in writing, executed by the Parties.

13.11 **Intentionally Deleted**

13.12 **Operatorship**

Purchaser acknowledges that Vendor is unable to assign to Purchaser operatorship of the Assets. Vendor shall, however, use reasonable efforts to assist Purchaser in its attempts to obtain operatorship of such Assets.

13.13 **Counterpart**

This Agreement may be executed in as many counterparts as are necessary and all executed counterparts together shall constitute one agreement.

13.14 **Invalidity**

If any provisions of this Agreement should be invalid, illegal or unenforceable in any respect, the validity, legality or enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

13.15 **Intentionally Deleted**

IN WITNESS WHEREOF the Parties have duly executed this Agreement as of the date first above written.

ANADARKO CANADA CORPORATION

Per: *(signed)*

COYOTE ENERGY INC.

Per: *(signed)*

Schedules intentionally deleted

16

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COYOTE ENERGY INC.

Evaluation of Oil & Gas Reserves
Based on Escalating Price Assumptions

As of August 1, 2002

McDANIEL & ASSOCIATES
consultants ltd.

Oil and Gas Reservoir Engineering

COYOTE ENERGY INC.

Evaluation of Oil & Gas Reserves
Based on Escalating Price Assumptions

As of August 1, 2002

Prepared For:

Coyote Energy Inc.
2200, 400 – 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Prepared By:

McDaniel & Associates Consultants Ltd.
2200, 255 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G6

August 2002

McDANIEL & ASSOCIATES
consultants ltd.

COYOTE ENERGY INC.

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McDaniel
& ASSOCIATES CONSULTANTS LTD.
Oil & Gas Reservoir Evaluations

August 21, 2002

Coyote Energy Inc.
2200, 400 – 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Attention: Mr. Jacob Roorda, President

Reference: **Coyote Energy Inc.**
Evaluation of Oil & Gas Reserves
Escalating Price Assumptions

Dear Sir:

Pursuant to your request we have prepared an evaluation of the crude oil, natural gas and natural gas products reserves and the present worth values of these reserves for the petroleum and natural gas interests of Coyote Energy Inc., hereinafter referred to as the "Company", as of August 1, 2002. The future net revenues and present worth values presented in this report were calculated using "Escalating Price" assumptions based on our opinion of the future crude oil, natural gas and natural gas product prices at July 1, 2002 and were presented in Canadian dollars before income tax.

The properties evaluated in this report were indicated to include essentially all of the Company's conventional petroleum and natural gas interests in Canada. The Company's principal crude oil properties are located in the Hayter and Thompson Lake areas in the province of Alberta. The principal natural gas property is located in the Thompson Lake area in the province of Alberta.

All of the Company's properties were evaluated in detail for this report, except for the Hayter and West Provost areas which were recently acquired from Anadarko Canada Corporation. These two properties were evaluated in detail by McDaniel & Associates for Anadarko as of June 1, 2002 and were mechanically updated to August 1, 2002 for this evaluation with no changes to the evaluation parameters.

The Company's share of proved remaining and probable additional crude oil, natural gas and natural gas products reserves as of August 1, 2002 and the respective present worth values assigned to these reserves based on "Escalating Price" assumptions were estimated to be as follows:

ESTIMATED COMPANY SHARE OF REMAINING RESERVES
AS OF AUGUST 1, 2002
MMCF, MBBL

	Proved Producing	Proved Non-Producing	Proved Undeveloped	Total Proved	Probable Additional	Total
Crude Oil						
Gross (1)	9,177	36	1,867	11,081	2,526	13,607
Net (2)	8,169	33	1,532	9,734	2,212	11,946
Natural Gas						
Gross (1)	1,348	298	-	1,646	340	1,986
Net (2)	1,079	233	-	1,312	266	1,578
Natural Gas Liquids						
Gross (1)	73	-	-	73	18	91
Net (2)	56	-	-	56	14	69

ESTIMATED COMPANY SHARE OF PRESENT WORTH VALUES BEFORE INCOME TAX
AS OF AUGUST 1, 2002
$1000 (3) (4)

			Discounted At		
	0%	10%	12%	15%	20%
Proved Developed Producing Reserves	99,174	83,660	81,234	77,911	73,079
Proved Developed Non-Producing Reserves	1,205	935	892	833	748
Proved Undeveloped Reserves	17,173	13,481	12,881	12,049	10,819
Total Proved Reserves	117,553	98,076	95,007	90,793	84,646
Probable Additional Reserves-Unrisked	30,401	20,879	19,569	17,854	15,526
Total Proved & Probable Reserves-Unrisked	**147,954**	**118,955**	**114,576**	**108,647**	**100,172**
Probable Additional Reserves-Risked (5)	15,201	10,440	9,785	8,927	7,763
Total Proved & Probable Reserves-Risked (5)	**132,753**	**108,515**	**104,791**	**99,720**	**92,409**

(1) Gross reserves are defined as the aggregate of the Company's working interest and royalty interest reserves before deductions of royalties payable to others.
(2) Net reserves are gross reserves less all royalties payable to others.
(3) Financial matters such as prepayments, take or pay payments, general obligations, etc. were not included.
(4) Based on "Escalating Price" assumptions at July 1, 2002 (see Price Schedules).
(5) Includes a 50 percent reduction in the probable present worth values to account for the risk associated with the probable additional reserves.

The Company's share of remaining reserves and present worth values are presented on a total Company basis in the summary section of this report. The location of the Company's properties and a graphical summary of the forecast production, net income and reserve distributions are also presented in this section. Tables summarizing the reserves, production and revenues for the various reserve classes are presented in Appendices 1 to 7. A summary of the Company's interests and encumbrances in each property is presented in Appendix 8. Discussions of the assumptions and methodology employed to prepare the reserve estimates and revenue forecasts are also contained in the "Evaluation Methodology" section.

Detailed reserve estimates and revenue forecasts and other supporting data for each of the properties that were reviewed in detail were provided in the detailed property report. Property discussions and a detailed description of the economic factors employed to derive the cash flow forecasts were also included therein.

The extent and character of all factual information supplied by the Company including ownership, well data, production, prices, revenues, operating costs, contracts, and other relevant data were relied upon by us in preparing this report and has been accepted as represented without independent verification. In view of the generality of the assignment the opinions expressed are not intended to provide a stand alone analysis of any specific property but to relate to an overall evaluation of the reserves of the Company.

This report was prepared by McDaniel & Associates Consultants Ltd. for the exclusive use of Coyote Energy Inc. and is not to be reproduced, distributed or made available, in whole or in part, to any person, company or organization other than Coyote Energy Inc. without the knowledge and consent of McDaniel & Associates Consultants Ltd. We reserve the right to revise any estimates provided herein if any relevant data existing prior to preparation of this report was not made available or if any data provided was found to be erroneous.

Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by B. H. Emslie"

B. H. Emslie, P. Eng.

"signed by R. Ott"

R. Ott, P. Geol.

BHE/RO:po
[02-421]

PERMIT TO PRACTICE
McDANIEL & ASSOCIATES CONSULTANTS LTD.

Signature "signed by B. H. Emslie"

Date Wednesday, August 21, 2002

PERMIT NUMBER: P 3145

The Association of Professional Engineers, Geologists and Geophysicists of Alberta

CERTIFICATE OF QUALIFICATION

I, Bryan Howard Emslie, Petroleum Engineer of 2200, 255 - 5th Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am a Senior Vice President of McDaniel & Associates Consultants Ltd. which Company did prepare, at the request of Coyote Energy Inc., the report entitled "Coyote Energy Inc., Evaluation of Oil & Gas Reserves, Based on Escalating Price Assumptions, As of August 1, 2002", dated August 21, 2002; and that I was involved in the preparation of this report.

2. That I attended the University of Alberta in the years 1973 to 1980 and that I graduated with Bachelor of Science Degree in Mechanical Engineering, that I am a registered Professional Engineer of the Association of Professional Engineers, Geologists & Geophysicists of Alberta and that I have in excess of twenty years experience in oil and gas reservoir studies and evaluations.

3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Coyote Energy Inc., any associate or affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

“signed by B. H. Emslie”

B. H. Emslie, P. Eng.

Calgary, Alberta
Dated: August 21, 2002

CERTIFICATE OF QUALIFICATION

I, Ronald Ott, Petroleum Geologist of 2200, 255 - 5th Avenue, S.W., Calgary, Alberta, Canada hereby certify:

1. That I am Chief Geologist of McDaniel & Associates Consultants Ltd. which Company did prepare, at the request of Coyote Energy Inc., the report entitled "Coyote Energy Inc., Evaluation of Oil & Gas Reserves, Based on Escalating Price Assumptions, As of August 1, 2002", dated August 21, 2002, and that I was involved in the preparation of this report.

2. That I attended University of Calgary in the years 1984 to 1988, graduating with a Bachelor of Science degree in Geology; that I am a member of the Canadian Society of Petroleum Geologists; that I am a registered Professional Geologist of the Association of Professional Engineers, Geologists & Geophysicists of Alberta and that I have in excess of eight years experience in oil and gas reservoir studies and evaluations.

3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Coyote Energy Inc., any associate or affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

"signed by R. Ott"

R. Ott, P. Geol.

Calgary, Alberta
Dated: August 21, 2002

Coyote Energy Inc.

Total Company Reserves and Present Worth Values
Escalating Prices as of August 1, 2002
Proved & Probable Reserves - Unrisked

Total Of All Areas

	Company Share of Remaining Reserves (mbbl,mmcf,mlt)		Company Share of Present Worth Values Before Income Tax (4)(5)(6) (M$)				
	Gross (1)	Net (2)	@0.0%	@10.0%	@12.0%	@15.0%	@20.0%
Proved Producing Reserves							
Crude Oil	9,177.4	8,169.2	94,609.1	80,130.8	77,856.3	74,735.3	70,188.6
Natural Gas	1,348.3	1,078.8	3,187.3	2,441.1	2,333.9	2,191.1	1,991.5
Natural Gas Liquids	73.4	55.6	1,378.1	1,088.1	1,044.0	984.1	898.7
Total			**99,174.4**	**83,660.0**	**81,234.2**	**77,910.5**	**73,078.8**
Proved Non-Producing Reserves							
Crude Oil	36.2	32.8	517.9	384.8	364.1	335.9	295.4
Natural Gas	298.1	232.9	687.1	549.8	527.6	497.0	451.9
Natural Gas Liquids	0.0	0.0	0.4	0.3	0.3	0.2	0.2
Total			**1,205.3**	**934.9**	**892.0**	**833.1**	**747.5**
Proved Undeveloped Reserves							
Crude Oil	1,867.3	1,532.3	17,172.7	13,480.5	12,880.8	12,049.0	10,819.3
Total			**17,172.7**	**13,480.5**	**12,880.8**	**12,049.0**	**10,819.3**
Total Proved Reserves							
Crude Oil	11,080.8	9,734.2	112,299.7	93,996.2	91,101.2	87,120.3	81,303.3
Natural Gas	1,646.4	1,311.7	3,874.4	2,990.9	2,861.6	2,688.1	2,443.4
Natural Gas Liquids	73.4	55.7	1,378.4	1,088.4	1,044.2	984.4	898.9
Total			**117,552.5**	**98,075.5**	**95,007.0**	**90,792.7**	**84,645.5**
Total Probable Reserves							
Crude Oil	2,526.1	2,212.1	29,222.3	20,153.8	18,903.6	17,265.5	15,039.1
Natural Gas	339.7	266.1	838.4	527.4	486.1	432.9	362.0
Natural Gas Liquids	18.0	13.6	340.3	197.9	179.4	155.8	125.1
Total			**30,401.1**	**20,879.0**	**19,569.1**	**17,854.2**	**15,526.2**
Total Proved & Probable Reserves							
Crude Oil	13,606.9	11,946.3	141,522.0	114,150.0	110,004.7	104,385.8	96,342.4
Natural Gas	1,986.1	1,577.8	4,712.8	3,518.4	3,347.7	3,120.9	2,805.4
Natural Gas Liquids	91.4	69.3	1,718.7	1,286.3	1,223.6	1,140.2	1,024.0
Total			**147,953.5**	**118,954.6**	**114,576.0**	**108,647.0**	**100,171.9**
BOE Reserves & PWV/BOE (3)							
Proved Producing	9,475.5	8,404.6	10.47	8.83	8.57	8.22	7.71
Proved Non-Producing	85.8	71.6	14.04	10.89	10.39	9.70	8.71
Proved Undeveloped	1,867.3	1,532.3	9.20	7.22	6.90	6.45	5.79
Total Proved	11,428.6	10,008.5	10.29	8.58	8.31	7.94	7.41
Total Probable	2,600.7	2,270.0	11.69	8.03	7.52	6.87	5.97
Total Proved & Probable	14,029.3	12,278.5	10.55	8.48	8.17	7.74	7.14

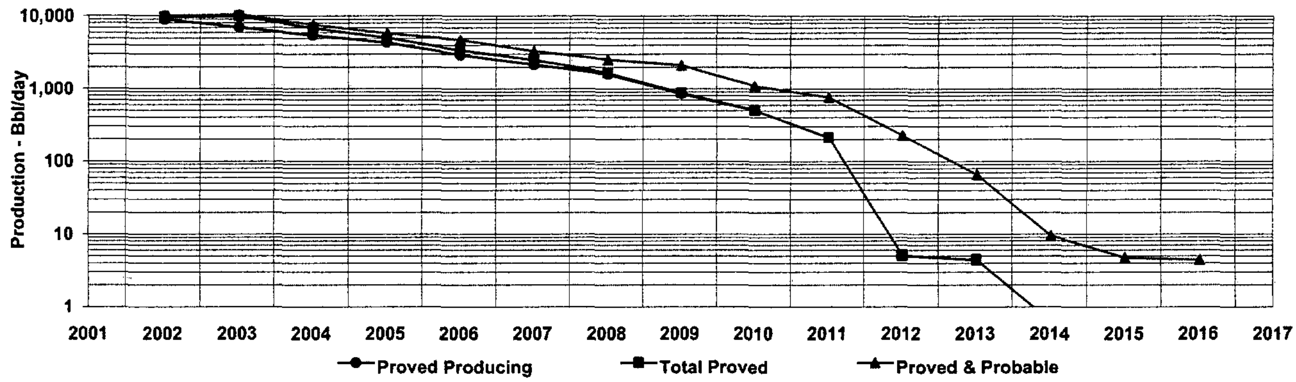
(1) Before royalty deductions.
(2) After royalty deductions.
(3) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE based on Gross BOE reserves.
(4) No allowance was made for the degree of risk associated with any of the reserve categories.
(5) Before allowance for Alberta Royalty Tax Credit
(6) Costs associated with extraction of natural gas products have in most cases been deducted from the natural gas revenues.

Coyote Energy Inc.
Location of Properties

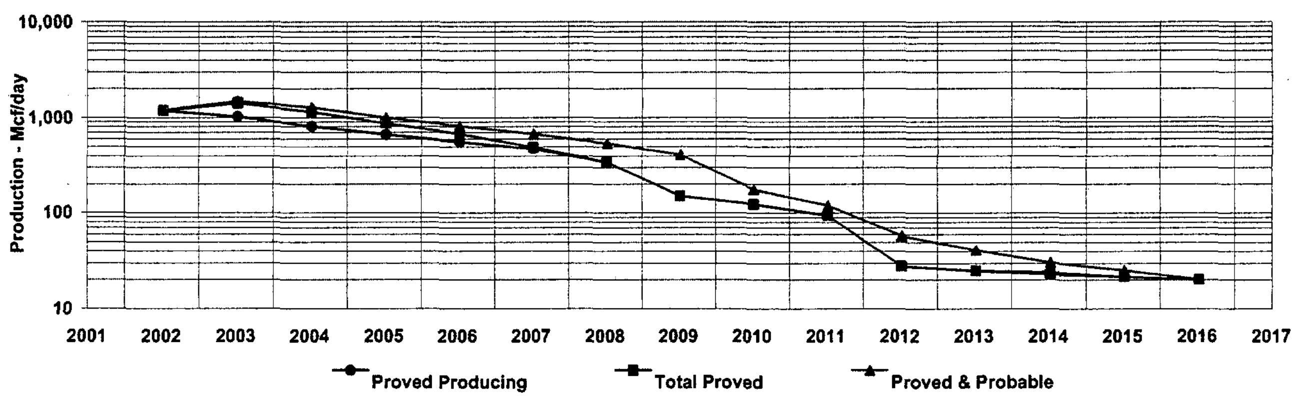
McDaniel
& ASSOCIATES CONSULTANTS LTD.

Coyote Energy Inc.
Escalating Prices
Total Company
Company Share

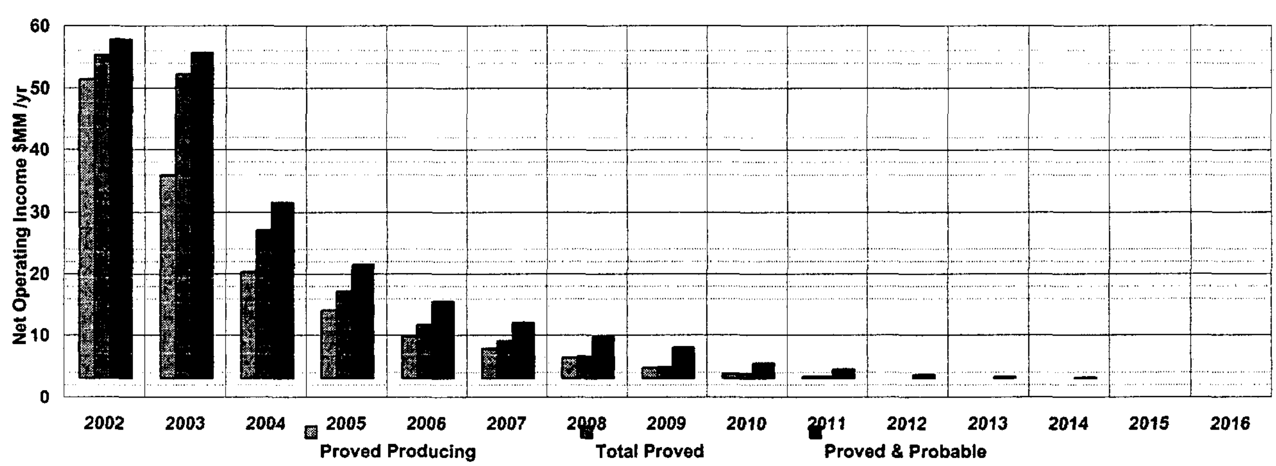
Crude Oil Production Profile



Natural Gas Production Profile



Before Tax Net Operating Income Profile



McDaniel & Associates
Consultants Ltd.

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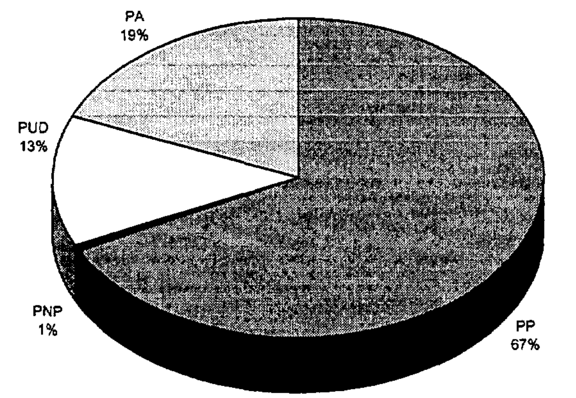
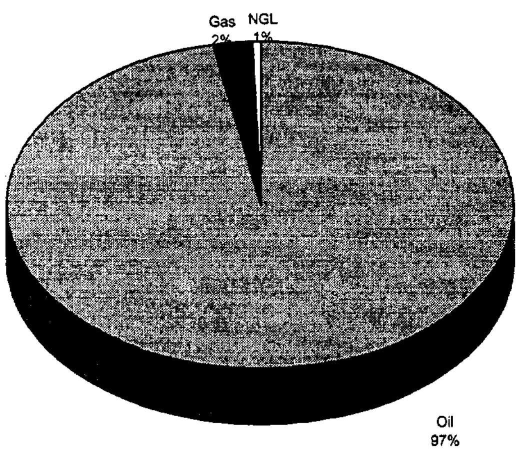
Coyote Energy Inc.
Escalating Prices
Reserve Distribution by Reserve Class and Product

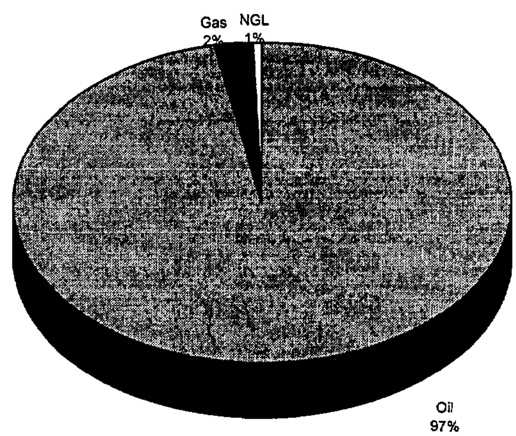
Reserve Distribution by Reserve Class



Reserve Distribution by Product Total Proved Reserves

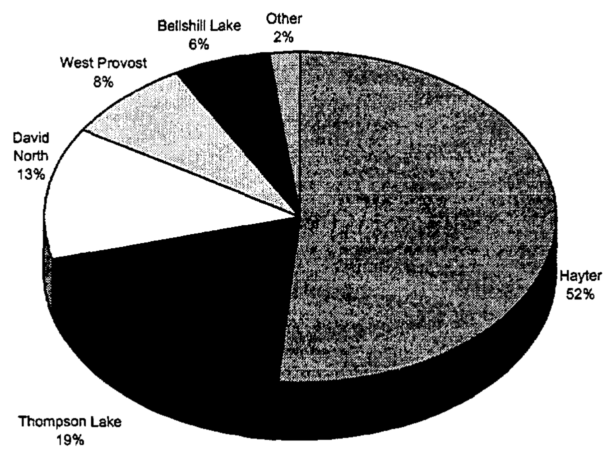


Reserve Distribution by Product Proved & Probable Reserves

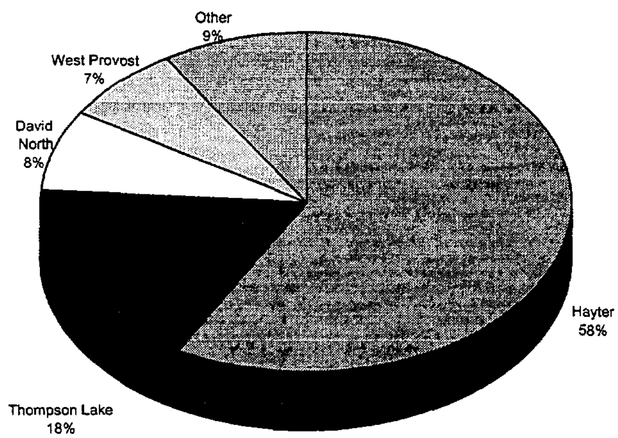


Coyote Energy Inc.
Escalating Prices
Reserve and Present Worth Value Distribution For Major Properties
Total Proved Reserves

Top 5 Properties by 15% PWV



Top 4 Crude Oil Properties



Top 4 Natural Gas Properties

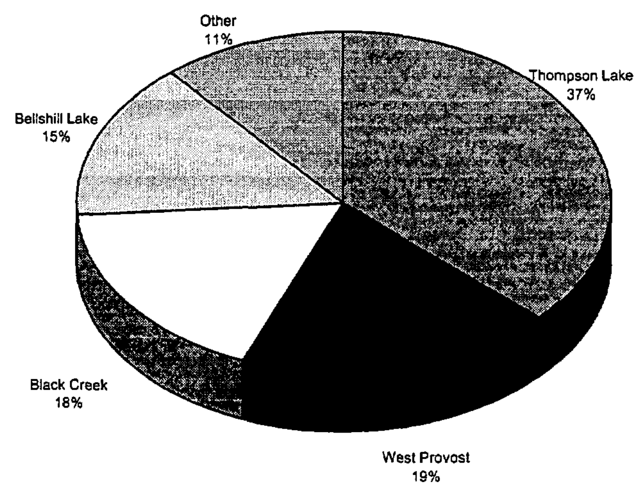


Table 1

McDaniel & Associates Consultants Ltd.

Summary of Price Forecasts

July 1, 2002

Year	WTI Crude Oil $US/BBL (1)	Edmonton Light Crude Oil $C/BBL (2)	Bow River Medium Crude Oil $C/BBL (3)	Heavy Crude Oil $C/BBL (4)	Alberta Average Natural Gas $C/Mmbtu (5)	Edmonton Cond. & Natural Gasolines $/Bbl	Edmonton Propane $/Bbl	Edmonton Butanes $/Bbl	Edmonton NGL Mix $/Bbl (6)	Sulphur $/LT	Inflation %	US/CAN Exchange Rate $US/$CAN
History												
1986	15.00	20.50	15.11	na	2.35	20.10	13.96	17.30	16.40	129.40	4.2	0.719
1987	19.30	24.30	20.79	na	1.64	23.80	9.98	16.80	15.10	89.20	4.4	0.755
1988	16.00	18.70	14.41	na	1.44	18.30	8.19	12.95	11.90	75.95	4.0	0.812
1989	19.60	22.20	18.09	na	1.47	21.80	8.14	10.35	11.60	72.00	5.0	0.844
1990	24.50	27.60	21.06	16.00	1.45	27.00	13.67	16.21	17.20	59.60	4.8	0.857
1991	21.40	23.40	15.07	9.05	1.18	22.90	11.91	15.25	15.30	54.15	5.6	0.873
1992	20.55	23.50	17.52	12.95	1.22	23.00	10.55	14.05	14.30	21.00	1.5	0.828
1993	18.60	21.90	16.70	13.30	1.89	21.50	14.10	13.55	15.40	-4.90	1.8	0.775
1994	17.20	22.20	18.43	15.00	1.83	21.75	12.50	13.45	14.70	11.65	0.2	0.732
1995	18.45	24.25	20.80	17.25	1.18	23.76	13.90	13.80	15.80	24.64	2.2	0.729
1996	22.10	29.35	25.11	20.05	1.50	28.75	22.20	17.15	21.70	12.63	1.6	0.733
1997	20.55	27.80	21.22	14.40	1.85	31.10	18.60	19.05	21.30	11.41	1.6	0.722
1998	14.40	20.35	14.60	9.40	1.90	21.85	10.95	11.90	13.50	8.54	1.0	0.687
1999	19.25	27.60	23.35	19.65	2.60	27.60	15.45	17.73	18.70	14.67	1.7	0.673
2000	30.31	44.72	34.35	27.80	5.20	46.25	31.55	35.00	35.70	15.00	2.7	0.674
2001	25.97	39.60	25.07	17.97	5.25	42.42	29.15	28.45	30.85	na	2.0	0.646
2002 (6mo)	23.95	37.25	29.45	25.45	3.53	37.20	16.35	21.95	22.35	na	2.0	0.635
Forecast												
2002 (6 mo)	25.00	37.50	31.50	25.00	4.50	37.50	25.20	24.70	27.50	0.00	2.0	0.650
2003	23.50	35.10	30.10	24.10	4.70	35.10	24.70	23.10	26.20	0.00	2.0	0.650
2004	21.80	32.00	27.00	21.00	4.55	32.00	23.10	21.10	24.20	0.00	2.0	0.660
2005	22.20	32.10	27.10	21.10	4.50	32.10	23.00	21.20	24.20	0.00	2.0	0.670
2006	22.60	32.20	27.20	21.20	4.45	32.20	23.00	21.20	24.20	0.00	2.0	0.680
2007	23.10	32.90	27.90	21.90	4.50	32.90	23.40	21.70	24.70	2.50	2.0	0.680
2008	23.60	33.60	28.60	22.60	4.50	33.60	23.60	22.20	25.10	5.00	2.0	0.680
2009	24.10	34.30	29.30	23.30	4.55	34.30	24.00	22.60	25.60	7.50	2.0	0.680
2010	24.60	35.00	30.00	24.00	4.65	35.00	24.50	23.10	26.10	10.00	2.0	0.680
2011	25.10	35.70	30.70	24.70	4.75	35.70	25.00	23.50	26.60	10.00	2.0	0.680
2012	25.60	36.40	31.40	25.40	4.85	36.40	25.50	24.00	27.20	10.00	2.0	0.680
2013	26.10	37.10	32.10	26.10	4.95	37.10	26.10	24.50	27.70	10.00	2.0	0.680
2014	26.60	37.80	32.80	26.80	5.00	37.80	26.40	24.90	28.20	10.00	2.0	0.680
2015	27.10	38.60	33.60	27.60	5.10	38.60	27.00	25.50	28.80	10.00	2.0	0.680
2016	27.60	39.30	34.30	28.30	5.20	39.30	27.50	25.90	29.30	10.00	2.0	0.680
2017	28.20	40.10	35.10	29.10	5.35	40.10	28.20	26.40	30.00	10.00	2.0	0.680
2018	28.80	41.00	36.00	30.00	5.45	41.00	28.70	27.00	30.60	10.00	2.0	0.680
2019	29.40	41.80	36.80	30.80	5.55	41.80	29.30	27.60	31.20	10.00	2.0	0.680
2020	30.00	42.70	37.70	31.70	5.65	42.70	29.90	28.20	31.90	10.00	2.0	0.680
2021	30.60	43.50	38.50	32.50	5.80	43.50	30.50	28.70	32.50	10.00	2.0	0.680
Thereafter	30.60	43.50	38.50	32.50	5.80	43.50	30.50	28.70	32.50	10.00	0.0	0.680

(1) West Texas Intermediate at Cushing Oklahoma
(2) Edmonton price for 40 API, 0.5% sulphur crude
(3) Bow River 26 degrees/2.1% sulphur crude oil at Hardisty Alberta
(4) Heavy crude oil 12 degrees at Hardisty Alberta
(5) Average Alberta field price
(6) NGL Mix based on 45 percent propane, 35 percent butane and 20 percent natural gasolines.

G020701 - Effective July 1, 2002

Table 2

McDaniel & Associates Consultants Ltd.

Summary of Natural Gas Price Forecasts

July 1, 2002

Year	U.S. Henry Hub Gas Price $US/Mmbtu	AECO Spot Price $C/GJ	Alberta Average Plantgate $C/Mmbtu (1)	Aggregator Plantgate $C/Mmbtu	Alberta Spot Sales Plantgate $C/Mmbtu	Sask. Prov. Gas Plantgate $C/Mmbtu	Sask. Spot Sales Plantgate $C/Mmbtu	British Columbia CanWest Plantgate $C/Mmbtu	British Columbia CanWest Wellhead $C/Mcf	B.C. Spot Sales Plantgate $C/Mmbtu
History										
1986	1.75	-	2.35	2.59	-	2.51	-	-	-	-
1987	1.50	-	1.64	1.82	-	1.86	-	-	-	-
1988	1.85	-	1.44	1.66	1.21	1.86	-	-	-	-
1989	1.68	-	1.47	1.57	1.28	1.60	-	-	-	-
1990	1.67	-	1.45	1.64	1.20	1.67	-	-	-	-
1991	1.54	-	1.18	1.31	0.97	1.61	-	-	-	1.13
1992	1.79	-	1.22	1.30	1.04	1.51	-	1.47	1.11	1.10
1993	2.13	-	1.89	1.60	2.16	2.16	-	1.73	1.37	2.13
1994	1.92	1.88	1.83	1.81	1.86	1.92	-	1.81	1.45	1.87
1995	1.62	1.12	1.18	1.23	1.02	1.35	-	1.29	0.90	1.12
1996	2.50	1.39	1.54	1.63	1.34	1.52	-	1.51	1.14	1.47
1997	2.59	1.71	1.84	1.86	1.67	1.85	-	1.78	1.43	1.98
1998	2.06	1.96	1.90	1.88	1.84	2.05	-	1.94	1.59	2.00
1999	2.28	2.79	2.60	2.46	2.78	2.82	2.96	2.52	2.19	2.77
2000	4.31	5.32	5.20	4.57	5.38	4.78	4.83	5.27	5.05	4.88
2001	3.98	5.15	5.25	5.25	5.25	5.70	6.15	6.75	6.58	6.30
2002 (6mo)	2.98	3.53	3.53	3.38	3.75	3.70	3.75	3.29	2.99	3.80
Forecast										
2002 (6 mo)	3.36	4.39	4.50	4.50	4.50	4.65	4.65	4.40	4.16	4.50
2003	3.53	4.62	4.70	4.70	4.70	4.85	4.85	4.60	4.36	4.70
2004	3.46	4.44	4.55	4.55	4.55	4.71	4.71	4.45	4.20	4.55
2005	3.48	4.40	4.50	4.50	4.50	4.66	4.66	4.40	4.13	4.50
2006	3.51	4.36	4.45	4.45	4.45	4.61	4.61	4.35	4.07	4.45
2007	3.54	4.40	4.50	4.50	4.50	4.67	4.67	4.40	4.12	4.50
2008	3.58	4.44	4.50	4.50	4.50	4.67	4.67	4.40	4.11	4.50
2009	3.62	4.48	4.55	4.55	4.55	4.72	4.72	4.45	4.15	4.55
2010	3.69	4.57	4.65	4.65	4.65	4.83	4.83	4.55	4.24	4.65
2011	3.77	4.67	4.75	4.75	4.75	4.93	4.93	4.65	4.34	4.75
2012	3.84	4.76	4.85	4.85	4.85	5.03	5.03	4.75	4.43	4.85
2013	3.92	4.85	4.95	4.95	4.95	5.14	5.14	4.85	4.53	4.95
2014	3.99	4.94	5.00	5.00	5.00	5.19	5.19	4.90	4.57	5.00
2015	4.07	5.04	5.10	5.10	5.10	5.29	5.29	5.00	4.66	5.10
2016	4.14	5.13	5.20	5.20	5.20	5.40	5.40	5.10	4.76	5.20
2017	4.23	5.24	5.35	5.35	5.35	5.55	5.55	5.25	4.90	5.35
2018	4.32	5.35	5.45	5.45	5.45	5.66	5.66	5.35	4.99	5.45
2019	4.41	5.47	5.55	5.55	5.55	5.76	5.76	5.45	5.09	5.55
2020	4.50	5.58	5.65	5.65	5.65	5.86	5.86	5.55	5.18	5.65
2021	4.59	5.69	5.80	5.80	5.80	6.02	6.02	5.70	5.32	5.80
Thereafter	4.59	5.69	5.80	5.80	5.80	6.02	6.02	5.70	5.32	5.80

(1) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the crown royalty calculations.

COYOTE ENERGY INC.

Evaluation of Oil & Gas Reserves
Based on Escalating Price Assumptions
As of August 1, 2002

Evaluation Methodology

INTRODUCTION

Estimates of the crude oil, natural gas and natural gas products reserves and the associated present worth values before income taxes attributable to the Canadian properties of the Company have been presented in this report as of August 1, 2002. Reserve estimates were prepared for 8 individual properties in which the Company was indicated to have an interest in Western Canada based on detailed studies of the reservoir and performance characteristics as well as historical revenues and costs.

The basic information employed in the preparation of this report was obtained from the Company's files, published sources and from our own files. Detailed reserve estimates and revenue forecasts and other supporting data for each of the properties that were reviewed in detail were provided in the detailed property report. Property discussions and a detailed description of the economic factors employed to derive the cash flow forecasts were also included therein.

The effective date of this report is August 1, 2002. The reserve estimates presented herein were based on the operating and economic conditions and development status as of that date except for changes planned for the immediate future or in the process of implementation. The assumptions and methodology employed in the preparation of this report conform with generally accepted petroleum engineering and evaluation principles. A brief review of the methodology employed in arriving at the reserves and present worth value estimates is presented in this section.

RESERVE ESTIMATES

Crude Oil

The crude oil reserve estimates presented in this report were based on a study of the volumetric data and performance characteristics of the individual wells and reservoirs in question. The oil-in-place estimates were based on individual well pore volume interpretations, geological studies of pool configurations as well as unitization studies and published estimates. In those cases where indicative oil production decline and/or increasing gas-oil and water-oil ratio trends were evident, the remaining reserves were determined by extrapolating these trends to economic limiting conditions. Where definitive production information was not yet available, the reserve estimates were based on analogy with similar wells or reservoirs or on theoretical studies of recovery efficiencies. The cumulative production figures were taken from published sources or from records of the Company and estimated for those recent periods where such data were not available.

Natural Gas and Products

The natural gas reserve estimates were based on a study of the volumetric data and performance characteristics of the individual wells and reservoirs in question. Volumetric estimates of the gas-in-place were based on individual well pore volume interpretations, geological studies of the pools and areas and on unitization studies and published estimates. Material balance estimates of the gas-in-place were employed where such information was available. The reserves recoverable from the currently producing properties were estimated from studies of performance characteristics and/or reservoir pressure histories. In cases of competitive drainage in multi-well pools the reserves were based on an analysis of the relevant factors relating to the future pool depletion by existing and possible future wells. The recovery factors for the non-producing properties were estimated from a consideration of test rates, reservoir pressures and by analogy with similar wells or reservoirs.

The natural gas products reserve estimates for the producing properties were predicated on a study of historical and anticipated future recoveries of these products from the natural gas reserves. The natural gas products recoveries from the non-producing natural gas reserves were estimated from gas analyses, well test information and from analogy with similar reservoirs. Natural gas products reserves were only assigned to non-producing properties in those cases where, in all likelihood the gas production would be processed through existing facilities capable of extracting these products or where such a facility will be available in the near future.

RESERVE CLASSIFICATION

The crude oil, natural gas and natural gas products reserves of the Company were classified into proved and probable additional categories. The proved reserves were considered to be those reserves estimated as recoverable under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir. Probable reserves are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future. A more detailed description of the factors considered in making these reserve assignments is presented in the "Reserve Definitions" at the end of this section.

The proved reserves have been further subdivided into proved producing, proved non-producing and proved undeveloped categories. Reserves were considered to be producing if these reserves are currently being produced or if definitive steps are being taken to begin production of these reserves in the immediate future. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area. Non-producing reserves recoverable from existing wells that require relatively minor capital expenditures to produce were classified as proved non-producing. Reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure is required were classified as proved undeveloped.

In all cases the crude oil and natural gas liquids reserves were expressed in barrels being equal to 34.972 Imperial gallons. The natural gas reserves were presented in thousands of standard cubic feet (MCF) and calculated at a base pressure of 14.65 psia and a base temperature of 60 degrees Fahrenheit.

Company Share of Reserves

The Company's net share of reserves was obtained by employing the Company's indicated gross working and royalty interests in the various properties in question less all royalties owned by others. In estimating net reserves the applicable Crown royalties were based on the regulations in effect as of August 1, 2002.

PRESENT WORTH VALUE ESTIMATES

The present worth values of the crude oil, natural gas and natural gas products reserves were obtained by employing future production and revenue analyses. The future crude oil production was in each instance predicated on a forecast of allowable rates and/or anticipated performance characteristics of the individual wells and reservoirs in question. The future natural gas production was predicated on the provisions of the natural gas purchase contracts where such contracts were available with consideration to the historical producing rates and the estimated deliverability. In those areas where shut-in natural gas reserves exist commencement of production was based on the proximity to a pipeline connection and the relevant factors relating to the future marketing of the reserves. Solution gas production was based on the forecast of the oil producing rates and producing gas-oil ratios. The natural gas products production forecasts were based on the anticipated recoveries of these products from the produced natural gas.

The Company's gross share of future crude oil revenue was derived by employing the Company's gross share of production and the forecast reference Edmonton crude oil prices less the historical quality and transportation price differential for each respective field. The forecast natural gas prices with an adjustment for the heating value of the gas were employed to calculate the gross share of future natural gas revenues. The forecast Edmonton natural gas products prices with adjustments to reflect historical price differentials realized by the Company in each respective property were employed to calculate the gross share of natural gas products revenues. Royalties and mineral taxes payable to the Crown were estimated based on the methods in effect as of August 1, 2002. Overriding royalties payable to others were estimated based on the indicated applicable rates. In those cases where a proportionate share of the natural gas gathering and processing charges were indicated to be payable by the Crown or royalties owned by others, these charges have been deducted in determining the net royalties payable.

In all cases, estimates of the applicable capital expenditures and operating costs with an allowance for inflation were deducted in arriving at the Company's share of future net revenues. No allowance for future well abandonment costs was made for any of the Company's working interest wells or for the abandonment of any facilities. The present worth values were then obtained by employing 10, 12, 15 and 20 percent nominal annual discount rates compounded annually.

The estimated present worth values of the proved plus probable additional reserves were obtained by employing future production and revenue analyses on a total proved plus probable reserve basis. All additional costs required to recover the probable additional reserves were included in the revenue forecasts. It should be pointed out that no allowance was made for any risk associated with the probable reserves in this report other than in the present worth value summary in the covering letter.

Summaries of the Company's share of remaining reserves together with forecast future revenues, royalties, taxes, operating and capital costs, cash flow and present worth values are presented in detailed tabulations in Appendices 1 to 7.

RESERVE DEFINITIONS

Crude Oil

A mixture, consisting mainly of pentanes and heavier hydrocarbons that may contain sulphur compounds, that is liquid at the conditions under which its volume is measured or estimated, but excluding such liquids obtained from the processing of natural gas.

Synthetic Oil

Oil derived from the upgrading of crude bitumen or by chemical modification of coal or other materials and which is largely interchangeable with conventional crude oil as a refinery feedstock.

Natural Gas

The lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions is essentially a gas, but which may contain liquids. The natural gas reserve estimates are reported on a marketable basis, that is the gas which is available to a transmission line after removal of certain hydrocarbons and non-hydrocarbon compounds present in the raw natural gas and which meets specifications for use as a domestic, commercial or industrial fuel.

Natural Gas Liquids

Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus, or a combination thereof.

Sulphur

Elemental sulphur removed from the produced natural gas by processing through an extraction plant.

Remaining Reserves

Remaining reserves are those quantities of crude oil, natural gas, natural gas liquids and sulphur remaining after deducting those quantities produced up to the reference date of the study.

Gross Reserves

The total of the Company's working interests and/or royalty interests share of reserves before deducting royalties owned by others.

Net Reserves

The total of the Company's working interests and/or royalty interests share of reserves after deducting the amounts attributable to the royalties owned by others.

Royalties

The term royalties, as used in this report, refers to royalties paid to others. The royalties deducted from the reserves are based on the royalty percentage calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling price the price forecasts for the individual properties in question has been employed.

Proved Reserves

Those reserves estimated as recoverable under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area.

Comments:

1. Where reserves are clearly known to exist in a reservoir and would be physically recoverable but cannot be termed "proved reserves" because they are not commercially recoverable due to their remote location (i.e. frontier reserves), these reserves are itemized separately in the report and their special circumstances fully explained.
2. Zones which have not been completed but which are interpreted to be productive from well logs (or core analyses) and which have conclusive drill stem tests or other production tests indicating economic producing rates are considered to be proved providing there is a high degree of certainty that these reserves will be produced.
3. Zones interpreted to be productive from well logs (or core analyses) either completed or behind pipe but which have not been tested or have inconclusive tests are considered proved only if offsetting wells indicate favorable tests or productive characteristics from this zone and there is a high degree of certainty that these reserves will be produced because of favorable reservoir characteristics.
4. The proved recovery efficiencies for presently shut-in reserves are estimated from theoretical considerations or by analogy to the nearest similar zone or area. In all cases the productive capacities of the individual wells or reservoirs in question are taken into account.
5. The proved natural gas reserves may be based on the assumption that additional compressor horsepower will be installed to achieve lower abandonment pressures providing there is a high degree of certainty that such action will be taken.
6. An allowance for increased recoveries in enhanced recovery (water-flood, solvent-flood, etc.) projects is made only on the basis of demonstrated more favorable performance from the project in question or from similar projects in like reservoirs. Increased proved recoveries may be assigned prior to the installation of the facilities if in our opinion there is a high degree of certainty that such facilities will be installed in the future. A gradual transfer of reserves from a probable additional to a proved category is usually made in such projects as more performance history is obtained. The assignment of higher recovery factors to these projects by regulatory authorities does not necessarily provide a basis for increased proved recoveries since such assignments must often be made prior to obtaining indicative performance history in order to provide sufficient incentives to institute such schemes.

7. Natural gas liquids and sulphur reserves are based on the recoveries of these products from the proved natural gas reserves and are dependent on current plant efficiencies. In the case of shut-in wells the reserves are based on analyses of the raw natural gas and anticipated extraction efficiencies.

Proved Producing Reserves

Those proved reserves that are actually on production, or if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner. An illustration of such a situation is where a well or zone is capable but is shut-in because its deliverability is not required to meet contract commitments. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area.

Proved Non-Producing Reserves

Those non-producing proved reserves recoverable from existing wells that require relatively minor capital expenditures to produce.

Proved Undeveloped Reserves

Those reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure will be required.

Probable Additional Reserves

Those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

Comments:

1. The probable additional natural gas reserves are based on the potential productive areas of the natural gas reservoirs in question which could not be deemed proved at this time as well as those solution gas reserves commercially recoverable from the probable additional crude oil reserves.
2. The probable additional reserves of natural gas liquids and sulphur were considered to be those reserves recoverable from the probable additional natural gas reserves.
3. Portions of the zones which have questionable potential based on well log interpretations (or core analyses) and which have not been indicated productive by conclusive tests are considered to be probable additional.

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Total Proved Reserves

Total Of All Areas

Year	No.Of Wells	Crude Oil Annual Volume mbbl	Crude Oil Sales Price $/bbl	Crude Oil Sales Revenue M$	Natural Gas Annual Volume mmcf	Natural Gas Sales Price $/mcf	Natural Gas Sales Revenue M$	Natural Gas Liquids Annual Volume mbbl	Natural Gas Liquids Sales Price $/bbl	Natural Gas Liquids Sales Revenue M$	Total Other Revenues M$	Gross Revenue M$
2002	423.4	1270.3	27.77	35279.6	136.5	4.50	614.3	7.5	27.64	207.0	22.2	36123.2
2003	428.4	3115.8	26.32	82016.0	389.9	4.70	1832.7	15.9	26.17	416.8	36.0	84301.5
2004	414.7	2177.0	23.55	51266.0	316.5	4.55	1440.1	13.4	24.19	324.1	32.0	53062.1
2005	386.6	1603.5	23.91	38339.7	240.8	4.50	1083.8	11.5	24.20	277.8	29.0	39730.3
2006	317.2	1079.9	24.58	26549.0	188.4	4.45	838.6	10.0	24.20	241.3	25.0	27653.9
2007	266.0	793.1	25.60	20300.9	135.5	4.50	609.9	8.7	24.74	216.0		21126.8
2008	188.3	534.3	26.44	14124.8	94.8	4.50	427.0	5.5	25.22	138.7		14690.5
2009	83.9	276.6	26.23	7254.7	41.5	4.55	189.1	0.3	27.41	8.8		7452.6
2010	57.3	159.4	27.77	4425.3	34.0	4.65	158.0	0.2	28.27	6.2		4589.6
2011	29.1	67.4	28.54	1925.0	26.0	4.75	123.3	0.1	33.07	4.6		2053.0
2012	1.5	1.6	31.94	50.5	7.8	4.85	37.7			0.0		88.2
2013	1.5	1.4	32.67	47.0	6.9	4.95	34.0					81.0
2014	0.8	0.2	33.75	8.1	6.4	5.00	32.0					40.1
2015	0.7				6.0	5.10	30.4					30.4
2016	0.7				5.6	5.20	29.0					29.0
REM.	0.7				9.7	5.40	52.2					52.2
TOTAL		**11080.5**	**25.41**	**281586.4**	**1646.3**	**4.58**	**7532.2**	**73.2**	**25.16**	**1841.3**	**144.2**	**291104.5**

Year	Crown Royalties Unadj. Royalty M$	Crown Royalties Royalty Adj. M$	Crown Royalties Adj. Royalty M$	Freehold Royalties Unadj. Royalty M$	Freehold Royalties Royalty Adj. M$	Freehold Royalties Adj. Royalty M$	Overriding Royalties Unadj. Royalty M$	Overriding Royalties Royalty Adj. M$	Overriding Royalties Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	1159.6	3.8	1155.8	3204.4	0.6	3203.8	319.3	0.1	319.2	724.3	5403.2	14.97
2003	2309.7	41.1	2268.7	8294.6	1.3	8293.2	720.8	0.1	720.7	1846.3	13128.9	15.58
2004	1240.4	33.1	1207.3	4691.7	1.3	4690.4	489.2	0.1	489.1	797.8	7184.5	13.55
2005	824.1	19.9	804.3	3355.7	1.2	3354.5	372.8	0.1	372.7	392.8	4924.4	12.40
2006	586.6	12.6	573.9	1978.3	1.1	1977.3	274.3	0.1	274.2	212.6	3038.1	11.00
2007	427.8	3.6	424.2	1395.1	1.0	1394.1	227.9	0.1	227.8	144.4	2190.5	10.37
2008	287.1	1.5	285.7	852.6	1.0	851.6	188.3	0.1	188.3	96.2	1421.7	9.68
2009	88.0	0.2	87.8	500.2	0.9	499.3	155.4	0.1	155.3	62.6	805.0	10.80
2010	62.5	0.1	62.5	204.0	0.9	203.1	125.0	0.0	124.9	32.1	422.6	9.21
2011	21.6	0.0	21.5	37.0	0.8	36.3	93.3	0.0	93.3	15.7	166.9	8.13
2012	0.1	0.0	0.1	18.5	0.8	17.7	0.2	0.0	0.2	0.6	18.6	21.11
2013	0.1	0.0	0.1	17.4	0.7	16.7	0.2	0.0	0.2	0.6	17.5	21.54
2014	0.1	0.0	0.1	8.2	0.7	7.5	0.2	0.0	0.2	0.4	8.1	20.30
2015	0.1	0.0	0.1	6.1	0.6	5.4	0.2	0.0	0.1	0.3	6.0	19.58
2016	0.1	0.0	0.1	5.8	0.6	5.2	0.2	0.0	0.1	0.3	5.7	19.57
REM.	0.1	0.0	0.1	10.4	1.0	9.4	0.3	0.0	0.3	0.5	10.2	19.57
TOTAL	**7008.1**	**116.0**	**6892.1**	**24579.8**	**14.4**	**24565.4**	**2967.3**	**0.9**	**2966.4**	**4327.5**	**38751.9**	**13.32**

Year	Operating Costs M$	Net Op. Income M$	Capital Costs Drilling & Compl M$	Capital Costs Equip & Facility M$	Capital Costs Total Capital M$	Net Revenues After Costs Annual M$	Net Revenues After Costs Cum M$	Net Revenues After Costs PWV @15.0% M$
2002	8944.7	21775.3	9046.0		9046.0	12729.3	12729.3	12364.0
2003	22052.9	49119.6	3470.7	229.5	3700.2	45419.5	58148.8	39957.7
2004	21806.6	24071.0	5.2		5.2	24065.8	82214.5	18410.3
2005	20615.6	14190.3	5.3		5.3	14185.0	96399.6	9436.1
2006	15995.3	8620.5				8620.4	105020.0	4986.4
2007	12899.7	6036.6				6036.6	111056.6	3036.3
2008	9666.2	3602.6				3602.5	114659.1	1575.7
2009	4832.0	1815.6				1815.5	116474.6	690.5
2010	3419.8	747.1				747.1	117221.7	247.0
2011	1626.0	260.1				260.1	117481.8	74.8
2012	48.9	20.7				20.7	117502.5	5.2
2013	49.6	14.0				14.0	117516.5	3.0
2014	21.8	10.2				10.2	117526.6	1.9
2015	16.2	8.3				8.3	117534.9	1.4
2016	16.3	7.0				7.0	117541.9	1.0
REM.	31.6	10.4				10.4	117552.3	1.2
TOTAL	**122043.1**	**130309.1**	**12527.2**	**229.5**	**12756.7**	**117552.3**		**90792.5**

Product	Remaining Reserves Gross	Remaining Reserves Net	Remaining Present Worth Value - M$ @10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	11080.8	9734.2	93996.2	91101.2	87120.3	81303.3
Natural Gas (mmcf)	1646.4	1311.7	2990.9	2861.6	2688.1	2443.4
Natural Gas Liquids (mbbl) .	73.4	55.7	1088.4	1044.2	984.4	898.9
Total			**98075.5**	**95007.0**	**90792.7**	**84645.5**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
Fixed Battery Costs	P-100.000		NRA	-	-	-	-	-3372.9	-3132.8	-2822.7
00/04-05-041-12-W4	W-100.000	ELL	PP	10.2	48.79	0.05	-	539.6	510.3	471.9
02/04-05-041-12-W4	W-100.000	ELL	PP	19.6	50.39	0.09	-	590.1	558.7	517.5
03/04-05-041-12-W4	W-100.000	ELL	PP	1.2	5.15	0.00	-	48.8	48.3	47.5
00/05-05-041-12-W4	W-100.000	ELL	PP	11.6	52.20	0.05	-	598.0	566.4	524.9
04/05-05-041-12-W4	W-100.000	ELL	PP	12.6	38.11	0.05	-	389.9	369.2	341.9
B0/05-05-041-12-W4	W-100.000	ELL	PP	12.7	60.50	0.06	-	722.2	684.0	633.7
00/06-05-041-12-W4	W- 40.000	GLAUC L	PP	42.6	-	0.21	-	113.7	112.0	109.7
02/10-05-041-12-W4	W-100.000	ELL	PNP	1.9	21.09	0.01	-	226.0	214.7	199.4
00/12-05-041-12-W4	W-100.000	ELL	PP	19.4	49.69	0.09	-	578.0	547.4	507.1
00/13-05-041-12-W4	W-100.000	ELL	PP	0.8	5.62	0.00	-	39.9	39.4	38.6
B0/14-05-041-12-W4	W-100.000	ELL	PP	10.8	51.43	0.05	-	607.0	577.6	538.8
C0/14-05-041-12-W4	W-100.000	ELL	PP	8.2	40.48	0.04	-	416.5	394.6	365.7
00/15-05-041-12-W4	W-100.000	ELL	PNP	3.6	15.06	0.01	-	169.9	159.8	146.1
02/15-05-041-12-W4	W-100.000	ELL	PP	2.1	7.81	0.01	-	113.0	111.3	108.7
A2/15-05-041-12-W4	W-100.000	ELL	PP	4.6	34.14	0.02	-	423.2	407.4	385.9
B2/15-05-041-12-W4	W-100.000	ELL	PP	17.1	59.88	0.08	-	722.2	683.8	633.3
02/16-05-041-12-W4	W-100.000	ELL	PP	3.8	15.81	0.02	-	225.9	221.0	214.2
00/01-06-041-12-W4	W-100.000	ELL	PP	11.7	19.53	0.05	-	142.9	137.0	129.1
00/02-06-041-12-W4	W-100.000	ELL	PP	8.7	38.81	0.04	-	429.5	406.8	376.9
02/07-06-041-12-W4	W-100.000	ELL	PP	4.4	26.91	0.02	-	247.5	236.1	221.0
02/08-06-041-12-W4	W-100.000	ELL	PP	11.4	21.09	0.05	-	277.2	268.4	256.2
03/08-06-041-12-W4	W-100.000	ELL	PP	14.2	29.67	0.06	-	302.4	287.0	266.7
05/08-06-041-12-W4	W-100.000	ELL	PP	12.1	47.46	0.06	-	566.6	537.0	498.0
02/09-06-041-12-W4	W-100.000	ELL	PP	8.8	43.31	0.04	-	475.7	446.7	408.9
02/15-15-041-12-W4	R- 3.750	ELL	PP	-	0.22	-	-	5.0	4.8	4.7
04/15-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
02/16-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
05/16-15-041-12-W4	R- 3.750	ELL	PP	-	0.05	-	-	1.3	1.3	1.2
Subtotal				**254.2**	**783.22**	**1.15**	-	**5599.0**	**5397.9**	**5124.9**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	PNP	292.6	-	-	-	539.1	517.5	487.6
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PP	47.2	-	0.19	-	163.6	155.6	145.1
00/11-05-040-08-W4	R- 15.000	VIK	PP	5.0	-	0.02	-	20.1	19.6	18.9
00/07-07-040-08-W4	R- 6.250	CLY	PP	2.2	-	0.01	-	9.4	9.3	9.1
00/10-07-040-08-W4	R- 15.000	VIK	PP	18.3	-	0.07	-	60.5	57.1	52.6
Subtotal				**72.6**	-	**0.29**	-	**253.6**	**241.6**	**225.6**
David North										
Lloydminster O Unit	W-100.000	LLOYD	PP	40.4	403.99	2.02	-	6270.5	6049.7	5750.3
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PP	52.5	429.37	2.62	-	6153.9	5925.3	5618.8
00/10-27-040-03-W4	W-100.000	LLOYD	PP	-	14.09	-	-	139.3	134.9	128.9
02/10-27-040-03-W4	W-100.000	LLOYD	PP	-	24.26	-	-	371.8	359.2	342.1
02/15-27-040-03-W4	W-100.000	LLOYD	PP	-	22.92	-	-	235.5	227.3	216.1
Subtotal				**92.9**	**894.64**	**4.64**	-	**13171.0**	**12696.5**	**12056.0**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	PP	-	71.94	-	-	415.2	404.5	389.8
N-24-40-1W4 1999 Wells	W- 93.750	DINA	PP	-	47.39	-	-	347.4	341.6	333.3
N-24-40-1W4 2002 Wells	W- 93.750	DINA	PP	-	202.69	-	-	2053.2	2002.0	1931.3
N-24-40-1W4 Future Locations	W- 93.750	DINA	PUD	-	168.75	-	-	991.8	922.4	828.2
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	PP	-	1276.76	-	-	9388.2	9049.1	8590.4
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	PP	-	98.02	-	-	703.0	681.7	652.6
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	PP	-	128.94	-	-	1096.8	1075.8	1046.1
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	PP	-	414.57	-	-	3982.6	3917.2	3824.3

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves: Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$): @10.0%	@12.0%	@15.0%
Hayter (cont'd)										
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	PP	-	155.50	-	-	1682.7	1656.3	1618.6
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	PP	-	380.08	-	-	4800.0	4661.9	4472.7
Sec 25-40-1W4 Future Locations	W- 94.517	DINA	PUD	-	1361.04	-	-	10692.9	10273.8	9689.4
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	PP	-	75.39	-	-	413.7	407.6	398.8
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	PP	-	23.79	-	-	220.4	217.3	212.8
Sec 34-40-1W4 2000 Wells	W- 75.000	DINA	PP	-	9.84	-	-	53.5	52.6	51.3
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	PP	-	647.94	-	-	2769.6	2716.8	2642.2
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	PP	-	8.57	-	-	65.4	64.7	63.7
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	PP	-	31.36	-	-	265.3	260.5	253.8
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	PP	-	151.76	-	-	1559.0	1530.6	1490.5
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	PP	-	306.60	-	-	2748.9	2702.2	2636.0
NW-35-40-1W4 Pre-2000 Wells	W- 75.000	DINA	PP	-	116.69	-	-	407.5	394.8	377.4
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	PP	-	117.50	-	-	1026.8	1009.8	985.8
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	PP	-	232.37	-	-	2138.4	2095.3	2034.9
NW-35-40-1W4 Future Locations	W- 75.000	DINA	PUD	-	337.50	-	-	1795.8	1684.5	1531.3
S-36-40-1W4 GOR Wells	R- 7.500	DINA	PP	-	2.26	-	-	50.4	49.6	48.5
00/09-34-040-01-W4	W- 75.000	SPKY	PP	-	10.16	-	-	98.7	96.0	92.3
00/15-34-040-01-W4	W- 75.000	SPKY	PP	-	7.08	-	-	69.7	68.2	66.2
00/01-03-041-01-W4	W- 75.000	SPKY	PP	-	27.99	-	-	210.0	199.6	186.0
Subtotal				-	**6412.48**	-	-	**50046.8**	**48536.5**	**46448.2**
Mestikow										
All Company Wells	W-100.000	DINA	PP	-	170.34	-	-	1414.4	1372.1	1314.0
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	PP	612.5	2011.52	67.37	-	18895.0	18321.1	17531.5
04/10-29-040-11-W4	W- 25.000	VIK	PP	1.6	-	-	-	2.2	2.1	2.1
Subtotal				**614.1**	**2011.52**	**67.37**	-	**18897.1**	**18323.3**	**17533.6**
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PP	27.9	379.18	-	-	3450.4	3331.6	3170.1
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PP	8.3	79.23	-	-	730.6	704.5	669.0
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PP	21.7	206.44	-	-	2182.6	2136.7	2072.0
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PP	4.3	55.63	-	-	615.2	606.9	595.0
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PP	0.4	6.96	-	-	71.2	70.2	68.7
Sec 16-38-3W4	W-100.000	DINA	PP	10.1	57.55	-	-	520.5	511.1	497.8
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PP	16.6	23.65	-	-	264.4	258.7	250.7
00/11-24-037-02-W4	W- 37.500	VIK	PP	0.5	-	-	-	0.2	0.2	0.2
00/07-27-037-02-W4	W- 42.188	VIK	PP	55.5	-	-	-	59.0	54.3	48.6
02/06-11-038-03-W4	W- 28.125	VIK	NRA	-	-	-	-	-	-	-
00/14-12-038-03-W4	W- 37.500	CLY	PP	13.1	-	-	-	18.7	18.2	17.5
00/07-13-038-03-W4	W- 37.500	VIK	PP	34.2	-	-	-	52.2	49.9	46.8
00/06-14-038-03-W4	W- 37.500	VIK	NRA	-	-	-	-	-	-	-
00/07-15-038-03-W4	W- 37.500	VIK	PP	7.3	-	-	-	9.1	9.0	8.7
00/07-17-038-03-W4	W- 37.500	VIK	PP	6.0	-	-	-	1.6	1.6	1.5
00/07-18-038-03-W4	W- 37.500	VIK	PP	24.0	-	-	-	30.1	28.8	27.1
00/14-07-039-01-W4	W- 29.371	MCLAR	PP	90.1	-	-	-	121.5	113.5	103.3
Bodo Compression Facility	P-100.000	ALL ZONES	NRA	-	-	-	-	27.1	26.6	25.8

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
West Provost (cont'd)										
Wells with NRA		ALL ZONES	NRA	-	-	-	-	-	-	-
Subtotal				**320.0**	**808.64**	**-**	**-**	**8154.5**	**7921.6**	**7602.7**
Subtotal Alberta				**1646.5**	**11080.83**	**73.45**	**-**	**98075.6**	**95007.0**	**90792.7**
TOTAL				**1646.5**	**11080.83**	**73.45**	**-**	**98075.6**	**95007.0**	**90792.7**

Coyote Energy Inc.

Summary of Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved Reserves

Area	Company Interest Reserves Gas bcf	Company Interest Reserves Oil mbbl	Company Interest Reserves NGL mbbl	Company Interest Reserves Sulphur mlt	Net Reserves After Royalty Gas bcf	Net Reserves After Royalty Oil mbbl	Net Reserves After Royalty NGL mbbl	Net Reserves After Royalty Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%	@20.0%
Alberta												
Bellshill Lake	0.25	783.2	1.2	-	0.21	716.0	0.9	-	5599.0	5397.9	5124.9	4733.3
Black Creek	0.29	-	-	-	0.23	-	-	-	539.1	517.5	487.6	443.8
Choice	0.07	-	0.3	-	0.07	-	0.3	-	253.6	241.6	225.6	203.5
David North	0.09	894.6	4.6	-	0.09	847.8	4.4	-	13171.0	12696.5	12056.0	11145.7
Hayter	-	6412.5	-	-	-	5329.9	-	-	50046.8	48536.5	46448.2	43371.5
Mestikow	-	170.3	-	-	-	159.4	-	-	1414.4	1372.1	1314.0	1229.3
Thompson Lake	0.61	2011.5	67.4	-	0.46	1922.7	50.0	-	18897.1	18323.3	17533.6	16379.5
West Provost	0.32	808.6	-	-	0.26	758.5	-	-	8154.5	7921.6	7602.7	7139.1
Subtotal Alberta	**1.65**	**11080.8**	**73.5**	**-**	**1.31**	**9734.3**	**55.7**	**-**	**98075.6**	**95007.0**	**90792.7**	**84645.6**
TOTAL	**1.65**	**11080.8**	**73.5**	**-**	**1.31**	**9734.3**	**55.7**	**-**	**98075.6**	**95007.0**	**90792.7**	**84645.6**

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Sorted By Company Oil Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company Oil Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	6412.5	-	-	6412.5	50046.8	48536.5	46448.2	57.87	57.87
2	Thompson Lake	0.61	2011.5	67.4	-	2181.2	18897.1	18323.3	17533.6	18.15	76.02
3	David North	0.09	894.6	4.6	-	914.8	13171.0	12696.5	12056.0	8.07	84.10
4	West Provost	0.32	808.6	-	-	862.0	8154.5	7921.6	7602.7	7.30	91.39
5	Bellshill Lake	0.25	783.2	1.2	-	826.7	5599.0	5397.9	5124.9	7.07	98.46
6	Mestikow	-	170.3	-	-	170.3	1414.4	1372.1	1314.0	1.54	100.00
7	Black Creek	0.29	-	-	-	48.8	539.1	517.5	487.6	-	100.00
8	Choice	0.07	-	0.3	-	12.4	253.6	241.6	225.6	-	100.00
	Total	**1.65**	**11080.8**	**73.5**	**-**	**11428.7**	**98075.6**	**95007.0**	**90792.7**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Sorted By Company Gas Reserves

Rank		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company Gas Reserves	
		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Thompson Lake	0.61	2011.5	67.4	-	2181.2	18897.1	18323.3	17533.6	37.30	37.30
2	West Provost	0.32	808.6	-	-	862.0	8154.5	7921.6	7602.7	19.43	56.73
3	Black Creek	0.29	-	-	-	48.8	539.1	517.5	487.6	17.77	74.50
4	Bellshill Lake	0.25	783.2	1.2	-	826.7	5599.0	5397.9	5124.9	15.44	89.94
5	David North	0.09	894.6	4.6	-	914.8	13171.0	12696.5	12056.0	5.64	95.59
6	Choice	0.07	-	0.3	-	12.4	253.6	241.6	225.6	4.41	100.00
7	Hayter	-	6412.5	-	-	6412.5	50046.8	48536.5	46448.2	-	100.00
8	Mestikow	-	170.3	-	-	170.3	1414.4	1372.1	1314.0	-	100.00
	Total	**1.65**	**11080.8**	**73.5**	**-**	**11428.7**	**98075.6**	**95007.0**	**90792.7**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Sorted By Company BOE Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company BOE Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	6412.5	-	-	6412.5	50046.8	48536.5	46448.2	56.11	56.11
2	Thompson Lake	0.61	2011.5	67.4	-	2181.2	18897.1	18323.3	17533.6	19.09	75.19
3	David North	0.09	894.6	4.6	-	914.8	13171.0	12696.5	12056.0	8.00	83.20
4	West Provost	0.32	808.6	-	-	862.0	8154.5	7921.6	7602.7	7.54	90.74
5	Bellshill Lake	0.25	783.2	1.2	-	826.7	5599.0	5397.9	5124.9	7.23	97.97
6	Mestikow	-	170.3	-	-	170.3	1414.4	1372.1	1314.0	1.49	99.46
7	Black Creek	0.29	-	-	-	48.8	539.1	517.5	487.6	0.43	99.89
8	Choice	0.07	-	0.3	-	12.4	253.6	241.6	225.6	0.11	100.00
	Total	**1.65**	**11080.8**	**73.5**	**-**	**11428.7**	**98075.6**	**95007.0**	**90792.7**	**100.00**	**-**

1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Sorted By @15.0% Present Worth Value

		Company Interest Reserves					Present Worth Value Before Tax (M$)			@15.0% Present Worth Value	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	6412.5	-	-	6412.5	50046.8	48536.5	46448.2	51.16	51.16
2	Thompson Lake	0.61	2011.5	67.4	-	2181.2	18897.1	18323.3	17533.6	19.31	70.47
3	David North	0.09	894.6	4.6	-	914.8	13171.0	12696.5	12056.0	13.28	83.75
4	West Provost	0.32	808.6	-	-	862.0	8154.5	7921.6	7602.7	8.37	92.12
5	Bellshill Lake	0.25	783.2	1.2	-	826.7	5599.0	5397.9	5124.9	5.64	97.77
6	Mestikow	-	170.3	-	-	170.3	1414.4	1372.1	1314.0	1.45	99.21
7	Black Creek	0.29	-	-	-	48.8	539.1	517.5	487.6	0.54	99.75
8	Choice	0.07	-	0.3	-	12.4	253.6	241.6	225.6	0.25	100.00
	Total	**1.65**	**11080.8**	**73.5**	**-**	**11428.7**	**98075.6**	**95007.0**	**90792.7**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

First Year Production, Revenue and Expenses by Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

2002 Summary

	Production					Revenue and Expenses				Average Values $/BOE (1)			
Area	Oil bopd	Gas mcf/d	NGL bpd	Sulphur lt/d	BOE (1) boepd	Gross Revenue $M	Encumb. $M	Oper. Exp $M	Net Rev. (2) $M	Gross Revenue	Encumb.	Oper Exp	Net Rev (2)
Alberta													
Bellshill Lake	382.4	189.2	0.7	-	413.9	1803	211	585	1007	28.64	3.35	9.29	16.00
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	46.6	0.2	-	7.8	33	-	-	33	27.37	-	-	27.37
David North	697.4	73.1	3.6	-	713.1	3448	227	572	2649	31.80	2.10	5.27	24.43
Hayter	5168.5	-	-	-	5168.5	19990	4130	3887	11973	25.43	5.25	4.95	15.23
Mestikow	123.9	-	-	-	123.9	514	46	153	316	27.27	2.42	8.10	16.75
Thompson Lake	1341.3	416.0	44.9	-	1455.5	7082	479	2749	3854	31.99	2.16	12.42	17.41
West Provost	639.7	173.2	-	-	668.1	3254	311	999	1944	32.02	3.06	9.83	19.13
Subtotal Alberta	**8353.2**	**898.1**	**49.4**	**-**	**8551.0**	**36123**	**5403**	**8945**	**21775**	**27.78**	**4.15**	**6.88**	**16.74**
TOTAL	**8353.2**	**898.1**	**49.4**	**-**	**8551.0**	**36123**	**5403**	**8945**	**21775**	**27.78**	**4.15**	**6.88**	**16.74**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE based on Gross BOE reserves.
(2) Excludes capital and abandonment expenses.

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Oil Production Forecast (mbbl) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	58	125	115	104	88	76	63	55	52	47	783	-	783
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	106	200	148	114	91	74	62	51	30	19	895	-	895
Hayter	786	2125	1358	924	513	331	199	129	42	2	6409	3	6413
Mestikow	19	38	30	25	21	18	16	4	-	-	170	-	170
Thompson Lake	204	435	372	321	280	247	153	-	-	-	2012	-	2012
West Provost	97	193	155	116	87	48	41	37	35	-	809	-	809
Subtotal Alberta	**1270**	**3116**	**2177**	**1604**	**1080**	**793**	**534**	**277**	**159**	**67**	**11078**	**3**	**11081**
TOTAL	**1270**	**3116**	**2177**	**1604**	**1080**	**793**	**534**	**277**	**159**	**67**	**11078**	**3**	**11081**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Gas Production Forecast (mmcf) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	29	58	36	28	24	21	17	15	14	13	254	-	254
Black Creek	-	108	92	55	33	5	-	-	-	-	293	-	293
Choice	7	15	12	10	7	6	5	4	4	3	72	0	73
David North	11	21	15	12	9	8	6	5	3	2	93	-	93
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	63	133	113	98	85	75	47	-	-	-	614	-	614
West Provost	26	55	49	39	30	22	20	16	13	8	278	42	320
Subtotal Alberta	**137**	**390**	**317**	**241**	**188**	**136**	**95**	**42**	**34**	**26**	**1604**	**42**	**1647**
TOTAL	**137**	**390**	**317**	**241**	**188**	**136**	**95**	**42**	**34**	**26**	**1604**	**42**	**1647**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

NGL Production Forecast (mstb) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	0	0	0	0	0	0	0	0	0	0	1	-	1
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	0	0	0	0	0	0	0	0	0	0	0	-	0
David North	1	1	1	1	0	0	0	0	0	0	5	-	5
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	7	15	12	11	9	8	5	-	-	-	67	-	67
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**8**	**16**	**13**	**12**	**10**	**9**	**6**	**0**	**0**	**0**	**73**	**-**	**73**
TOTAL	**8**	**16**	**13**	**12**	**10**	**9**	**6**	**0**	**0**	**0**	**73**	**-**	**73**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Gross Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1803	3681	2933	2648	2237	1985	1689	1516	1446	1357	21294	-	21294
Black Creek	-	507	419	248	146	21	-	-	-	-	1341	-	1341
Choice	33	70	55	44	32	28	24	20	18	13	336	2	338
David North	3448	6226	4131	3203	2563	2147	1832	1558	946	592	26648	-	26648
Hayter	19990	52138	29128	19921	11134	7408	4610	3072	1048	54	148503	106	148608
Mestikow	514	973	681	562	476	421	378	94	-	-	4098	-	4098
Thompson Lake	7082	14500	11196	9707	8501	7669	4871	-	-	-	63525	-	63525
West Provost	3254	6206	4518	3398	2564	1449	1288	1192	1132	38	25038	213	25252
Subtotal Alberta	**36123**	**84302**	**53062**	**39730**	**27654**	**21127**	**14691**	**7453**	**4590**	**2053**	**290784**	**321**	**291105**
TOTAL	**36123**	**84302**	**53062**	**39730**	**27654**	**21127**	**14691**	**7453**	**4590**	**2053**	**290784**	**321**	**291105**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Encumbrance Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	211	413	316	276	221	193	163	143	135	124	2194	-	2194
Black Creek	-	106	64	24	8	1	-	-	-	-	203	-	203
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	227	403	262	200	158	131	110	90	48	23	1654	-	1654
Hayter	4130	10690	5509	3612	1995	1329	787	504	182	12	28751	24	28776
Mestikow	46	73	45	33	25	22	18	4	-	-	266	-	266
Thompson Lake	479	948	695	579	489	429	270	-	-	-	3890	-	3890
West Provost	311	495	292	201	142	86	73	64	58	7	1729	42	1771
Subtotal Alberta	**5403**	**13129**	**7185**	**4924**	**3038**	**2191**	**1422**	**805**	**423**	**167**	**38686**	**66**	**38752**
TOTAL	**5403**	**13129**	**7185**	**4924**	**3038**	**2191**	**1422**	**805**	**423**	**167**	**38686**	**66**	**38752**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Capital Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	-	-	5	5	-	-	-	-	-	-	11	-	11
Black Creek	-	230	-	-	-	-	-	-	-	-	230	-	230
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	-	-	-	-	-	-	-	-	-	-	-	-	-
Hayter	9046	3471	-	-	-	-	-	-	-	-	12517	-	12517
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	-	-	-	-	-	-	-	-	-	-	-	-	-
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**9046**	**3700**	**5**	**5**	**-**	**-**	**-**	**-**	**-**	**-**	**12757**	**-**	**12757**
TOTAL	**9046**	**3700**	**5**	**5**	**-**	**-**	**-**	**-**	**-**	**-**	**12757**	**-**	**12757**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Operating Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	585	1399	1395	1357	1317	1291	1219	1193	1208	1211	12175	-	12175
Black Creek	-	68	68	52	42	7	-	-	-	-	236	-	236
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	*572*	*1274*	*1173*	*1088*	*1012*	*940*	*869*	*802*	*557*	*367*	*8653*	-	*8653*
Hayter	3887	10095	10137	9588	5566	3533	2479	1801	684	32	47802	72	47874
Mestikow	153	364	325	325	326	290	293	74	-	-	2150	-	2150
Thompson Lake	2749	6422	6231	6071	5950	5845	3859	-	-	-	37127	-	37127
West Provost	999	2431	2478	2135	1783	994	948	961	970	16	13716	112	13828
Subtotal Alberta	**8945**	**22053**	**21807**	**20616**	**15995**	**12900**	**9666**	**4832**	**3420**	**1626**	**121859**	**184**	**122043**
TOTAL	**8945**	**22053**	**21807**	**20616**	**15995**	**12900**	**9666**	**4832**	**3420**	**1626**	**121859**	**184**	**122043**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Net Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1007	1869	1217	1010	700	501	306	179	103	22	6915	-	6915
Black Creek	-	104	287	172	97	13	-	-	-	-	672	-	672
Choice	33	70	55	44	32	28	24	20	18	13	336	2	338
David North	2649	4549	2696	1914	1393	1077	852	667	341	202	16341	-	16341
Hayter	2927	27881	13481	6721	3573	2546	1345	767	182	9	59433	9	59442
Mestikow	316	536	310	205	125	109	67	15	-	-	1683	-	1683
Thompson Lake	3854	7129	4270	3057	2062	1394	742	-	-	-	22508	-	22508
West Provost	1944	3281	1748	1062	638	368	266	167	103	14	9593	59	9653
Subtotal Alberta	**12729**	**45419**	**24066**	**14185**	**8620**	**6037**	**3603**	**1816**	**747**	**260**	**117482**	**70**	**117552**
TOTAL	**12729**	**45419**	**24066**	**14185**	**8620**	**6037**	**3603**	**1816**	**747**	**260**	**117482**	**70**	**117552**

Table 1

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Total Proved & Probable Reserves - Unrisked

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids				
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Total Other Revenues M$	Gross Revenue M$
2002	423.4	1320.8	27.72	36616.1	138.2	4.50	622.0	7.6	27.60	209.8	22.2	37470.1
2003	428.4	3286.8	26.30	86457.8	405.0	4.70	1903.6	16.5	26.18	432.3	36.0	88829.7
2004	415.7	2413.9	23.48	56681.8	353.5	4.55	1608.3	14.3	24.20	346.3	32.0	58668.4
2005	400.4	1868.3	23.82	44504.7	276.4	4.50	1243.8	12.5	24.19	303.3	29.0	46080.8
2006	371.1	1506.3	24.06	36236.2	224.7	4.45	1000.1	11.1	24.17	268.8	25.0	37530.1
2007	298.0	1047.8	25.30	26506.8	185.5	4.50	834.5	9.9	24.76	245.1		27586.5
2008	254.6	805.1	26.27	21148.2	148.7	4.50	669.2	8.9	25.14	223.8		22041.2
2009	234.0	668.8	27.21	18196.7	114.0	4.55	518.8	8.0	25.66	206.3		18921.8
2010	108.4	347.2	27.20	9444.5	49.0	4.65	227.8	1.6	26.44	41.2		9713.6
2011	76.8	243.0	27.79	6751.2	32.9	4.75	156.2	0.3	29.97	8.7		6916.1
2012	35.4	71.6	31.25	2236.3	16.1	4.85	77.9	0.2	27.23	6.0		2320.2
2013	14.5	20.8	32.62	677.6	11.4	4.95	56.5	0.1	26.38	3.4		737.5
2014	2.5	3.0	33.37	101.4	8.5	5.00	42.4	0.0	21.00	0.4		144.3
2015	1.5	1.5	34.31	52.5	7.0	5.10	35.8			0.1		88.4
2016	1.5	1.4	35.08	49.8	5.6	5.20	29.0					78.8
REM.	0.8	0.3	36.35	11.3	9.7	5.40	52.2					63.5
TOTAL		**13606.7**	**25.40**	**345672.9**	**1986.0**	**4.57**	**9078.0**	**91.1**	**25.18**	**2295.4**	**144.2**	**357190.9**

	Crown Royalties			Freehold Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	1226.6	3.9	1222.7	3368.7	0.6	3368.1	327.4	0.1	327.3	779.7	5697.9	15.22
2003	2546.6	39.6	2507.0	8799.3	1.3	8797.9	746.7	0.1	746.6	2006.5	14058.0	15.83
2004	1459.6	36.1	1423.5	5302.2	1.3	5300.9	523.4	0.1	523.3	980.6	8228.3	14.03
2005	1056.1	23.7	1032.4	3901.6	1.2	3900.5	408.6	0.1	408.5	530.1	5871.5	12.75
2006	759.4	16.4	743.1	3140.1	1.1	3139.0	336.5	0.1	336.5	351.8	4570.3	12.19
2007	584.5	11.6	573.0	1994.9	1.0	1993.8	265.4	0.1	265.3	218.2	3050.4	11.06
2008	450.7	7.2	443.6	1498.4	1.0	1497.4	223.9	0.1	223.8	157.6	2322.4	10.54
2009	378.4	2.0	376.4	1139.6	0.9	1138.7	188.5	0.1	188.5	119.5	1823.1	9.63
2010	138.5	0.4	138.1	637.9	0.9	637.1	158.6	0.0	158.5	75.1	1008.9	10.39
2011	70.0	0.0	70.0	476.1	0.8	475.3	139.9	0.0	139.9	56.7	742.0	10.73
2012	25.7	0.0	25.7	98.4	0.8	97.6	21.3	0.0	21.3	10.6	155.2	6.69
2013	0.1	0.0	0.1	38.5	0.7	37.8	2.7	0.0	2.7	4.1	44.7	6.06
2014	0.1	0.0	0.1	20.2	0.7	19.5	0.4	0.0	0.3	0.8	20.8	14.40
2015	0.1	0.0	0.1	17.9	0.6	17.3	0.2	0.0	0.1	0.5	18.0	20.36
2016	0.1	0.0	0.1	17.0	0.6	16.4	0.2	0.0	0.1	0.5	17.1	21.68
REM.	0.1	0.0	0.1	12.9	1.0	11.9	0.3	0.0	0.3	0.5	12.8	20.16
TOTAL	**8696.6**	**140.9**	**8555.8**	**30463.6**	**14.4**	**30449.2**	**3344.0**	**0.9**	**3343.1**	**5292.9**	**47641.3**	**13.34**

			Capital Costs			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Drilling & Compl M$	Equip & Facility M$	Total Capital M$	Annual M$	Cum M$	PWV @15.0% M$
2002	8955.4	22816.8	9046.0		9046.0	13770.8	13770.8	13375.5
2003	22119.3	52652.3	3470.7	229.5	3700.2	48952.2	62722.9	43065.6
2004	21987.6	28452.3	5.2		5.2	28447.2	91170.1	21762.1
2005	21757.5	18451.8	5.3		5.3	18446.5	109616.6	12270.8
2006	20416.7	12543.1				12543.0	122159.6	7255.4
2007	15441.5	9094.5				9094.5	131254.1	4574.5
2008	12914.3	6804.5				6804.5	138058.5	2976.2
2009	12076.2	5022.6				5022.5	143081.0	1910.2
2010	6252.1	2452.5				2452.5	145533.6	811.0
2011	4701.4	1472.7				1472.7	147006.3	423.5
2012	1559.0	605.9				605.9	147612.2	151.5
2013	431.6	261.1				261.2	147873.4	56.8
2014	82.5	40.9				40.9	147914.3	7.8
2015	51.1	19.3				19.3	147933.6	3.2
2016	51.9	9.8				9.8	147943.4	1.4
REM.	40.7	10.0				10.0	147953.4	1.2
TOTAL	**148838.9**	**160710.0**	**12527.2**	**229.5**	**12756.7**	**147953.4**		**108646.6**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	**Gross**	**Net**	**@10.0%**	**@12.0%**	**@15.0%**	**@20.0%**
Crude Oil (mbbl)	13606.9	11946.3	114150.0	110004.7	104385.8	96342.4
Natural Gas (mmcf)	1986.1	1577.8	3518.4	3347.7	3120.9	2805.4
Natural Gas Liquids (mbbl)	91.4	69.3	1286.3	1223.6	1140.2	1024.0
Total			**118954.6**	**114576.0**	**108647.0**	**100171.9**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
Fixed Battery Costs	P-100.000		NRA	-	-	-	-	-3372.9	-3132.8	-2822.7
00/04-05-041-12-W4	W-100.000	ELL	P	10.2	48.79	0.05	-	539.6	510.3	471.9
02/04-05-041-12-W4	W-100.000	ELL	P	19.6	50.39	0.09	-	590.1	558.7	517.5
03/04-05-041-12-W4	W-100.000	ELL	P	1.2	5.15	0.00	-	48.8	48.3	47.5
00/05-05-041-12-W4	W-100.000	ELL	P	11.6	52.20	0.05	-	598.0	566.4	524.9
04/05-05-041-12-W4	W-100.000	ELL	P	12.6	38.11	0.05	-	389.9	369.2	341.9
B0/05-05-041-12-W4	W-100.000	ELL	P	12.7	60.50	0.06	-	722.2	684.0	633.7
00/06-05-041-12-W4	W- 40.000	GLAUC L	P	52.0	-	0.25	-	136.2	133.9	130.6
02/10-05-041-12-W4	W-100.000	ELL	NP	2.3	26.09	0.01	-	274.1	259.0	238.7
00/12-05-041-12-W4	W-100.000	ELL	P	19.4	49.69	0.09	-	578.0	547.4	507.1
00/13-05-041-12-W4	W-100.000	ELL	P	0.8	5.62	0.00	-	39.9	39.4	38.6
B0/14-05-041-12-W4	W-100.000	ELL	P	10.8	51.43	0.05	-	607.0	577.6	538.8
C0/14-05-041-12-W4	W-100.000	ELL	P	8.2	40.48	0.04	-	416.5	394.6	365.7
00/15-05-041-12-W4	W-100.000	ELL	NP	4.8	20.06	0.02	-	221.8	207.7	188.7
02/15-05-041-12-W4	W-100.000	ELL	P	2.1	7.81	0.01	-	113.0	111.3	108.7
A2/15-05-041-12-W4	W-100.000	ELL	P	4.6	34.14	0.02	-	423.2	407.4	385.9
B2/15-05-041-12-W4	W-100.000	ELL	P	17.1	59.88	0.08	-	722.2	683.8	633.3
02/16-05-041-12-W4	W-100.000	ELL	P	3.8	15.81	0.02	-	225.9	221.0	214.2
00/01-06-041-12-W4	W-100.000	ELL	P	11.7	19.53	0.05	-	142.9	137.0	129.1
00/02-06-041-12-W4	W-100.000	ELL	P	8.7	38.81	0.04	-	429.5	406.8	376.9
02/07-06-041-12-W4	W-100.000	ELL	P	4.4	26.91	0.02	-	247.5	236.1	221.0
02/08-06-041-12-W4	W-100.000	ELL	P	11.4	21.09	0.05	-	277.2	268.4	256.2
03/08-06-041-12-W4	W-100.000	ELL	P	14.2	29.67	0.06	-	302.4	287.0	266.7
05/08-06-041-12-W4	W-100.000	ELL	P	12.1	47.46	0.06	-	566.6	537.0	498.0
02/09-06-041-12-W4	W-100.000	ELL	P	8.8	43.31	0.04	-	475.7	446.7	408.9
02/15-15-041-12-W4	R- 3.750	ELL	P	-	0.22	-	-	5.0	4.8	4.7
04/15-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
02/16-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
05/16-15-041-12-W4	R- 3.750	ELL	P	-	0.05	-	-	1.3	1.3	1.2
Subtotal				**265.4**	**793.22**	**1.21**	-	**5721.5**	**5512.0**	**5227.6**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	NP	409.4	-	-	-	768.2	731.7	681.9
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	P	64.1	-	0.26	-	204.0	191.5	175.4
00/11-05-040-08-W4	R- 15.000	VIK	P	5.0	-	0.02	-	20.1	19.6	18.9
00/07-07-040-08-W4	R- 6.250	CLY	P	2.2	-	0.01	-	9.4	9.3	9.1
00/10-07-040-08-W4	R- 15.000	VIK	P	18.3	-	0.07	-	60.5	57.1	52.6
Subtotal				**89.5**	-	**0.36**	-	**294.0**	**277.4**	**255.9**
David North										
Lloydminster O Unit	W-100.000	LLOYD	P	53.2	531.85	2.65	-	7889.8	7537.1	7069.4
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	P	64.8	529.37	3.23	-	7422.2	7090.8	6654.6
00/10-27-040-03-W4	W-100.000	LLOYD	P	-	14.09	-	-	139.3	134.9	128.9
02/10-27-040-03-W4	W-100.000	LLOYD	P	-	29.26	-	-	430.7	413.7	390.7
02/15-27-040-03-W4	W-100.000	LLOYD	P	-	27.92	-	-	274.3	263.0	247.8
Subtotal				**118.0**	**1132.49**	**5.89**	-	**16156.3**	**15439.3**	**14491.4**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	P	-	90.67	-	-	485.7	470.9	450.5
N-24-40-1W4 1999 Wells	W- 93.750	DINA	P	-	66.05	-	-	450.5	440.6	426.8
N-24-40-1W4 2002 Wells	W- 93.750	DINA	P	-	256.67	-	-	2525.8	2452.4	2352.1
N-24-40-1W4 Future Locations	W- 93.750	DINA	UND	-	206.25	-	-	1370.6	1274.8	1146.7
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	P	-	1559.43	-	-	11186.8	10702.5	10058.6
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	P	-	121.57	-	-	835.5	805.4	764.6
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	P	-	175.69	-	-	1427.3	1392.7	1344.5
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	P	-	506.83	-	-	4782.7	4691.1	4562.1

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Hayter (cont'd)										
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	P	-	201.07	-	-	2115.9	2076.7	2021.3
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	P	-	489.82	-	-	5981.5	5776.7	5500.5
Sec 25-40-1W4 Future Locations	W- 94.517	DINA	UND	-	1663.50	-	-	13604.6	12989.9	12146.4
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	P	-	112.79	-	-	541.5	530.8	515.8
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	P	-	31.20	-	-	275.9	271.1	264.3
Sec 34-40-1W4 2000 Wells	W- 75.000	DINA	P	-	9.84	-	-	53.5	52.6	51.3
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	P	-	797.73	-	-	3242.0	3165.6	3059.0
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	P	-	13.50	-	-	93.8	92.5	90.6
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	P	-	41.24	-	-	338.5	330.8	320.1
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	P	-	200.64	-	-	1993.2	1948.8	1886.7
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	P	-	404.96	-	-	3499.0	3426.6	3324.8
NW-35-40-1W4 Pre-2000 Wells	W- 75.000	DINA	P	-	116.69	-	-	407.5	394.8	377.4
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	P	-	155.30	-	-	1311.8	1285.7	1248.9
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	P	-	305.18	-	-	2744.9	2677.0	2582.9
NW-35-40-1W4 Future Locations	W- 75.000	DINA	UND	-	412.50	-	-	2527.8	2374.1	2164.8
S-36-40-1W4 GOR Wells	R- 7.500	DINA	P	-	2.26	-	-	50.4	49.6	48.5
00/09-34-040-01-W4	W- 75.000	SPKY	P	-	10.16	-	-	98.7	96.0	92.3
00/15-34-040-01-W4	W- 75.000	SPKY	P	-	7.08	-	-	69.7	68.2	66.2
00/01-03-041-01-W4	W- 75.000	SPKY	P	-	35.48	-	-	249.2	234.3	215.2
Subtotal				**-**	**7994.13**	**-**	**-**	**62264.2**	**60072.3**	**57082.8**
Mestikow										
All Company Wells	W-100.000	DINA	P	-	195.31	-	-	1585.1	1531.7	1459.0
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	P	763.2	2506.50	83.95	-	22631.8	21789.7	20648.8
04/10-29-040-11-W4	W- 25.000	VIK	P	1.6	-	-	-	2.2	2.1	2.1
Subtotal				**764.8**	**2506.50**	**83.95**	**-**	**22634.0**	**21791.8**	**20650.9**
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	P	33.4	454.00	-	-	3968.4	3811.6	3600.8
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	P	10.3	97.94	-	-	865.0	827.8	778.3
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	P	25.6	243.69	-	-	2517.2	2456.0	2370.7
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	P	5.7	74.11	-	-	800.6	786.8	767.3
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	P	0.6	10.69	-	-	101.5	99.5	96.5
Sec 16-38-3W4	W-100.000	DINA	P	13.6	77.54	-	-	661.4	645.7	623.8
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	P	19.2	27.38	-	-	297.6	290.5	280.5
00/11-24-037-02-W4	W- 37.500	VIK	P	0.5	-	-	-	0.2	0.2	0.2
00/07-27-037-02-W4	W- 42.188	VIK	P	55.5	-	-	-	59.0	54.3	48.6
02/06-11-038-03-W4	W- 28.125	VIK	NRA	-	-	-	-	-	-	-
00/14-12-038-03-W4	W- 37.500	CLY	P	13.1	-	-	-	18.7	18.2	17.5
00/07-13-038-03-W4	W- 37.500	VIK	P	34.2	-	-	-	52.2	49.9	46.8
00/06-14-038-03-W4	W- 37.500	VIK	NRA	-	-	-	-	-	-	-
00/07-15-038-03-W4	W- 37.500	VIK	P	7.3	-	-	-	9.1	9.0	8.7
00/07-17-038-03-W4	W- 37.500	VIK	P	6.0	-	-	-	1.6	1.6	1.5
00/07-18-038-03-W4	W- 37.500	VIK	P	24.0	-	-	-	30.1	28.8	27.1
00/14-07-039-01-W4	W- 29.371	MCLAR	P	90.1	-	-	-	121.5	113.5	103.3
Bodo Compression Facility	P-100.000	ALL ZONES	NRA	-	-	-	-	27.1	26.6	25.8

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

				Company Gross Interest Reserves				Present Worth Value Before Tax (M$)		
Area and Property	Company Interest %	Zones	Reserve Class	Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	@10.0%	@12.0%	@15.0%
West Provost (cont'd)										
Wells with NRA		ALL ZONES	NRA	-	-	-	-	-	-	-
Subtotal				**339.1**	**985.34**	**-**	**-**	**9531.3**	**9220.0**	**8797.5**
Subtotal Alberta				**1986.1**	**13606.99**	**91.40**	**-**	**118954.6**	**114576.1**	**108647.0**
TOTAL				**1986.1**	**13606.99**	**91.40**	**-**	**118954.6**	**114576.1**	**108647.0**

Coyote Energy Inc.

Summary of Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

	Company Interest Reserves				Net Reserves After Royalty				Present Worth Value Before Tax (M$)			
Area	Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	@10.0%	@12.0%	@15.0%	@20.0%
Alberta												
Bellshill Lake	0.27	793.2	1.2	-	0.22	725.1	1.0	-	5721.5	5512.0	5227.6	4820.4
Black Creek	0.41	-	-	-	0.32	-	-	-	768.2	731.7	681.9	610.2
Choice	0.09	-	0.4	-	0.09	-	0.4	-	294.0	277.4	255.9	227.0
David North	0.12	1132.5	5.9	-	0.11	1073.5	5.6	-	16156.3	15439.3	14491.4	13182.3
Hayter	-	7994.1	-	-	-	6646.6	-	-	62264.2	60072.3	57082.8	52764.8
Mestikow	-	195.3	-	-	-	182.7	-	-	1585.1	1531.7	1459.0	1354.4
Thompson Lake	0.76	2506.5	83.9	-	0.57	2394.4	62.3	-	22634.0	21791.8	20650.9	19021.2
West Provost	0.34	985.3	-	-	0.27	924.1	-	-	9531.3	9220.0	8797.5	8191.5
Subtotal Alberta	**1.99**	**13607.0**	**91.4**	**-**	**1.58**	**11946.3**	**69.3**	**-**	**118954.6**	**114576.1**	**108647.0**	**100171.9**
TOTAL	**1.99**	**13607.0**	**91.4**	**-**	**1.58**	**11946.3**	**69.3**	**-**	**118954.6**	**114576.1**	**108647.0**	**100171.9**

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By Company Oil Reserves

		Company Interest Reserves					Present Worth Value			Company Oil Reserves	
		Gas	Oil	NGL	Sulphur	BOE (1)	Before Tax (M$)			% of	Cumulative
Rank		bcf	mbbl	mbbl	mlt	mbbl	@ 10.0 %	@ 12.0%	@ 15.0 %	Total	%
1	Hayter	-	7994.1	-	-	7994.1	62264.2	60072.3	57082.8	58.75	58.75
2	Thompson Lake	0.76	2506.5	83.9	-	2717.9	22634.0	21791.8	20650.9	18.42	77.17
3	David North	0.12	1132.5	5.9	-	1158.0	16156.3	15439.3	14491.4	8.32	85.49
4	West Provost	0.34	985.3	-	-	1041.9	9531.3	9220.0	8797.5	7.24	92.74
5	Bellshill Lake	0.27	793.2	1.2	-	838.7	5721.5	5512.0	5227.6	5.83	98.56
6	Mestikow	-	195.3	-	-	195.3	1585.1	1531.7	1459.0	1.44	100.00
7	Black Creek	0.41	-	-	-	68.2	768.2	731.7	681.9	-	100.00
8	Choice	0.09	-	0.4	-	15.3	294.0	277.4	255.9	-	100.00
	Total	**1.99**	**13607.0**	**91.4**	**-**	**14029.4**	**118954.6**	**114576.1**	**108647.0**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane,
1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By Company Gas Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company Gas Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0%	@ 15.0 %	% of Total	Cumulative %
1	Thompson Lake	0.76	2506.5	83.9	-	2717.9	22634.0	21791.8	20650.9	38.51	38.51
2	Black Creek	0.41	-	-	-	68.2	768.2	731.7	681.9	20.62	59.12
3	West Provost	0.34	985.3	-	-	1041.9	9531.3	9220.0	8797.5	17.07	76.19
4	Bellshill Lake	0.27	793.2	1.2	-	838.7	5721.5	5512.0	5227.6	13.36	89.55
5	David North	0.12	1132.5	5.9	-	1158.0	16156.3	15439.3	14491.4	5.94	95.49
6	Choice	0.09	-	0.4	-	15.3	294.0	277.4	255.9	4.51	100.00
7	Hayter	-	7994.1	-	-	7994.1	62264.2	60072.3	57082.8	-	100.00
8	Mestikow	-	195.3	-	-	195.3	1585.1	1531.7	1459.0	-	100.00
	Total	**1.99**	**13607.0**	**91.4**	**-**	**14029.4**	**118954.6**	**114576.1**	**108647.0**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By Company BOE Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company BOE Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	7994.1	-	-	7994.1	62264.2	60072.3	57082.8	56.98	56.98
2	Thompson Lake	0.76	2506.5	83.9	-	2717.9	22634.0	21791.8	20650.9	19.37	76.35
3	David North	0.12	1132.5	5.9	-	1158.0	16156.3	15439.3	14491.4	8.25	84.61
4	West Provost	0.34	985.3	-	-	1041.9	9531.3	9220.0	8797.5	7.43	92.03
5	Bellshill Lake	0.27	793.2	1.2	-	838.7	5721.5	5512.0	5227.6	5.98	98.01
6	Mestikow	-	195.3	-	-	195.3	1585.1	1531.7	1459.0	1.39	99.40
7	Black Creek	0.41	-	-	-	68.2	768.2	731.7	681.9	0.49	99.89
8	Choice	0.09	-	0.4	-	15.3	294.0	277.4	255.9	0.11	100.00
	Total	**1.99**	**13607.0**	**91.4**	**-**	**14029.4**	**118954.6**	**114576.1**	**108647.0**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By @15.0% Present Worth Value

		Company Interest Reserves					Present Worth Value Before Tax (M$)			@15.0% Present Worth Value	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	7994.1	-	-	7994.1	62264.2	60072.3	57082.8	52.54	52.54
2	Thompson Lake	0.76	2506.5	83.9	-	2717.9	22634.0	21791.8	20650.9	19.01	71.55
3	David North	0.12	1132.5	5.9	-	1158.0	16156.3	15439.3	14491.4	13.34	84.89
4	West Provost	0.34	985.3	-	-	1041.9	9531.3	9220.0	8797.5	8.10	92.98
5	Bellshill Lake	0.27	793.2	1.2	-	838.7	5721.5	5512.0	5227.6	4.81	97.79
6	Mestikow	-	195.3	-	-	195.3	1585.1	1531.7	1459.0	1.34	99.14
7	Black Creek	0.41	-	-	-	68.2	768.2	731.7	681.9	0.63	99.76
8	Choice	0.09	-	0.4	-	15.3	294.0	277.4	255.9	0.24	100.00
	Total	**1.99**	**13607.0**	**91.4**	**-**	**14029.4**	**118954.6**	**114576.1**	**108647.0**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

First Year Production, Revenue and Expenses by Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

2002 Summary

	Production					Revenue and Expenses				Average Values $/BOE (1)			
Area	Oil bopd	Gas mcf/d	NGL bpd	Sulphur lt/d	BOE (1) boepd	Gross Revenue $M	Encumb. $M	Oper. Exp $M	Net Rev. (2) $M	Gross Revenue	Encumb.	Oper Exp	Net Rev (2)
Alberta													
Bellshill Lake	382.4	191.0	0.7	-	414.2	1804	211	585	1008	28.64	3.35	9.29	16.00
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	47.1	0.2	-	7.9	33	-	-	33	27.47	-	-	27.47
David North	714.4	74.9	3.7	-	730.6	3533	234	575	2724	31.79	2.11	5.17	24.51
Hayter	5447.9	-	-	-	5447.9	21068	4392	3887	12789	25.43	5.30	4.69	15.44
Mestikow	125.5	-	-	-	125.5	521	47	153	321	27.28	2.45	8.02	16.81
Thompson Lake	1358.0	421.1	45.5	-	1473.7	7170	488	2757	3926	31.99	2.18	12.30	17.52
West Provost	657.5	175.0	-	-	686.1	3341	326	999	2016	32.02	3.13	9.57	19.32
Subtotal Alberta	**8685.7**	**909.0**	**50.1**	**-**	**8885.8**	**37470**	**5698**	**8955**	**22817**	**27.73**	**4.22**	**6.63**	**16.88**
TOTAL	**8685.7**	**909.0**	**50.1**	**-**	**8885.8**	**37470**	**5698**	**8955**	**22817**	**27.73**	**4.22**	**6.63**	**16.88**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE based on Gross BOE reserves.
(2) Excludes capital and abandonment expenses.

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Oil Production Forecast (mbbl) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	58	125	115	105	89	80	66	55	52	47	793	-	793
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	109	215	166	133	109	91	78	66	57	50	1074	59	1132
Hayter	829	2255	1539	1112	863	499	346	262	161	111	7977	17	7994
Mestikow	19	39	32	27	23	20	17	16	3	-	195	-	195
Thompson Lake	207	450	395	349	311	279	252	228	36	-	2507	-	2507
West Provost	100	203	167	142	110	78	46	42	38	36	962	23	985
Subtotal Alberta	**1321**	**3287**	**2414**	**1868**	**1506**	**1048**	**805**	**669**	**347**	**243**	**13508**	**99**	**13607**
TOTAL	**1321**	**3287**	**2414**	**1868**	**1506**	**1048**	**805**	**669**	**347**	**243**	**13508**	**99**	**13607**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Gas Production Forecast (mmcf) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	29	60	43	28	24	21	18	15	14	13	265	-	265
Black Creek	-	114	110	76	53	37	20	-	-	-	409	-	409
Choice	7	15	13	11	8	7	6	6	5	4	82	8	90
David North	11	22	17	14	11	9	8	7	6	5	111	7	118
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	64	137	120	106	95	85	77	69	11	-	765	-	765
West Provost	27	57	50	42	34	26	20	17	13	11	295	44	339
Subtotal Alberta	**138**	**405**	**354**	**276**	**225**	**185**	**149**	**114**	**49**	**33**	**1928**	**58**	**1986**
TOTAL	**138**	**405**	**354**	**276**	**225**	**185**	**149**	**114**	**49**	**33**	**1928**	**58**	**1986**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

NGL Production Forecast (mstb) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	0	0	0	0	0	0	0	0	0	0	1	-	1
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	0	0	0	0	0	0	0	0	0	0	0	0	0
David North	1	1	1	1	1	0	0	0	0	0	6	0	6
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	7	15	13	12	10	9	8	8	1	-	84	-	84
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**8**	**17**	**14**	**13**	**11**	**10**	**9**	**8**	**2**	**0**	**91**	**0**	**91**
TOTAL	**8**	**17**	**14**	**13**	**11**	**10**	**9**	**8**	**2**	**0**	**91**	**0**	**91**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Gross Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1804	3689	2976	2675	2271	2090	1773	1516	1446	1357	21595	-	21595
Black Creek	-	534	501	343	235	164	91	-	-	-	1868	-	1868
Choice	33	73	59	48	38	33	29	26	23	18	381	39	420
David North	3533	6697	4658	3743	3083	2644	2301	1998	1774	1576	32007	1926	33933
Hayter	21068	55311	32998	23980	18712	11179	8004	6251	3947	2797	184248	497	184745
Mestikow	521	1005	718	602	516	461	417	381	81	-	4701	-	4701
Thompson Lake	7170	14996	11897	10561	9442	8675	8006	7427	1206	-	79380	-	79380
West Provost	3341	6526	4861	4128	3234	2340	1421	1324	1237	1168	29580	970	30550
Subtotal Alberta	**37470**	**88830**	**58668**	**46081**	**37530**	**27587**	**22041**	**18922**	**9714**	**6916**	**353758**	**3433**	**357191**
TOTAL	**37470**	**88830**	**58668**	**46081**	**37530**	**27587**	**22041**	**18922**	**9714**	**6916**	**353758**	**3433**	**357191**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Encumbrance Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	211	415	321	281	225	201	172	143	135	124	2228	-	2228
Black Creek	-	118	92	48	24	12	5	-	-	-	299	-	299
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	234	438	300	237	193	164	142	118	103	90	2020	92	2111
Hayter	4392	11475	6379	4371	3353	2011	1441	1052	634	468	35577	102	35678
Mestikow	47	77	50	37	28	25	21	18	3	-	306	-	306
Thompson Lake	488	995	755	649	563	506	457	416	68	-	4896	-	4896
West Provost	326	541	331	249	184	131	85	75	66	60	2048	75	2123
Subtotal Alberta	**5698**	**14058**	**8228**	**5871**	**4570**	**3050**	**2322**	**1823**	**1009**	**742**	**47373**	**269**	**47642**
TOTAL	**5698**	**14058**	**8228**	**5871**	**4570**	**3050**	**2322**	**1823**	**1009**	**742**	**47373**	**269**	**47642**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Capital Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	-	-	5	5	-	-	-	-	-	-	11	-	11
Black Creek	-	230	-	-	-	-	-	-	-	-	230	-	230
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	-	-	-	-	-	-	-	-	-	-	-	-	-
Hayter	9046	3471	-	-	-	-	-	-	-	-	12517	-	12517
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	-	-	-	-	-	-	-	-	-	-	-	-	-
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**9046**	**3700**	**5**	**5**	-	-	-	-	-	-	**12757**	-	**12757**
TOTAL	**9046**	**3700**	**5**	**5**	-	-	-	-	-	-	**12757**	-	**12757**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Operating Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	585	1400	1406	1359	1319	1326	1253	1193	1208	1211	12260	-	12260
Black Creek	-	71	77	62	52	45	31	-	-	-	336	-	336
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	575	1290	1193	1110	1033	960	888	820	821	788	9477	1087	10564
Hayter	3887	10095	10205	10256	9493	5240	3639	3008	2216	1717	59756	316	60072
Mestikow	153	366	328	327	328	293	295	298	75	-	2463	-	2463
Thompson Lake	2757	6467	6303	6160	6049	5950	5861	5796	962	-	46304	-	46304
West Provost	999	2431	2478	2484	2143	1628	948	961	970	985	16027	814	16841
Subtotal Alberta	**8955**	**22119**	**21988**	**21758**	**20417**	**15442**	**12914**	**12076**	**6252**	**4701**	**146622**	**2217**	**148839**
TOTAL	**8955**	**22119**	**21988**	**21758**	**20417**	**15442**	**12914**	**12076**	**6252**	**4701**	**146622**	**2217**	**148839**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Net Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1008	1874	1243	1030	726	562	349	179	103	22	7096	-	7096
Black Creek	-	116	333	233	159	107	55	-	-	-	1004	-	1004
Choice	33	73	59	48	38	33	29	26	23	18	381	39	420
David North	2724	4970	3165	2396	1857	1521	1272	1060	850	697	20511	747	21258
Hayter	3743	30270	16414	9353	5866	3928	2924	2190	1097	612	76398	79	76477
Mestikow	321	562	341	239	159	143	101	65	2	-	1932	-	1932
Thompson Lake	3926	7533	4839	3752	2830	2219	1688	1216	177	-	28180	-	28180
West Provost	2016	3554	2052	1395	908	581	387	288	200	123	11505	81	11586
Subtotal Alberta	**13771**	**48952**	**28447**	**18447**	**12543**	**9095**	**6805**	**5023**	**2453**	**1473**	**147006**	**947**	**147954**
TOTAL	**13771**	**48952**	**28447**	**18447**	**12543**	**9095**	**6805**	**5023**	**2453**	**1473**	**147006**	**947**	**147954**

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Total Probable Reserves - Unrisked

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids			
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Gross Revenue M$
2002		50.5	26.45	1336.4	1.7	4.52	7.6	0.1	27.60	2.8	1346.9
2003		170.9	25.98	4441.8	15.1	4.70	70.9	0.6	26.14	15.4	4528.2
2004	1.0	236.9	22.86	5415.8	36.9	4.55	168.2	0.9	24.10	22.2	5606.2
2005	13.8	264.8	23.28	6165.0	35.5	4.50	160.0	1.0	24.49	25.5	6350.5
2006	53.9	426.3	22.72	9687.2	36.3	4.45	161.4	1.1	24.37	27.5	9876.2
2007	32.0	254.7	24.37	6205.9	49.9	4.50	224.6	1.2	24.90	29.1	6459.7
2008	66.3	270.9	25.93	7023.5	53.8	4.50	242.2	3.4	25.15	85.0	7350.7
2009	150.0	392.2	27.90	10942.0	72.5	4.55	329.7	7.7	25.62	197.5	11469.2
2010	51.1	187.9	26.72	5019.3	15.0	4.65	69.8	1.3	26.13	35.0	5124.0
2011	47.6	175.6	27.49	4826.2	6.9	4.75	32.9	0.2	27.13	4.1	4863.1
2012	34.0	70.0	31.24	2185.8	8.3	4.85	40.2	0.2	27.05	5.9	2232.0
2013	13.0	19.3	32.60	630.5	4.5	4.95	22.5	0.1	26.38	3.4	656.5
2014	1.7	2.8	33.33	93.3	2.1	5.00	10.4	0.0	19.50	0.4	104.2
2015	0.8	1.5	34.31	52.5	1.0	5.10	5.4			0.1	58.0
2016	0.8	1.4	35.08	49.8							49.8
REM.	0.8	0.3	36.35	11.3							11.3
TOTAL		**2526.0**	**25.37**	**64086.4**	**339.6**	**4.55**	**1545.8**	**17.9**	**25.36**	**454.0**	**66086.3**

	Crown Royalties			Freehold Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	67.0	0.1	66.9	164.3		164.3	8.1		8.1	55.4	294.7	21.88
2003	236.9	-1.5	238.3	504.7		504.7	25.9		25.9	160.2	929.1	20.52
2004	219.1	2.9	216.2	610.5		610.5	34.2		34.2	182.9	1043.8	18.62
2005	231.9	3.8	228.1	545.9		545.9	35.8		35.8	137.2	947.1	14.91
2006	172.8	3.7	169.1	1161.7		1161.7	62.2		62.2	139.1	1532.2	15.51
2007	156.7	7.9	148.8	599.8		599.8	37.5	-0.0	37.5	73.8	859.9	13.31
2008	163.6	5.7	157.9	645.8		645.8	35.6	0.0	35.6	61.3	900.6	12.25
2009	290.4	1.8	288.7	639.4	0.0	639.4	33.2	-0.0	33.2	56.8	1018.1	8.88
2010	75.9	0.3	75.7	433.9		433.9	33.6		33.6	43.0	586.3	11.44
2011	48.4		48.4	439.1		439.1	46.6		46.6	41.0	575.1	11.83
2012	25.6		25.6	79.9		79.9	21.1		21.1	10.0	136.6	6.12
2013				21.1	0.0	21.1	2.5		2.5	3.5	27.2	4.15
2014				12.0		12.0	0.2		0.2	0.5	12.6	12.13
2015				11.8		11.8				0.2	12.0	20.77
2016				11.2		11.2				0.2	11.4	22.90
REM.				2.5		2.5				0.0	2.6	22.89
TOTAL	**1688.4**	**24.8**	**1663.7**	**5883.6**	**0.0**	**5883.6**	**376.6**	**-0.0**	**376.6**	**965.3**	**8889.4**	**13.45**

			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Annual M$	Cum M$	PWV @15.0% M$
2002	10.7	1041.4	1041.4	1041.4	1011.5
2003	66.4	3532.6	3532.7	4574.1	3107.8
2004	181.0	4381.4	4381.3	8955.4	3351.8
2005	1141.9	4261.5	4261.5	13216.9	2834.8
2006	4421.4	3922.6	3922.6	17139.5	2269.0
2007	2541.9	3057.9	3057.9	20197.4	1538.1
2008	3248.1	3201.9	3201.9	23399.3	1400.4
2009	7244.1	3207.0	3207.0	26606.3	1219.8
2010	2832.3	1705.4	1705.4	28311.7	564.0
2011	3075.4	1212.6	1212.6	29524.3	348.7
2012	1510.1	585.2	585.2	30109.6	146.3
2013	382.1	247.2	247.2	30356.7	53.8
2014	60.8	30.8	30.8	30387.5	5.8
2015	34.9	11.0	11.0	30398.5	1.8
2016	35.6	2.8	2.8	30401.3	0.4
REM.	9.1	-0.4	-0.4	30400.9	-0.0
TOTAL	**26795.8**	**30400.9**	**30400.9**		**17854.0**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	**Gross**	**Net**	**@10.0%**	**@12.0%**	**@15.0%**	**@20.0%**
Crude Oil (mbbl)	2526.1	2212.1	20153.8	18903.6	17265.5	15039.1
Natural Gas (mmcf)	339.7	266.1	527.4	486.1	432.9	362.0
Natural Gas Liquids (mbbl)	18.0	13.6	197.9	179.4	155.8	125.1
Total			**20879.0**	**19569.1**	**17854.2**	**15526.2**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
00/06-05-041-12-W4	W- 40.000	GLAUC L	PA	9.5	-	0.05	-	22.5	21.8	20.9
02/10-05-041-12-W4	W-100.000	ELL	PA	0.4	5.00	0.00	-	48.1	44.3	39.3
00/15-05-041-12-W4	W-100.000	ELL	PA	1.2	5.00	0.01	-	51.9	47.9	42.5
Subtotal				**11.1**	**10.00**	**0.05**	**-**	**122.5**	**114.0**	**102.7**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	PA	116.8	-	-	-	229.2	214.2	194.3
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PA	16.9	-	0.07	-	40.3	35.8	30.3
David North										
Lloydminster O Unit	W-100.000	LLOYD	PA	12.8	127.86	0.64	-	1619.3	1487.3	1319.2
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PA	12.2	100.00	0.61	-	1268.3	1165.4	1035.8
02/10-27-040-03-W4	W-100.000	LLOYD	PA	-	5.00	-	-	58.9	54.4	48.6
02/15-27-040-03-W4	W-100.000	LLOYD	PA	-	5.00	-	-	38.8	35.7	31.7
Subtotal				**25.0**	**237.85**	**1.25**	**-**	**2985.3**	**2742.9**	**2435.3**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	PA	-	18.72	-	-	70.5	66.3	60.8
N-24-40-1W4 1999 Wells	W- 93.750	DINA	PA	-	18.66	-	-	103.1	99.0	93.5
N-24-40-1W4 2002 Wells	W- 93.750	DINA	PA	-	53.99	-	-	472.6	450.4	420.7
N-24-40-1W4 Future Locations	W- 93.750	DINA	PA	-	37.50	-	-	378.8	352.4	318.4
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	PA	-	282.67	-	-	1798.6	1653.5	1468.2
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	PA	-	23.55	-	-	132.5	123.6	112.0
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	PA	-	46.75	-	-	330.5	316.9	298.4
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	PA	-	92.26	-	-	800.1	774.0	737.8
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	PA	-	45.58	-	-	433.2	420.4	402.7
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	PA	-	109.74	-	-	1181.5	1114.8	1027.8
Sec 25-40-1W4 Future Locations	W- 94.517	DINA	PA	-	302.45	-	-	2911.7	2716.1	2457.0
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	PA	-	37.40	-	-	127.8	123.2	116.9
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	PA	-	7.40	-	-	55.5	53.8	51.5
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	PA	-	149.79	-	-	472.4	448.8	416.8
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	PA	-	4.93	-	-	28.4	27.8	26.9
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	PA	-	9.88	-	-	73.2	70.3	66.3
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	PA	-	48.88	-	-	434.2	418.2	396.3
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	PA	-	98.36	-	-	750.1	724.3	688.7
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	PA	-	37.81	-	-	285.0	275.8	263.1
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	PA	-	72.81	-	-	606.5	581.7	548.0
NW-35-40-1W4 Future Locations	W- 75.000	DINA	PA	-	75.00	-	-	732.0	689.6	633.5
00/01-03-041-01-W4	W- 75.000	SPKY	PA	-	7.50	-	-	39.2	34.7	29.2
Subtotal				**-**	**1581.65**	**-**	**-**	**12217.5**	**11535.7**	**10634.6**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Mestikow										
All Company Wells	W-100.000	DINA	PA	-	24.98	-	-	170.6	159.6	145.0
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	PA	150.7	494.98	16.58	-	3736.9	3468.6	3117.3
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PA	5.5	74.81	-	-	518.0	480.0	430.7
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PA	2.0	18.71	-	-	134.3	123.3	109.3
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PA	3.9	37.25	-	-	334.6	319.4	298.7
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PA	1.4	18.48	-	-	185.3	179.9	172.4
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PA	0.2	3.72	-	-	30.3	29.3	27.8
Sec 16-38-3W4	W-100.000	DINA	PA	3.5	20.00	-	-	141.0	134.6	126.0
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PA	2.6	3.73	-	-	33.2	31.8	29.8
Subtotal				**19.1**	**176.70**	**-**	**-**	**1376.8**	**1298.3**	**1194.8**
Subtotal Alberta				**339.7**	**2526.16**	**17.95**	**-**	**20879.0**	**19569.1**	**17854.3**
TOTAL				**339.7**	**2526.16**	**17.95**	**-**	**20879.0**	**19569.1**	**17854.3**

Coyote Energy Inc.

Table 1

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Proved Producing Reserves

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids				
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Total Other Revenues M$	Gross Revenue M$
2002	420.4	1182.5	27.95	33048.6	136.5	4.50	614.3	7.5	27.64	207.0	22.2	33892.3
2003	406.9	2236.7	27.04	60469.6	282.0	4.70	1325.7	15.9	26.17	416.8	36.0	62248.1
2004	391.9	1743.5	24.07	41961.1	223.7	4.55	1017.6	13.4	24.18	324.0	32.0	43334.8
2005	362.9	1387.4	24.25	33650.9	183.2	4.50	824.6	11.5	24.20	277.6	29.0	34782.1
2006	293.5	933.7	25.02	23362.0	153.9	4.45	685.0	10.0	24.18	241.1	25.0	24313.1
2007	243.9	681.4	26.11	17794.5	130.3	4.50	586.3	8.7	24.74	215.9		18596.7
2008	184.8	513.9	26.57	13654.4	94.8	4.50	427.0	5.5	25.22	138.7		14220.2
2009	82.1	268.0	26.31	7050.1	41.5	4.55	189.1	0.3	27.41	8.8		7248.0
2010	57.3	159.4	27.77	4425.3	34.0	4.65	158.0	0.2	28.27	6.2		4589.6
2011	29.1	67.4	28.54	1925.0	26.0	4.75	123.3	0.1	33.07	4.6		2053.0
2012	1.5	1.6	31.94	50.5	7.8	4.85	37.7			0.0		88.2
2013	1.5	1.4	32.67	47.0	6.9	4.95	34.0					81.0
2014	0.8	0.2	33.75	8.1	6.4	5.00	32.0					40.1
2015	0.7				6.0	5.10	30.4					30.4
2016	0.7				5.6	5.20	29.0					29.0
REM.	0.7				9.7	5.40	52.2					52.2
TOTAL		**9177.1**	**25.87**	**237447.2**	**1348.2**	**4.57**	**6166.3**	**73.2**	**25.16**	**1840.9**	**144.2**	**245598.8**

	Crown Royalties			Freehold Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	1077.0	3.8	1073.2	2856.1	0.6	2855.5	305.6	0.1	305.5	624.2	4858.4	14.34
2003	1723.5	7.1	1716.5	4964.6	1.3	4963.3	577.6	0.1	577.5	874.6	8131.9	13.07
2004	1012.3	4.1	1008.2	3278.8	1.3	3277.5	409.1	0.1	409.0	448.6	5143.3	11.88
2005	698.2	2.9	695.3	2672.3	1.2	2671.1	331.1	0.1	331.0	302.4	3999.9	11.51
2006	525.4	2.5	522.9	1510.8	1.1	1509.7	244.8	0.1	244.7	171.0	2448.3	10.08
2007	400.3	2.2	398.1	1015.8	1.0	1014.7	206.0	0.1	205.9	118.0	1736.8	9.34
2008	270.9	1.5	269.4	791.9	1.0	790.9	186.9	0.1	186.8	92.8	1339.9	9.42
2009	75.2	0.2	75.0	500.2	0.9	499.3	155.2	0.1	155.1	62.6	792.1	10.93
2010	62.5	0.1	62.5	204.0	0.9	203.1	125.0	0.0	124.9	32.1	422.6	9.21
2011	21.6	0.0	21.5	37.0	0.8	36.3	93.3	0.0	93.3	15.7	166.9	8.13
2012	0.1	0.0	0.1	18.5	0.8	17.7	0.2	0.0	0.2	0.6	18.6	21.11
2013	0.1	0.0	0.1	17.4	0.7	16.7	0.2	0.0	0.2	0.6	17.5	21.54
2014	0.1	0.0	0.1	8.2	0.7	7.5	0.2	0.0	0.2	0.4	8.1	20.30
2015	0.1	0.0	0.1	6.1	0.6	5.4	0.2	0.0	0.1	0.3	6.0	19.58
2016	0.1	0.0	0.1	5.8	0.6	5.2	0.2	0.0	0.1	0.3	5.7	19.57
REM.	0.1	0.0	0.1	10.4	1.0	9.4	0.3	0.0	0.3	0.5	10.2	19.57
TOTAL	**5867.5**	**24.5**	**5843.1**	**17897.8**	**14.4**	**17883.4**	**2635.7**	**0.9**	**2634.8**	**2744.6**	**29106.1**	**11.86**

			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Annual M$	Cum M$	PWV @15.0% M$
2002	8899.4	20134.4	20134.4	20134.4	19556.6
2003	21223.2	32893.1	32893.1	53027.5	28937.6
2004	20916.5	17275.0	17275.0	70302.5	13215.3
2005	19682.0	11100.2	11100.1	81402.6	7384.0
2006	15063.3	6801.5	6801.5	88204.1	3934.2
2007	12022.1	4837.8	4837.8	93041.8	2433.3
2008	9526.8	3353.4	3353.3	96395.2	1466.7
2009	4754.5	1701.5	1701.4	98096.6	647.1
2010	3419.8	747.1	747.1	98843.7	247.0
2011	1626.0	260.1	260.1	99103.8	74.8
2012	48.9	20.7	20.7	99124.5	5.2
2013	49.6	14.0	14.0	99138.5	3.0
2014	21.8	10.2	10.2	99148.6	1.9
2015	16.2	8.3	8.3	99156.9	1.4
2016	16.3	7.0	7.0	99163.9	1.0
REM.	31.6	10.4	10.4	99174.3	1.2
TOTAL	**117317.9**	**99174.3**	**99174.3**		**77910.3**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	**Gross**	**Net**	**@10.0%**	**@12.0%**	**@15.0%**	**@20.0%**
Crude Oil (mbbl)	9177.4	8169.2	80130.8	77856.3	74735.3	70188.6
Natural Gas (mmcf)	1348.3	1078.8	2441.1	2333.9	2191.1	1991.5
Natural Gas Liquids (mbbl)	73.4	55.6	1088.1	1044.0	984.1	898.7
Total			**83660.0**	**81234.2**	**77910.5**	**73078.8**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Proved Producing Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves: Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$): @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
Fixed Battery Costs	P-100.000		NRA	-	-	-	-	-3372.9	-3132.8	-2822.7
00/04-05-041-12-W4	W-100.000	ELL	PP	10.2	48.79	0.05	-	539.6	510.3	471.9
02/04-05-041-12-W4	W-100.000	ELL	PP	19.6	50.39	0.09	-	590.1	558.7	517.5
03/04-05-041-12-W4	W-100.000	ELL	PP	1.2	5.15	0.00	-	48.8	48.3	47.5
00/05-05-041-12-W4	W-100.000	ELL	PP	11.6	52.20	0.05	-	598.0	566.4	524.9
04/05-05-041-12-W4	W-100.000	ELL	PP	12.6	38.11	0.05	-	389.9	369.2	341.9
B0/05-05-041-12-W4	W-100.000	ELL	PP	12.7	60.50	0.06	-	722.2	684.0	633.7
00/06-05-041-12-W4	W- 40.000	GLAUC L	PP	42.6	-	0.21	-	113.7	112.0	109.7
00/12-05-041-12-W4	W-100.000	ELL	PP	19.4	49.69	0.09	-	578.0	547.4	507.1
00/13-05-041-12-W4	W-100.000	ELL	PP	0.8	5.62	0.00	-	39.9	39.4	38.6
B0/14-05-041-12-W4	W-100.000	ELL	PP	10.8	51.43	0.05	-	607.0	577.6	538.8
C0/14-05-041-12-W4	W-100.000	ELL	PP	8.2	40.48	0.04	-	416.5	394.6	365.7
02/15-05-041-12-W4	W-100.000	ELL	PP	2.1	7.81	0.01	-	113.0	111.3	108.7
A2/15-05-041-12-W4	W-100.000	ELL	PP	4.6	34.14	0.02	-	423.2	407.4	385.9
B2/15-05-041-12-W4	W-100.000	ELL	PP	17.1	59.88	0.08	-	722.2	683.8	633.3
02/16-05-041-12-W4	W-100.000	ELL	PP	3.8	15.81	0.02	-	225.9	221.0	214.2
00/01-06-041-12-W4	W-100.000	ELL	PP	11.7	19.53	0.05	-	142.9	137.0	129.1
00/02-06-041-12-W4	W-100.000	ELL	PP	8.7	38.81	0.04	-	429.5	406.8	376.9
02/07-06-041-12-W4	W-100.000	ELL	PP	4.4	26.91	0.02	-	247.5	236.1	221.0
02/08-06-041-12-W4	W-100.000	ELL	PP	11.4	21.09	0.05	-	277.2	268.4	256.2
03/08-06-041-12-W4	W-100.000	ELL	PP	14.2	29.67	0.06	-	302.4	287.0	266.7
05/08-06-041-12-W4	W-100.000	ELL	PP	12.1	47.46	0.06	-	566.6	537.0	498.0
02/09-06-041-12-W4	W-100.000	ELL	PP	8.8	43.31	0.04	-	475.7	446.7	408.9
02/15-15-041-12-W4	R- 3.750	ELL	PP	-	0.22	-	-	5.0	4.8	4.7
04/15-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
02/16-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
05/16-15-041-12-W4	R- 3.750	ELL	PP	-	0.05	-	-	1.3	1.3	1.2
Subtotal				**248.7**	**747.07**	**1.13**	-	**5203.1**	**5023.4**	**4779.4**
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PP	47.2	-	0.19	-	163.6	155.6	145.1
00/11-05-040-08-W4	R- 15.000	VIK	PP	5.0	-	0.02	-	20.1	19.6	18.9
00/07-07-040-08-W4	R- 6.250	CLY	PP	2.2	-	0.01	-	9.4	9.3	9.1
00/10-07-040-08-W4	R- 15.000	VIK	PP	18.3	-	0.07	-	60.5	57.1	52.6
Subtotal				**72.6**	**-**	**0.29**	-	**253.6**	**241.6**	**225.6**
David North										
Lloydminster O Unit	W-100.000	LLOYD	PP	40.4	403.99	2.02	-	6270.5	6049.7	5750.3
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PP	52.5	429.37	2.62	-	6153.9	5925.3	5618.8
00/10-27-040-03-W4	W-100.000	LLOYD	PP	-	14.09	-	-	139.3	134.9	128.9
02/10-27-040-03-W4	W-100.000	LLOYD	PP	-	24.26	-	-	371.8	359.2	342.1
02/15-27-040-03-W4	W-100.000	LLOYD	PP	-	22.92	-	-	235.5	227.3	216.1
Subtotal				**92.9**	**894.64**	**4.64**	-	**13171.0**	**12696.5**	**12056.0**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	PP	-	71.94	-	-	415.2	404.5	389.8
N-24-40-1W4 1999 Wells	W- 93.750	DINA	PP	-	47.39	-	-	347.4	341.6	333.3
N-24-40-1W4 2002 Wells	W- 93.750	DINA	PP	-	202.69	-	-	2053.2	2002.0	1931.3
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	PP	-	1276.76	-	-	9388.2	9049.1	8590.4
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	PP	-	98.02	-	-	703.0	681.7	652.6
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	PP	-	128.94	-	-	1096.8	1075.8	1046.1
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	PP	-	414.57	-	-	3982.6	3917.2	3824.3
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	PP	-	155.50	-	-	1682.7	1656.3	1618.6
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	PP	-	380.08	-	-	4800.0	4661.9	4472.7
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	PP	-	75.39	-	-	413.7	407.6	398.8

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Proved Producing Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Hayter (cont'd)										
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	PP	-	23.79	-	-	220.4	217.3	212.8
Sec 34-40-1W4 2000 Wells	W- 75.000	DINA	PP	-	9.84	-	-	53.5	52.6	51.3
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	PP	-	647.94	-	-	2769.6	2716.8	2642.2
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	PP	-	8.57	-	-	65.4	64.7	63.7
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	PP	-	31.36	-	-	265.3	260.5	253.8
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	PP	-	151.76	-	-	1559.0	1530.6	1490.5
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	PP	-	306.60	-	-	2748.9	2702.2	2636.0
NW-35-40-1W4 Pre-2000 Wells	W- 75.000	DINA	PP	-	116.69	-	-	407.5	394.8	377.4
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	PP	-	117.50	-	-	1026.8	1009.8	985.8
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	PP	-	232.37	-	-	2138.4	2095.3	2034.9
S-36-40-1W4 GOR Wells	R- 7.500	DINA	PP	-	2.26	-	-	50.4	49.6	48.5
00/09-34-040-01-W4	W- 75.000	SPKY	PP	-	10.16	-	-	98.7	96.0	92.3
00/15-34-040-01-W4	W- 75.000	SPKY	PP	-	7.08	-	-	69.7	68.2	66.2
00/01-03-041-01-W4	W- 75.000	SPKY	PP	-	27.99	-	-	210.0	199.6	186.0
Subtotal				-	**4545.18**	-	-	**36566.2**	**35655.8**	**34399.2**
Mestikow										
All Company Wells	W-100.000	DINA	PP	-	170.34	-	-	1414.4	1372.1	1314.0
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	PP	612.5	2011.52	67.37	-	18895.0	18321.1	17531.5
04/10-29-040-11-W4	W- 25.000	VIK	PP	1.6	-	-	-	2.2	2.1	2.1
Subtotal				**614.1**	**2011.52**	**67.37**	-	**18897.1**	**18323.3**	**17533.6**
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PP	27.9	379.18	-	-	3450.4	3331.6	3170.1
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PP	8.3	79.23	-	-	730.6	704.5	669.0
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PP	21.7	206.44	-	-	2182.6	2136.7	2072.0
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PP	4.3	55.63	-	-	615.2	606.9	595.0
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PP	0.4	6.96	-	-	71.2	70.2	68.7
Sec 16-38-3W4	W-100.000	DINA	PP	10.1	57.55	-	-	520.5	511.1	497.8
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PP	16.6	23.65	-	-	264.4	258.7	250.7
00/11-24-037-02-W4	W- 37.500	VIK	PP	0.5	-	-	-	0.2	0.2	0.2
00/07-27-037-02-W4	W- 42.188	VIK	PP	55.5	-	-	-	59.0	54.3	48.6
02/06-11-038-03-W4	W- 28.125	VIK	NRA	-	-	-	-	-	-	-
00/14-12-038-03-W4	W- 37.500	CLY	PP	13.1	-	-	-	18.7	18.2	17.5
00/07-13-038-03-W4	W- 37.500	VIK	PP	34.2	-	-	-	52.2	49.9	46.8
00/06-14-038-03-W4	W- 37.500	VIK	NRA	-	-	-	-	-	-	-
00/07-15-038-03-W4	W- 37.500	VIK	PP	7.3	-	-	-	9.1	9.0	8.7
00/07-17-038-03-W4	W- 37.500	VIK	PP	6.0	-	-	-	1.6	1.6	1.5
00/07-18-038-03-W4	W- 37.500	VIK	PP	24.0	-	-	-	30.1	28.8	27.1
00/14-07-039-01-W4	W- 29.371	MCLAR	PP	90.1	-	-	-	121.5	113.5	103.3
Bodo Compression Facility	P-100.000	ALL ZONES	NRA	-	-	-	-	27.1	26.6	25.8
Wells with NRA		ALL ZONES	NRA	-	-	-	-	-	-	-
Subtotal				**320.0**	**808.64**	-	-	**8154.5**	**7921.6**	**7602.7**
Subtotal Alberta				**1348.4**	**9177.38**	**73.43**	-	**83660.1**	**81234.2**	**77910.6**
TOTAL				**1348.4**	**9177.38**	**73.43**	-	**83660.1**	**81234.2**	**77910.6**

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Proved Non-Producing Reserves

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids			
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Gross Revenue M$
2003	1.0				107.9	4.70	507.0				507.0
2004	2.0	7.9	24.11	191.4	92.8	4.55	422.4			0.1	613.9
2005	3.0	14.2	24.17	343.0	57.6	4.50	259.2	0.0	24.00	0.2	602.5
2006	3.0	9.5	24.22	230.8	34.5	4.45	153.6			0.2	384.6
2007	1.8	4.5	24.84	111.3	5.3	4.50	23.7			0.0	135.0
TOTAL		**36.1**	**24.25**	**876.5**	**298.1**	**4.58**	**1366.0**	**0.0**	**24.00**	**0.5**	**2243.0**

	Crown Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2003	140.0	34.0	106.0					106.0	20.91
2004	93.2	29.0	64.2	19.5		19.5	4.5	88.1	14.35
2005	64.6	17.0	47.7	14.2		14.2	2.4	64.3	10.67
2006	26.9	10.1	16.8	11.2		11.2	1.5	29.5	7.68
2007	4.9	1.4	3.5	7.1		7.1	0.8	11.4	8.44
TOTAL	**329.6**	**91.5**	**238.1**	**52.0**		**52.0**	**9.3**	**299.4**	**13.35**

			Capital Costs			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Drilling & Compl M$	Equip & Facility M$	Total Capital M$	Annual M$	Cum M$	PWV @15.0% M$
2003	67.9	333.1		229.5	229.5	103.6	103.6	91.2
2004	113.0	412.8	5.2		5.2	407.6	511.2	311.8
2005	141.0	397.2	5.3		5.3	391.9	903.1	260.7
2006	123.5	231.5				231.5	1134.7	133.9
2007	52.9	70.7				70.6	1205.3	35.5
TOTAL	**498.3**	**1445.3**	**10.5**	**229.5**	**240.0**	**1205.3**		**833.2**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	Gross	Net	@10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	36.2	32.8	384.8	364.1	335.9	295.4
Natural Gas (mmcf)	298.1	232.9	549.8	527.6	497.0	451.9
Natural Gas Liquids (mbbl)	0.0	0.0	0.3	0.3	0.2	0.2
Total			**934.9**	**892.0**	**833.1**	**747.5**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Proved Non-Producing Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
02/10-05-041-12-W4	W-100.000	ELL	PNP	1.9	21.09	0.01	-	226.0	214.7	199.4
00/15-05-041-12-W4	W-100.000	ELL	PNP	3.6	15.06	0.01	-	169.9	159.8	146.1
Subtotal				**5.5**	**36.15**	**0.02**	-	**395.9**	**374.5**	**345.5**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	PNP	292.6	-	-	-	539.1	517.5	487.6
Subtotal Alberta				**298.1**	**36.15**	**0.02**	-	**934.9**	**892.0**	**833.2**
TOTAL				**298.1**	**36.15**	**0.02**	-	**934.9**	**892.0**	**833.2**

McDANIEL & ASSOCIATES
CONSULTANTS LTD.

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Proved Undeveloped Reserves

Total Of All Areas

		Crude Oil			
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Gross Revenue M$
2002	15.1	87.8	25.40	2230.9	2230.9
2003	20.7	879.2	24.51	21546.3	21546.3
2004	20.7	425.5	21.42	9113.4	9113.4
2005	20.7	201.9	21.52	4345.8	4345.8
2006	20.7	136.6	21.63	2956.1	2956.1
2007	20.7	107.2	22.34	2395.1	2395.1
2008	3.4	20.4	23.06	470.4	470.4
2009	1.9	8.6	23.76	204.6	204.6
TOTAL		**1867.3**	**23.17**	**43262.6**	**43262.6**

	Crown Royalties			Freehold Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	82.7		82.7	348.3		348.3	13.7		13.7	100.1	544.8	24.42
2003	446.2		446.2	3330.0		3330.0	143.2		143.2	971.7	4891.1	22.70
2004	134.9		134.9	1412.9		1412.9	60.6		60.6	344.7	1953.2	21.43
2005	61.3		61.3	683.4		683.4	27.4		27.4	88.0	860.2	19.79
2006	34.3		34.3	467.5		467.5	18.3		18.3	40.2	560.2	18.95
2007	22.7		22.7	379.4		379.4	14.7		14.7	25.5	442.3	18.47
2008	16.3		16.3	60.6		60.6	1.4		1.4	3.4	81.8	17.39
2009	12.8		12.8				0.2		0.2		13.0	6.33
TOTAL	**811.0**		**811.0**	**6682.1**		**6682.1**	**279.6**		**279.6**	**1573.7**	**9346.4**	**21.60**

			Capital Costs			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Drilling & Compl M$	Equip & Facility M$	Total Capital M$	Annual M$	Cum M$	PWV @15.0% M$
2002	45.2	1640.9	9046.0		9046.0	-7405.1	-7405.1	-7192.5
2003	761.9	15893.4	3470.7		3470.7	12422.8	5017.7	10929.0
2004	777.1	6383.2				6383.2	11400.9	4883.1
2005	792.6	2692.9				2693.0	14093.8	1791.4
2006	808.5	1587.4				1587.4	15681.3	918.2
2007	824.7	1128.2				1128.2	16809.4	567.5
2008	139.4	249.2				249.2	17058.6	109.0
2009	77.5	114.1				114.1	17172.7	43.4
TOTAL	**4226.9**	**29689.4**	**12516.7**		**12516.7**	**17172.7**		**12049.0**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	*Gross*	*Net*	*@10.0%*	*@12.0%*	*@15.0%*	*@20.0%*
Crude Oil (mbbl)	1867.3	1532.3	13480.5	12880.8	12049.0	10819.3
Total			**13480.5**	**12880.8**	**12049.0**	**10819.3**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Proved Undeveloped Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Alberta										
Hayter										
N-24-40-1W4 Future Locations	W- 93.750	DINA	PUD	-	168.75	-	-	991.8	922.4	828.2
Sec 25-40-1W4 Future Locations	W- 94.517	DINA	PUD	-	1361.04	-	-	10692.9	10273.8	9689.4
NW-35-40-1W4 Future Locations	W- 75.000	DINA	PUD	-	337.50	-	-	1795.8	1684.5	1531.3
Subtotal				**-**	**1867.29**	**-**	**-**	**13480.5**	**12880.8**	**12049.0**
Subtotal Alberta				**-**	**1867.29**	**-**	**-**	**13480.5**	**12880.8**	**12049.0**
TOTAL				**-**	**1867.29**	**-**	**-**	**13480.5**	**12880.8**	**12049.0**

Coyote Energy Inc.

Summary of Crude Oil Reserve Estimates
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Volumetric Factors: Area acre	Net Pay ft	Por. %	Sw %	Sg %	Oil Shr.	Property Gross Crude Oil Reserves: Orig. OIP mbbl	Rec. %	Orig. Res. mbbl	Cum. Prod. mbbl	Rem. Res. mbbl	Company Share: Rem. Res. mbbl	2002 Rate bopd	Reserves based on
Alberta																	
Bellshill Lake																	
00/04-05-041-12-W4/0	W-100.000	ELL	PR									383	334	48	48.8	21	Decl
02/04-05-041-12-W4/0	W-100.000	ELL	PR									360	309	50	50.4	23	Decl
03/04-05-041-12-W4/0	W-100.000	ELL	PR		16.4	27.0	30.0		0.93			106	100	5	5.2	9	Decl
00/05-05-041-12-W4/2	W-100.000	ELL	PR									339	286	52	52.2	24	Decl
04/05-05-041-12-W4/2	W-100.000	ELL	PR									225	187	38	38.1	16	Decl
B0/05-05-041-12-W4/0	W-100.000	ELL	PR									328	267	60	60.5	28	Decl
02/10-05-041-12-W4/0	W-100.000	ELL	PR									115	93	21	21.1		Decl
			PA											5	5.0		Decl
00/12-05-041-12-W4/2	W-100.000	ELL	PR									214	165	49	49.7	22	Decl
00/13-05-041-12-W4/0	W-100.000	ELL	PR		23.0	27.0	25.0					95	89	5	5.6	7	Decl
B0/14-05-041-12-W4/0	W-100.000	ELL	PR									220	168	51	51.4	27	Decl
C0/14-05-041-12-W4/0	W-100.000	ELL	PR									289	248	40	40.5	18	Decl
00/15-05-041-12-W4/0	W-100.000	ELL	PR									150	134	15	15.1		Decl
			PA											5	5.0		Decl
02/15-05-041-12-W4/2	W-100.000	ELL	PR									120	112	7	7.8	13	Decl
A2/15-05-041-12-W4/0	W-100.000	ELL	PR									145	110	34	34.1	23	Decl
B2/15-05-041-12-W4/0	W-100.000	ELL	PR									229	169	59	59.9	28	Decl
02/16-05-041-12-W4/0	W-100.000	ELL	PR		13.1	27.0	25.0		0.93			113	97	15	15.8	18	Decl
00/01-06-041-12-W4/0	W-100.000	ELL	PR									110	90	19	19.5	9	Decl

Coyote Energy Inc.

Summary of Crude Oil Reserve Estimates
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

				Volumetric Factors						Property Gross Crude Oil Reserves					Company Share		
Area and Property	Company Interest %	Zones	Reserve Class	Area acre	Net Pay ft	Por. %	Sw %	Sg %	Oil Shr.	Orig. OIP mbbl	Rec. %	Orig. Res. mbbl	Cum. Prod. mbbl	Rem. Res. mbbl	Rem. Res. mbbl	2002 Rate bopd	Reserves based on
00/02-06-041-12-W4/0	W-100.000	ELL	PR									101	62	38	38.8	17	Decl
02/07-06-041-12-W4/3	W-100.000	ELL	PR									140	113	26	26.9	13	Decl
02/08-06-041-12-W4/0	W-100.000	ELL	PR									126	104	21	21.1	16	Decl
03/08-06-041-12-W4/0	W-100.000	ELL	PR									178	148	29	29.7	13	Decl
05/08-06-041-12-W4/0	W-100.000	ELL	PR									181	133	47	47.5	23	Decl
02/09-06-041-12-W4/0	W-100.000	ELL	PR									239	196	43	43.3	15	Decl
02/15-15-041-12-W4/0	R- 3.750	ELL	PR									220	214	5	0.2	0	Decl
04/15-15-041-12-W4/0	R- 3.750	ELL	PR									8	8				
02/16-15-041-12-W4/0	R- 3.750	ELL	PR									79	79				
05/16-15-041-12-W4/0	R- 3.750	ELL	PR									21	19	1	0.0	0	
Subtotal			**PR**									**4834**	**4034**	**778**	**783.2**	**382**	
			PA											**10**	**10.0**		
David North																	
Lloydminster O Unit	W-100.000	LLOYD	PR									5764	5360	403	404.0	319	Decl
			PA											128	127.9	9	Decl
Sec 26 &	W-100.000	DINA/CUMM	PR									1600	1170	429	429.4	336	Decl
NE-27-40-3W4			PA											100	100.0	7	Decl
00/10-27-040-03-W4/0	W-100.000	LLOYD	PR									40	25	14	14.1	9	Decl
02/10-27-040-03-W4/0	W-100.000	LLOYD	PR									60	35	24	24.3	18	Perf
			PA											5	5.0	0	Perf
02/15-27-040-03-W4/0	W-100.000	LLOYD	PR									30	7	22	22.9	15	Perf
			PA											5	5.0	0	Perf
Subtotal			**PR**									**7494**	**6597**	**892**	**894.6**	**697**	
			PA											**238**	**237.9**	**17**	

Coyote Energy Inc.

Summary of Crude Oil Reserve Estimates
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

				Volumetric Factors						Property Gross Crude Oil Reserves					Company Share		
Area and Property	Company Interest %	Zones	Reserve Class	Area acre	Net Pay ft	Por. %	Sw %	Sg %	Oil Shr.	Orig. OIP mbbl	Rec. %	Orig. Res. mbbl	Cum. Prod. mbbl	Rem. Res. mbbl	Rem. Res. mbbl	2002 Rate bopd	Reserves based on
Hayter																	
N-24-40-1W4	W- 93.750	DINA	PR									780	703	76	71.9	52	Decl
Pre-1999 Wells			PA											20	18.7	1	Decl
N-24-40-1W4	W- 93.750	DINA	PR									320	269	50	47.4	57	Decl
1999 Wells			PA											20	18.7	2	Decl
N-24-40-1W4	W- 93.750	DINA	PR									270	53	216	202.7	255	
2002 Wells			PA											60	54.0	27	
N-24-40-1W4	W- 93.750	DINA	PR									180		180	168.8	338	
Future Locations			PA											40	37.5	5	
Sec 25-40-1W4	W- 94.517	DINA	PR									8800	7449	1350	1276.8	798	Decl
Pre-1998 Wells			PA											300	282.7	20	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									500	396	103	98.0	67	Decl
1998 Wells			PA											25	23.6	2	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									550	413	136	128.9	146	Decl
1999 Wells			PA											50	46.8	10	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									1700	1261	438	414.6	592	Decl
2000 Wells			PA											100	92.3	36	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									550	385	164	155.5	253	Decl
2001 Wells			PA											50	45.6	24	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									540	137	402	380.1	451	Decl
2002 Wells			PA											120	109.7	48	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									1440		1440	1361.0	1863	
Future Locations			PA											320	302.5		
Sec 34-40-1W4	W- 75.000	DINA	PR									1450	1349	100	75.4	93	Decl
Pre-1999 Wells			PA											50	37.4	2	Decl
Sec 34-40-1W4	W- 75.000	DINA	PR									150	118	31	23.8	38	Decl
1999 Wells			PA											10	7.4	2	Decl

Coyote Energy Inc.

Summary of Crude Oil Reserve Estimates
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Volumetric Factors: Area acre	Net Pay ft	Por. %	Sw %	Sg %	Oil Shr.	Property Gross Crude Oil Reserves: Orig. OIP mbbl	Rec. %	Orig. Res. mbbl	Cum. Prod. mbbl	Rem. Res. mbbl	Company Share: Rem. Res. mbbl	2002 Rate bopd	Reserves based on
Hayter (cont'd)																	
Sec 34-40-1W4	W- 75.000	DINA	PR									45	31	13	9.8	11	Perf
2000 Wells																	
S&NE-35-40-1W4	W-100.000	DINA	PR									5200	4552	647	647.9	543	Decl
Pre-1998 Wells			PA											150	149.8	5	Decl
S&NE-35-40-1W4	W-100.000	DINA	PR									65	56	8	8.6	20	Decl
1998 Wells			PA											5	4.9	1	Decl
S&NE-35-40-1W4	W-100.000	DINA	PR									145	113	31	31.4	37	Decl
1999 Wells			PA											10	9.9	2	Decl
S&NE-35-40-1W4	W-100.000	DINA	PR									575	423	151	151.8	209	Decl
2000 Wells			PA											50	48.9	18	Decl
S&NE-35-40-1W4	W-100.000	DINA	PR									600	293	306	306.6	403	Decl
2001 Wells			PA											100	98.4	29	Decl
NW-35-40-1W4	W- 75.000	DINA	PR									950	794	155	116.7	62	Decl
Pre-2000 Wells																	
NW-35-40-1W4	W- 77.500	DINA	PR									520	368	151	117.5	171	Decl
2000 Wells			PA											50	37.8	15	Decl
NW-35-40-1W4	W- 75.000	DINA	PR									600	290	309	232.4	302	Decl
2001 Wells			PA											100	72.8	31	Decl
NW-35-40-1W4	W- 75.000	DINA	PR									450		450	337.5	684	
Future Locations			PA											100	75.0	9	
S-36-40-1W4	R- 7.500	DINA	PR									400	369	30	2.3	4	Decl
GOR Wells																	
00/09-34-040-01-W4/2	W- 75.000	SPKY	PR		5.9	30.0	25.0		0.97			185	171	13	10.2	7	Decl
00/15-34-040-01-W4/2	W- 75.000	SPKY	PR									15	5	9	7.1	6	Decl
00/01-03-041-01-W4/2	W- 75.000	SPKY	PR		7.2	28.5	25.0		0.97			150	112	37	28.0	11	Decl
			PA						0.97					10	7.5	0	Decl
Subtotal			PR									27130	20110	6996	6412.5	7473	
			PA											1740	1581.6	291	

Coyote Energy Inc.

Summary of Crude Oil Reserve Estimates
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

				Volumetric Factors						Property Gross Crude Oil Reserves					Company Share		
Area and Property	Company Interest %	Zones	Reserve Class	Area acre	Net Pay ft	Por. %	Sw %	Sg %	Oil Shr.	Orig. OIP mbbl	Rec. %	Orig. Res. mbbl	Cum. Prod. mbbl	Rem. Res. mbbl	Rem. Res. mbbl	2002 Rate bopd	Reserves based on
Mestikow																	
All Company Wells	W-100.000	DINA	PR									785	614	170	170.3	124	Decl
			PA											25	25.0	2	Decl
Thompson Lake																	
Thompson Lake	W- 99.045	GLAUC	PR									23500	21469	2030	2011.5	1340	Decl
Total Field			PA											500	495.0	17	Decl
West Provost																	
Secs 10 & 15-38-3W4	W- 37.500	DINA	PR			29.0	20.0		0.95	17011	51.7	8800	7788	1011	379.2	216	Decl
Pre 1995 Wells			PA						0.95					200	74.8	4	Decl
Secs 10 & 15-38-3W4	W- 37.500	DINA	PR			29.0	20.0		0.95	1706	58.6	1000	788	211	79.2	44	Decl
1995 Wells			PA						0.95					50	18.7	1	Decl
Secs 10 & 15-38-3W4	W- 37.500	DINA	PR			29.0	20.0		0.95	6561	54.9	3600	3049	550	206.4	200	Decl
1996 Wells			PA						0.95					100	37.2	5	Decl
Secs 10 & 15-38-3W4	W- 37.500	DINA	PR			29.0	20.0		0.95	2409	52.9	1275	1126	148	55.6	86	Decl
1997 Wells			PA						0.95					50	18.5	5	Decl
Secs 10 & 15-38-3W4	W- 37.500	DINA	PR			29.0	20.0		0.95	391	51.1	200	181	18	7.0	10	Decl
1998 Wells			PA						0.95					10	3.7	1	Decl
Sec 16-38-3W4	W-100.000	DINA	PR			29.0	20.0		0.95	1181	45.7	540	482	57	57.5	61	Perf
			PA						0.95					20	20.0	1	Perf
Secs 10 & 15-38-3W4	W- 37.500	REX	PR									400	336	63	23.7	23	Decl
Rex Wells			PA											10	3.7	0	Decl
Subtotal			PR							29259		15815	13750	2058	808.6	639	
			PA											440	176.7	18	
Subtotal Alberta			PR							29259		79558	66574	12924	11080.8	10656	
			PA											2953	2526.2	344	
TOTAL			PR							29259		79558	66574	12924	11080.8	10656	
			PA											2953	2526.2	344	

McDANIEL & ASSOCIATES
CONSULTANTS LTD.

Coyote Energy Inc.

Summary of Natural Gas Reserve Estimates
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Volumetric Factors: Area acre	Net Pay ft	Por. %	Sw %	So %	Pres. psia	Temp. deg R	Z	Property Gross Natural Gas Reserves: Orig. Raw GIP mmcf	Rec. %	Orig. Raw Res. mmcf	Cum. Prod. mmcf	Rem. Raw. Res. mmcf	Surf. Loss %	Rem. Sales Res. mmcf	Company Share: Rem. Sales Res. mmcf	2002 Rate mcf/d	Reserves based on
Alberta																					
Bellshill Lake																					
00/04-05-041-12-W4/0	W-100.000	ELL	PR																10.2	4	
02/04-05-041-12-W4/0	W-100.000	ELL	PR																19.6	9	
03/04-05-041-12-W4/0	W-100.000	ELL	PR																1.2	2	
00/05-05-041-12-W4/2	W-100.000	ELL	PR																11.6	5	
04/05-05-041-12-W4/2	W-100.000	ELL	PR																12.6	5	
B0/05-05-041-12-W4/0	W-100.000	ELL	PR																12.7	6	
00/06-05-041-12-W4/2	W- 40.000	GLAUC L	PR		7.2	22.0	30.0							1925	1813	112	5.0	107	42.6	84	Perf
			PA											25		25	5.0	24	9.5	2	Perf
02/10-05-041-12-W4/0	W-100.000	ELL	PR																1.9		
			PA																0.4		
00/12-05-041-12-W4/2	W-100.000	ELL	PR																19.4	9	
00/13-05-041-12-W4/0	W-100.000	ELL	PR																0.8	1	
B0/14-05-041-12-W4/0	W-100.000	ELL	PR																10.8	6	
C0/14-05-041-12-W4/0	W-100.000	ELL	PR																8.2	4	
00/15-05-041-12-W4/0	W-100.000	ELL	PR																3.6		
			PA																1.2		
02/15-05-041-12-W4/2	W-100.000	ELL	PR																2.1	3	
A2/15-05-041-12-W4/0	W-100.000	ELL	PR																4.6	3	
B2/15-05-041-12-W4/0	W-100.000	ELL	PR																17.1	8	

Coyote Energy Inc.

Summary of Natural Gas Reserve Estimates
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

				Volumetric Factors								Property Gross Natural Gas Reserves							Company Share		
Area and Property	Company Interest %	Zones	Reserve Class	Area acre	Net Pay ft	Por. %	Sw %	So %	Pres. psia	Temp. deg R	Z	Orig. Raw GIP mmcf	Rec. %	Orig. Raw Res. mmcf	Cum. Prod. mmcf	Rem. Raw. Res. mmcf	Surf. Loss %	Rem. Sales Res. mmcf	Rem. Sales Res. mmcf	2002 Rate mcf/d	Reserves based on
02/16-05-041-12-W4/0	W-100.000	ELL	PR																3.8	4	
00/01-06-041-12-W4/0	W-100.000	ELL	PR																11.7	5	
00/02-06-041-12-W4/0	W-100.000	ELL	PR																8.7	4	
02/07-06-041-12-W4/3	W-100.000	ELL	PR																4.4	2	
02/08-06-041-12-W4/0	W-100.000	ELL	PR																11.4	9	
03/08-06-041-12-W4/0	W-100.000	ELL	PR																14.2	6	
05/08-06-041-12-W4/0	W-100.000	ELL	PR																12.1	6	
02/09-06-041-12-W4/0	W-100.000	ELL	PR																8.8	3	
Subtotal			**PR**											**1925**	**1813**	**112**		**107**	**254.2**	**189**	
			PA											**25**		**25**		**24**	**11.1**	**2**	
Black Creek																					
00/06-20-041-03-W4	W-100.000	MCLAR	PR	160	13.1	29.0	50.0	5.0	708	540	0.900	616	50.0	308		308	5.0	293	292.6		Vol
			PA										20.0	123		123	5.0	117	116.8		Vol
Choice																					
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PR											9250	8551	699	5.0	665	47.2	29	Decl
			PA											250		250	5.0	238	16.9	1	Decl
00/11-05-040-08-W4/0	R- 15.000	VIK	PR											760	725	35	5.0	33	5.0	5	Decl
00/07-07-040-08-W4/0	R- 6.250	CLY	PR	160	7.9	28.0	40.0		914	544	0.890	620		380	344	36	5.0	35	2.2	5	Decl
00/10-07-040-08-W4/0	R- 15.000	VIK	PR											950	822	128	5.0	122	18.3	8	Decl
Subtotal			**PR**									**620**		**11340**	**10442**	**898**		**855**	**72.6**	**47**	
			PA											**250**		**250**		**238**	**16.9**	**1**	

Coyote Energy Inc.

Summary of Natural Gas Reserve Estimates
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Volumetric Factors: Area acre	Net Pay ft	Por. %	Sw %	So %	Pres. psia	Temp. deg R	Z	Property Gross Natural Gas Reserves: Orig. Raw GIP mmcf	Rec. %	Orig. Raw Res. mmcf	Cum. Prod. mmcf	Rem. Raw. Res. mmcf	Surf. Loss %	Rem. Sales Res. mmcf	Company Share: Rem. Sales Res. mmcf	2002 Rate mcf/d	Reserves based on
David North																					
Lloydminster O Unit	W-100.000	LLOYD	PR																40.4	32	
			PA																12.8	1	
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PR																52.5	41	
			PA																12.2	1	
Subtotal			**PR**																**92.9**	**73**	
			PA																**25.0**	**2**	
Thompson Lake																					
Thompson Lake Total Field	W- 99.045	GLAUC	PR																612.5	408	
			PA																150.7	5	
04/10-29-040-11-W4/2	W- 25.000	VIK	PR											80	73	7	5.0	7	1.6	8	Decl
Subtotal			**PR**											**80**	**73**	**7**		**7**	**614.1**	**416**	
			PA																**150.7**	**5**	
West Provost																					
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PR																27.9	16	
			PA																5.5	0	
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PR																8.3	5	
			PA																2.0	0	
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PR																21.7	21	
			PA																3.9	1	
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PR																4.3	7	
			PA																1.4	0	
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PR																0.4	1	
			PA																0.2	0	
Sec 16-38-3W4	W-100.000	DINA	PR																10.1	11	
			PA																3.5	0	

Coyote Energy Inc.

Summary of Natural Gas Reserve Estimates
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Volumetric Factors: Area acre	Net Pay ft	Por. %	Sw %	So %	Pres. psia	Temp. deg R	Z	Property Gross Natural Gas Reserves: Orig. Raw GIP mmcf	Rec. %	Orig. Raw Res. mmcf	Cum. Prod. mmcf	Rem. Raw. Res. mmcf	Surf. Loss %	Rem. Sales Res. mmcf	Company Share: Rem. Sales Res. mmcf	2002 Rate mcf/d	Reserves based on
West Provost (cont'd)																					
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PR																16.6	16	
			PA																2.6	0	
00/11-24-037-02-W4/0	W- 37.500	VIK	PR		4.0	26.0	45.0		838	540	0.890			775	773	2	6.0	2	0.5	3	Perf
00/07-27-037-02-W4/0	W- 42.188	VIK	PR		3.3	22.0	50.0		673	540	0.894			525	385	140	6.0	131	55.5	13	Perf
02/06-11-038-03-W4/0	W- 28.125	VIK	PR		6.0	23.0	40.0		843	540	0.896			377	377						
00/14-12-038-03-W4/0	W- 37.500	CLY	PR		24.9	26.0	25.0		785	548	0.918			1600	1563	37	6.0	35	13.1	11	Perf
00/07-13-038-03-W4/0	W- 37.500	VIK	PR		4.9	24.0	40.0		810	531	0.875			1100	1003	97	6.0	91	34.2	17	Perf
00/06-14-038-03-W4/0	W- 37.500	VIK	PR		5.0	20.0	40.0		844	540	0.815			456	456						
00/07-15-038-03-W4/2	W- 37.500	VIK	PR											460	439	21	6.0	20	7.3	9	Perf
00/07-17-038-03-W4/0	W- 37.500	VIK	PR		3.0	21.0	40.0		802	540	0.875			360	343	17	6.0	16	6.0	6	Perf
00/07-18-038-03-W4/0	W- 37.500	VIK	PR		7.0	21.0	45.0		810	540	0.875			950	882	68	6.0	64	24.0	11	Perf
00/14-07-039-01-W4/0	W- 29.371	MCLAR	PR	213	18.7	30.0	30.0		800	540	0.900	2130	75.0	1598	1275	323	5.0	307	90.1	29	Perf
Bodo Compression Facility	P- 100.000	ALL ZONES	PR																		
Subtotal			PR									2130		8201	7496	705		666	320.0	173	
			PA																19.1	2	
Subtotal Alberta			PR									3366		21854	19824	2030		1928	1646.5	897	
			PA											398		398		379	339.7	11	
TOTAL			PR									3366		21854	19824	2030		1928	1646.5	897	
			PA											398		398		379	339.7	11	

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
Alberta		
Bellshill Lake		
Fixed Battery Costs	OWNED BY COMPANY	
	Working Interest	100.00000 %
Northstar et al Hzl Bell 4-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Northstar et al Hzl 4C2 Bell 4-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Northstar ARC Hz 4C3 Bell 4-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Northstar etal Hzl Bell 5-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Northstar Hzl 5C2 Bell 5-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Northstar etal Hzl 5B Bell 5-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Renaissance Bellh Lk 6-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	40.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
Northstar Hzl 10B Bell 10-5-41-12 NE-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar ARC Hz 12C Bell 12-5-41-12 NW-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar Hzl 13C2 Bell 13-5-41-12 NW-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar ARC 14B Bell 14-5-41-12 NW-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar Hzl 14C Bell 14-5-41-12 NW-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar Hzl 15A2 Bell 15-5-41-12 NE-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Government Royalty	 100.00000 % ALTA NEW CROWN
Northstar ARC Hz14C2 Bell 14-5-41-12 NE-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar ARC 15A3 Bell 15-5-41-12 NE-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
Bellshill Lake (cont'd)		
Northstar ARC 15B2	OWNED BY COMPANY	
Bell 15-5-41-12	Working Interest	100.00000 %
NE-5-41-12W4	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150
		MIN 10.00 %
		MAX 15.00 %
Northstar Hzl 16D	OWNED BY COMPANY	
Bell 16-5-41-12	Working Interest	100.00000 %
NE-5-41-12W4	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150
		MIN 10.00 %
		MAX 15.00 %
Northstar ARC 100 1C	OWNED BY COMPANY	
Bell 1-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 100 2A	OWNED BY COMPANY	
Bell 2-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 102 7D	OWNED BY COMPANY	
Bell 7-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 8C	OWNED BY COMPANY	
Bell 8-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 8D	OWNED BY COMPANY	
Bell 8-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 105 8C	OWNED BY COMPANY	
Bell 8-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 9D	OWNED BY COMPANY	
Bell 9-6-41-12	Working Interest	100.00000 %
NE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Tiv et al Bell	OWNED BY COMPANY	
15-15BQ-41-12	Gross Overriding Royalty	1/150
Lsd 15-15-41-12W4		MIN 5.00 %
		MAX 15.00 %
	Percentage of production	75.00000 %
TIV et al 104 Bell	OWNED BY COMPANY	
15-15-41-12	Gross Overriding Royalty	1/150
NE-15-41-12W4		MIN 5.00 %
		MAX 15.00 %
	Percentage of production	75.00000 %

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
Bellshill Lake (cont'd)		
TIV et al Bell	OWNED BY COMPANY	
16B-15-41-12	Gross Overriding Royalty	1/150
NE-15-41-12W4		MIN 5.00 %
		MAX 15.00 %
	Percentage of production	75.00000 %
TIV et al 105 Bell	OWNED BY COMPANY	
16-15-41-12	Gross Overriding Royalty	1/150
NE-15-41-12W4		MIN 5.00 %
		MAX 15.00 %
	Percentage of production	75.00000 %
Black Creek		
Morrison et al	OWNED BY COMPANY	
Provost 6-20-41-3	Working Interest	100.00000 %
Sec 20-41-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Choice		
Choice Viking Gas	OWNED BY COMPANY	
Unit No. 1	Gross Overriding Royalty	7.10690 %
ACL Provost	OWNED BY COMPANY	
11-5-40-8	Gross Overriding Royalty	15.00000 %
Sec 5-40-8W4		
Husky Avid Provost	OWNED BY COMPANY	
7-7-40-8	Gross Overriding Royalty	6.25000 %
Sec 7-40-8W4		
ACL Provost	OWNED BY COMPANY	
10-7-40-8	Gross Overriding Royalty	15.00000 %
Sec 7-40-8W4		
David North		
Lloydminster O Unit	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	4.34000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1.47000 %
Sec 26 &	OWNED BY COMPANY	
NE-27-40-3W4	Working Interest	100.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	2.94000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.40000 %
Northstar Provost	OWNED BY COMPANY	
10-27-40-3	Working Interest	100.00000 %
Lsd-10-27-40-3W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1.47000 %

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
David North (cont'd)		
Northstar 10A	OWNED BY COMPANY	
Provost 10-27-40-3	Working Interest	100.00000 %
Lsd 10-27-40-3W4	ENCUMBRANCES	
	Freehold Royalty Payable	4.34000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1.47000 %
Northstar 102	OWNED BY COMPANY	
Provost 15-27-40-3	Working Interest	100.00000 %
Lsd 15-27-40-3W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	7.90000 %
Hayter		
N-24-40-1W4	OWNED BY COMPANY	
Pre-1999 Wells	Working Interest	93.75000 %
N-24-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.10000 %
N-24-40-1W4	OWNED BY COMPANY	
1999 Wells	Working Interest	93.75000 %
N-24-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.10000 %
N-24-40-1W4	OWNED BY COMPANY	
2002 Wells	Working Interest	93.75000 %
N-24-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.10000 %
N-24-40-1W4	OWNED BY COMPANY	
Future Locations	Working Interest	93.75000 %
N-24-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.10000 %
Sec 25-40-1W4	OWNED BY COMPANY	
Pre-1998 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 25-40-1W4	OWNED BY COMPANY	
1998 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 25-40-1W4	OWNED BY COMPANY	
1999 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
Hayter (cont'd)		
Sec 25-40-1W4	OWNED BY COMPANY	
2000 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 25-40-1W4	OWNED BY COMPANY	
2001 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 25-40-1W4	OWNED BY COMPANY	
2002 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 25-40-1W4	OWNED BY COMPANY	
Future Locations	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 34-40-1W4	OWNED BY COMPANY	
Pre-1999 Wells	Working Interest	75.00000 %
Sec 34-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.50000 %
Sec 34-40-1W4	OWNED BY COMPANY	
1999 Wells	Working Interest	75.00000 %
Sec 34-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.50000 %
Sec 34-40-1W4	OWNED BY COMPANY	
2000 Wells	Working Interest	75.00000 %
Sec 34-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.50000 %
S&NE-35-40-1W4	OWNED BY COMPANY	
Pre-1998 Wells	Working Interest	100.00000 %
S&NE-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
S&NE-35-40-1W4	OWNED BY COMPANY	
1998 Wells	Working Interest	100.00000 %
S&NE-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
Hayter (cont'd)		
S&NE-35-40-1W4	OWNED BY COMPANY	
1999 Wells	Working Interest	100.00000 %
S&NE-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
S&NE-35-40-1W4	OWNED BY COMPANY	
2000 Wells	Working Interest	100.00000 %
S&NE-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
S&NE-35-40-1W4	OWNED BY COMPANY	
2001 Wells	Working Interest	100.00000 %
S&NE-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
NW-35-40-1W4	OWNED BY COMPANY	
Pre-2000 Wells	Working Interest	75.00000 %
NW-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	25.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.50000 %
NW-35-40-1W4		
2000 Wells		
14-35 wells	INTEREST NUMBER 1	
	OWNED BY COMPANY	
	Working Interest	75.00000 %
	Percentage of production	50.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	25.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.50000 %
03/12-35 well	INTEREST NUMBER 2	
	OWNED BY COMPANY	
	Working Interest	80.00000 %
	Percentage of production	50.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	23.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.50000 %
NW-35-40-1W4	OWNED BY COMPANY	
2001 Wells	Working Interest	75.00000 %
NW-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	25.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.50000 %
NW-35-40-1W4	OWNED BY COMPANY	
Future Locations	Working Interest	75.00000 %
NW-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	25.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.50000 %
S-36-40-1W4	OWNED BY COMPANY	
GOR Wells	Gross Overriding Royalty	7.50000 %
S-36-40-1W4		

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
Hayter (cont'd)		
NorcenInt et al	OWNED BY COMPANY	
Hayter 9-34-40-1	Working Interest	75.00000 %
Lsd 9-34-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.50000 %
UPRI et al 15D	OWNED BY COMPANY	
Hayter 15-34-40-1	Working Interest	75.00000 %
NE-34-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.50000 %
NorcenInt CS Hayter	OWNED BY COMPANY	
1B-3-41-1	Working Interest	75.00000 %
SE-3-41-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	22.50000 %
	Mineral Tax	ALTA MIN. TAX
Mestikow		
All Company Wells	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	2.00000 %
Thompson Lake		
Thompson Lake		
Total Field		
Lsds 1, 8-10, 15 & 16-	INTEREST NUMBER 1	
34-40-11W4	OWNED BY COMPANY	
Lsds 2-7, 10-15,-	Working Interest	98.83750 %
Lsds 1-8, 10 & 11-	Tract Factor	75.60000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Lsds 1, 4-6, 8, 13,	INTEREST NUMBER 2	
Lsds 3 & 4-1-41-11W4	OWNED BY COMPANY	
Lsds 1& 8-3-41-11W4	Working Interest	100.00000 %
NW-35-40-11W4	Tract Factor	17.66000 %
Lsds 2-36-40-11W4	ENCUMBRANCES	
	Freehold Royalty Payable	10.00000 %
	Mineral Tax	ALTA MIN. TAX
Lsd 10-25-40-11W4	INTEREST NUMBER 3	
	OWNED BY COMPANY	
	Working Interest	99.31270 %
	Tract Factor	0.49000 %
	Percentage of production	19.50000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Lsd 10-25-40-11W4	INTEREST NUMBER 4	
	OWNED BY COMPANY	
	Working Interest	99.31270 %
	Tract Factor	0.49000 %
	Percentage of production	80.50000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	10.00000 %
	Mineral Tax	ALTA MIN. TAX

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	**Ownership Information**	
Thompson Lake (cont'd)		
Lsd 15-25-40-11W4	INTEREST NUMBER 5	
	OWNED BY COMPANY	
	Working Interest	98.83750 %
	Tract Factor	6.25000 %
	Percentage of production	46.25000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	10.00000 %
	Mineral Tax	ALTA MIN. TAX
Lsd 15-25-40-11W4	INTEREST NUMBER 6	
	OWNED BY COMPANY	
	Working Interest	98.83750 %
	Tract Factor	6.25000 %
	Percentage of production	53.75000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Husky 104 Provost	OWNED BY COMPANY	
10-29-40-11	Working Interest	25.00000 %
Sec 29-40-11W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
West Provost		
Secs 10 & 15-38-3W4	OWNED BY COMPANY	
Pre 1995 Wells	Working Interest	37.50000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Secs 10 & 15-38-3W4	OWNED BY COMPANY	
1995 Wells	Working Interest	37.50000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Secs 10 & 15-38-3W4		
1996 Wells		
Lsds 9&16 Sec 10	INTEREST NUMBER 1	
	OWNED BY COMPANY	
	Working Interest	37.50000 %
	Percentage of production	97.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Remaining Lands	INTEREST NUMBER 2	
	OWNED BY COMPANY	
	Working Interest	37.50000 %
	Percentage of production	3.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Secs 10 & 15-38-3W4		
1997 Wells		
Lsds 9&16 Sec 10	INTEREST NUMBER 1	
	OWNED BY COMPANY	
	Working Interest	37.50000 %
	Percentage of production	97.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
West Provost (cont'd)		
Remaining Lands	INTEREST NUMBER 2	
	OWNED BY COMPANY	
	Working Interest	37.50000 %
	Percentage of production	3.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Secs 10 & 15-38-3W4	OWNED BY COMPANY	
1998 Wells	Working Interest	37.50000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Sec 16-38-3W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Secs 10 & 15-38-3W4	OWNED BY COMPANY	
Rex Wells	Working Interest	37.50000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcenint et al	OWNED BY COMPANY	
Provost 11C-24-37-2	Working Interest	37.50000 %
Sec 24-37-2W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcenint et al		
Provost 7-27-37-2		
S&NE-27-37-2W4	INTEREST NUMBER 1	
	OWNED BY COMPANY	
	Working Interest	42.18750 %
	Percentage of production	75.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	26.66667 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.44444 %
NW-27-37-2W4	INTEREST NUMBER 2	
	OWNED BY COMPANY	
	Working Interest	42.18750 %
	Percentage of production	25.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
Norcenint Dome et al	OWNED BY COMPANY	
Prov. 6-11-38-3	Working Interest	28.12500 %
Sec 11-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Norcenint et al	OWNED BY COMPANY	
Provost 14D-12-38-3	Working Interest	37.50000 %
Sec 12-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %

Coyote Energy Inc.

List Of Interests and Encumbrances
Escalating Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
West Provost (cont'd)		
Norcen et al Provost	OWNED BY COMPANY	
7-13-38-3	Working Interest	37.50000 %
Sec 13-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcenint et al	OWNED BY COMPANY	
Provost 6B-14-38-3	Working Interest	37.50000 %
Sec 14-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcenint et al	OWNED BY COMPANY	
Provost 7-15-38-3	Working Interest	37.50000 %
Sec 15-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Norcen Int et al	OWNED BY COMPANY	
Provost 7-17-38-3	Working Interest	37.50000 %
Sec 17-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcenint et al	OWNED BY COMPANY	
Provost 7-18-38-3	Working Interest	37.50000 %
Sec 18-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcen et al Hayter		
14-7-39-1		
SE-7-39-1W4	INTEREST NUMBER 1	
	OWNED BY COMPANY	
	Working Interest	29.37100 %
	Percentage of production	25.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	25.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.26667 %
SW-7-39-1W4	INTEREST NUMBER 2	
Frac NW-7-39-1W4	OWNED BY COMPANY	
(54.76 Ha)	Working Interest	29.37100 %
Frac NE-7-39-1W4	Percentage of production	68.18750 %
(55.8 Ha)	ENCUMBRANCES	
	Freehold Royalty Payable	20.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.26667 %
	Gross Overriding Royalty	0.63838 %
Frac N-7-39-1W4	INTEREST NUMBER 3	
(17.44 Ha)	OWNED BY COMPANY	
	Working Interest	29.37100 %
	Percentage of production	6.81250 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	0.26667 %
Bodo Compression	OWNED BY COMPANY	
Facility	Working Interest	100.00000 %

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COYOTE ENERGY INC.

Evaluation of Oil & Gas Reserves
Based on Constant Price Assumptions

As of August 1, 2002

McDANIEL & ASSOCIATES
consultants ltd.

Oil and Gas Reservoir Engineering

COYOTE ENERGY INC.

Evaluation of Oil & Gas Reserves
Based on Constant Price Assumptions

As of August 1, 2002

Prepared For:

Coyote Energy Inc.
2200, 400 – 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Prepared By:

McDaniel & Associates Consultants Ltd.
2200, 255 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G6

August 2002

COYOTE ENERGY INC.

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APPENDIX 6 PROVED UNDEVELOPED RESERVES

APPENDIX 7 SUMMARY OF RESERVE ESTIMATES

APPENDIX 8 COMPANY INTEREST DATA

McDaniel & ASSOCIATES CONSULTANTS LTD.
Oil & Gas Reservoir Evaluations

August 22, 2002

Coyote Energy Inc.
2200, 400 – 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Attention: Mr. Jacob Roorda, President

Reference: **Coyote Energy Inc.**
Evaluation of Oil & Gas Reserves
Constant Price Assumptions

Dear Sir:

Pursuant to your request we have prepared an evaluation of the crude oil, natural gas and natural gas products reserves and the present worth values of these reserves for the petroleum and natural gas interests of Coyote Energy Inc., hereinafter referred to as the "Company", as of August 1, 2002. The future net revenues and present worth values presented in this report were calculated using "Constant Price" assumptions based on our opinion of the crude oil, natural gas and natural gas product prices for the remainder of 2002 with no inflation of operating or capital costs and were presented in Canadian dollars before income tax.

The properties evaluated in this report were indicated to include essentially all of the Company's conventional petroleum and natural gas interests in Canada. The Company's principal crude oil properties are located in the Hayter and Thompson Lake areas in the province of Alberta. The principal natural gas property is located in the Thompson Lake area in the province of Alberta.

All of the Company's properties were evaluated in detail for this report, except for the Hayter and West Provost areas which were recently acquired from Anadarko Canada Corporation. These two properties were evaluated in detail by McDaniel & Associates for Anadarko as of June 1, 2002 and were mechanically updated to August 1, 2002 for this evaluation with no changes to the evaluation parameters.

The Company's share of proved remaining and probable additional crude oil, natural gas and natural gas products reserves as of August 1, 2002 and the respective present worth values assigned to these reserves based on "Constant Price" assumptions were estimated to be as follows:

Suite 2200, Bow Valley Square 3, 255-5th Avenue S.W., Calgary, Alberta T2P 3G6
Tel: (403) 262-5506 Fax: (403) 233-2744 Email: mcdaniel@mcdan.com Website: www.mcdan.com

ESTIMATED COMPANY SHARE OF REMAINING RESERVES
AS OF AUGUST 1, 2002
MMCF, MBBL

	Proved Producing	Proved Non-Producing	Proved Undeveloped	Total Proved	Probable Additional	Total
Crude Oil						
Gross (1)	9,181	36	1,867	11,084	2,526	13,610
Net (2)	8,163	33	1,532	9,727	2,208	11,935
Natural Gas						
Gross (1)	1,349	298	-	1,647	340	1,987
Net (2)	1,079	233	-	1,312	266	1,578
Natural Gas Liquids						
Gross (1)	73	-	-	73	18	91
Net (2)	56	-	-	56	14	14

ESTIMATED COMPANY SHARE OF PRESENT WORTH VALUES BEFORE INCOME TAX
AS OF AUGUST 1, 2002
$1000 (3) (4)

			Discounted At		
	0%	10%	12%	15%	20%
Proved Developed Producing Reserves	127,416	104,242	100,681	95,835	88,861
Proved Developed Non-Producing Reserves	1,360	1,047	997	929	831
Proved Undeveloped Reserves	20,779	16,330	15,611	14,615	13,147
Total Proved Reserves	149,555	121,619	117,290	111,380	102,838
Probable Additional Reserves-Unrisked	39,017	26,185	24,435	22,151	19,069
Total Proved & Probable Reserves-Unrisked	**188,572**	**147,804**	**141,724**	**133,531**	**121,907**
Probable Additional Reserves-Risked (5)	19,508	13,092	12,217	11,076	9,534
Total Proved & Probable Reserves-Risked (5)	**169,064**	**134,712**	**129,507**	**122,455**	**112,373**

(1) Gross reserves are defined as the aggregate of the Company's working interest and royalty interest reserves before deductions of royalties payable to others.
(2) Net reserves are gross reserves less all royalties payable to others.
(3) Financial matters such as prepayments, take or pay payments, general obligations, etc. were not included.
(4) Based on "Constant Price" assumptions (see Price Schedules).
(5) Includes a 50 percent reduction in the probable present worth values to account for the risk associated with the probable additional reserves.

The Company's share of remaining reserves and present worth values are presented on a total Company basis in the summary section of this report. The location of the Company's properties and a graphical summary of the forecast production, net income and reserve distributions are also presented in this section. Tables summarizing the reserves, production and revenues for the various reserve classes are presented in Appendices 1 to 7. A summary of the Company's interests and encumbrances in each property is presented in Appendix 8. Discussions of the assumptions and methodology employed to prepare the reserve estimates and revenue forecasts are also contained in the "Evaluation Methodology" section.

The extent and character of all factual information supplied by the Company including ownership, well data, production, prices, revenues, operating costs, contracts, and other relevant data were relied upon by us in preparing this report and has been accepted as represented without independent verification. In view of the generality of the assignment the opinions expressed are not intended to provide a stand alone analysis of any specific property but to relate to an overall evaluation of the reserves of the Company.

This report was prepared by McDaniel & Associates Consultants Ltd. for the exclusive use of Coyote Energy Inc. and is not to be reproduced, distributed or made available, in whole or in part, to any person, company or organization other than Coyote Energy Inc. without the knowledge and consent of McDaniel & Associates Consultants Ltd. We reserve the right to revise any estimates provided herein if any relevant data existing prior to preparation of this report was not made available or if any data provided was found to be erroneous.

Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by B. H. Emslie"

B. H. Emslie, P. Eng.

"signed by R. Ott"

R. Ott, P. Geol.

BHE/RO:po
[02-465]

PERMIT TO PRACTICE
McDANIEL & ASSOCIATES CONSULTANTS LTD.

Signature ____________

Date Thursday, August 22, 2002

PERMIT NUMBER: P 3145

The Association of Professional Engineers, Geologists and Geophysicists of Alberta

CERTIFICATE OF QUALIFICATION

I, Bryan Howard Emslie, Petroleum Engineer of 2200, 255 - 5th Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am a Senior Vice President of McDaniel & Associates Consultants Ltd. which Company did prepare, at the request of Coyote Energy Inc., the report entitled "Coyote Energy Inc., Evaluation of Oil & Gas Reserves, Based on Constant Price Assumptions, As of August 1, 2002", dated August 22, 2002; and that I was involved in the preparation of this report.

2. That I attended the University of Alberta in the years 1973 to 1980 and that I graduated with Bachelor of Science Degree in Mechanical Engineering, that I am a registered Professional Engineer of the Association of Professional Engineers, Geologists & Geophysicists of Alberta and that I have in excess of twenty years experience in oil and gas reservoir studies and evaluations.

3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Coyote Energy Inc., any associate or affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

"signed by B. H. Emslie"

B. H. Emslie, P. Eng.

Calgary, Alberta
Dated: August 22, 2002

CERTIFICATE OF QUALIFICATION

I, Ronald Ott, Petroleum Geologist of 2200, 255 - 5th Avenue, S.W., Calgary, Alberta, Canada hereby certify:

1. That I am Chief Geologist of McDaniel & Associates Consultants Ltd. which Company did prepare, at the request of Coyote Energy Inc., the report entitled "Coyote Energy Inc., Evaluation of Oil & Gas Reserves, Based on Constant Price Assumptions, As of August 1, 2002", dated August 22, 2002, and that I was involved in the preparation of this report.

2. That I attended University of Calgary in the years 1984 to 1988, graduating with a Bachelor of Science degree in Geology; that I am a member of the Canadian Society of Petroleum Geologists; that I am a registered Professional Geologist of the Association of Professional Engineers, Geologists & Geophysicists of Alberta and that I have in excess of eight years experience in oil and gas reservoir studies and evaluations.

3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Coyote Energy Inc., any associate or affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

"signed by R. Ott"

R. Ott, P. Geol.

Calgary, Alberta
Dated: August 22, 2002

Coyote Energy Inc.

Total Company Reserves and Present Worth Values
Constant Prices as of August 1, 2002
Proved & Probable Reserves - Unrisked

Total Of All Areas

	Company Share of Remaining Reserves (mbbl,mmcf,mlt)		Company Share of Present Worth Values Before Income Tax (4)(5)(6) (M$)				
	Gross (1)	Net (2)	@0.0%	@10.0%	@12.0%	@15.0%	@20.0%
Proved Producing Reserves							
Crude Oil	9,180.8	8,162.5	122,684.6	100,603.4	97,202.2	92,569.3	85,894.4
Natural Gas	1,349.0	1,079.4	3,225.2	2,454.9	2,344.4	2,197.5	1,992.5
Natural Gas Liquids	73.4	55.6	1,506.4	1,184.1	1,135.0	1,068.5	973.6
Total			**127,416.2**	**104,242.4**	**100,681.7**	**95,835.3**	**88,860.5**
Proved Non-Producing Reserves							
Crude Oil	36.2	32.6	676.7	502.0	474.8	437.9	384.8
Natural Gas	298.1	232.9	682.5	544.2	521.9	491.1	445.8
Natural Gas Liquids	0.0	0.0	0.4	0.3	0.3	0.3	0.2
Total			**1,359.6**	**1,046.5**	**997.0**	**929.2**	**830.8**
Proved Undeveloped Reserves							
Crude Oil	1,867.3	1,531.5	20,779.3	16,330.4	15,611.1	14,615.3	13,147.0
Total			**20,779.3**	**16,330.4**	**15,611.1**	**14,615.3**	**13,147.0**
Total Proved Reserves							
Crude Oil	11,084.3	9,726.6	144,140.6	117,435.8	113,288.1	107,622.4	99,426.1
Natural Gas	1,647.1	1,312.3	3,907.7	2,999.0	2,866.3	2,688.6	2,438.3
Natural Gas Liquids	73.4	55.7	1,506.8	1,184.4	1,135.3	1,068.8	973.8
Total			**149,555.1**	**121,619.3**	**117,289.7**	**111,379.8**	**102,838.2**
Total Probable Reserves							
Crude Oil	2,526.1	2,208.3	37,785.9	25,427.9	23,740.5	21,538.0	18,561.8
Natural Gas	339.7	266.1	862.1	541.5	498.9	443.8	370.5
Natural Gas Liquids	18.0	13.6	368.8	215.1	195.1	169.6	136.4
Total			**39,016.8**	**26,184.5**	**24,434.5**	**22,151.4**	**19,068.7**
Total Proved & Probable Reserves							
Crude Oil	13,610.4	11,934.9	181,926.5	142,863.8	137,028.7	129,160.4	117,987.9
Natural Gas	1,986.8	1,578.4	4,769.8	3,540.6	3,365.2	3,132.4	2,808.8
Natural Gas Liquids	91.4	69.3	1,875.6	1,399.5	1,330.4	1,238.4	1,110.2
Total			**188,571.9**	**147,803.8**	**141,724.3**	**133,531.2**	**121,906.9**
BOE Reserves & PWV/BOE (3)							
Proved Producing	9,479.1	8,398.0	13.44	11.00	10.62	10.11	9.37
Proved Non-Producing	85.8	71.5	15.84	12.19	11.61	10.82	9.68
Proved Undeveloped	1,867.3	1,531.5	11.13	8.75	8.36	7.83	7.04
Total Proved	11,432.2	10,001.0	13.08	10.64	10.26	9.74	9.00
Total Probable	2,600.7	2,266.2	15.00	10.07	9.40	8.52	7.33
Total Proved & Probable	14,032.9	12,267.2	13.44	10.53	10.10	9.52	8.69

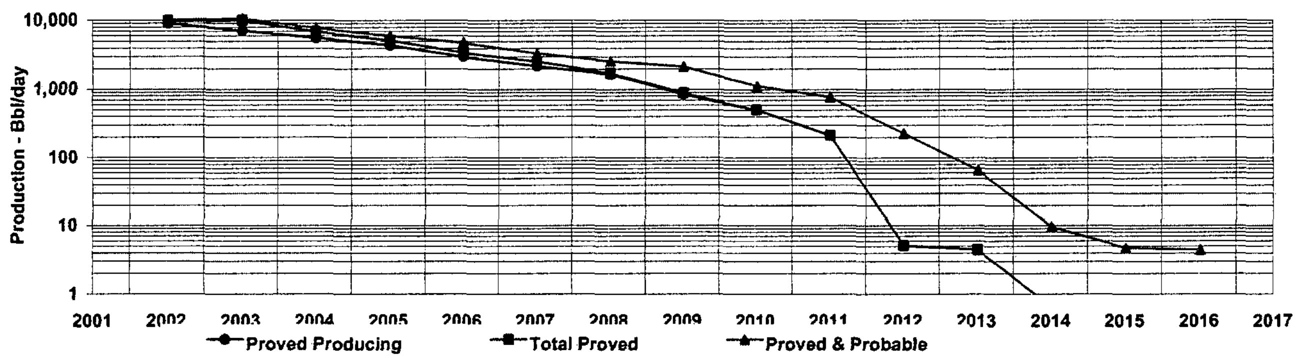
(1) Before royalty deductions.
(2) After royalty deductions.
(3) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE based on Gross BOE reserves.
(4) No allowance was made for the degree of risk associated with any of the reserve categories.
(5) Before allowance for Alberta Royalty Tax Credit
(6) Costs associated with extraction of natural gas products have in most cases been deducted from the natural gas revenues.

Coyote Energy Inc.
Location of Properties

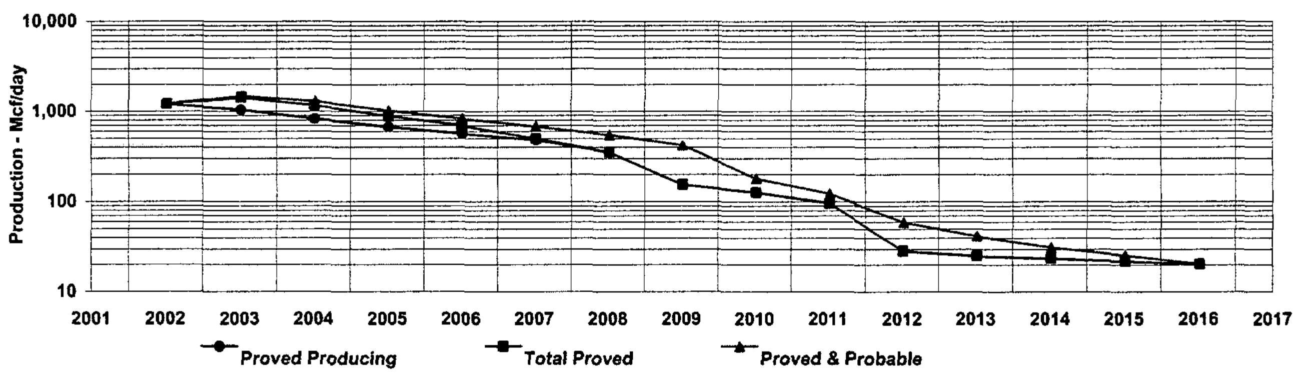
McDaniel & Associates Consultants Ltd.

Coyote Energy Inc.
Constant Prices
Total Company
Company Share

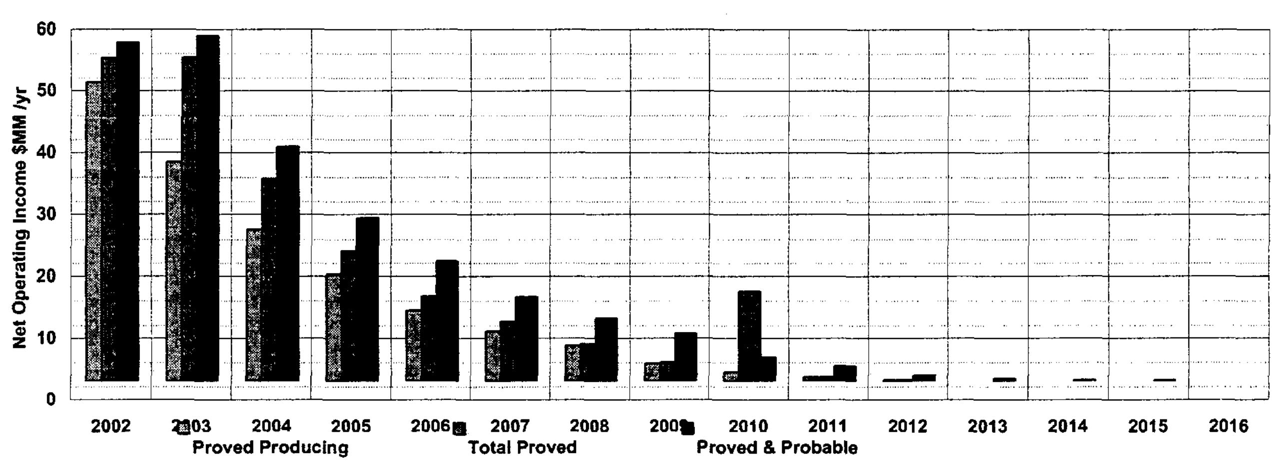
Crude Oil Production Profile



Natural Gas Production Profile

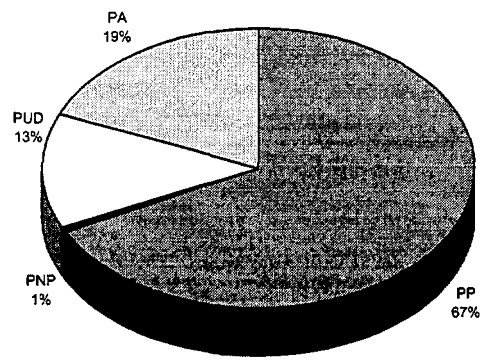


Before Tax Net Operating Income Profile

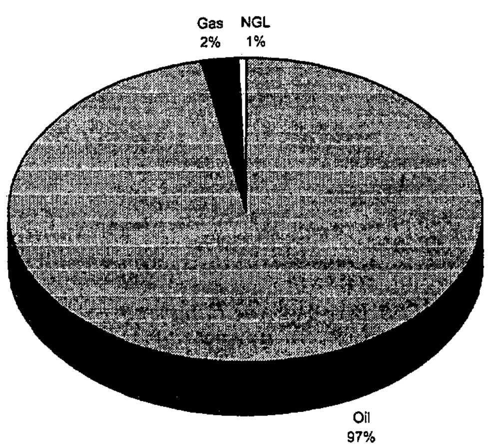


Coyote Energy Inc.
Constant Prices
Reserve Distribution by Reserve Class and Product

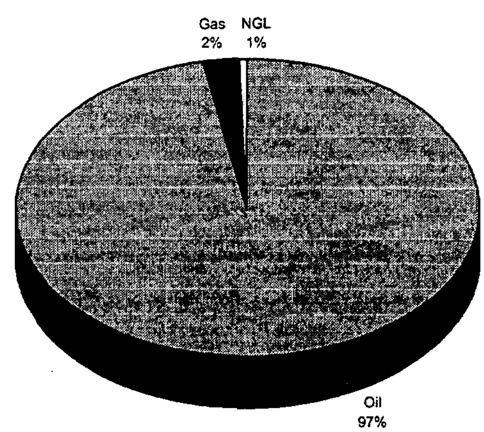
Reserve Distribution by Reserve Class



Reserve Distribution by Product Total Proved Reserves

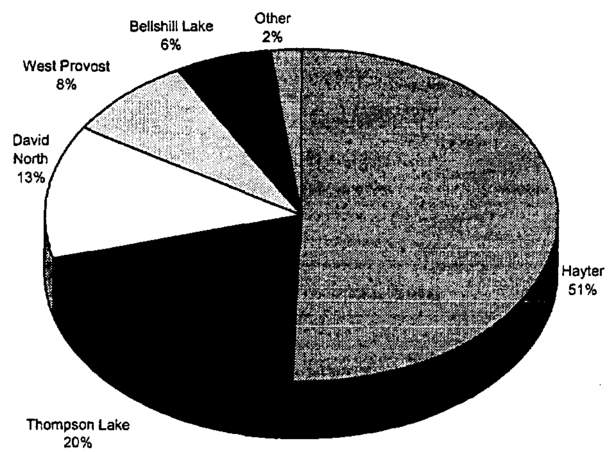


Reserve Distribution by Product Proved & Probable Reserves

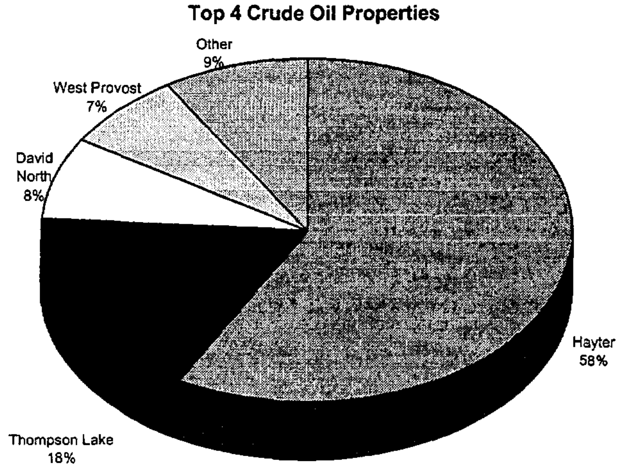


Coyote Energy Inc.
Constant Prices
Reserve and Present Worth Value Distribution For Major Properties
Total Proved Reserves

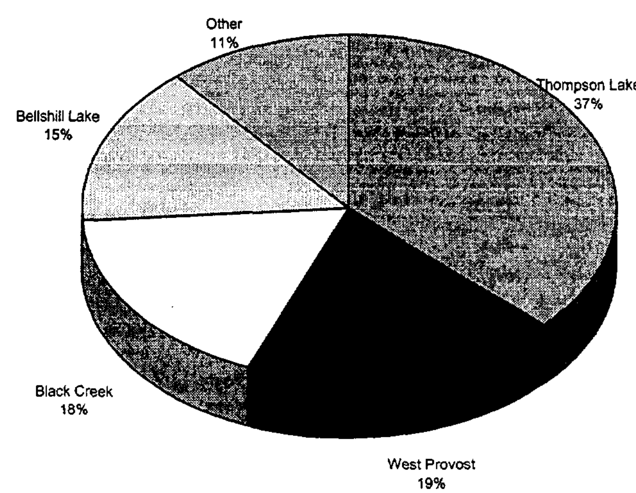
Top 5 Properties by 10% PWV



Top 4 Crude Oil Properties



Top 4 Natural Gas Properties



McDaniel & Associates Consultants Ltd.

Constant Product Price Schedule

Crude Oil Prices	
West Texas Intermediate ($U.S./bbl)	25.00
Edmonton Light Crude ($Cdn./bbl)	37.50
Bow River Medium Crude ($Cdn./bbl)	31.50
Hardisty Heavy ($Cdn./bbl)	25.00
Natural Gas (@ Field Gate $Cdn./MMbtu)	
Alberta Average	4.50
Transcanada Gas Services Ltd.	4.50
Pan Alberta Gas Ltd.	4.50
Spot Sales	4.50
Saskatchewan Average	4.65
CanWest Plant Gate (British Columbia)	4.40
Natural Gas Liquids (Edmonton Reference Price $Cdn./bbl)	
Propane	25.20
Field Butane	24.70
NGL Mix	27.50
Natural Gasolines & Condensate	37.50
Sulphur (Alberta Average @ Plant Gate $Cdn./LT)	0.00

All prices correspond to the 2002 (6 mos) forecast price in the McDaniel & Associates July 1, 2002 escalating price schedule.

SC020711

COYOTE ENERGY INC.

Evaluation of Oil & Gas Reserves
Based on Constant Price Assumptions
As of August 1, 2002

Evaluation Methodology

INTRODUCTION

Estimates of the crude oil, natural gas and natural gas products reserves and the associated present worth values before income taxes attributable to the Canadian properties of the Company have been presented in this report as of August 1, 2002. Reserve estimates were prepared for 8 individual properties in which the Company was indicated to have an interest in Western Canada based on detailed studies of the reservoir and performance characteristics as well as historical revenues and costs.

The basic information employed in the preparation of this report was obtained from the Company's files, published sources and from our own files.

The effective date of this report is August 1, 2002. The reserve estimates presented herein were based on the operating and economic conditions and development status as of that date except for changes planned for the immediate future or in the process of implementation. The assumptions and methodology employed in the preparation of this report conform with generally accepted petroleum engineering and evaluation principles. A brief review of the methodology employed in arriving at the reserves and present worth value estimates is presented in this section.

RESERVE ESTIMATES

Crude Oil

The crude oil reserve estimates presented in this report were based on a study of the volumetric data and performance characteristics of the individual wells and reservoirs in question. The oil-in-place estimates were based on individual well pore volume interpretations, geological studies of pool configurations as well as unitization studies and published estimates. In those cases where indicative oil production decline and/or increasing gas-oil and water-oil ratio trends were evident, the remaining reserves were determined by extrapolating these trends to economic limiting conditions. Where definitive production information was not yet available, the reserve estimates were based on analogy with similar wells or reservoirs or on theoretical studies of recovery efficiencies. The cumulative production figures were taken from published sources or from records of the Company and estimated for those recent periods where such data were not available.

Natural Gas and Products

The natural gas reserve estimates were based on a study of the volumetric data and performance characteristics of the individual wells and reservoirs in question. Volumetric estimates of the gas-in-place were based on individual well pore volume interpretations, geological studies of the pools and areas and on unitization studies and published estimates. Material balance estimates of the gas-in-place were employed where such information was available. The reserves recoverable from the currently producing properties were estimated from studies of performance characteristics and/or reservoir pressure histories. In cases of competitive drainage in multi-well pools the reserves were based on an analysis of the relevant factors relating to the future pool depletion by existing and possible future wells. The recovery factors for the non-producing properties were estimated from a consideration of test rates, reservoir pressures and by analogy with similar wells or reservoirs.

The natural gas products reserve estimates for the producing properties were predicated on a study of historical and anticipated future recoveries of these products from the natural gas reserves. The natural gas products recoveries from the non-producing natural gas reserves were estimated from gas analyses, well test information and from analogy with similar reservoirs. Natural gas products reserves were only assigned to non-producing properties in those cases where, in all likelihood the gas production would be processed through existing facilities capable of extracting these products or where such a facility will be available in the near future.

RESERVE CLASSIFICATION

The crude oil, natural gas and natural gas products reserves of the Company were classified into proved and probable additional categories. The proved reserves were considered to be those reserves estimated as recoverable under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir. Probable reserves are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future. A more detailed description of the factors considered in making these reserve assignments is presented in the "Reserve Definitions" at the end of this section.

The proved reserves have been further subdivided into proved producing, proved non-producing and proved undeveloped categories. Reserves were considered to be producing if these reserves are currently being produced or if definitive steps are being taken to begin production of these reserves in the immediate future. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area. Non-producing reserves recoverable from existing wells that require relatively minor capital expenditures to produce were classified as proved non-producing. Reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure is required were classified as proved undeveloped.

In all cases the crude oil and natural gas liquids reserves were expressed in barrels being equal to 34.972 Imperial gallons. The natural gas reserves were presented in thousands of standard cubic feet (MCF) and calculated at a base pressure of 14.65 psia and a base temperature of 60 degrees Fahrenheit.

Company Share of Reserves

The Company's net share of reserves was obtained by employing the Company's indicated gross working and royalty interests in the various properties in question less all royalties owned by others. In estimating net reserves the applicable Crown royalties were based on the regulations in effect as of August 1, 2002.

PRESENT WORTH VALUE ESTIMATES

The present worth values of the crude oil, natural gas and natural gas products reserves were obtained by employing future production and revenue analyses. The future crude oil production was in each instance predicated on a forecast of allowable rates and/or anticipated performance characteristics of the individual wells and reservoirs in question. The future natural gas production was predicated on the provisions of the natural gas purchase contracts where such contracts were available with consideration to the historical producing rates and the estimated deliverability. In those areas where shut-in natural gas reserves exist commencement of production was based on the proximity to a pipeline connection and the relevant factors relating to the future marketing of the reserves. Solution gas production was based on the forecast of the oil producing rates and producing gas-oil ratios. The natural gas products production forecasts were based on the anticipated recoveries of these products from the produced natural gas.

The Company's gross share of future crude oil revenue was derived by employing the Company's gross share of production and the indicated reference Edmonton crude oil prices less the historical quality and transportation price differential for each respective field. The indicated natural gas prices with an adjustment for the heating value of the gas were employed to calculate the gross share of future natural gas revenues. The indicated Edmonton natural gas products prices with adjustments to reflect historical price differentials realized by the Company in each respective property were employed to calculate the gross share of natural gas products revenues. Royalties and mineral taxes payable to the Crown were estimated based on the methods in effect as of August 1, 2002. Overriding royalties payable to others were estimated based on the indicated applicable rates. In those cases where a proportionate share of the natural gas gathering and processing charges were indicated to be payable by the Crown or royalties owned by others, these charges have been deducted in determining the net royalties payable.

In all cases, estimates of the applicable capital expenditures and operating costs with no allowance for inflation were deducted in arriving at the Company's share of future net revenues. No allowance for future well abandonment costs was made for any of the Company's working interest wells or for the abandonment of any facilities. The present worth values were then obtained by employing 10, 12, 15 and 20 percent nominal annual discount rates compounded annually.

The estimated present worth values of the proved plus probable additional reserves were obtained by employing future production and revenue analyses on a total proved plus probable reserve basis. All additional costs required to recover the probable additional reserves were included in the revenue forecasts. It should be pointed out that no allowance was made for any risk associated with the probable reserves in this report other than in the present worth value summary in the covering letter.

Summaries of the Company's share of remaining reserves together with forecast future revenues, royalties, taxes, operating and capital costs, cash flow and present worth values are presented in detailed tabulations in Appendices 1 to 7.

RESERVE DEFINITIONS

Crude Oil

A mixture, consisting mainly of pentanes and heavier hydrocarbons that may contain sulphur compounds, that is liquid at the conditions under which its volume is measured or estimated, but excluding such liquids obtained from the processing of natural gas.

Synthetic Oil

Oil derived from the upgrading of crude bitumen or by chemical modification of coal or other materials and which is largely interchangeable with conventional crude oil as a refinery feedstock.

Natural Gas

The lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions is essentially a gas, but which may contain liquids. The natural gas reserve estimates are reported on a marketable basis, that is the gas which is available to a transmission line after removal of certain hydrocarbons and non-hydrocarbon compounds present in the raw natural gas and which meets specifications for use as a domestic, commercial or industrial fuel.

Natural Gas Liquids

Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus, or a combination thereof.

Sulphur

Elemental sulphur removed from the produced natural gas by processing through an extraction plant.

Remaining Reserves

Remaining reserves are those quantities of crude oil, natural gas, natural gas liquids and sulphur remaining after deducting those quantities produced up to the reference date of the study.

Gross Reserves

The total of the Company's working interests and/or royalty interests share of reserves before deducting royalties owned by others.

Net Reserves

The total of the Company's working interests and/or royalty interests share of reserves after deducting the amounts attributable to the royalties owned by others.

Royalties

The term royalties, as used in this report, refers to royalties paid to others. The royalties deducted from the reserves are based on the royalty percentage calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling price the price forecasts for the individual properties in question has been employed.

Proved Reserves

Those reserves estimated as recoverable under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area.

Comments:

1. Where reserves are clearly known to exist in a reservoir and would be physically recoverable but cannot be termed "proved reserves" because they are not commercially recoverable due to their remote location (i.e. frontier reserves), these reserves are itemized separately in the report and their special circumstances fully explained.

2. Zones which have not been completed but which are interpreted to be productive from well logs (or core analyses) and which have conclusive drill stem tests or other production tests indicating economic producing rates are considered to be proved providing there is a high degree of certainty that these reserves will be produced.

3. Zones interpreted to be productive from well logs (or core analyses) either completed or behind pipe but which have not been tested or have inconclusive tests are considered proved only if offsetting wells indicate favorable tests or productive characteristics from this zone and there is a high degree of certainty that these reserves will be produced because of favorable reservoir characteristics.

4. The proved recovery efficiencies for presently shut-in reserves are estimated from theoretical considerations or by analogy to the nearest similar zone or area. In all cases the productive capacities of the individual wells or reservoirs in question are taken into account.

5. The proved natural gas reserves may be based on the assumption that additional compressor horsepower will be installed to achieve lower abandonment pressures providing there is a high degree of certainty that such action will be taken.

6. An allowance for increased recoveries in enhanced recovery (water-flood, solvent-flood, etc.) projects is made only on the basis of demonstrated more favorable performance from the project in question or from similar projects in like reservoirs. Increased proved recoveries may be assigned prior to the installation of the facilities if in our opinion there is a high degree of certainty that such facilities will be installed in the future. A gradual transfer of reserves from a probable additional to a proved category is usually made in such projects as more performance history is obtained. The assignment of higher recovery factors to these projects by regulatory authorities does not necessarily provide a basis for increased proved recoveries since such assignments must often be made prior to obtaining indicative performance history in order to provide sufficient incentives to institute such schemes.

7. Natural gas liquids and sulphur reserves are based on the recoveries of these products from the proved natural gas reserves and are dependent on current plant efficiencies. In the case of shut-in wells the reserves are based on analyses of the raw natural gas and anticipated extraction efficiencies.

Proved Producing Reserves

Those proved reserves that are actually on production, or if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner. An illustration of such a situation is where a well or zone is capable but is shut-in because its deliverability is not required to meet contract commitments. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area.

Proved Non-Producing Reserves

Those non-producing proved reserves recoverable from existing wells that require relatively minor capital expenditures to produce.

Proved Undeveloped Reserves

Those reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure will be required.

Probable Additional Reserves

Those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

Comments:

1. The probable additional natural gas reserves are based on the potential productive areas of the natural gas reservoirs in question which could not be deemed proved at this time as well as those solution gas reserves commercially recoverable from the probable additional crude oil reserves.
2. The probable additional reserves of natural gas liquids and sulphur were considered to be those reserves recoverable from the probable additional natural gas reserves.
3. Portions of the zones which have questionable potential based on well log interpretations (or core analyses) and which have not been indicated productive by conclusive tests are considered to be probable additional.

Table 1

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Constant Prices as of August 1,2002

Total Proved Reserves

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids				
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Total Other Revenues M$	Gross Revenue M$
2002	423.4	1270.3	27.77	35279.6	136.5	4.50	614.3	7.5	27.64	207.0	22.2	36123.2
2003	428.4	3115.8	27.38	85301.2	389.9	4.50	1754.7	15.9	27.46	437.5	36.0	87529.4
2004	414.8	2177.3	27.73	60371.9	316.6	4.50	1424.5	13.4	27.48	368.3	32.0	62196.7
2005	388.0	1605.4	28.01	44969.1	241.2	4.50	1085.5	11.5	27.50	315.7	29.0	46399.4
2006	318.2	1081.2	28.63	30958.7	188.6	4.50	848.9	10.0	27.50	274.1	25.0	32106.7
2007	266.0	793.1	28.98	22980.1	135.5	4.50	609.9	8.7	27.54	240.5		23830.5
2008	188.3	534.3	29.15	15573.2	94.8	4.50	427.0	5.5	27.63	152.0		16152.3
2009	83.9	276.6	28.24	7811.6	41.5	4.50	187.0	0.3	29.47	9.4		8008.0
2010	57.3	159.4	29.24	4660.4	34.0	4.50	152.9	0.2	29.86	6.6		4820.0
2011	29.1	67.4	29.70	2002.9	26.0	4.50	116.8	0.1	33.93	4.8		2124.5
2012	1.5	1.6	31.93	50.5	7.8	4.50	35.0			0.0		85.4
2013	1.5	1.4	31.95	46.0	6.9	4.50	30.9					76.9
2014	0.8	0.2	32.29	7.8	6.4	4.50	28.8					36.5
2015	0.7				6.0	4.50	26.9					26.9
2016	0.7				5.6	4.50	25.1					25.1
REM.	0.7				9.7	4.50	43.5					43.5
TOTAL		**11084.0**	**27.97**	**310012.9**	**1646.9**	**4.50**	**7411.8**	**73.2**	**27.55**	**2015.8**	**144.2**	**319585.2**

	Crown Royalties			Freehold Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	1159.6	3.8	1155.8	3204.4	0.6	3203.8	319.3	0.1	319.2	724.3	5403.1	14.97
2003	2415.0	40.3	2374.6	8599.0	1.3	8597.7	751.5	0.1	751.3	1913.5	13637.3	15.59
2004	1494.4	32.2	1462.2	5549.0	1.2	5547.8	578.6	0.1	578.5	941.3	8529.8	13.72
2005	997.8	19.2	978.6	3947.7	1.1	3946.6	444.6	0.1	444.5	460.4	5830.1	12.57
2006	711.9	12.1	699.8	2313.0	1.0	2312.0	325.8	0.1	325.6	247.4	3584.9	11.17
2007	505.9	3.3	502.6	1580.0	0.9	1579.1	260.5	0.1	260.4	162.6	2504.7	10.51
2008	334.0	1.3	332.7	936.9	0.9	936.0	210.0	0.1	209.9	105.4	1584.0	9.81
2009	102.9	0.2	102.7	534.2	0.8	533.4	168.9	0.0	168.8	66.9	871.8	10.89
2010	71.7	0.1	71.7	211.6	0.7	210.8	132.9	0.0	132.9	33.4	448.8	9.31
2011	23.9	0.0	23.9	37.3	0.7	36.7	97.4	0.0	97.4	16.0	174.0	8.19
2012	0.1	0.0	0.1	18.0	0.6	17.3	0.2	0.0	0.2	0.6	18.2	21.30
2013	0.1	0.0	0.1	16.5	0.6	15.9	0.2	0.0	0.2	0.5	16.7	21.71
2014	0.1	0.0	0.1	7.5	0.5	6.9	0.2	0.0	0.1	0.3	7.5	20.57
2015	0.1	0.0	0.1	5.4	0.5	4.9	0.1	0.0	0.1	0.3	5.3	19.88
2016	0.1	0.0	0.1	5.0	0.4	4.6	0.1	0.0	0.1	0.3	5.0	19.82
REM.	0.1	0.0	0.1	8.7	0.8	7.9	0.2	0.0	0.2	0.4	8.6	19.83
TOTAL	**7817.8**	**112.7**	**7705.1**	**26974.2**	**12.6**	**26961.5**	**3290.2**	**0.8**	**3289.4**	**4673.7**	**42629.9**	**13.35**

			Capital Costs			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Drilling & Compl M$	Equip & Facility M$	Total Capital M$	Annual M$	Cum M$	PWV @10.0% M$
2002	8944.7	21775.3	9046.0		9046.0	12729.3	12729.3	12479.1
2003	21621.1	52270.9	3402.6	225.0	3627.6	48643.2	61372.6	44573.7
2004	20966.4	32700.3	5.0		5.0	32695.3	94067.9	27236.4
2005	19472.9	21096.3	5.0		5.0	21091.2	115159.1	15972.5
2006	14810.8	13711.0				13711.0	128870.1	9439.4
2007	11684.2	9641.6				9641.6	138511.7	6034.3
2008	8583.8	5984.4				5984.4	144496.1	3404.9
2009	4206.9	2929.3				2929.3	147425.4	1515.1
2010	2919.0	1452.2				1452.2	148877.6	682.8
2011	1360.6	589.8				589.8	149467.5	252.1
2012	40.1	27.1				27.1	149494.6	10.5
2013	39.9	20.3				20.3	149514.9	7.2
2014	17.2	11.8				11.8	149526.7	3.8
2015	12.5	9.0				9.0	149535.7	2.6
2016	12.4	7.7				7.7	149543.5	2.1
REM.	23.3	11.6				11.6	149555.1	2.7
TOTAL	**114716.0**	**162238.8**	**12458.7**	**225.0**	**12683.7**	**149555.1**		**121619.2**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	Gross	Net	@10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	11084.3	9726.6	117435.8	113288.1	107622.4	99426.1
Natural Gas (mmcf)	1647.1	1312.3	2999.0	2866.3	2688.6	2438.3
Natural Gas Liquids (mbbl)	73.4	55.7	1184.4	1135.3	1068.8	973.8
Total			**121619.3**	**117289.7**	**111379.8**	**102838.2**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Total Proved Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves: Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$): @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
Fixed Battery Costs	P-100.000		NRA	-	-	-	-	-3106.5	-2892.7	-2615.9
00/04-05-041-12-W4	W-100.000	ELL	PP	10.2	48.79	0.05	-	649.2	612.3	563.9
02/04-05-041-12-W4	W-100.000	ELL	PP	19.6	50.39	0.09	-	702.9	663.7	612.3
03/04-05-041-12-W4	W-100.000	ELL	PP	1.5	6.36	0.00	-	60.6	59.7	58.4
00/05-05-041-12-W4	W-100.000	ELL	PP	11.6	52.20	0.05	-	714.2	674.6	622.7
04/05-05-041-12-W4	W-100.000	ELL	PP	12.6	38.11	0.05	-	479.5	452.4	416.9
B0/05-05-041-12-W4	W-100.000	ELL	PP	12.7	60.50	0.06	-	854.5	807.3	745.4
00/06-05-041-12-W4	W- 40.000	GLAUC L	PP	42.6	-	0.21	-	110.6	109.0	106.7
02/10-05-041-12-W4	W-100.000	ELL	PNP	1.9	21.09	0.01	-	296.4	281.5	261.2
00/12-05-041-12-W4	W-100.000	ELL	PP	19.4	49.69	0.09	-	689.7	651.4	601.0
00/13-05-041-12-W4	W-100.000	ELL	PP	1.2	7.89	0.00	-	58.0	56.7	54.9
B0/14-05-041-12-W4	W-100.000	ELL	PP	10.8	51.43	0.05	-	721.9	684.9	636.0
C0/14-05-041-12-W4	W-100.000	ELL	PP	8.2	40.48	0.04	-	510.3	481.8	444.4
00/15-05-041-12-W4	W-100.000	ELL	PNP	3.6	15.06	0.01	-	216.8	203.9	186.4
02/15-05-041-12-W4	W-100.000	ELL	PP	2.1	7.81	0.01	-	125.3	123.2	120.3
A2/15-05-041-12-W4	W-100.000	ELL	PP	4.6	34.14	0.02	-	506.3	485.9	458.2
B2/15-05-041-12-W4	W-100.000	ELL	PP	17.1	59.88	0.08	-	852.9	805.6	743.5
02/16-05-041-12-W4	W-100.000	ELL	PP	3.8	15.81	0.02	-	259.8	253.8	245.3
00/01-06-041-12-W4	W-100.000	ELL	PP	11.7	19.53	0.05	-	198.7	188.7	175.5
00/02-06-041-12-W4	W-100.000	ELL	PP	8.7	38.81	0.04	-	521.1	491.9	453.6
02/07-06-041-12-W4	W-100.000	ELL	PP	4.4	26.91	0.02	-	317.4	301.1	279.5
02/08-06-041-12-W4	W-100.000	ELL	PP	11.4	21.09	0.05	-	332.0	320.3	304.3
03/08-06-041-12-W4	W-100.000	ELL	PP	14.2	29.67	0.06	-	377.9	357.1	329.7
05/08-06-041-12-W4	W-100.000	ELL	PP	12.1	47.46	0.06	-	672.9	636.0	587.5
02/09-06-041-12-W4	W-100.000	ELL	PP	8.8	43.31	0.04	-	574.5	538.3	491.2
02/15-15-041-12-W4	R- 3.750	ELL	PP	-	0.22	-	-	5.4	5.3	5.1
04/15-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
02/16-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
05/16-15-041-12-W4	R- 3.750	ELL	PP	-	0.05	-	-	1.3	1.3	1.3
Subtotal				**254.9**	**786.70**	**1.15**	-	**7703.6**	**7355.1**	**6889.2**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	PNP	292.6	-	-	-	533.2	511.5	481.6
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PP	47.2	-	0.19	-	161.6	153.7	143.2
00/11-05-040-08-W4	R- 15.000	VIK	PP	5.0	-	0.02	-	19.8	19.3	18.6
00/07-07-040-08-W4	R- 6.250	CLY	PP	2.2	-	0.01	-	9.2	9.1	8.9
00/10-07-040-08-W4	R- 15.000	VIK	PP	18.3	-	0.07	-	59.8	56.4	52.0
Subtotal				**72.6**	-	**0.29**	-	**250.4**	**238.5**	**222.6**
David North										
Lloydminster O Unit	W-100.000	LLOYD	PP	40.4	403.99	2.02	-	7207.4	6933.8	6563.6
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PP	52.5	429.37	2.62	-	7158.5	6868.3	6480.3
00/10-27-040-03-W4	W-100.000	LLOYD	PP	-	14.09	-	-	173.0	166.8	158.2
02/10-27-040-03-W4	W-100.000	LLOYD	PP	-	24.26	-	-	429.8	414.0	392.5
02/15-27-040-03-W4	W-100.000	LLOYD	PP	-	22.92	-	-	283.0	271.9	256.8
Subtotal				**92.9**	**894.64**	**4.64**	-	**15251.7**	**14654.7**	**13851.4**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	PP	-	71.94	-	-	585.4	566.6	540.5
N-24-40-1W4 1999 Wells	W- 93.750	DINA	PP	-	47.39	-	-	437.0	428.1	415.4
N-24-40-1W4 2002 Wells	W- 93.750	DINA	PP	-	202.69	-	-	2384.2	2315.0	2220.0
N-24-40-1W4 Future Locations	W- 93.750	DINA	PUD	-	168.75	-	-	1240.8	1158.3	1046.4
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	PP	-	1276.76	-	-	11817.9	11327.1	10666.8
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	PP	-	98.02	-	-	898.3	865.6	821.2
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	PP	-	128.94	-	-	1330.0	1298.9	1255.4
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	PP	-	414.57	-	-	4643.5	4553.3	4425.9

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Total Proved Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves: Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$): @10.0%	@12.0%	@15.0%
Hayter (cont'd)										
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	PP	-	155.50	-	-	1905.7	1871.4	1822.8
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	PP	-	380.08	-	-	5376.6	5207.9	4977.4
Sec 25-40-1W4 *Future Locations*	W- 94.517	DINA	PUD	-	1361.04	-	-	12821.3	12317.8	11617.3
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	PP	-	75.39	-	-	555.2	544.6	529.5
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	PP	-	23.79	-	-	255.3	251.1	245.2
Sec 34-40-1W4 2000 Wells	W- 75.000	DINA	PP	-	9.84	-	-	72.9	71.3	69.1
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	PP	-	647.94	-	-	4140.8	4029.9	3875.0
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	PP	-	8.57	-	-	70.5	69.7	68.6
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	PP	-	31.36	-	-	320.9	313.8	303.9
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	PP	-	151.76	-	-	1802.4	1764.3	1710.8
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	PP	-	306.60	-	-	3264.2	3197.3	3103.1
NW-35-40-1W4 Pre-2000 Wells	W- 75.000	DINA	PP	-	116.69	-	-	639.7	613.5	577.9
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	PP	-	117.50	-	-	1191.3	1168.3	1135.8
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	PP	-	232.37	-	-	2477.8	2418.9	2336.8
NW-35-40-1W4 Future Locations	W- 75.000	DINA	PUD	-	337.50	-	-	2268.3	2135.0	1951.7
S-36-40-1W4 GOR Wells	R- 7.500	DINA	PP	-	2.26	-	-	52.8	51.9	50.8
00/09-34-040-01-W4	W- 75.000	SPKY	PP	-	10.16	-	-	127.9	123.6	117.8
00/15-34-040-01-W4	W- 75.000	SPKY	PP	-	7.08	-	-	89.2	86.9	83.7
00/01-03-041-01-W4	W- 75.000	SPKY	PP	-	27.99	-	-	265.9	251.1	231.8
Subtotal				**-**	**6412.48**	**-**	**-**	**61035.7**	**59001.4**	**56200.7**
Mestikow										
All Company Wells	W-100.000	DINA	PP	-	170.34	-	-	1873.3	1805.0	1711.9
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	PP	612.5	2011.52	67.37	-	24742.7	23845.7	22620.5
04/10-29-040-11-W4	W- 25.000	VIK	PP	1.6	-	-	-	2.1	2.1	2.1
Subtotal				**614.1**	**2011.52**	**67.37**	**-**	**24744.8**	**23847.8**	**22622.5**
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PP	27.9	379.18	-	-	4433.3	4248.1	3999.2
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PP	8.3	79.23	-	-	935.8	895.7	841.9
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PP	21.7	206.44	-	-	2720.1	2650.0	2552.2
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PP	4.3	55.63	-	-	728.4	716.7	699.9
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PP	0.4	6.96	-	-	85.7	84.2	82.1
Sec 16-38-3W4	W-100.000	DINA	PP	10.1	57.55	-	-	666.7	651.9	631.1
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PP	16.6	23.65	-	-	327.4	318.9	307.1
00/11-24-037-02-W4	W- 37.500	VIK	PP	0.5	-	-	-	0.2	0.2	0.2
00/07-27-037-02-W4	W- 42.188	VIK	PP	55.5	-	-	-	61.4	56.4	50.2
02/06-11-038-03-W4	W- 28.125	VIK	NRA	-	-	-	-	-	-	-
00/14-12-038-03-W4	W- 37.500	CLY	PP	13.1	-	-	-	19.0	18.5	17.7
00/07-13-038-03-W4	W- 37.500	VIK	PP	34.2	-	-	-	54.5	51.9	48.5
00/06-14-038-03-W4	W- 37.500	VIK	NRA	-	-	-	-	-	-	-
00/07-15-038-03-W4	W- 37.500	VIK	PP	7.3	-	-	-	9.0	8.8	8.6
00/07-17-038-03-W4	W- 37.500	VIK	PP	6.0	-	-	-	1.8	1.7	1.7
00/07-18-038-03-W4	W- 37.500	VIK	PP	24.0	-	-	-	32.1	30.6	28.6
00/14-07-039-01-W4	W- 29.371	MCLAR	PP	90.1	-	-	-	124.1	115.6	105.0
Bodo Compression Facility	P-100.000	ALL ZONES	NRA	-	-	-	-	27.1	26.6	25.8

reduce the rate at which interest is payable thereon, or any fee hereunder payable to the Participant, to a level below the rate at which the Participant is entitled to receive such interest or fee, (E) alter the rights or obligations of the Company to prepay the related Loans or (F) consent to any other modification, supplement or waiver hereof or of any of the other Loan Documents to the extent that the same, under Section 11.09 or 12.04 hereof, requires the consent of each Bank.

(d) In addition to the assignments and participations permitted under the foregoing provisions of this Section 12.06, including, without limitation, Section 12.06(c) hereof, any Bank may assign and pledge all or any portion of its Loans and its Notes to any Federal Reserve Bank as collateral security pursuant to Regulation A and any Operating Circular issued by such Federal Reserve Bank. No such assignment shall release the assigning Bank from its obligations hereunder.

(e) A Bank may furnish any information concerning the Company or any of its Subsidiaries in the possession of such Bank from time to time to assignees and participants (including prospective assignees and participants), subject, however, to the provisions of Section 12.13(b) hereof.

(f) Anything in this Section 12.06 to the contrary notwithstanding, no Bank may assign or participate any interest in any Loan or Reimbursement Obligation held by it hereunder to the Obligors or any of their Affiliates or Subsidiaries without the prior written consent of each Bank.

(g) The Administrative Agent shall provide copies to the Company from time to time (and promptly following any request from the Company for such copies) of the Administrative Questionnaire as completed by each Bank.

12.07 Indemnification. The Company and each other Obligor hereby jointly and severally agrees (i) to indemnify the Administrative Agent, each Bank and the Issuing Bank and their respective directors, officers, employees, attorneys and agents from, and hold each of them harmless against, any and all losses, liabilities, claims, damages or expenses incurred by any of them (including, without limitation, any and all losses, liabilities, claims, damages or expenses incurred by the Administrative Agent, any Bank or the Issuing Bank, whether or not the Administrative Agent, any Bank or the Issuing Bank is a party thereto) (collectively, "Damages") arising out of or by reason of any investigation or litigation or other proceedings (including any threatened investigation or litigation or other proceedings) relating to the extensions of credit hereunder or any actual or proposed use by the Company or any other Obligor of the proceeds of any of the extensions of credit hereunder, including, without limitation, the reasonable fees and disbursements of counsel incurred in connection with any such investigation or litigation or other proceedings (but excluding any such losses, liabilities, claims, damages or expenses incurred by reason of the gross negligence, bad faith or willful misconduct of the Person to be indemnified) and (ii) not to assert any claim against the Administrative Agent, any Bank, the Issuing Bank, any of their affiliates, or any of their respective directors, officers, employees, attorneys and agents, on any theory of liability, for special, indirect, consequential or punitive damages arising out of or otherwise relating to any of the transactions contemplated herein or in any other Loan Document; provided that the Company or any other Obligor may enforce the obligations, if applicable, of the Banks and the Issuing

Bank hereunder. Without limiting the generality of the foregoing, Company and the other Obligors will indemnify the Administrative Agent, each Bank and the Issuing Bank from, and hold the Administrative Agent, each Bank and the Issuing Bank harmless against, any losses, liabilities, claims, damages or expenses described in the preceding sentence (but excluding, as provided in the preceding sentence, any loss, liability, claim, damage or expense incurred by reason of the gross negligence, bad faith or willful misconduct of the Person to be indemnified) arising under any Environmental Law as a result of the past, present or future operations of the Company or any of its Subsidiaries (or any predecessor in interest to the Company or any of its Subsidiaries), or the past, present or future condition of any site or facility owned, operated or leased by the Company or any of its Subsidiaries (or any such predecessor in interest), or any Release or threatened Release of any Hazardous Materials from any such site or facility, including any such Release or threatened Release which shall occur during any period when the Administrative Agent or any Bank shall be in possession of any such site or facility following the exercise by the Administrative Agent or any Bank of any of its rights and remedies hereunder or under any of the Security Documents other than any Release caused by the gross negligence, bad faith or willful misconduct of the Administrative Agent or any Bank or any agent, security agent or receiver acting on behalf of the Administrative Agent or any Bank.

12.08 Survival. The obligations of the Obligors under Sections 2.03, 5.01, 5.05, 5.06, 5.07, 12.03 and 12.07 hereof, the obligations of the Subsidiary Guarantors under Section 6.03 hereof and the obligations of the Banks under Section 11.05 hereof shall survive the repayment of the Loans, Bankers' Acceptances and Reimbursement Obligations and the termination of the Commitments. In addition, each representation and warranty made, or deemed to be made by a notice of any extension of credit (whether by means of a Loan, Bankers' Acceptance or a Letter of Credit), herein or pursuant hereto shall survive the making of such representation and warranty, and no Bank shall be deemed to have waived, by reason of making any extension of credit hereunder (whether by means of a Loan, Bankers' Acceptance or a Letter of Credit), any Default which may arise by reason of such representation or warranty proving to have been false or misleading, notwithstanding that such Bank or the Administrative Agent may have had notice or knowledge or reason to believe that such representation or warranty was false or misleading at the time such extension of credit was made.

12.09 Captions. The table of contents and captions and section headings appearing herein are included solely for convenience of reference and are not intended to affect the interpretation of any provision of this Agreement.

12.10 Counterparts. This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one and the same instrument and any of the parties hereto may execute this Agreement by signing any such counterpart.

12.11 Governing Law; Submission to Jurisdiction. This Agreement and the Notes shall be governed by, and construed in accordance with, the law of the State of New York. Each Obligor hereby submits to the nonexclusive jurisdiction of the United States District Court for the Southern District of New York and of any New York state court sitting in New York City for the purposes of all legal proceedings arising out of or relating to this Agreement or the transactions contemplated hereby. Each Obligor irrevocably waives, to the fullest extent permitted by applicable law, any objection which it may now or hereafter have to the laying of the venue of any such proceeding brought in such a court and any claim that any such proceeding brought in such a court has been brought in an inconvenient forum.

12.12 Waiver of Jury Trial. **EACH OF THE OBLIGORS, THE ADMINISTRATIVE AGENT, THE BANKS AND THE ISSUING BANK HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.**

12.13 Treatment of Certain Information.

(a) Each of the Banks and the Administrative Agent agrees (on behalf of itself and each of its affiliates, directors, officers, employees and representatives) to use reasonable precautions to keep confidential, in accordance with their customary procedures for handling confidential information of the same nature and in accordance with safe and sound banking practices, any non-public information supplied by any Obligor or any of its Subsidiaries pursuant to this Agreement, provided that nothing herein shall limit the disclosure of any such information (i) to the extent required by statute, rule, regulation or judicial process, (ii) to counsel for any of the Banks or Administrative Agent, (iii) to bank examiners, auditors or accountants, (iv) to the Administrative Agent or any other Bank, (v) in connection with any litigation in respect of the Loan Documents to which any one or more of the Banks or the Administrative Agent is a party, (vi) to a Subsidiary or Affiliate of such Bank as provided in clause (a) above or (vii) to any assignee or participant (or prospective assignee or participant).

(b) In the event a Bank or the Administrative Agent is required to disclose confidential information pursuant to this Section 12.13, it shall only disclose such information as it is legally required to disclose or it would customarily disclose under similar circumstances to any Governmental Authority and shall use reasonable efforts to obtain confidential treatment for any information so disclosed. In addition, it shall promptly provide notice of the requirement to the Company setting out the requirements and circumstances surrounding the required disclosure and any other information it deems relevant so that the Company may take any appropriate steps to protect such confidential information.

12.14 Judgment Currency. This is an international loan transaction in which the specification of Canadian Dollars or U.S. Dollars is of the essence, and the stipulated currency shall in each instance be the Currency of account and payment in all instances. A payment obligation in one currency hereunder (the "Original Currency") shall not be discharged by an amount paid in another currency (the "Other Currency"), whether pursuant to any judgment expressed in or converted into any Other Currency or in another place except to the extent that such tender or recovery results in the effective receipt by the payee of the full amount of the Original Currency payable by it under this Agreement. If for the purpose of obtaining judgment in any court it is necessary to convert a sum due hereunder in the Original Currency into the Other Currency, the rate of exchange that shall be applied shall be that at which in accordance with normal banking procedures the Administrative Agent could purchase Original Currency with the Other Currency on the Business Day next preceding the day on which such judgment is rendered. The obligation of each Obligor in respect of any such sum due from it to the

Administrative Agent or any Bank hereunder or under any other Loan Document (in this Section 12.14 called an "Entitled Person") shall, notwithstanding the rate of exchange actually applied in rendering such judgment, be discharged only to the extent that on the Business Day following receipt by such Entitled Person of any sum adjudged to be due hereunder in the Other Currency such Entitled Person may in accordance with normal banking procedures purchase and transfer the Original Currency to Toronto with the amount of the judgment currency so adjudged to be due; and each Obligor hereby, as a separate obligation and notwithstanding any such judgment, agrees jointly and severally to indemnify such Entitled Person against, and to pay such Entitled Person on demand, in the Original Currency, the amount (if any) by which the sum originally due to such Entitled Person in the Original Currency hereunder exceeds the amount of the Original Currency so purchased and transferred.

12.15 Agent for Service of Process. THE COMPANY AND EACH OBLIGOR HEREBY IRREVOCABLY DESIGNATES, APPOINTS AND EMPOWERS CT CORPORATION SYSTEM AS ITS DESIGNEE, APPOINTEE AND AGENT TO RECEIVE, ACCEPT AND ACKNOWLEDGE FOR AND ON ITS BEHALF, AND IN RESPECT OF ITS PROPERTY, SERVICE OF ANY AND ALL LEGAL PROCESS, SUMMONS, NOTICES AND DOCUMENTS WHICH MAY BE SERVED IN ANY ACTION OR PROCEEDING. IF FOR ANY REASON SUCH DESIGNEE, APPOINTEE AND AGENT SHALL CEASE TO BE AVAILABLE TO ACT AS SUCH, THE COMPANY AND EACH OBLIGOR, AGREES TO DESIGNATE A NEW DESIGNEE, APPOINTEE AND AGENT IN NEW YORK CITY ON THE TERMS AND FOR THE PURPOSES OF THIS PROVISION SATISFACTORY TO THE ADMINISTRATIVE AGENT. EACH OF THE COMPANY, THE OBLIGORS AND THE ADMINISTRATIVE AGENT IRREVOCABLY CONSENTS TO THE SERVICE OF PROCESS OUT OF ANY OF THE AFOREMENTIONED COURTS IN ANY SUCH ACTION OR PROCEEDING BY THE MAILING OF COPIES THEREOF BY REGISTERED OR CERTIFIED MAIL, POSTAGE PREPAID TO THE ADMINISTRATIVE AGENT AND THE COMPANY AT ITS RESPECTIVE ADDRESS REFERRED TO IN SECTION 12.02.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed and delivered as of the day and year first above written.

HARVEST OPERATIONS CORP.

By: *(signed) "David Rain"*
Name: David Rain
Title: Corporate Secretary

Address for Notices:

2400, 500 – 4th Avenue S.W.
Calgary, Alberta
T2P 2V6
Canada

Attention: Bruce Chernoff

Telecopier No.: (403) 266-1438
Telephone No.: (403) 920-0128

WESTLB AG, NEW YORK BRANCH,
as Administrative Agent

By: *(signed) "Roderick L. Fraser*
Name: Roderick L. Fraser
Title: Managing Director

By: *(signed) "Michael D. Peist"*
Name: Michael D. Peist
Title: Director

Address for Notices:

1211 Avenue of the Americas
New York, New York 10036
United States of America

Attention: Transaction Management

WESTLB AG, NEW YORK BRANCH,
as Issuing Bank

By: *(signed) "Roderick L. Fraser"*
Name: Roderick L. Fraser
Title: Managing Director

By: (signed) "Michael D. Peist"
Name: Michael D. Peist
Title: Director

Address for Notices:

1211 Avenue of the Americas
New York, New York 10036
United States of America

Attention: Transaction Management

BANKS

WESTLB AG, NEW YORK BRANCH

By: *(signed) "Roderick L. Fraser"*
Name: Roderick L. Fraser
Title: Managing Director

By: (signed) "Michael D. Peist"
Name: Michael D. Peist
Title: Director

Address for Notices:

1211 Avenue of the Americas
New York, New York 10036
United States of America

Attention: Transaction Management

ANNEX I

Banks and Commitments

Banks	Commitments
WestLB AG, New York Branch	$60,000,000

SCHEDULE I

Liens

1. **PHH Vehicle Management Services Inc.**
   Leased vehicles together with all attachments, accessions, appurtenances, accessories or replacement parts, and all proceeds thereof.

2. **Anadarko Canada Corporation**
   As outlined in Article 16 of the September 6, 2002 Crude Oil Purchase Agreement between Anadarko Canada Corporation ("Anadarko") and the Borrower, the Borrower granted a lien, charge and security interest to Anadarko with respect to:

(a) the interest of the Borrower in the "Assets" (as defined in the August 1, 2002 Purchase & Sale Agreement between Anadarko and the Borrower) and all proceeds of production derived therefrom:

(b) all present and after-acquired personal property; and

(c) the proceeds of sale of the Borrower's production of the liquid hydrocarbon to be delivered by the Borrower to Anadarko under that agreement.

The lien, charge and security interest is stated under the agreement to be subordinate and postponed to any of the Borrower's "Indebtedness for Borrowed Money" (as defined in that agreement).

SCHEDULE II

Subsidiaries and Investments

None.

Capitalization

	Authorized	Issued	Outstanding	Amount
Common Shares	Unlimited	1	1	$1.00
First Preferred Shares	Unlimited	None	None	Nil

Environmental Matters

Type	Description	Area	Field	Location	AEUB Approval # or License #
Natural gas processing facility	Gas Plant	Hayter/Provost	West Provost	16-31-37-2 W4	5261
Oil Battery		Hayter/Provost	East Hayter	8-35-40-1 W4	1987-1109
Oil Battery		Thompson	Metiskow	5-22-39-6 W4M	1997-690
Oil Battery		Thompson	David North	15-26-40-3 W4M	C0369
Oil Battery		Hayter/Provost	North Hayter	1-34-40-1 W4	CP1308
Oil Battery		Thompson	Bellshill	11-5-41-12 W4M	FS05507
Oil Battery		Thompson	Thompson Lake	4-2-41-11 W4M	FS05579
Oil Battery		Hayter/Provost	West Provost	3-15-38-3 W4	MS4820
Well	Injection/Disposal Well	Hayter/Provost	East Hayter	13C-36-40-1W4/2	212072
Well	Injection/Disposal Well	Hayter/Provost	East Hayter	15D-35-40-1W4	202792
Well	Injection/Disposal Well	Hayter/Provost	East Hayter	9B-24-40-1W4/2	153453
Well	Injection/Disposal Well	Hayter/Provost	North Hayter	2D-34-40-1W4	84427
Well	Injection/Disposal Well	Hayter/Provost	North Hayter	5C-34-40-1W4	255554
Well	Injection/Disposal Well	Hayter/Provost	North Hayter	8C-34-40-1W4/2	78738
Well	Injection/Disposal Well	Hayter/Provost	North Hayter	8-3-41-1W4	82949
Well	Injection/Disposal Well	Hayter/Provost	West Provost	10A2-15-38-3W4	202856
Well	Injection/Disposal Well	Hayter/Provost	West Provost	12A2-10-38-3W4	2099317
Well	Injection/Disposal Well	Hayter/Provost	West Provost	14A-15-38-3W4	152923
Well	Injection/Disposal Well	Hayter/Provost	West Provost	14C-15-38-3W4	135468
Well	Injection/Disposal Well	Hayter/Provost	West Provost	15C-15-38-3W4	186646
Well	Injection/Disposal Well	Hayter/Provost	West Provost	2A-15-38-3W4	152900
Well	Injection/Disposal Well	Hayter/Provost	West Provost	3C-10-38-3W4	188391
Well	Injection/Disposal Well	Hayter/Provost	West Provost	4A-15-38-3W4	152903
Well	Injection/Disposal Well	Hayter/Provost	West Provost	4B-10-38-3W4	102729
Well	Injection/Disposal Well	Hayter/Provost	West Provost	5D-10-38-3W4	156496
Well	Injection/Disposal Well	Hayter/Provost	West Provost	9B-15-38-3W4	186569
Well	Injection/Disposal Well	Thompson	Bellshill	100/8-5-41-12 W4M	A0107699
Well	Injection/Disposal Well	Thompson	Bellshill	100/9-5-41-12 W4M	A0151457
Well	Injection/Disposal Well	Thompson	Bellshill	100/8-7-41-12 W4M	A0101859
Well	Injection/Disposal Well	Thompson	David North	100/2-26-40-3 W4M	A0101273
Well	Injection/Disposal Well	Thompson	David North	102/12-26-40-3 W4M	A0103159
Well	Injection/Disposal Well	Thompson	David North	102/2-26-40-3 W4M	A0172903
Well	Injection/Disposal Well	Thompson	David North	102/11-26-40-3 W4M	A0103157
Well	Injection/Disposal Well	Thompson	David North	100/3-26-40-3 W4M	A0101272
Well	Injection/Disposal Well	Thompson	David North	102/15-26-40-3 W4M	A009963
Well	Injection/Disposal Well	Thompson	David North	102/9-27-40-3 W4M	A0171631
Well	Injection/Disposal Well	Thompson	David North	103/9-26-40-3 W4M	A0172332
Well	Injection/Disposal Well	Thompson	David North	103/16-27-40-3 W4M	A0172330
Well	Injection/Disposal Well	Thompson	David North	100/1-26-40-3 W4M	A0178411
Well	Injection/Disposal Well	Thompson	David North	105/8-26-40-3 W4M	A0189079
Well	Injection/Disposal Well	Thompson	David North	102/8-26-40-3 W4M	A0103158

Well	Injection/Disposal Well	Thompson	David North	102/9-26-40-3 W4M	A010360
Well	Injection/Disposal Well	Thompson	David North	104/8-26-40-3 W4M	189091
Well	Injection/Disposal Well	Thompson	David North	104/10-26-40-3 W4M	171634
Well	Injection/Disposal Well	Thompson	David North	100/9-27-40-3 W4M	58218
Well	Injection/Disposal Well	Thompson	David North	100/15-26-40-3 W4M	A0053258
Well	Injection/Disposal Well	Thompson	Metiskow	100/2-22-39-6 W4M	A0193414
Well	Injection/Disposal Well	Thompson	Metiskow	102/6-22-39-6 W4M	A0191824
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C3/3-36-40-11 W4M	158777
Well	Injection/Disposal Well	Thompson	Thompson Lake	104/8-25-40-11 W4M	158774
Well	Injection/Disposal Well	Thompson	Thompson Lake	100/3-36-40-11 W4M	152442
Well	Injection/Disposal Well	Thompson	Thompson Lake	1A0/6-36-40-11 W4M	153188
Well	Injection/Disposal Well	Thompson	Thompson Lake	100/13-35-40-11 W4M	A0170296
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C0/13-35-40-11 W4M	A0152781
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C0/10-34-40-11 W4M	A0152773
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C0/9-34-40-11 W4M	A0152775
Well	Injection/Disposal Well	Thompson	Thompson Lake	104/15-34-40-11 W4M	A0158372
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C0/8-2-41-11 W4M	A0152805
Well	Injection/Disposal Well	Thompson	Thompson Lake	1B0/10-2-41-11 W4M	A0152801
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C0/3-1-41-11 W4M	A0153761
Well	Injection/Disposal Well	Thompson	Thompson Lake	1C2/3-2-41-11 W4M	A0152764
Well	Injection/Disposal Well	Thompson	Thompson Lake	1A0/4-2-41-11 W4M	A0152765
Well	Injection/Disposal Well	Thompson	Thompson Lake	100/3-2-41-11 W4M	170293
Well	Injection/Disposal Well	Thompson	Thompson Lake	100/8-3-41-11 W4M	A0152044
Well	Injection/Disposal Well	Thompson	Thompson Lake	102/4-2-41-11 W4M	170294
Well	Injection/Disposal Well	Thompson	Thompson Lake	102/5-2-41-11 W4M	A0156725
Well	Injection/Disposal Well	Thompson	Thompson Lake	100/11-2-41-11 W4M	A0171800
Well	Injection/Disposal Well	Thompson	Thompson Lake	1B2/10-2-41-11 W4M	A0170150
Underground Storage Facility	Flare Knock-Out	Hayter/Provost	Hayter	3-25-40-1 W4M	
Underground Storage Facility	Floor Drain	Hayter/Provost	Hayter	3-25-40-1 W4M	
Underground Storage Facility	Floor Drain	Hayter/Provost	Hayter	1-34-40-1 W4M	
Underground Storage Facility	Floor Drain	Hayter/Provost	Hayter	3-25-40-1 W4M	
Underground Storage Facility	Flare Knock-Out	Hayter/Provost	Hayter	3-25-40-1 W4M	
Underground Storage Facility	Flare Knock-Out	Hayter/Provost	Hayter	2-25-40-1 W4M	
Underground Storage Facility	Floor Drain	Hayter/Provost	Hayter	1-34-40-1 W4M	
Underground Storage Facility	Water Tank Trays	Hayter/Provost	West Provost	3-15-38-3 W4M	
Underground Storage Facility	Oil Tank Trays	Hayter/Provost	West Provost	3-15-38-3 W4M	
Underground Storage Facility	Process Bldg Trays	Hayter/Provost	West Provost	3-15-38-3 W4M	
Underground Storage Facility	Blowdown	Hayter/Provost	Bodo	14-7-39-1 W4M	
Underground Storage Facility	Separator Blowdown	Hayter/Provost	Bodo	6-11-38-3 W4M	
Underground Storage Facility	Produced Water	Hayter/Provost	Bodo	6-10-38-2 W4M	
Underground Storage Facility	Separator Blowdown	Hayter/Provost	Bodo	7-15-38-3 W4M	
Underground Storage Facility	Separator Blowdown	Hayter/Provost	Bodo	6-16-38-3 W4M	
Underground Storage Facility	Separator Blowdown	Hayter/Provost	Bodo	7-13-38-3 W4M	

Underground Storage Facility	Separator Drain	Hayter/Provost	Bodo	6-14-38-3 W4M
Underground Storage Facility	Waste Oil	Hayter/Provost	Bodo	16-31-37-2 W4M
Underground Storage Facility	Scrubber Drain	Hayter/Provost	Bodo	16-31-37-2 W4M
Underground Storage Facility	Dehy Drain	Hayter/Provost	Bodo	16-31-37-2 W4M
Underground Storage Facility	Produced Water	Hayter/Provost	Bodo	8-15-38-2 W4M
Underground Storage Facility	Produced Water	Hayter/Provost	Bodo	15-11-38-2 W4M
Underground Storage Facility	Produced Water	Hayter/Provost	Bodo	7-12-38-2 W4M
Underground Storage Facility	Flare Knock-Out	Thompson	Bellshill	11-5-41-12 W4M
Underground Storage Facility	Flare Knock-Out	Thompson	Bellshill	11-5-41-12 W4M
Underground Storage Facility	Separator Drain	Thompson	Bellshill	11-5-41-12 W4M
Underground Storage Facility	Injection Bldg Drain	Thompson	Thompson Lake	4-2-41-11 W4M
Underground Storage Facility	FKO Bldg Drain	Thompson	Thompson Lake	4-2-41-11 W4M
Underground Storage Facility	Dehy Drain	Thompson	Thompson Lake	4-2-41-11 W4M
Underground Storage Facility	Header Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Header Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	FWKO Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	FWKO Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Treater Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Treater Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Cut Shack Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Cut Shack Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	VRU Bldg	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Injection Bldg Drain	Thompson	Metiskow	5-22-39-6 W4M
Underground Storage Facility	Injection Bldg Drain	Thompson	David North	15-26-40-3 W4M
Underground Storage Facility	Injection Bldg	Thompson	David North	15-26-40-3 W4M
Underground Storage Facility	VRU Bldg	Thompson	David North	15-26-40-3 W4M
Underground Storage Facility	Old Injection Bldg	Thompson	David North	15-26-40-3 W4M
Underground Storage Facility	Header Bldg	Thompson	David North	15-26-40-3 W4M
Underground Storage Facility	Treater Bldg	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Oil	Thompson	Bellshill	11-5-41-12 W4M
Aboveground Storage Facility	Oil	Thompson	Bellshill	11-5-41-12 W4M
Aboveground Storage Facility	Oil	Thompson	Bellshill	11-5-41-12 W4M
Aboveground Storage Facility	Slop Oil	Thompson	Bellshill	11-5-41-12 W4M
Aboveground Storage Facility	Produced Water	Thompson	Bellshill	11-5-41-12 W4M
Aboveground Storage Facility	Produced Water	Thompson	Bellshill	11-5-41-12 W4M

Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Produced Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Pop Tank	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Sweet Water	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Pop Tank	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Waste Tank	Thompson	Thompson Lake	4-2-41-11 W4M
Aboveground Storage Facility	Oil	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Oil	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Oil	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Produced Water	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Produced Water	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Emulsion	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Emulsion	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Pop Tank	Thompson	Metiskow	5-22-39-6 W4M
Aboveground Storage Facility	Oil	Thompson	David North	15-26-40-3 W4M
Aboveground Storage	Oil	Thompson	David North	15-26-40-3 W4M

Facility

Aboveground Storage Facility	Oil	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Oil	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Produced Water	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Produced Water	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Produced Water	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Slop Oil	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Slop Oil	Thompson	David North	15-26-40-3 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Oil	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Oil	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Oil	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Treater 1	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Treater 2	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	FWKO 1	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	FWKO 2	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Settling	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Test Tank	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Desand	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Truck Tank	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Slop Oil 1	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Slop Oil 2	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Slop Oil 3	Hayter/Provost	North Hayter	1-34-40-1 W4M
Aboveground Storage Facility	Production	Hayter/Provost	North Hayter	1B2-34-40-1 W4M
Aboveground Storage Facility	Production	Hayter/Provost	North Hayter	9-34-40-1 W4M
Aboveground Storage Facility	Production	Hayter/Provost	North Hayter	16-5-41-1 W4M
Aboveground Storage Facility	Production	Hayter/Provost	North Hayter	1-3-41-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Oil	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Production	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Recycle	Hayter/Provost	East Hayter	8-35-40-1 W4M

Aboveground Storage Facility	Test Tank	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Desand	Hayter/Provost	East Hayter	8-35-40-1 W4M
Aboveground Storage Facility	Test Tank	Hayter/Provost	East Hayter	3A-25-40-1 W4M
Aboveground Storage Facility	Test Tank	Hayter/Provost	East Hayter	3B-25-40-1 W4M
Aboveground Storage Facility	Test Tank	Hayter/Provost	East Hayter	2A-25-40-1 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Production-Oil	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Sales-Oil	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Sales-Oil	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Desand	Hayter/Provost	West Provost	3-15-38-3 W4M
Aboveground Storage Facility	Production-Oil	Hayter/Provost	West Provost	4A-10-38-3 W4M
Aboveground Storage Facility	Production-Oil	Hayter/Provost	West Provost	14B-10-38-3 W4M
Aboveground Storage Facility	Production-Oil	Hayter/Provost	West Provost	6B-15-38-3 W4M
Aboveground Storage Facility	Slop Tank 1	Hayter/Provost	West Provost	12A-10-38-3 W4M
Aboveground Storage Facility	Slop Tank 2	Hayter/Provost	West Provost	12A-10-38-3 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	16-31-37-2 W4M
Aboveground Storage Facility	Produced Water	Hayter/Provost	West Provost	14D-12-38-3 W4M

EXHIBIT A

FORM OF NOTE

Date: [________________]

U.S.$[________________] New York, New York

FOR VALUE RECEIVED, the undersigned, Harvest Operations Corp., a corporation organized under the laws of the Province of Alberta, Canada ("Harvest"), promises to pay to the order of WestLB AG, New York Branch as Administrative Agent (the "Administrative Agent"), for the ratable benefit of [________________] ("Bank") on the Commitment Termination Date as defined in the Credit Agreement, hereinafter referred to, in the currency in which the Loans, Bankers' Acceptances Liabilities and Letter of Credit Liabilities and any payments in respect thereof under the Credit Agreement are denominated and in immediately available funds, the principal amount of U.S.$[________________], or, if less, the aggregate unpaid principal amount of all the Loans, Bankers' Acceptance Liabilities and Letter of Credit Liabilities and any payments in respect thereof made by the Administrative Agent for the account of the Bank to Harvest pursuant to the Credit Agreement, and to pay interest at such office, in like money, from the date hereof on the unpaid principal amount of such Loans, Bankers' Acceptances Liabilities and Letter of Credit Liabilities and any payments in respect thereof from time to time outstanding at the rates and on the dates specified in the Credit Agreement.

The Administrative Agent is authorized for the ratable benefit of the Bank to record, on the schedule annexed hereto and made a part hereof or on other appropriate records of the Administrative Agent, the date and amount of each Loan, Bankers' Acceptances Liability and Letter of Credit Liability and any payments in respect thereof made by the Administrative Agent, each continuation thereof, the interest rate from time to time on each Loan, Bankers' Acceptances Liability and Letter of Credit Liability and any payments in respect thereof and the date and amount of each payment or prepayment of principal thereof. Any such recordation shall constitute prima facie evidence of the accuracy of the information so recorded, provided that the failure of the Administrative Agent to make any such recordation (or any error in such recordation) shall not affect the obligations of Harvest hereunder or under the Credit Agreement in respect of the Loans, Bankers' Acceptances Liabilities and Letter of Credit Liabilities and any payments in respect thereof.

This Note is one of the Notes referred to in the Credit Agreement dated as of November [12], 2002 (as amended, supplemented or otherwise modified and in effect from time to time, the "Credit Agreement") among Harvest, the Subsidiary Guarantors party thereto and the Administrative Agent, and is entitled to the benefits thereof. Capitalized terms used herein without definition have the meanings assigned to them in the Credit Agreement.

This Note is subject to optional and mandatory prepayment as provided in the Credit Agreement.

Upon the occurrence of the Commitment Termination Date, the Administrative Agent shall have all of the remedies specified in the Credit Agreement. Harvest hereby waives presentment, demand, protest and all notices of any kind.

In case an Event of Default (as defined in the Credit Agreement) shall occur and be continuing, the principal of and accrued interest on this Note may be declared to be due and payable in the manner and with the effect provided in the Credit Agreement.

THIS NOTE AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES UNDER THIS NOTE SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

HARVEST OPERATIONS CORP.

By: ________________________________
Name:
Title:

Schedule to Note

Sample Summary Sheet
for Harvest Operations Corp.
Under the Credit Agreement

Loan Amount and Currency	Type	Date of Loan	Termination Date/Interest Rate and Other Loan Variables

EXHIBIT B

Exhibit Not Attached

EXHIBIT C

Exhibit Not Attached

EXHIBIT D

FORM OF USAGE CERTIFICATE

[Date]

WestLB AG, New York Branch
as Administrative Agent
1211 Avenue of the Americas
New York, New York 10036

Re: Harvest Operations Corp. Credit Agreement

Ladies and Gentlemen:

This certificate is hereby delivered pursuant to Section 2.02(b) of the Credit Agreement dated as of November __, 2002 (the "Credit Agreement") among Harvest Operations Corp., each Subsidiary of the Company that becomes a Subsidiary Guarantor, the Banks from time to time party thereto, WestLB AG, New York Branch, as Issuing Bank and WestLB AG, New York Branch, as Administrative Agent. Capitalized terms used herein and not otherwise defined shall have the meanings set forth in the Credit Agreement.

On the date hereof, we have delivered to you a [notice of borrowing] [request for issuance of a [Letter of Credit] [Bankers' Acceptance]]. After giving effect to such [borrowing] [issuance], the Usage Ratio will be [_______], which has been calculated as follows: [*insert details of calculation*].

I further certify that I am the [chief financial officer] [controller] [treasurer] [assistant treasurer] of the Company.

____
Name:

EXHIBIT E

Exhibit Not Attached

EXHIBIT F

CALCULATION OF NET PROCEEDS
OF BANKERS' ACCEPTANCE

The Net Proceeds of any Bankers' Acceptance shall be equal to the following formula:

Net Proceeds =

$$\frac{\text{Principal Amount of Bankers' Acceptance}}{100} \quad \text{X} \quad \text{Price}$$

Price =

$$\frac{100}{1 + \dfrac{\text{Bankers' Acceptance Rate + BA Fee Rate}}{100} \quad \text{X} \quad \dfrac{\text{Term}}{365}}$$

The Price of any Bankers' Acceptance shall be rounded to nearest 1/1000 of 1%.

14

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ADMINISTRATION AGREEMENT

between

VALIANT TRUST COMPANY

(the "Trustee")

and

HARVEST OPERATIONS CORP.

(the "Administrator")

Dated September 27, 2002

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ADMINISTRATION AGREEMENT

This Administration Agreement is made effective the 27th day of September, 2002 between VALIANT TRUST COMPANY, (the "Trustee") and HARVEST OPERATIONS CORP., an Alberta corporation (the "Administrator").

WHEREAS the Trustee wishes to retain the Administrator to provide certain administrative and advisory services in connection with the Trust and the Units (as defined herein);

AND WHEREAS the Administrator is willing to provide administrative and advisory services on the terms and conditions hereinafter set out;

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the mutual covenants herein contained and other good and valuable consideration receipt of which is hereby acknowledged by each of the parties hereto, the parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definition

In this Agreement, unless the context otherwise requires, the following terms shall have the following respective meanings:

(a) "affiliate" shall have the meaning ascribed to that term in the *Securities Act* (Alberta) as at the date hereof;

(b) "associate" shall have the meaning ascribed to that term in the *Securities Act* (Alberta) as at the date hereof;

(c) "Business Day" means a day, other than a Saturday, Sunday or statutory holiday, when banks are generally open in the city of Calgary, Alberta, for the transaction of banking business;

(d) "person" means an individual, partnership, corporation, business trust, joint stock company, trust, unincorporated association, joint venture or other entity or organization of whatever nature;

(e) "Transfer Agent" means the transfer agent from time to time for the Units;

(f) "Trust" means Harvest Energy Trust, a trust governed by the Trust Indenture;

(g) "Trust Fund" has the meaning set out in the Trust Indenture;

(h) "Trust Indenture" means the amended and restated indenture dated September 27, 2002 by which the Trust is governed;

(i) "Unitholders" means the holders of Units in the Trust; and

(j) "Units" means trust units of the Trust.

1.2 Additional Definitions

Unless the context otherwise requires, capitalized terms used in this Agreement without definition that are defined in the Trust Indenture shall have the meaning ascribed thereto in the Trust Indenture.

1.3 Interpretation

In this Agreement, except as otherwise expressly provided:

(a) "this Agreement" means this agreement, as amended and in effect from time to time;

(b) any reference in this Agreement to a designated "Article", "section", "subsection", "schedule" or other subdivision is a reference to the designated Article, Section, subsection, schedule or other subdivision of this Agreement;

(c) the recitals hereto are incorporated into and form part of this Agreement;

(d) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section, subsection, schedule or other subdivision of this Agreement;

(e) the division of this Agreement into Articles, Sections, subsections, schedules and other subdivisions and the provision of headings are for convenience of reference only and shall not affect the interpretation of the provisions to which they relate or of any other provisions hereof;

(f) words importing the singular number only shall include the plural and vice versa and words importing the use of any gender shall include any other gender, the word "or" is not exclusive and the word "including" is not limiting 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;

(g) all dollar amounts are stated and are to be paid in lawful currency of Canada;

(h) where the time for doing an act falls or expires on a day which is not a business day, the time for doing such act is extended to the next business day; and

(i) any reference to a statute includes and is a reference to such statute and to the regulations made pursuant thereto in effect on the date of this Agreement unless otherwise specifically provided.

1.4 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Province of Alberta and the federal laws of Canada applicable therein and the courts of such province shall have non-exclusive jurisdiction over any dispute hereunder, to which jurisdiction the parties attorn.

1.5 References to Acts Performed by the Trust

For greater certainty, where any reference is made in this Agreement to an act to be or not to be performed by the Trust, such reference shall be construed and applied for all purposes as if it referred to an act to be or not to be performed by the Trustee on behalf of the Trust.

1.6 Liability of Trustee and Unitholders

The parties hereto acknowledge that the Trustee is entering into this Agreement solely in its capacity as Trustee and the obligations of the Trustee hereunder shall not be personally binding upon the Trustee, or any of the Unitholders or any annuitant under a plan of which a Unitholder is a trustee or carrier (an "annuitant") and that any recourse against the Trust, the Trustee, any Unitholder or annuitant in any manner in respect of any indebtedness, obligation or liability of the Trustee arising hereunder or arising in connection herewith or from the matters to which this Agreement relates, if any, including without limitation claims based on negligence or otherwise tortious behaviour, shall be limited to, and satisfied only out of, the Trust Fund.

ARTICLE 2
ADMINISTRATION OF THE TRUST

2.1 General Delegation of Authority

Subject to and in accordance with the terms, conditions and limitations of the Trust Indenture and to the other provisions of this Agreement, the Trustee hereby delegates to the Administrator, and the Administrator hereby accepts the delegation of the authority to perform the Trustee's duties under the Trust Indenture, and agrees to be responsible for the administration and management of all general and administrative affairs of the Trust in accordance with the provisions hereof. The exercise of powers by the Administrator shall not adversely affect the status of the Trust as a "unit trust" and a "mutual fund trust" for the purposes of the Tax Act.

2.2 Specific Delegation of Authority

It is acknowledged and agreed that in furtherance of its obligations under Section 2.1 to administer and manage the general and administrative affairs of the Trust, and not in limitation thereof; the Administrator will, subject to the direction of the Trustee:

(a) keep and maintain at its offices in Calgary, Alberta at all times books, records and accounts which shall contain particulars of operations, receipts, disbursements and investments relating to the Trust Fund and such books, records and accounts shall be kept pursuant to normal commercial practices that will permit the preparation of financial statements in accordance with Canadian generally accepted accounting principles which, as early as practicable, shall be in accordance with those required to be kept by a distributing corporation (as defined in the *Business Corporations Act* (Alberta)) (except that nothing herein shall be construed as requiring the books, records or documents of the Administrator to be audited) and in each case shall also be in accordance with those required to be kept by a reporting issuer under applicable securities legislation in Canada and those required of the Trust under the *Income Tax Act* (Canada) and the Income Tax Regulations applicable with respect thereto, all as amended from time to time;

(b) prepare all returns, filings and documents and make all determinations necessary for the discharge of the Trustee's obligations under Sections 16.2, 16.3, 16.5, 16.6 and 16.7 of the Trust Indenture;

(c) monitor the tax status of the Trust and provide information to the Trustee regarding the taxable portions of distributions;

(d) prepare and submit all income tax returns and filings to the Trustee in sufficient time prior to the dates upon which they must be filed so that the Trustee has a reasonable opportunity to review them, approve them, execute them and return them to the Administrator; and arrange for their filing within the time required by applicable tax law;

(e) provide advice with respect to the Trust's obligations as a reporting issuer and ensure compliance by the Trust with continuous disclosure obligations under applicable securities legislation including the preparation and filing of reports and other documents with all applicable regulatory authorities;

(f) provide investor relations services to the Trust including assisting with communications with Unitholders;

(g) at the request and under the direction of the Trustee, call and hold all annual and/or special meetings of the Unitholders pursuant to Article 10 of the Trust Indenture, prepare all materials (including notices of meetings and information circulars) in respect thereof and submit all such materials to the Trustee in sufficient time prior to the dates upon which they must be mailed, filed or otherwise relied upon so that the Trustee has a reasonable opportunity to review them, approve them, execute them and return them to the Administrator for filing or mailing or otherwise;

(h) provide, for performing its obligations hereunder, office space, equipment and personnel including all accounting, clerical, secretarial, corporate and administrative services as may be reasonably necessary to perform its obligations hereunder;

(i) provide or cause to be provided such audit, accounting, engineering, legal, insurance and other professional services as are reasonably required or desirable for the purposes of the Trust including, without limitation, administration of the Direct Royalties, from time to time and provide or cause to be provided such legal, engineering, financial and other advice and analysis as the Trustee may require or desire to permit it to make informed decisions in connection with the discharge by it of its responsibilities as Trustee, to the extent such advice and analysis can be reasonably provided or arranged by the Administrator;

(j) provide assistance in negotiating the terms of any financing required by the Trust or otherwise in connection with the Trust Fund;

(k) take all actions reasonably necessary in connection with, or in relation to, those matters referred to in Section 7.4 of the Trust Indenture;

(l) take all actions reasonably necessary in connection with, or in relation to, all matters relating to the redemption of Units pursuant to the Trust Indenture;

(m) take all actions reasonably necessary in connection with, or in relation to, the voting rights on any investments in the Trust Fund or any Subsequent Investments;

(n) take all actions reasonably necessary in connection with, or in relation to, directly or indirectly, the borrowing of money from or incurring indebtedness by the Trust to any person and in connection therewith, to cause the Trust to guarantee, indemnify or act as a surety with respect to payment or performance of any indebtedness, liabilities or obligation of any kind of any person, including, without limitation, the Administrator and any subsidiary (as defined in the *Securities Act* (Alberta) of the Trust; to enter into any other obligations on behalf of the Trust; or enter into any subordination agreement on behalf of the Trust or any other person, and to assign, charge, pledge, hypothecate, convey, transfer, mortgage, subordinate, and grant any security interest, mortgage or encumbrance over or with respect to all or any of the Trust Fund or to subordinate the interests of the Trust in the Trust Fund to any other person;

(o) take all actions reasonably necessary in connection with, or in relation to, the guarantee by the Trust of obligations of the Administrator or any other affiliate of the Trust pursuant to any debt for borrowed money or obligations resulting or arising from hedging instruments incurred by the Administrator or any such affiliate, as the case may be, and pledging securities issued by the Administrator or the affiliate, as the case may be, as security for such guarantee provided that such guarantee is incidental to the Trust's direct or indirect investment in the Administrator or any such affiliate or the business and affairs (existing or proposed) of the Administrator or any such affiliate, and each such guarantee entered into by the Trustee shall be binding upon, and enforceable in accordance with its terms against, the Trust;

(p) take all actions reasonably necessary in connection with, or in relation to, the Trust providing indemnities for the directors and officers of the Administrator and any affiliates;

(q) provide or cause to be provided to the Trustee any services reasonably necessary for the Trustee to be able to consider any future acquisitions or divestitures by the Trustee of any portion of the Trust Fund, including Direct Royalties;

(r) provide advice to the Trustee with respect to determining the timing and terms of future offerings of Units, if any;

(s) administer all of the records and documents relating to the Trust Fund other than maintenance of a register of Unitholders;

(t) provide advice and, at the request and under the direction of the Trustee, direction to the Transfer Agent;

(u) take all actions reasonably necessary in connection with, or in relation to, those matters referred to in Sections 7.1(b) and 8.1 of the Trust Indenture;

(v) determine, from time to time, all amounts required to be determined pursuant to Article 5 of the Trust Indenture, including the amounts available for distribution to Unitholders, and arrange for payment thereof to the Unitholders in accordance with Article 5 of the Trust Indenture;

(w) provide advice and assistance to the Trustee with respect to the performance of the obligations of the Trust and the enforcement of the rights of the Trust under all agreements entered into by the Trust;

(x) monitor the status of the Units as eligible investments for registered retirement savings plans, registered retirement income funds, and deferred profit sharing plans (all within the meaning of the Tax Act) and immediately provide the Trustee with written notice when the Administrator reasonably foresees that such Units may cease to have such status, or, if not reasonably foreseen, when the Units cease to have such status;

(y) in the event that withholding taxes are exigible on any distributions or redemption amounts distributed under the Trust Indenture or any other agreement, the Administrator shall withhold the withholding taxes required and shall promptly remit such taxes to the appropriate taxing authority. In the event that withholding taxes are exigible on any distributions or redemption amounts distributed under the Trust Indenture or any other agreement and the Administrator is, or was, unable to withhold taxes from a particular distribution to a Unitholder or has not otherwise withheld taxes on past distributions to a Unitholder, the Administrator shall be permitted to withhold amounts from other distributions to satisfy the Administrator's withholding tax obligations;

(z) provide such additional administrative and support services pertaining to the Trust, the Trust Fund and the Units and matters incidental thereto as may be reasonably requested by the Trustee from time to time;

(aa) administer all matters relating to the Direct Royalties and the Trust, including: (i) determining the total amounts owing to Unitholders and arranging cash distributions; (ii) providing Unitholders with periodic reports on the NPI, the Direct Royalties and the Properties; and (iii) providing Unitholders with financial reports and tax information relating to the Properties, the NPI and the Direct Royalties;

(bb) provide management services for the economic and efficient exploitation of the Properties and the Direct Royalties;

(cc) take all actions reasonably necessary in connection with, or in relation to, the Capital Fund (as defined in the Trust Indenture); and

(dd) recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for the Trust.

2.3 Restrictions on Delegation of Authority

Notwithstanding any other provisions of this Agreement, the Trustee shall not and is not hereby delegating to the Administrator any authority to manage the following affairs of the Trust:

(a) the issue, certification, countersigning, transfer, exchange and cancellation of certificates representing Units;

(b) the maintenance of a register of Unitholders;

(c) the delivery of distributions to Unitholders, although the calculation of distributions shall be made by the Administrator and approved by the board of directors of the Administrator and submitted by the Administrator to the Trustee for distribution to the Unitholders;

(d) the mailing of notices, financial statements and reports to Unitholders pursuant to Sections 14.1, 16.2 and 16.3 of the Trust Indenture, although the Administrator shall be responsible for the preparation or causing the preparation of such notices, financial statements and reports;

(e) the provision of a basic list of registered Unitholders (as defined in the Trust Indenture) to Unitholders in accordance with the procedures outlined in the Trust Indenture;

(f) the amendment or waiver of the performance or breach of any term or provision of this Agreement or the NPI Agreement on behalf of the Trust;

(g) the renewal or termination of this Agreement on behalf of the Trust; and

(h) any matter which requires the approval of the Unitholders under the terms of the Trust Indenture.

2.4 Power and Authorities of the Administrator

Subject to any direction of the Trustee from time to time, the Administrator shall have full right, power and authority to do and refrain from doing all such things as are necessary or appropriate in order to discharge its duties hereunder. In particular, and without limiting the generality of the foregoing, the Administrator shall have full right, power and authority to execute and deliver all contracts, leases, licences and other documents and agreements, to make applications and filings with governmental and regulatory authorities and to take such other actions as the Administrator considers appropriate in connection with the Trust in the name of and on behalf of the Trust and no person shall be required to determine the authority of the Administrator to give any undertaking or enter into any commitment on behalf of the Trust, provided that the Administrator shall not have the authority to commit to any transaction which would require the approval of the Unitholders in accordance with the Trust Indenture or take any action required to be taken by the Trustee under the Trust Indenture or take any action requiring approval of the Trustee without such approval having been given.

2.5 Distributions to Unitholders

In connection with determining the amounts payable from time to time to Unitholders and arranging for distribution to them, it is understood and agreed that the Administrator shall determine from time to time the amounts available for distribution to Unitholders and shall provide a written statement thereof to the Trustee prior to the date on which such distribution must be made and shall cause such amount to be paid by the Transfer Agent on behalf of the Trust following the declaration by the Trustee that such amounts are due and payable by the Trust pursuant to Article 5 of the Trust Indenture; provided however that the Administrator shall not be obligated to make any such payment unless the Administrator has monies of the Trust available to make such distribution.

2.6 Annual Certificate

The Administrator shall deliver to the Trustee within 60 days after the end of each calendar year and at any other time upon the demand of the Trustee, a certificate signed by a senior officer of the Administrator stating that:

(a) the Administrator has complied with all of its duties contained in this Agreement relating to the management of the general and administrative affairs of the Trust, which, if not complied with, would, with the giving of notice, lapse of time or otherwise, constitute a default of the Administrator under this Agreement or, if there has been a failure so to comply, giving particulars thereof; and

(b) as at the end of such year or other time period requested by the Trustee, the Units were eligible investments for registered retirement savings plan, registered retirement income funds and deferred profit sharing plans (all within the meaning of the Tax Act).

ARTICLE 3
PAYMENT OF EXPENSES

3.1 Payment of Expenses

The Administrator shall pay for and shall bear all outlays and expenses to third parties incurred by the Administrator in the administration of the affairs of the Trust and the performance by the Administrator of its duties hereunder (including costs and expenses incurred in calling and convening meetings of Unitholders, in reporting to Unitholders and in making distributions to Unitholders), and shall not seek reimbursement from the Trust for any of such outlays and expenses.

3.2 No Fee

The Administrator shall not be entitled to the payment of a fee for the services provided by the Administrator to the Trust under this Agreement.

3.3 Remuneration and Expenses of the Trustee

The Administrator shall pay the remuneration and expenses of the Trustee as provided in Section 7.6 of the Trust Indenture.

ARTICLE 4
CONDUCT OF THE ADMINISTRATOR

4.1 Administrator's Acknowledgement

The Administrator acknowledges and agrees that it has received a copy of the Trust Indenture and is familiar with and understands the duties of the Administrator and the Trustee thereunder, including those which are being delegated to the Administrator under this Agreement. The Administrator agrees to comply in all respects with the provisions of the Trust Indenture in the performance of its duties and obligations hereunder.

4.2 Standard of Care and Delegation

(a) In exercising its powers and discharging its duties under this Agreement, the Administrator shall act honestly and in good faith and exercise the degree of care, diligence and skill that a reasonably prudent oil and natural gas industry advisor and administrator would exercise in comparable circumstances. The Administrator's objective in exercising its powers and discharging its duties hereunder shall be to maximize the income distributable to the Unitholders to the extent consistent with long-term growth in the value of the Trust. In pursuing such objective, the Administrator will employ prudent oil and natural gas business practices. All of the Administrator's activities in relation to this Agreement and the Trust will be conducted in accordance with applicable laws with a view to the best interests of the Unitholders and the Trust.

(b) The Administrator may delegate specific aspects of its obligations hereunder to any person, including any of its affiliates or associates and including the Transfer Agent, provided that:

   (i) such delegation shall not relieve the Administrator of any of its obligations under this Agreement and provided that the Administrator shall not delegate any of its obligations hereunder to manage and administer the affairs of the Trust unless the Administrator shall have notified the Trustee of the name of the person or persons to which delegation is to be made and the terms and conditions thereof and the Trustee has provided prior written consent to such delegation; and

   (ii) the Administrator shall not in any manner, directly or indirectly, be liable or held to account for the activities or inactivities of any person to which any such obligations may have been delegated provided that in making such specific delegation, the Administrator acted in accordance with subsection 4.2(a).

4.3 Liability

The Administrator shall not be liable, answerable or accountable to the Trust for:

(a) any loss or damage resulting from, incidental to or relating to the provision of the services provided for hereunder, including any exercise or refusal to exercise a discretion, any mistake or error of judgment or any act or omission believed by the Administrator to be within the scope of authority conferred on it by this Agreement, unless such loss or damage resulted from a breach by the Administrator of the standard of care set forth in Section 4.2(a); or

(b) any reasonable reliance by the Administrator in performing its obligations hereunder on:

(i) statements of fact of other persons (any of which may be persons with which the Administrator is affiliated or associated) who are reasonably considered by the Administrator to be knowledgeable of such facts; or

(ii) the opinion or advice of or information obtained from any solicitor, auditor, valuer, engineer, surveyor, appraiser or other expert who is reasonably considered by the Administrator to be a person on whom reliance should be had under the circumstances;

provided that in obtaining such statements of fact, opinions, advice or information, the Administrator acted in accordance with subsection 4.2(a).

4.4 No Liability for Advice

The Administrator shall not be liable, answerable or accountable for any loss or damage resulting from the advice given to the Trust by the Administrator or the exercise by the Administrator of a discretion or its refusal to exercise a discretion, provided that the Administrator acted in accordance with subsection 4.2(a) and the loss or damage suffered by the Trustee is not attributable to the Administrator's gross negligence, wilful default, bad faith or fraud.

4.5 Conflict of Interest

(a) To the extent there is a conflict of interest between the Administrator acting in that capacity and the Trust in respect of any matter, the Administrator shall resolve such conflicts, on a basis consistent with the objectives and funds of each group of interested parties and the time limitations on investment of such funds, all consistent with the duty of the Administrator to deal fairly and in good faith with each group or persons.

(b) In the event that the interests of the Administrator are in conflict with those of the Trust or the Unitholders, the Administrator shall make decisions acting in good faith, having regard to the best interests of the Unitholders and the Trust and in a manner that would not contravene its fiduciary obligations to Unitholders.

4.6 Confidentiality

Subject to Section 2.2, the Administrator shall not, without the prior written consent of the Trustee, disclose to any third party any information about the Trust acquired or developed pursuant to the performance of services under this Agreement except that consent shall not be required to the following disclosure:

(a) information disclosed as required by law or the regulations, rules or policies of any stock exchange on which any Units are listed or as may be required by the regulations or policies of any securities commission or other securities regulatory agency, governmental agency or other authority of competent jurisdiction and the requirements of any court; or

(b) information disclosed as necessary for the purposes of any debt or equity financing undertaken by the Trust; or

(c) information disclosed that the Administrator acting reasonably deems to be necessary to be disclosed on a confidential basis for the proper performance of its duties and obligations under this Agreement, including without limitation, disclosure of information to consultants and other third parties engaged by or assisting the Administrator in accordance with the terms of this Agreement in order to carry out the purposes of this Agreement.

The provisions of this Section 4.6 shall not merge upon the termination of this Agreement.

4.7 Indemnification of the Administrator

The Administrator and any person who, at the request of the Administrator, is serving or shall have served as a director, officer, employee, advisor, partner, consultant, agent or subcontractor of the Administrator shall be indemnified and saved harmless by the Trust against all losses (other than loss of profit), claims, damages, liabilities, obligations, costs and expenses (including judgments, fines, penalties, amounts paid in settlement and counsel and accountants' fees) of whatsoever kind or nature incurred by, borne by or asserted against any of such indemnified parties in any way arising from and related in any manner to the provision of services and the performance of obligations by the Administrator pursuant to this Agreement, unless such indemnified party is found liable for or guilty of fraud, wilful default or gross negligence. The foregoing right of indemnification shall not be exclusive of any other rights to which the Administrator or any person referred to in this Section 4.6 may be entitled as a matter of law or equity or which may be lawfully granted to him.

4.8 Indemnification of the Trust and the Trustee

The Trust, the Trustee and any person who, at the request of the Trustee, is serving or shall have served as an officer, employee, advisor, consultant, agent or subcontractor of the Trustee in respect of the Trust shall be indemnified and saved harmless by the Administrator against all losses, claims, damages, liabilities, obligations, costs and expenses (including judgments, fines, penalties, amounts paid in settlement and counsel and accountants' fees) of whatsoever kind or nature incurred by, borne by or asserted against any of such indemnified parties in any way arising from or related in any manner to the failure by the Administrator to discharge its duties and liabilities hereunder in accordance with the duty of loyalty and standard of care specified in Section 4.2(a), the breach by the Administrator of its obligations hereunder or the fraud, wilful default, negligence or bad faith of the Administrator or its employees in the provision of services or the performance of its obligations hereunder, unless such losses, claims, damages, liabilities, obligations, costs and expenses (including judgments, fines, penalties, amounts paid in settlement, and counsel and accountants fees) arise from the fraud, wilful default or negligence of such indemnified party. The foregoing right of indemnification shall not be exclusive of any rights to which the Trust, the Trustee or any person referred to in this Section 4.7 may be entitled as a matter of law or equity or which may be lawfully granted to him.

ARTICLE 5
TERM AND TERMINATION

5.1 Term

Subject to Section 5.4, this Agreement shall continue in force for a period of ten years from the date of this Agreement unless terminated earlier by the Trust, in its sole discretion, by notice in writing to the Administrator given at least 30 days prior to the effective date of termination which shall be stated in such notice and upon payment to the Administrator of any amounts required to be paid to it as provided for in Section 5.5.

5.2 Automatic Renewal

Subject to Section 5.4 and any earlier termination pursuant to Section 5.1, upon the expiry of the ten-year initial term of this Agreement provided pursuant to Section 5.1, the term of this Agreement shall be automatically renewed for a further term of three years subject to the Trust's right of earlier termination on the same basis as provided in Section 5.1 and subject to Section 5.4 and thereafter automatically for such additional three-year renewal terms upon the expiry of each preceding renewal term, all subject to Section 5.1 and Section 5.4.

5.3 Effect of Termination

Upon the effective date of termination of this Agreement, the Administrator shall:

(a) forthwith pay to the Trust, or to the order of the Trust, all monies collected and held for the Trust pursuant to this Agreement;

(b) as soon thereafter as is reasonably practicable, deliver to the Trust, or to the order of the Trust, a complete auditor's report including a statement showing all payments collected by it and a statement of all monies held by it during the period following the date of the last audited statement furnished to the Trust; and

(c) forthwith, to the extent that it is able, subject to any applicable legal and contractual restrictions, deliver to and, where applicable, transfer into the custody of the Trustee all property and documents of the Trust then in the custody of the Administrator.

5.4 Default

This Agreement shall be immediately terminable by written notice from the Administrator or the Trustee to the other, as the case may be, in the event that:

(a) the Trust terminates;

(b) the Administrator:

(i) institutes proceedings for it to be adjudicated a voluntary bankrupt, or consents to the filing of a bankruptcy proceeding against it;

(ii) files a petition or answer or consent seeking reorganization, readjustment, arrangement, composition or similar relief under any bankruptcy law;

(iii) consents to the appointment of a receiver, liquidator, Trustee or assignee in bankruptcy; or

(iv) makes an assignment for the benefit of its creditors generally;

(c) a court having jurisdiction enters a decree or order adjudging the Administrator a bankrupt or insolvent or for the appointment of a receiver, Trustee or assignee in bankruptcy;

(d) any proceeding with respect to the Administrator is commenced under the *Bankruptcy and Insolvency Act* (Canada) or the *Companies' Creditors' Arrangement Act* (Canada) or similar legislation relating to a compromise or arrangement with creditors or claimants; or

(e) control of the Administrator changes other than pursuant to actions taken by the Trust or Trustee, pursuant to a resolution passed by Unitholders.

5.5 Payment

Upon a written notice to terminate this Agreement being given pursuant to Section 5.1 or 5.4, the Trust shall either pay to the Administrator, before or at the time of the termination of this Agreement, all costs and expenses incurred or required to be incurred by the Administrator in terminating contracts the Administrator has entered into in the performance by the Administrator of its duties under this Agreement (less any amount owing by the Administrator to the Trust) or, at the election of the Trust, assume the obligations of the Administrator under such contracts or any of them.

5.6 Continuing Obligations

Notwithstanding termination of this Agreement, the parties hereto shall not be relieved from any obligations or liabilities arising prior to such termination.

ARTICLE 6
GENERAL

6.1 Access to Records

The Trust and the Administrator shall provide to the other full and free access to all records, documents and materials in its possession or control and relating to the Trust and the services to be provided by the Administrator hereunder. The Administrator shall retain or cause to be retained all books and records related to it and its obligations hereunder for a period of two years following termination of this Agreement, or such longer periods as required in accordance with income tax or other statutory requirements, during which period the Trust shall continue to have the access thereto described above.

6.2 Amendments

This Agreement shall not be amended or varied in its terms by oral agreement or by representations or otherwise except by instrument in writing executed by the duly authorized representatives of the parties hereto or their respective successors or assigns.

6.3 Assignment

This Agreement shall not be assigned by either party hereto without the prior written consent of the other party, which consent shall not be unreasonably withheld or refused, save and except that the Administrator may assign this Agreement to an affiliate or associate of the Administrator without the consent of the Trust if such affiliate or associate will agree, in writing, with the Trust to be bound by all of the provisions of this Agreement and to remain an affiliate or associate of the Administrator during the term of this Agreement.

6.4 Severability

The provisions of this Agreement are severable. In the event of the unenforceability or invalidity of any one or more of the provisions of this Agreement under applicable law, such unenforceability or invalidity shall not render any of the other terms, covenants, conditions or provisions hereof unenforceable or invalid.

6.5 Notice

All notices required or permitted herein under this Agreement shall be in writing and may be given by delivering such notice or mailing such notice by pre-paid registered mail or by facsimile transmission to the address set forth below. Any such notice or other communication shall, if delivered, be deemed to have been given or made and received on the date delivered (or the next business day if the day of delivery is not a business day), and if mailed, shall be deemed to have been given or made and received on the third business day following the day on which it was so mailed and if faxed (with confirmation received) shall be deemed to have been given or made and received on the day on which it was so faxed (or the next business day if the day of sending is not a business day). The parties hereto may give from time to time written notice of change of address in the manner aforesaid.

Valiant Trust Company
510, 550 - 6th Avenue S.W.
Calgary, Alberta T2P 0S2

Attention: Manager, Corporate Trust Department
Telecopier No.: (403) 233-2857

Harvest Operations Corp.
Suite 2400, 500 – 6th Avenue S.W
Calgary, Alberta T2P 0S2

Attention: Jacob Roorda, President
Telecopier No.: (403) 266-1438

6.6 Force Majeure

Delays in or failure of performance by a party hereto of a term or provision of this Agreement shall not constitute a default hereunder, and the obligations of a party shall be suspended during such time and to such extent that the performance of its obligations is prevented or delayed, in whole or in part, by force majeure, whenever, wherever and in respect of whomsoever such force majeure occurs.

For the purposes of this Agreement events of force majeure include strikes, lock-outs, industrial disturbance, storm, fire, flood, landslide, snowslide, earthquake, explosion, lightning, tempest, action of elements, interruption or delay in transportation including, without limitation, highway or railway closures, cessation or interruption of power supplies, acts of God, laws, rules and regulations of any government or any governmental or regulatory authority, unavoidable accidents, inability to obtain or delay in obtaining necessary permits or approvals from government or any governmental or regulatory authority, inability to obtain or delay in obtaining necessary materials, facilities and equipment in the open market, or any other cause whether similar or dissimilar to those specifically enumerated, to the extent that such cause and the effects thereof are beyond the reasonable control of the party, provided that a party's own lack of funds shall not be considered an event beyond a party's reasonable control.

6.7 Further Assurances

Each party hereto agrees to execute any and all documents and to perform such other acts as may be necessary or expedient to carry out the purposes of this Agreement and the transactions contemplated hereby.

6.8 Time of Essence

Time is of the essence in respect of this Agreement.

6.9 No Partnership

Nothing herein shall be construed as creating a partnership and no Party shall have any partnership rights or liabilities hereunder or in connection herewith.

6.10 Entire Agreement

This Agreement constitutes the entire agreement between the parties hereto, and supersedes all prior agreements, in respect of the subject matter hereof.

6.11 Enurement

This Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors (including additional or successor Trustee appointed pursuant to the Trust Indenture) and permitted assigns.

6.12 Counterparts

This Agreement may be executed in several counterparts, each of which when executed by any of the parties shall be deemed to be an original, and such counterparts shall together constitute one and the same instrument.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be duly executed as of the date first above written.

VALIANT TRUST COMPANY

Per: (signed) "*Zinat H. Damji*"

Per: (signed) "*Cheryl Dahlager*"

HARVEST OPERATIONS CORP.

Per: (signed) "*Jacob Roorda*"

AGREL 04 MAR -9 AM 7:21

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Hayter and West Provost Areas, Alberta

THIS AGREEMENT made as of the 1st day of August, 2002.

BETWEEN:

ANADARKO CANADA CORPORATION, a body corporate, with offices in the City of Calgary, in the Province of Alberta ("**Vendor**")

- and -

COYOTE ENERGY INC., a body corporate, with offices in the City of Calgary, in the Province of Alberta ("**Purchaser**")

WHEREAS Vendor has agreed to sell and Purchaser has agreed to purchase certain oil and gas interests subject to and in accordance with the terms and conditions hereof;

NOW THEREFORE in consideration of the mutual covenants contained within this Agreement, the Parties covenant and agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement, including the recitals and schedules to this Agreement:

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

"**AFEs**" means the capital expenditures pursuant to the outstanding authorizations for expenditure set out in Schedule "C" arising as of and subsequent to the Effective Date for which the final accounting adjustments have not been completed and for which the Purchaser shall be responsible;

"**Affiliate**" means any corporation, partnership or legal entity which (a) controls directly or indirectly a party; (b) is controlled directly or indirectly by such party; or (c) is directly or indirectly controlled by a corporation, partnership or legal entity which directly or indirectly controls such party. A corporation will be deemed to be controlled by any such entity that owns or effectively controls, other than by way of security only, sufficient voting shares of that corporation whether directly or through the ownership of shares of another corporation that owns shares of that corporation or through other equity interests to elect the majority of its board of directors and control of a partnership means the ownership, directly or indirectly, of 50% or more of the voting rights in the partnership;

"**Assets**" means the Petroleum and Natural Gas Rights, the Tangibles and the Miscellaneous Interests;

"**Business Day**" means any day of the week except Saturday, Sunday and any statutory holiday in Alberta;

"**Certificate**" means a written certification of a matter or matters of fact which, if required from a corporation, shall be made by an officer of the corporation, on behalf of the corporation and not in any personal capacity;

"**Closing**" means the transfer by Vendor to Purchaser of beneficial ownership and risk of the Assets and the payment by Purchaser to Vendor of the purchase consideration and the completion of all matters incidental in accordance with the terms and conditions of this Agreement;

"**Closing Date**" means 10:00 a.m. on November 1, 2002, or such other time and date as may be agreed to in writing by the Parties;

"**Deposit**" means the sum of money set out in clause 2.4;

"**Dollar**" or "**$**" means a Canadian dollar;

"**Effective Date**" means 8:00 a.m. on June 1, 2002;

"**Field Facilities**" means the facility or facilities set out in Schedule "A" under that heading;

"**GST**" means the goods and services tax as provided for in the *Excise Tax Act*, R.S.C. 1985, c. E-15, as amended, or any successor or parallel provincial or federal legislation that imposes a tax on the recipient of goods or services supplied under this Agreement;

"**Lands**" means the lands set out in Schedule "A" under that heading;

"**Leased Substances**" means all Petroleum Substances or rights to Petroleum Substances which are granted, reserved or otherwise conferred by or under the Title Documents;

"**Material Title Defect**" means any defect or irregularity in Vendor's title to any of the Assets that has the effect of or may have the effect of reducing the value of the affected Asset(s) by at least twenty-five thousand dollars ($25,000.00), such defects or irregularities exclude Permitted Encumbrances and Preferential Rights;

"**Miscellaneous Interests**" means, subject to the exclusions and limitations provided in this definition, the Vendor's Interest in all property, assets and rights (other than the Petroleum and Natural Gas Rights and Tangibles) pertaining or ancillary to either the Petroleum and Natural Gas Rights or Tangibles to which Vendor is entitled including, but not limited to, the following:

(a) contracts and agreements relating to the Petroleum and Natural Gas Rights or Tangibles, including, without limitation, gas purchase contracts, operating agreements, processing agreements, transportation agreements, the Production and Marketing Contracts and agreements for the construction, ownership and operation of facilities;

(b) rights to enter upon, use or occupy the surface of the Lands for the purpose of gaining access to or otherwise using the Petroleum and Natural Gas Rights and the Tangibles, or either of them;

(c) Leased Substances produced from the Lands except those that are beyond the wellhead at the Effective Date or sale proceeds in respect of such Leased Substances if title has passed to the purchaser thereof;

(d) the Wells, including the wellbores and casing;

(e) all records, books, files, data, documents, licenses, permits or authorizations relating directly to the Petroleum and Natural Gas Rights or Tangibles and reservoir and environmental studies that relate solely to the Petroleum and Natural Gas Rights or Tangibles; and

(f) the Seismic Data; but

excluding any of the foregoing that pertain to Vendor's tax or financial records, economic evaluations, geophysical or geological data (with the exception of the Seismic Data);

"**Party**" means Vendor or Purchaser, and Parties means both of them;

"**Permitted Encumbrances**" means:

(a) any encumbrances, overriding royalties, liens, adverse claims, reductions in interest and other burdens set out in Schedule "A";

(b) agreements for the sale of Leased Substances, that are terminable on 30 days notice or less (without penalty);

(c) easements, rights of way, road use agreements, crossing agreements, servitudes and other similar rights in land including, without limitation, rights of way and servitudes for highways and other roads, railways, sewers, drains, gas and oil pipelines, gas and water mains, electric light, power, telephone, telegraph or cable television conduits, poles, wires or cables;

(d) the right reserved to or vested in any governmental or other public authority by the terms of any lease, licence, franchise, grant or permit or by any statutory provision to terminate any such lease, licence, franchise, grant or permit, or to require annual or other periodic payments as a condition of the continuance of them;

(e) rights of general application reserved to or vested in any governmental authority to levy taxes on Leased Substances or the income therefrom, and governmental requirements and limitations of general applications as to production rates or the operations of any property;

(f) the Production and Marketing Contracts and any agreements or plans relating to pooling or unitization which are binding on Vendor as well as agreements respecting the processing, treating or transmission of Leased Substances or the operation of Wells by contract field operators;

(g) liens incurred or created in the ordinary course of business as security in favour of the person who is conducting the development or operation of any of the Assets, for Vendor's proportionate share of the costs and expenses thereof;

(h) the reservations, limitations, provisos and conditions in any grants or transfers from the Crown of any of the Lands or interests in them and statutory exceptions to title;

(i) liens for taxes, assessments or governmental charges that are not due, or the validity of which is being contested in good faith by Vendor;

(j) mechanics', builders' or materialmen's liens in respect of services rendered or goods supplied for which payment is not due;

(k) provisions for penalties and forfeitures under agreements as a consequence of non-participation in operations; and

(l) any security held by any third party encumbering Vendor's interest in and to the Assets or any part or portion thereof, a discharge in respect of which Vendor delivers to Purchaser on or prior to the Closing Date in a form acceptable to Purchaser, acting reasonably, as contemplated in subclause 3.2(d) hereof;

"**Petroleum and Natural Gas Rights**" means the Vendor's Interest in and to the Title Documents and the Leased Substances and the rights granted in respect of the Title Documents and Leased Substances as set out in Schedule "A";

"**Petroleum Substances**" means any of crude oil, crude bitumen and products derived therefrom, synthetic crude oil, petroleum, natural gas, natural gas liquids, and any and all other substances related to any of the foregoing, whether liquid, solid or gaseous, and whether hydrocarbons or not, including without limitation, sulphur;

"**Preferential Right**" means a right of first refusal, preemptive right of purchase or similar right whereby any party, other than Vendor or Purchaser, has the right to acquire or purchase all or a portion of the Assets as a consequence of Vendor having agreed to sell the Assets to Purchaser in accordance herewith;

"**Prime Rate**" means an annual rate of interest equal to the annual rate of interest announced from time to time of the main branch of TD Canada Trust in Calgary, Alberta, as a reference rate then in effect for determining interest rates on Canadian dollar commercial loans provided that such rate shall be determined on the last day of each month and applied to the next succeeding month;

"**Production and Marketing Contracts**" means the agreements set out in Schedule "B";

"**Purchase Price**" means the sum of money first set out in clause 2.2 hereof;

"**Regulations**" means all statutes, laws, orders and regulations in effect from time to time and made by governments or governmental boards or agencies having jurisdiction over the Assets;

"**Seismic Data**" means one non-exclusive, non-transferable, licensed copy of Vendor's proprietary seismic data, including without limitation (provided it is available): (i) the SegP Survey on a 3.5 inch diskette; (ii) microfiche copies of the observer's reports, drilling reports and chaining reports; (iii) basic field data on a CD-ROM; all processed stack versions on a CD-ROM; and all notes, as specifically set out in Schedule "F";

"**Specific Conveyances**" means all conveyances, assignments, transfers, novations and other documents or instruments that are reasonably required or desirable to convey, assign and transfer the Assets to Purchaser and to novate Purchaser in the place and stead of Vendor with respect to the Assets and shall include, where applicable, Declarations of Special Operator for pipelines and/or wells;

"**Tangibles**" means the Vendor's Interest in:

(a) the Field Facilities; and

(b) in any and all tangible depreciable property and assets (other than the Field Facilities) which are located within or upon the Lands on the Effective Date and which are used or intended to be used in producing, processing, gathering, treating, measuring, making marketable or injecting Leased Substances or any of them or in connection with water injection or removal operations that pertain to the Petroleum and Natural Gas Rights, or are otherwise used or intended to be used in exploiting the Petroleum and Natural Gas Rights;

"**this Agreement", "herein", "hereto", "hereof**" and similar expressions mean and refer to this Agreement of Purchase and Sale and any agreement amending this Agreement of Purchase and Sale or any agreement or instrument which is supplemental or ancillary to this Agreement of Purchase and Sale;

"**Title Documents**" means, collectively, any and all leases (including leases to be granted by Vendor to Purchaser in respect of Vendor's fee simple lands, if any), reservations, permits, licenses, unit agreements, assignments, trust declarations, operating agreements, royalty agreements, gross overriding royalty agreements, participation agreements, farm-in agreements, sale and purchase agreements, pooling agreements and any other documents and agreements granting, reserving or otherwise conferring rights to: (i) explore for, drill for, produce, take, use or market Petroleum Substances; (ii) share in production of Petroleum Substances; (iii) share in the proceeds from, or measured or calculated by reference to the value or quantity of, Petroleum Substances which are produced; and (iv) acquire any of the rights described in items (i) to (iii) of this definition; including without limitation those, if any, set out in Schedule "A", but only to the extent that the foregoing items (i) through (iv) pertain to Petroleum Substances within, upon or under the Lands;

"**Vendor's Counsel**" means Macleod Dixon LLP;

"**Vendor's Interest**" means, in respect of a particular property, right or asset, the undivided interest of the Vendor in the Petroleum and Natural Gas Rights as described under the title "Vendor's Interest" in Schedule "A" and a corresponding interest in the Tangibles and Miscellaneous Interests;

"**Wells**" means all wells, regardless of status, including producing, shut-in, water source, observation, disposal, injection, capped, abandoned and suspended wells located on the Lands or lands pooled or unitized therewith, including but not limited to those under the title "Wells" on Schedule "A".

1.2 **Intentionally Deleted**

1.3 **Headings**

The insertion of headings in this Agreement is for convenience of reference only and shall not affect the construction or interpretation of this Agreement.

1.4 **Included Words and Gender**

When the context reasonably permits, words suggesting the singular shall be construed as the plural and vice versa and words suggesting gender or gender neutrality shall be construed as suggesting the masculine, feminine and neutral gender.

1.5 **Time**

In this Agreement all times are Mountain Standard Time or Daylight Saving Time, whichever is in effect pursuant to the *Daylight Saving Time Act* (Alberta).

1.6 **Conflicts**

If there is any conflict or inconsistency between a provision in the body of this Agreement and that contained in a schedule (except Schedule A) or a conveyance document, the provision in the body of this Agreement shall prevail. In the case of a conflict between a provision in the body of this Agreement and Schedule "A", Schedule "A" will prevail.

1.7 **Invalidity of Provisions**

If any of the provisions of this agreement should be determined to be invalid, illegal or unenforceable in any respect, the validity, legality or enforceability of the remaining provisions herein shall not in any way be affected or impaired by such determination.

1.8 **Knowledge or Awareness**

Where in this agreement a representation and warranty of the Vendor is made "to the best of its knowledge", "of which it has knowledge", or "to its knowledge", such knowledge is limited to matters within the actual knowledge of the officers or management employees having titles of "Director", "Manager" or "Vice President". "Actual knowledge" for purposes of this Agreement means information personally known after reasonable inquiry or review of Vendor's files or records, and does not include knowledge and awareness of any other person or constructive or imputed knowledge.

ARTICLE 2
PURCHASE AND SALE

2.1 **Agreement of Purchase and Sale**

(a) Subject to, and in accordance with the terms of this Agreement, Vendor hereby agrees to sell and Purchaser hereby agrees to purchase from Vendor the Assets, subject to the Permitted Encumbrances.

(b) Possession, beneficial ownership and risk of and title to the Assets shall pass to Purchaser as of the Closing Date.

2.2 **Purchase Price**

The consideration to be paid by Purchaser to Vendor for the Assets shall be $71,840,000.00 (the "Purchase Price") adjusted in accordance with Article 7 hereof. At Closing, Purchaser shall pay to Vendor the Purchase Price as adjusted in accordance with Article 7 less the Deposit (plus interest in accordance with clause 2.5).

2.3 **GST and Other Taxes**

(a) The parties acknowledge that, notwithstanding any other provision in this Agreement, the Purchase Price is exclusive of any GST or other taxes, fees, charges, levies or similar assessments that may be imposed by any governmental authority with respect to the subject transaction.

(b) The Purchaser acknowledges that it is responsible for paying any GST or other taxes (other than income taxes), fees, charges, levies or similar assessments which may be imposed by any governmental authority in respect of the subject transaction.

(c) The parties shall jointly elect at Closing pursuant to Section 167 of the *Excise Tax Act* (Canada) to have the provisions thereof concerning the acquisition of part of a business apply to the subject transaction and the Purchaser undertakes to file such election with the Canada Customs and Revenue Agency in a timely and proper fashion.

(d) The GST registration numbers for the parties are:

Vendor	-	871433199RT
Purchaser	-	863096665RT

The Purchaser agrees that it shall be solely liable and responsible for, and shall promptly indemnify and save the Vendor (including its directors, officers, employees and agents) harmless from and against, any and all direct or indirect losses suffered, sustained, paid or incurred by the Vendor by reason of any matter or thing arising out of, resulting from, attributable to or connected with the aforesaid GST election and any and all claims of the Canada Customs and Revenue Agency or other governmental authorities with respect to GST or any other taxes (other than income taxes), fees, charges, levies or similar assessments which may be imposed with respect to the subject transaction including, without limitation, any associated interest charges or penalties.

2.4 **Deposit**

Purchaser shall pay to Vendor's Counsel the amount of $5,000,000.00, which represents a deposit on the Assets (the "Deposit"). The Deposit will be held in escrow by Vendor's Counsel in an interest bearing account pursuant to an Escrow Agreement of even date among Vendor, Purchaser and Vendor's Counsel. If Closing occurs on the Closing Date, Vendor and Purchaser shall thereupon cause the Deposit and all interest thereon to be released to the Vendor, which amount will be applied towards the Purchase Price. If Closing does not occur on the Closing Date, the Deposit shall be governed by clauses 3.2 and 3.3.

If Closing does not occur and the Deposit is returned to Purchaser pursuant to clauses 3.2 or 3.3, Purchaser shall receive interest on the Deposit from the date the Deposit was received up to and including the date the Deposit is returned to the Purchaser. For purposes of this clause only, "interest" shall mean the interest which Vendor's Counsel receives on the Deposit. Vendor's Counsel shall provide evidence of such interest to Purchaser upon request.

2.5 **Interest**

At Closing, Purchaser shall pay to Vendor an amount equal to the interest that would have accrued on the Purchase Price less any Deposit at the Prime Rate plus one (1%) per cent, calculated daily and not compounded, from and including the Effective Date to and including the day prior to the Closing Date, which amount shall constitute an increase to the Purchase Price and shall be allocated to the Petroleum and Natural Gas Rights.

2.6 **Form of Payment**

All payments to be made at Closing shall be made by certified cheque or bank draft.

2.7 **Allocation of Purchase Price**

The parties shall allocate the Purchase Price as follows:

(a)	To Petroleum and Natural Gas Rights	$	57,472,000.00
(b)	To Tangibles	$	14,367,999.00
(c)	To Miscellaneous Interests	$	1.00
	TOTAL	$	71,840,000.00

In determining the Purchase Price, the Parties have taken into account Purchaser's assumption of responsibility for the future abandonment, reclamation costs and environmental responsibilities associated with the Assets and Vendor's release of responsibility therefor.

2.8 **Specific Conveyances**

Vendor shall prepare the Specific Conveyances at its cost, and will use reasonable efforts to prepare the Specific Conveyances and distribute them to the Purchaser prior to Closing. No Specific Conveyances will confer or impose upon a Party any greater right or obligation than contemplated in this Agreement. All Specific Conveyances that are prepared and circulated to Purchaser a reasonable time prior to the Closing Date shall be executed and delivered by the Parties at Closing. Prior and subsequent to the Closing Date, Vendor shall cooperate with Purchaser to secure execution of such documents by third parties, as required. Forthwith after Closing, Vendor shall circulate and at Purchaser's cost register, as the case may be, all Specific Conveyances that by their nature may be circulated or registered.

2.9 **Title Documents and Miscellaneous Interests**

Vendor shall deliver to Purchaser as soon as practicable after Closing and in any case no later than 10 Business Days after Closing: (i) copies of the Title Documents; and (ii) any other agreements and documents to which the Assets are subject and copies of contracts, agreements, records, books, documents, licenses, reports and data comprising Miscellaneous Interests which are now in the possession of Vendor or of which it gains possession prior to Closing provided that if Vendor retains any interest in any property to which such Title Documents and Miscellaneous Interests are applicable, Vendor may retain the original copy of such Title Documents and Miscellaneous Interests and provide a copy of same to the Purchaser.

2.10 **Governmental Security Deposits**

In the event that prior to or after the Closing Date a governmental authority or regulatory agency requires as a pre-requisite to or a condition of the transfer of any licence, permit or approval pertaining to the Assets, a security deposit or any kind of monetary payment, such amount shall be paid by the party whose actions, inactions or assets triggered the requirement to make the payment. Such party will make the payment as and when due.

2.11 **Intentionally Deleted**

ARTICLE 3
CLOSING

3.1 **Closing and Adjustments**

(a) The Closing shall take place at the offices of Vendor at 425 - 1st Street S.W. Calgary, Alberta on the Closing Date.

(b) On the Closing Date, Vendor and Purchaser shall, to the extent practicable, adjust and settle accounts pertaining to the Assets in the manner contemplated by Article 7.

3.2 **Purchaser's Conditions Precedent**

The obligation of Purchaser to purchase the Assets is subject to the following conditions precedent, which are for the exclusive benefit of Purchaser and may be waived by Purchaser:

(a) subject to clause 11.3, there has been no material damage to the Assets between the Effective Date and the Closing Date;

(b) the representations and warranties of Vendor shall be true and correct in all material respects when made and as of the Closing Date and a Certificate to that effect shall have been delivered by Vendor to Purchaser at Closing;

(c) all obligations of Vendor contained in this Agreement to be performed prior to or at Closing shall have been timely performed in all material respects and a Certificate to that effect shall have been delivered by Vendor to Purchaser at Closing;

(d) at or prior to Closing, Vendor shall deliver to Purchaser any releases and registrable discharges in a form acceptable to Purchaser acting reasonably of any adverse liens and encumbrances that are not Permitted Encumbrances and relate to security held against the Assets or any portion thereof;

(e) Vendor shall have obtained all necessary regulatory or governmental approvals required to permit the transaction to be completed;

(f) Vendor shall have obtained approval under the *Competition Act* and all applicable waiting periods shall have expired or been terminated;

(g) no Third Party action shall have been commenced or threatened, the subject of which is to block or stop this transaction or any part thereof;

(h) **intentionally deleted.**

If any one or more of the preceding conditions precedent is not satisfied or waived by Purchaser in the manner provided for herein for waiver at or before the Closing, Purchaser may rescind this Agreement by written notice to Vendor and, in such event, Vendor shall forthwith return the Deposit (plus accrued interest as described in clause 2.4) to Purchaser and Purchaser and Vendor shall be released and discharged from all obligations hereunder except as provided in clause 13.2.

3.3 **Vendor's Conditions Precedent**

The obligation of Vendor to sell the Assets is subject to the following conditions precedent, which are for the exclusive benefit of the Vendor and may be waived by Vendor:

(a) Purchaser shall have tendered to Vendor in the manner stipulated in this agreement the total consideration payable to Vendor;

(b) the representations and warranties of Purchaser shall be true and correct in all material respects when made and as of the Closing Date and a Certificate to that effect shall have been delivered by Purchaser to Vendor at Closing;

(c) all obligations of Purchaser contained in this Agreement to be performed prior to or at Closing shall have been timely performed in all material respects and a Certificate to that effect shall have been delivered by Purchaser to Vendor at Closing;

(d) Purchaser shall have obtained all necessary regulatory or governmental approvals required to permit the transaction to be completed;

(e) no Third Party action shall have been commenced or threatened, the subject of which is to block or stop this transaction or any part thereof; and

(f) Purchaser shall have obtained approval under the *Competition Act* and all applicable waiting periods shall have expired or been terminated.

If any one or more of the preceding conditions precedent is not satisfied or waived by Vendor in the manner provided for herein for waiver at or before Closing, Vendor may rescind this Agreement by written notice to Purchaser and, in such event, Vendor shall be entitled to retain the Deposit (plus accrued interest as described in clause 2.4) as liquidated damages and not as penalty and Purchaser and Vendor shall be released and discharged from all obligations hereunder except as provided in clause 13.2. Notwithstanding the foregoing, in the event Vendor elects to rescind the Agreement because condition precedents 3.3(e) and (f) is not satisfied or waived, Vendor will return the Deposit (plus accrued interest as described in clause 2.4) to the Purchaser.

3.4 **Efforts to Fulfill Conditions Precedent**

Purchaser and Vendor shall proceed diligently and in good faith and use all reasonable efforts to fulfill and assist in the fulfillment of the conditions precedent. If there is a condition precedent that is to be met prior to or at August 14, 2002 or the Closing Date, and if, by the time the condition precedent is to be met the Party for whose benefit the condition precedent exists fails to notify the other Party that the condition precedent has not been met, the condition precedent shall be deemed conclusively to have been met.

ARTICLE 4
REPRESENTATIONS AND WARRANTIES

4.1 Vendor's Representations

Purchaser acknowledges that it is purchasing the Assets on an "as is, where is" basis, without representation or warranty and without reliance on any information provided to or on behalf of Purchaser by Vendor, except for the following representations and warranties, which are made (unless otherwise indicated below in writing) by Vendor as of the date hereof and the Closing Date provided always that the following representations and warranties are made subject to the matters described in the Disclosure Statement in Schedule "G" and that the following representations and warranties will not limit in any manner or derogate from the provisions of clause 6.3 "Environmental Matters":

(a) Standing: it is a corporation duly incorporated and validly existing under the laws of its jurisdiction of incorporation and is authorized to carry on business in all jurisdictions in which the Assets are located;

(b) Requisite Authority: it has the corporate capacity, power and authority to execute and deliver this Agreement, to sell the Assets on the terms set out in this Agreement and to perform its obligations under this Agreement;

(c) No Conflict: the execution and delivery of this Agreement and the completion of the sale of the Assets in accordance with the terms of this Agreement do not and will not violate or conflict with any provision of:

  (i) the charter, bylaws or equivalent governing documents relating to it or any Regulations applicable to it; or

  (ii) any agreement or instrument to which it is a party or by which it is bound and of which it has knowledge or any judgment, decree or order applicable to it.

(d) Execution and Enforceability: as at the date hereof and the Closing Date, this Agreement and all documents executed and delivered pursuant to this Agreement are and will be duly authorized, executed and delivered by it and are legal, valid and binding obligations of it enforceable against it in accordance with their terms except to the extent limited by bankruptcy, insolvency, liquidation, reorganization, moratorium or other laws of general application affecting creditors' rights generally or by general equitable principles;

(e) Authorizations: no authorization or approval or other action by, or notice to or filing with, any governmental authority or regulatory body exercising jurisdiction over the Assets is required for the due execution, delivery and performance by it of this Agreement, other than authorizations, approvals or exemptions previously obtained and currently in force or regulatory consents or approvals to the transfer of well and pipeline licenses and permits and other similar licenses and permits available only after the Closing Date in the ordinary course;

(f) Encumbrances, No Cancellation or Reduction: it does not warrant title to the Assets but does warrant that other than Permitted Encumbrances, (i) Vendor has not alienated or encumbered or permitted the alienation or encumbrance of the Assets or any part or portion thereof, (ii) Vendor has not committed and is not aware of there having been committed any act or omission whereby the interest of the Vendor in and to the Assets or any part or portion thereof may be canceled or determined, (iii) the Assets are now free and clear of all liens, royalties, conversions, rights and other claims of third parties created by, through or under Vendor except as shown on Schedule "A" or of which Purchaser has actual knowledge without inquiry, and (iv) except as otherwise disclosed in Schedule "A", none of the Assets are subject to reduction by reference to payout of any well or otherwise pursuant to a right created by, through or under Vendor;

(g) **Intentionally deleted**;

(h) Knowledge of Default: in respect of those portions of the Assets where Vendor is Operator, and in respect of the other portions of the Assets to the best of its knowledge, it has not received any notice of and it is not in material default under any agreement pertaining to the Assets, which default has not been rectified or waived as of the date of this Agreement;

(i) Lawsuits and Claims: in respect of those portions of the Assets where it is Operator, and, in respect of other portions of the Assets to the best of its knowledge, no suit, action or other proceeding before any court or governmental agency has been commenced or, to the best of its knowledge, threatened against Vendor which might result in impairment or loss of the interest of the Vendor in and to the Assets or which might otherwise adversely affect the Assets;

(j) Payment of Royalties and Taxes: in respect of those portions of the Assets where Vendor is Operator and, in respect of other portions of the Assets to the best of its knowledge, and except for Permitted Encumbrances, all *ad valorem*, property, production, severance and similar taxes and assessments based on, or measured by, the ownership of the Assets or the production of Petroleum Substances from the Assets, or the receipt of proceeds from them, and all royalties and rentals pertaining to the Assets accruing prior to Effective Date, that are payable by it will be or will have been properly paid and discharged;

(k) Residency For Tax Purposes: it is not a non-resident of Canada within the meaning of section 116 of the *Income Tax Act* (Canada) and the interest of Vendor in and to the Assets does not constitute all or substantially all of the property of the Vendor;

(l) Take or Pay Obligations: it has no take or pay obligations relating to the Assets;

(m) **Intentionally Deleted**;

(n) Broker's Fees: it has not incurred any obligation or liability, contingent or otherwise, for broker's or finder's fees in respect of this Agreement or the transaction to be effected by it for which Purchaser shall have any liability or obligation;

(o) Sales Contracts: except for the Production and Marketing Contracts, it is not obligated to sell or deliver Petroleum Substances produced from the Lands to any person pursuant to agreements which cannot be terminated on 30 days' notice or less and it has not assigned or in any way restricted its right to receive the proceeds from the sale of Petroleum Substances produced from the Lands, except where Permitted Encumbrances would apply and except for the Production and Marketing Contracts, it has not pre-sold any Petroleum Substances beyond the wellhead at the Effective Date;

(p) Quiet Enjoyment: subject to the rents, covenants, conditions and stipulations in the Title Documents and any other agreements pertaining to the Assets and on the lessee's or holder's part thereunder to be paid, performed and observed, the Permitted Encumbrances and Material Title Defects waived by the Purchaser, Purchaser may enter into and upon, hold and enjoy the Lands for the residue of the respective terms of the Title Documents and all renewals or extensions thereof as to the interests hereunder assigned for Purchaser's own use and benefit without any interruption of or by Vendor or any other person whomsoever claiming by, through or under Vendor;

(q) Operations: all Assets operated by Vendor, while such Assets were operated by the Vendor, and to the best of its knowledge, those of the Assets operated by Third Parties were operated in accordance with good oil and gas industry practices and in material compliance with the Regulations in force and effect at the time of such operations, provided that nothing in this representation and warranty shall be construed as a statement by Vendor on any matter pertaining to the environmental status of the Assets, its compliance with environmental Regulations or to the presence or absence of environmental damage or contamination or other environmental problems or liabilities;

(r) Abandonment, Remediations, Reclamations: to the best of its knowledge all abandonments, remediations and reclamations of any of the Assets have been conducted in accordance with normal industry practice and in accordance with the Regulations, provided that nothing in this representation and warranty shall be construed as a statement by Vendor on any matter pertaining to the environmental status of the Assets, its compliance with environmental Regulations or to the presence or absence of environmental damage or contamination or other environmental problems or liabilities.

(s) Lease Operating Statements: it has prepared its lease operating statements in accordance with generally accepted accounting principles and are consistent with normal industry practice for the Assets; and

(t) AMIs: to the best of its knowledge, there are no Area of Mutual Interest ("AMIs") obligations affecting the Assets other than those AMIs disclosed in the data room managed by Waterous Securities Inc. on behalf of Vendor for the "2002 Heavy Oil and Natural Gas Property Offering".

4.2 Limitation

(a) Vendor makes no representations or warranties with respect to the Assets, except as contained in clause 4.1. Vendor disclaims any liability or responsibility for any representation or warranty (other than the representations and warranties made in clause 4.1) that may have been made or alleged to have been made and contained in any document or statement made or communicated to Purchaser including, but not limited to, any opinion, information or advice provided to Purchaser by any shareholder, director, officer, employee, agent, consultant or representative of Vendor in respect of:

(i) the quantity, quality or recoverability of Petroleum Substances within or under the Lands;

(ii) estimates of prices or future cash flows arising from the sale of Petroleum Substances produced from the Lands or estimates of other revenues attributable to the Assets or the availability or continued availability of transportation to sell those Petroleum Substances;

(iii) any engineering, geological or other interpretations or economic evaluations respecting the Assets; and

(iv) the quality, condition, fitness or suitability for purpose or merchantability of any of the Assets.

(b) Purchaser acknowledges it has made, and will continue prior to Closing Date to make, its own independent examination, investigation, analysis, evaluation and verification of the Assets, including Purchaser's own estimate and appraisal of the extent and value of the Petroleum Substances attributable to the Lands and it has relied solely on same as to its assessment of the condition (environmental or otherwise), quantum and value of the Assets;

(c) Except with respect to the representations and warranties in clause 4.1, Purchaser forever releases and discharges Vendor and its directors, officers, servants, agents and employees from any claims and all liability to Purchaser or Purchaser's assigns and successors, as a result of the use or reliance upon advice, information or materials pertaining to the Assets which was delivered or made available to Purchaser by Vendor or its directors, officers, servants, agents or employees prior to or pursuant to this Agreement, including, without limitation, any evaluations, projections, reports and interpretive or non-factual materials prepared by or for Vendor, or otherwise in Vendor's possession.

4.3 **Purchaser's Representations**

Purchaser makes the following representations and warranties to Vendor, which are made (unless otherwise indicated below in writing) as of the date hereof and the Closing Date:

(a) Standing: it is a corporation duly incorporated and validly existing under the laws of its jurisdiction of incorporation and is authorized to carry on business in all jurisdictions in which the Assets are located;

(b) Requisite Authority: it has the corporate capacity, power and authority to execute and deliver this Agreement and to purchase and pay for the Assets on the terms set out in this Agreement and to perform its other obligations under this Agreement;

(c) No Conflict: the execution and delivery of this Agreement and the completion of the purchase of the Assets in accordance with the terms of this Agreement do not and will not violate or conflict with any provision of:

(i) the charter, bylaws or equivalent governing documents relating to it or any Regulations applicable to it; or

(ii) any agreement or instrument to which it is a party or by which it is bound and of which it has knowledge or any judgment, decree or order applicable to it;

(d) Execution and Enforceability: as at the date hereof and the Closing Date, this Agreement and all documents executed and delivered pursuant to this Agreement are and will be duly authorized, executed and delivered by it and are legal, valid and binding obligations of it enforceable against it in accordance with their terms except to the extent limited by bankruptcy, insolvency, liquidation, reorganization, moratorium or other laws of general application affecting creditors' rights generally or by general equitable principles;

(e) Investment Canada Act: it is not a "non-Canadian" for the purposes of the *Investment Canada Act* (Canada);

(f) Authorizations: except under the *Competition Act,* no authorization or approval or other action by, or notice to or filing with, any governmental authority or regulatory body exercising jurisdiction over the Assets is required for the due execution, delivery and performance by it of this Agreement, other than authorizations, approvals or exemptions previously obtained and currently in force or regulatory consents or approvals to the transfer of well and pipeline licenses and permits and other similar licenses and permits available only after the Closing Date in the ordinary course;

(g) Purchaser as Principal: it is acquiring the Assets in its capacity as a principal and is not purchasing the Assets as agent for a third party or for the purpose of resale;

(h) AEUB License Transfer Requirements and Compliance: as of the date hereof and the Closing Date, (i) its Licensee Liability Rating, as determined by the AEUB prior to, or as a result of this transaction and the transfer of licenses contemplated herein, is and will be greater than one (1), (ii) it is not on "refer" status at the AEUB, and (iii) it is unaware of any other reason why the Well, Field Facilities or pipeline license transfers from Vendor to Purchaser will not be approved by the AEUB; and

(i) Financing: it will have at Closing sufficient cash, available lines of credit or other sources of immediately available funds to enable it to pay the Purchase Price to the Vendor at Closing.

ARTICLE 5
INDEMNITIES FOR
REPRESENTATIONS & WARRANTIES

5.1 Vendor's Indemnities for Representations and Warranties

Vendor shall be liable to Purchaser for and shall, in addition, indemnify Purchaser from and against, all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Purchaser which would not have been suffered, sustained, paid or incurred had all of the representations and warranties contained in clause 4.1 been accurate and truthful. Nothing in this clause 5.1 shall be construed so as to cause Vendor to be liable to or indemnify Purchaser (i) for any loss of profits or other consequential damages suffered by Purchaser or any punitive damages; (ii) any loss, cost claims, damages, expenses and liabilities that do not on an individual basis exceed $1,000,000; and (iii) any loss, cost claims, damages, expenses and liabilities that result from the actions or omissions of the Purchaser after the date of this Agreement.

5.2 **Limitation**

In no event shall the total of Vendor's liabilities and indemnities hereunder exceed the unadjusted Purchase Price. The provisions of clause 5.1 shall only be effective when the amount determined by the Parties to be recoverable from Vendor in the aggregate exceeds a deductible amount of five percent (5%) of the unadjusted Purchase Price, after which point Purchaser will be entitled to recovery from Vendor only with respect to an amount in excess of such deductible.

5.3 **Purchaser's Indemnities for Representations and Warranties**

Purchaser shall be liable to Vendor for and shall, in addition, indemnify Vendor from and against, all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor which would not have been suffered, sustained, paid or incurred had all of the representations and warranties contained in clause 4.3 been accurate and truthful, provided however that nothing in this clause 5.3 shall be construed so as to cause Purchaser to be liable to or indemnify Vendor in connection with any representation or warranty contained in clause 4.3 if and to the extent that Vendor did not rely upon such representation or warranty.

5.4 **Time Limitation**

No claim under this Article 5 shall be made or be enforceable by a Party unless notice of such claim, with reasonable particulars, is given by such Party to the Party against whom the claim is made within a period of one (1) year from the Closing Date.

ARTICLE 6
PURCHASER'S INDEMNITIES

6.1 **Purchaser's General Indemnity**

Purchaser shall:

(a) be liable to Vendor for all claims, liabilities, actions, proceedings, demands, losses, costs, damages (including legal costs on a solicitor/client basis) and expenses whatsoever which Vendor may suffer, sustain, pay or incur; and, in addition

(b) indemnify and save Vendor and its directors, officers, servants, agents and employees harmless from and against all claims, liabilities, actions, proceedings, demands, losses, costs, damages (including legal costs on a solicitor/client basis) and expenses whatsoever which may be brought against or suffered, sustained, paid or incurred by Vendor or its directors, officers, servants, agents or employees;

by reason of any matter or thing arising out of, resulting from, attributable to or connected with the Assets and occurring or accruing on or after the Closing Date, except any claims, liabilities, actions, proceedings, demands, losses, costs, damages (including legal costs on a solicitor/client basis) and expenses, to the extent that the same are caused by the gross negligence or willful or wanton misconduct of Vendor and except where such matter arose as a direct result of a breach of a representation and warranty in clause 4.1 that Purchaser has provided notice of to Vendor pursuant to clause 5.4, in which case the above indemnity will not apply.

6.2 **Abandonment and Reclamation**

Purchaser shall see to the timely performance of all abandonment and reclamation obligations pertaining to the Assets which in the absence of this Agreement would be the responsibility of Vendor, including, but not limited to, such obligations pertaining to any abandoned Wells for which the well license transfer has not been approved by the subject regulatory body. Purchaser shall be liable to Vendor and shall, in addition, indemnify Vendor from and against all losses, costs, claims, damages, expenses and liabilities suffered, sustained, paid or incurred by Vendor should Purchaser fail to timely perform such obligations.

6.3 **Environmental Matters**

Notwithstanding the foregoing provisions of this clause, it is understood and agreed that Purchaser is acquiring the Assets on an "as is, where is" basis as of the Closing Date. Purchaser agrees that it has been or will be provided prior to the Closing Date with the right and opportunity to conduct due diligence investigations with respect to existing or potential environmental problems pertaining to the Assets; is familiar with the condition and use of the Assets; it can determine for itself whether the Assets are satisfactory from an environmental standpoint; and that it is not relying upon any representation or warranty from Vendor as to the condition, environmental or otherwise, of the Assets. Purchaser further agrees that on and after the Closing Date it shall:

(a) be solely liable and responsible for any and all losses, costs, damages (including legal costs on a solicitor/client basis) and expenses which Vendor may suffer, sustain, pay or incur; and, in addition

(b) indemnify and save Vendor and its directors, officers, servants, agents and employees harmless from and against any and all claims, liabilities, actions, proceedings, demands, losses, costs, damages (including legal costs on a solicitor/client basis) and expenses whatsoever which may be brought against or suffered by Vendor or its directors, officers, servants, agents or employees or which it may suffer, sustain, pay or incur;

by reason of any matter or thing arising out of, resulting from, attributable to or connected with any environmental damage or contamination or other environmental problems pertaining to the Assets, or any of them, whether occurring or accruing before, on or after the Effective Date and whether or not the subject regulatory body approves the license transfer for abandoned Wells including, without limitation, surface, underground, air, ground water or surface water contamination, damage from or removal of hazardous or toxic substances, spills of any nature whatsoever, clean-up, plugging, decommissioning, abandonment and reclamation (or failure to perform any or all of the foregoing) and the breach of applicable Regulations in effect at any time. Purchaser hereby releases Vendor from any environmental claims Purchaser may have against Vendor that in any way relate to, or are directly or indirectly caused by the Assets. Purchaser acknowledges and agrees that it shall not be entitled to any rights or remedies under the common law or statute pertaining to such damage, contamination or problems relative to Vendor including, without limitation, the right to name Vendor as a third party to any action including any action commenced by any person against Purchaser. Nothing herein contained shall prejudice any claims or remedies that

Vendor may have against Purchaser in relation to such claim or remedy outside this contract including rights and remedies under the common law and statute.

6.4 **Application To Other Documentation**

The liabilities and indemnities contained in Article 6 shall be deemed to apply to, and shall not merge in, any conveyances, transfers, assignments, novation agreements and other documents or instruments conveying the Assets to Purchaser or otherwise provided with respect to the transactions herein, despite the actual terms of such agreements, notwithstanding any rule of law, equity or statute to the contrary, and all such rules are hereby waived. Any claim by a Party must be made by notice to the other and include particulars of the claim and of the facts giving rise to it.

ARTICLE 7
OPERATING ADJUSTMENTS

7.1 **Adjustments**

(a) Five (5) Business Days before Closing Date, Vendor shall prepare and submit to Purchaser an interim statement of adjustments effective as of the Effective Date and prepared in accordance with this Article. Such statement will contain Vendor's good faith estimate of such adjustments and all reasonable applicable back-up. At Closing Date the Parties shall, to the extent practicable, adjust and settle accounts pertaining to the Assets. The Purchase Price shall be adjusted to reflect the adjustments and settlements shown on the interim statement of adjustments.

(b) Subject to subclauses (d), (e) and (f), all benefits and obligations of any kind and nature accruing payable, paid, received or receivable with respect to the Assets, prior to the Effective Date, including without limitation operating costs, capital costs, lease rentals, royalty obligations, GST, AFEs and the proceeds from the sale of production from the Lands that is beyond the wellhead prior to the Effective Date are for Vendor's account.

(c) Subject to subclauses (d), (e) and (f), all benefits and obligations of any kind and nature accruing payable, paid, received or receivable with respect to the Assets on and after the Effective Date, including without limitation operating costs, capital costs, lease rentals, royalty obligations, AFEs, GST and the proceeds from the sale of production from the Lands that is beyond the wellhead on and after the Effective Date are for Purchaser's account.

(d) The following provisions will apply to the apportionment of the revenues, costs, expenses and other relevant charges referred to in subclauses (b) and (c):

(i) all prepaid rentals and similar payments required to preserve any of the Title Documents, whether paid before or after the Effective Date for the Assets, shall be apportioned between Vendor and Purchaser on a per diem basis as of the Effective Date, unless and to the extent that such allocation is waived by Vendor;

(ii) operating, capital cost advances, AFEs and similar prepayments made by Vendor for the Assets prior to Closing Date and relating to benefits accruing after the Effective Date are the responsibility of Purchaser and an amount equal to such prepayments shall be credited to Vendor at Closing Date;

(iii) there will be no adjustments for Alberta Royalty Tax Credits;

(iv) Purchaser will be credited with an amount equal to the proceeds from the sale of production from the Lands from the Effective Date to Closing Date less all royalties, operating expenses, and overhead pertaining to the Assets from the Effective Date to Closing Date; and

(v) for further certainty, Vendor will provide Purchaser with actuals of crown royalties only.

(e) **Intentionally deleted**

(f) Notwithstanding any of the foregoing, accounting or adjustments resulting from joint venture or royalty audits for the Assets:

(i) relating to the period prior to Closing Date and for which audit queries are outstanding at Closing Date; or

(ii) that occur after Closing Date but not later than 2 years after Closing Date or for the applicable period in the governing operating agreements included in Miscellaneous Interests, whichever is later (in the case of joint venture audits), or 4 years after Closing Date (in the case of Crown royalty audits);

shall be made as they occur and payment for them shall be made within 30 days of each adjustment and shall be made by Purchaser to Vendor, or vice versa, as the case may be. The costs of any audit shall be the responsibility of the party initiating the audit.

(g) Disputed Payments and Interest on Overdue Payments

(i) If either party does not remit payment to the other party of an amount payable to such party in accordance with the terms of this agreement, then the non-paying party shall pay interest on such amount to the other party at the Prime Rate plus one percent calculated daily and not compounded from the date such payment was due until it is paid.

(ii) If either party disputes the correctness of an amount payable at or after Closing pursuant hereto, the payment shall nevertheless be made by the due date. To the extent that any disputed amount is subsequently determined not to have been payable, the party who has received it shall within fifteen (15) days from the date of such determination, pay such excess amount to the other party, together with interest at a rate equal to the Prime Rate plus one percent (1%) calculated daily and not compounded from the date of the overpayment until it is repaid. Each party shall retain complete records, pertinent to the subject matter of this agreement for a sufficient period of time to meet the requirements of this clause 7.1(g).

(h) Use of Joint Venture Billing Statements: To the extent possible, joint venture billing statements from operators of the Assets shall be used as a basis for adjustments pursuant to this clause. Costs, expenses and revenues shall be treated as having been incurred or having accrued in the month to which they are attributed in the joint venture billing statements unless it can be demonstrated that they were incurred or accrued in a different month.

(i) Tax Audits: If the amount of GST paid by the Purchaser pursuant to the provisions of this Agreement is subject to audit by the relevant governmental authorities, and it is determined by those authorities that an additional amount of GST should be assessed, the Purchaser shall be responsible for the payment of such additional amount including any related penalties.

7.2 **Intentionally Deleted**

7.3 **Intentionally Deleted**

ARTICLE 8
MAINTENANCE OF ASSETS

8.1 **Maintenance of Assets**

From the date of this Agreement until Closing Date, Vendor shall operate and maintain the Assets in a prudent manner in accordance with generally accepted oil and gas industry practices and in compliance with all material covenants and conditions contained in all agreements relating to the Assets.

8.2 **Consent of Transferee**

Notwithstanding clause 8.1, Vendor shall not, without the written consent of Purchaser, which consent shall not be unreasonably withheld by Purchaser and which, if provided, shall be provided in a timely manner:

(a) make any commitment or propose, initiate or authorize any capital expenditure with respect to the Assets of which Vendor's share is in excess of $10,000.00, except in case of an emergency or in respect of amounts which Vendor may be committed to expend or be deemed to authorize for expenditure without its consent;

(b) surrender or abandon any of the Assets;

(c) amend or terminate any Title Document or any other agreement or document to which the Assets are subject (including without limitation any employment contract relating to the Employees), or enter into any new agreement or commitment relating to the Assets; or

(d) sell, encumber or otherwise dispose of any of the Assets or any part or portion thereof excepting sales of the Leased Substances or any of them in the normal course of business.

Notwithstanding the foregoing, Vendor may assume such obligations or commitments and propose or initiate such operations or the exercise of any such right or option without the prior consent of Purchaser, if Vendor reasonably determines that such expenditures or actions are necessary for the protection of life, property, or income, in which case Vendor shall promptly notify Purchaser of such intentions or actions and Vendor's estimate of the costs and expenses associated therewith.

8.3 **Post-Closing Administration**

From Closing until Purchaser becomes the recognized holder of the Assets in the place of Vendor, the provisions of clauses 8.1 and 8.2 shall apply to the Assets and Vendor shall, to the extent its interest permits and, subject to the Title Documents and other agreements to which the Assets are subject:

(a) hold possession of the Assets on behalf of and in trust for Purchaser and receive and hold all proceeds, benefits and advantages accruing from the Assets for the benefit, use and ownership of Purchaser, with entitlement to commingle any of them with its own or any other assets;

(b) in a timely manner deliver to Purchaser all revenues, proceeds and other benefits received by Vendor for the Assets after deduction of any amounts owing by Purchaser to Vendor in respect of the Assets;

(c) in a timely manner deliver to Purchaser all third party notices and communications received by Vendor for the Assets;

(d) in a timely manner deliver to third parties all notices and communications as Purchaser may reasonably request and all monies and other items Purchaser reasonably provides for the Assets; and

(e) as agent of Purchaser, do and perform all acts and things, and execute and deliver all agreements, notices and other documents and instruments, that Purchaser reasonably requests for the purpose of facilitating the exercise of rights incidental to the ownership of the Assets.

Vendor shall not be liable to Purchaser for any loss or damage suffered by Purchaser in connection with the arrangement established by this clause 8.3, except to the extent that the loss or damage is caused by Vendor's gross negligence or its willful misconduct. Purchaser shall indemnify and save Vendor and its directors, officers, servants, agents and employees harmless from and against any liabilities, losses, costs, claims, demands, actions, proceedings and damages (including legal costs on a solicitor/client basis) which may be brought against or suffered by any of them arising out of the performance by Vendor of its obligations under this clause 8.3. An action or omission of Vendor or its directors, officers, servants, agents or employees shall not be regarded as gross negligence or willful misconduct to the extent it was done or omitted to be done in accordance with the instructions of or with the concurrence of Purchaser. Nothing in this clause 8.3 shall be construed as extending or restricting or limiting in any manner any of the other representations, warranties or other obligations of the parties under this Agreement.

The Vendor may retain or subsequently obtain from Purchaser copies or photocopies of any of the documents included in the Miscellaneous Interests that it considers necessary to enable it to comply with any laws or the requirements of any authority.

All costs incurred in connection with the operation of the Assets, for which Vendor is operator, after the Closing Date until Vendor is relieved of its responsibilities as operator, shall be reimbursed by Purchaser to Vendor.

8.4 **Purchaser's Post Closing Obligations**

(a) Subject to Article 7.1, on and after the Closing Date, Purchaser shall be liable for and shall discharge and satisfy as they become due all obligations in respect of the Assets and the Title Documents including, without limitation:

(i) the payment of all royalties under the Title Documents; and

(ii) any and all statutes, orders, writs, injunctions or decrees of any governmental agency relating to the Assets.

(b) Promptly after Closing, Purchaser will remove any signs which indicate Vendor's ownership or operation of the Assets. If Purchaser fails to remove such signs, Vendor will have the right to enter onto the Lands for the purpose of removing the signs and all costs relating thereto will be for the Purchaser's account. Except for such grace period for eliminating usage of signs bearing Vendor's name, Purchaser will have no right to use any logos, trademarks, or trade names belonging to Vendor or its Affiliates.

(c) Promptly after Closing, Purchaser will erect or install any signs (i) required by governmental agencies to indicate that Purchaser is the operator of the Assets; and (ii) notifying working interest owners, purchasers of Petroleum Substances, lessors, suppliers, contractors, governmental agencies or any other third party of Purchaser's interest in the Assets.

For further certainty the provisions of this clause will survive the Closing.

ARTICLE 9
PREFERENTIAL RIGHTS

9.1 **Preferential Rights**

Within five (5) days from the execution and delivery of this Agreement, Purchaser shall advise Vendor in writing of its bona fide allocations of value for Vendor's Interest in and to that portion of the Assets subject to Preferential Rights. The Parties will consult with respect to that value or allocation as appropriate in the circumstances. Any dispute between the Parties with respect to that value or allocation will be resolved by a single arbitrator pursuant to the *Arbitration Act* (Alberta). Vendor shall comply with the applicable provisions of such Preferential Right and shall, as quickly as possible, send notices to the third parties (and Purchaser, if applicable) holding such rights. Vendor shall notify Purchaser in writing forthwith upon each third party exercising or waiving a Preferential Right. If any such third party elects to exercise such a right, the definition of Assets shall be deemed to be amended to exclude those Assets in respect of which the right has been exercised, such Assets shall not be conveyed to Purchaser and the Purchase Price, the tax allocations and the GST shall be reduced accordingly.

ARTICLE 10
PRECLOSING INFORMATION

10.1 **Title Examination**

At all reasonable times from the date hereof until the Closing Date, and subject to the Title Documents, any limitations arising out of the Miscellaneous Interests, and the provisions of any confidentiality or other agreements, Vendor shall, if and as requested by Purchaser, make available to Purchaser and Purchaser's counsel in Vendor's offices in Calgary, information pertaining to the Assets to which Vendor has possession or to which it has access.

ARTICLE 11
TITLE DEFECTS, CASUALTY LOSS AND MATERIAL ENVIRONMENTAL DEFICIENCY

11.1 **Notice of Material Title Defects**

(a) No later than twelve (12) Business Days prior to the Closing Date, Purchaser shall give Vendor written notice of Material Title Defects ("Notice"). Such Notice shall include:

(i) a description of each Material Title Defect, in reasonable detail and the Assets directly affected thereby;

(ii) supporting documents reasonably necessary for Vendor to verify the existence of the alleged Material Title Defect;

(iii) the Purchaser's *bona fide* estimate of the amount of the unadjusted Purchase Price to be allocated to each of the Assets affected by the Material Title Defect;

(iv) the amount by which the Purchaser reasonably believes the portion of the unadjusted Purchase Price allocated to the affected Assets pursuant to clause 11.1(a) (iii) has been or will be reduced by the Material Title Defect ("Material Title Defect Amount") together with the computations and information upon which Purchaser's belief is based; and

(v) Purchaser's requirements for the curing or removal of same.

Failure by the Purchaser to include a Material Title Defect in the Notice shall be deemed to be waiver of such Material Title Defect for the purposes hereof.

(b) Prior to the Closing Date, Vendor shall diligently make all reasonable efforts to cure or remove all Material Title Defects which are contained in the Notice. In order to maximize the time available to cure such Material Title Defects, Purchaser shall notify Vendor of the existence of any Material Title Defects on an on-going basis as soon as reasonably possible after becoming aware of same. If Vendor is unable to cure or remove any Material Title Defects on or before the third Business Day prior to the Closing Date and at such date there remains Material Title Defects and the aggregate value of the Material Title Defect Amount is:

(i) five percent (5%) or less of the Purchase Price, Purchaser shall complete the purchase of all of the Assets on the Closing Date without any adjustment to the Purchase Price;

(ii) greater than five percent (5%) of the Purchase Price, Purchaser may, subject to a Party's right to terminate this Agreement pursuant to clause 11.1(b)(iii), elect to:

(A) with the agreement of Vendor, postpone Closing for an additional ten (10) Business Days, in which case Vendor shall diligently continue to make all reasonable efforts to cure or remove all Material Title Defects; or

(B) waive the uncured or unremoved Material Title Defects, in which case Purchaser shall complete the purchase of the Assets on the Closing Date without any adjustment to the Purchase Price; or

(C) not waive the uncured or unremoved Material Title Defects, in which case Purchaser shall purchase the Assets (including the Assets that are affected by the uncured or unremoved Material Title Defects) and the Purchase Price shall be decreased by the Material Title Defect Amount;

(iii) twenty percent (20%) or more of the Purchase Price, in addition to the elections set out in clauses 11.1(b)(ii), either Vendor or Purchaser may terminate this Agreement upon written notice to the other Party, in which case the Parties shall have no further obligation to each other hereunder, except for obligations arising pursuant to clause 13.2 and the Vendor shall forthwith return to Purchaser the Deposit plus interest accrued thereon;

(c) if at the end of the ten (10) day period referred to in clause 11.1(b)(ii)(A) there remains uncured or unremoved Material Title Defects and the aggregate value of the Assets affected thereby are:

(i) five percent (5%) or less of the Purchase Price, Purchaser shall complete the purchase of all of the Assets on the second (2^{nd}) Business Day following such tenth (10^{th}) day without an adjustment to the Purchase price; or

(ii) greater than five percent (5%) of the Purchase Price, Purchaser shall then proceed to purchase all of the Assets on the second (2^{nd}) Business Day following such tenth (10^{th}) Business Day in accordance with either clause 11.1(b)(ii)(B) or (C), subject to a Party's right to terminate this Agreement pursuant to clause 11.1(b)(iii) and in such event, the events described in clause 11.1(b)(ii)(B) or (C) or 11.1(b)(iii), as the case may be, shall occur; and

(d) any election under clause 11.1(b)(ii) or (iii) must be made by Purchaser on or before 4:00 p.m., Calgary time, on the second Business Day prior to Closing. Any election under clause 11.1(c)(ii) must be made on or before 4:00 p.m., Calgary time, on the first Business Day following the end of the ten day period referred to therein. Failure by Purchaser to give timely notice of an election under either of clauses 11.1(b)(ii) or (iii) or 11.1(c)(ii) above shall be deemed to be a waiver by Purchaser of the remaining Material Title Defects and Vendor and Purchaser shall close the transactions contemplated hereunder on the Closing Date or the revised Closing Date, as the case may be, in accordance with the terms hereof.

11.2 **Value Disputes**

If Vendor disagrees with the value allocated by Purchaser to the Material Title Defect Amount, the Parties shall forthwith meet in good faith to discuss the issue. If after such a meeting the issue has not been resolved or if a Party does not forthwith meet to discuss the same, the issue shall be resolved by a single arbitrator pursuant to the *Arbitration Act* (Alberta). The decision of the arbitrator shall take into account the likelihood that such defect or omission shall manifest and shall be final and shall not be subject to review. All costs of arbitration shall be borne by the Parties equally. Closing shall proceed based upon the Purchase Price payable in accordance with clause 2.2. Within five (5) Business Days from the date the decision of the arbitrator has been rendered, the Parties shall make an adjustment between themselves to reflect the decision of the arbitrator.

11.3 **Casualty Loss**

(a) If, after the date of this Agreement but prior to the Closing Date, any portion of the Assets is destroyed by fire or other casualty and the loss as a result of such individual casualty exceeds five percent (5%) of the unadjusted Purchase Price, Purchaser will nevertheless be required to close and Vendor will elect by written notice to Purchaser prior to Closing to either (i) to cause the Assets affected by any casualty to be repaired or restored to at least its condition prior to such casualty, at Vendor's sole cost, as promptly as reasonably practicable (which work may continue after the Closing Date), (ii) to indemnify Purchaser through a document reasonably acceptable to Vendor and Purchaser against any costs or expenses that Purchaser reasonably incurs to repair the Assets subject to any casualty; or (iii) to treat such casualty as a Material Title Defect with respect to the affected Assets under clause 11.1. In each case, Vendor will retain all rights to insurance and other claims against third parties with respect to the casualty or taking except to the extent the Parties otherwise agree in writing.

(b) If after the date of this Agreement but prior to the Closing Date, any portion of the Assets is destroyed by fire or other casualty and the loss as a result of such individual casualty is five percent (5%) or less of the unadjusted Purchase Price, Purchaser will nevertheless be required to Close and Vendor will, at Closing, pay to Purchaser all sums paid to Vendor by third parties by reason of such casualty and will assign, transfer and set over to Purchaser or subrogate Purchaser to all of Vendor's right, title and interest (if any) in insurance claims, unpaid awards, and other rights against third parties (other than Affiliates of Vendor and its and their directors, officers, employees and agents) arising out of the casualty.

(c) Notwithstanding subclause 11.3(a) if after the date of this Agreement but prior to the Closing Date, any portion of the Assets is destroyed by fire or other casualty and the loss as a result of such individual casualty is twenty percent (20%) or more of the Purchase Price, the Purchaser may elect to terminate this Agreement in accordance with clause 3.2.

11.4 **Intentionally Deleted**

ARTICLE 12
INTENTIONALLY DELETED

ARTICLE 13
GENERAL

13.1 **Notices**

(a) All notices, waivers and other communications permitted or required hereunder shall be in writing and shall be delivered as follows:

(i) by personal service on a party at the address of such party set out below, in which case the item so served shall be deemed to have been received by that party when personally served; or

(ii) by facsimile transmission to a party to the fax number of such party set out below, in which case the item so transmitted shall be deemed to have been received by that party when successfully transmitted by the party sending such facsimile transmission;

A party may from time to time change its address for service or its fax number or both by giving written notice of such change to the other party.

(b) For the purposes of this clause 13.1, the address for service of the Parties shall be as follows:

Vendor: Anadarko Canada Corporation
Box 2595, Station "M"
425 - 1st Street S.W.
Calgary, Alberta T2P 4V4

Attention: Acquisitions and Divestitures Team Leader
Telephone: (403) 231-0372
Facsimile: (403) 231-0043

Purchaser: Coyote Energy Inc.
1800, 500 – 4th Avenue S.W.
Calgary, Alberta T2P 2V6

Attention: Al Ralston
Telephone: (403) 232-1522
Facsimile: (403) 207-1522

13.2 **Public Announcements**

In the event that Closing does not occur, or until Closing has occurred, each Party shall keep confidential all information obtained from the other party in connection with the Assets and shall not release any information concerning this Agreement and the transactions herein provided for, without the prior written consent of the other Party, which consent shall not be unreasonably withheld. Nothing contained herein shall prevent a party at any time from furnishing information (i) to any governmental agency or regulatory authority or to the public if required by applicable law, provided that the Parties shall advise each other in advance of any public statement which they propose to make; (ii) in connection with obtaining consents or complying with preferential, pre-emptive or first purchase rights contained in Title Documents and any other agreements and documents to which the Assets are subject.

13.3 **Enurement**

This Agreement enures to the benefit of and is binding upon the Parties and their respective successors and permitted assigns.

13.4 **Assignment**

A Party may not assign its interest in this Agreement without the prior written consent of the other Party, such consent not to be unreasonably withheld, provided however the Purchaser may, upon delivery of written notice, and delivery of a parental guarantee in form and substance satisfactory to the Vendor, acting reasonably, direct, assign and transfer all benefit under this Agreement and direct the conveyance and transfer of the Assets to any wholly owned subsidiary of Purchaser and such subsidiary will agree to be bound by the rights, duties, representations, warranties, covenants and obligations of Purchaser hereunder, provided however, that any such assignment will not relieve the Purchaser from any of its obligations hereunder.

13.5 **Time of Essence**

Time is of the essence in this Agreement.

13.6 **Governing Law**

This Agreement shall in all respects be governed by, interpreted and construed in accordance with the laws of the Province of Alberta and the laws of Canada applicable therein and shall in every regard be treated as a contract made in the Province of Alberta. The Parties irrevocably attorn to the exclusive jurisdiction of the courts of the Province of Alberta in respect of all matters arising out of this Agreement.

13.7 **Further Assurances**

Each Party will, from time to time and at all times after Closing, without further consideration, do such further acts and deliver all such further assurances, deeds and documents as shall be reasonably required in order to fully perform and carry out the terms of this Agreement.

13.8 **Waiver**

A waiver by either Party is not effective unless in writing and a waiver affects only the matter and its occurrence specifically identified in the writing granting the waiver and does not extend to any other matter or occurrence.

13.9 **No-Merger**

The covenants, representations, warranties and indemnities contained in this Agreement shall be deemed to be restated in any and all assignments, conveyances, transfers and other documents conveying the interests of Vendor in and to the Assets to Purchaser, subject to any and all time and other limitations contained in this Agreement. There shall not be any merger of any covenant, representation, warranty or indemnity in such assignments, conveyances, transfers and other documents notwithstanding any rule of law, equity or statute to the contrary and such rules are hereby waived.

13.10 **No Amendment Except in Writing**

No amendment shall be made to this Agreement unless in writing, executed by the Parties.

13.11 **Intentionally Deleted**

13.12 **Operatorship**

Purchaser acknowledges that Vendor is unable to assign to Purchaser operatorship of the Assets. Vendor shall, however, use reasonable efforts to assist Purchaser in its attempts to obtain operatorship of such Assets.

13.13 **Counterpart**

This Agreement may be executed in as many counterparts as are necessary and all executed counterparts together shall constitute one agreement.

13.14 **Invalidity**

If any provisions of this Agreement should be invalid, illegal or unenforceable in any respect, the validity, legality or enforceability of the remaining provisions contained herein shall not in any way be affected or impaired thereby.

13.15 **Intentionally Deleted**

IN WITNESS WHEREOF the Parties have duly executed this Agreement as of the date first above written.

ANADARKO CANADA CORPORATION

Per: *(signed)*

COYOTE ENERGY INC.

Per: *(signed)*

Schedules intentionally deleted

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COYOTE ENERGY INC.

Evaluation of Oil & Gas Reserves
Based on Escalating Price Assumptions

As of August 1, 2002

McDANIEL & ASSOCIATES
consultants ltd.

Oil and Gas Reservoir Engineering

COYOTE ENERGY INC.

Evaluation of Oil & Gas Reserves Based on Escalating Price Assumptions

As of August 1, 2002

Prepared For:

Coyote Energy Inc.
2200, 400 - 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Prepared By:

McDaniel & Associates Consultants Ltd.
2200, 255 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G6

August 2002

McDANIEL & ASSOCIATES
consultants ltd.

COYOTE ENERGY INC.

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APPENDIX 6 PROVED UNDEVELOPED RESERVES

APPENDIX 7 SUMMARY OF RESERVE ESTIMATES

APPENDIX 8 COMPANY INTEREST DATA

August 21, 2002

Coyote Energy Inc.
2200, 400 – 3rd Avenue S.W.
Calgary, Alberta
T2P 4H2

Attention: Mr. Jacob Roorda, President

Reference: **Coyote Energy Inc.**
Evaluation of Oil & Gas Reserves
Escalating Price Assumptions

Dear Sir:

Pursuant to your request we have prepared an evaluation of the crude oil, natural gas and natural gas products reserves and the present worth values of these reserves for the petroleum and natural gas interests of Coyote Energy Inc., hereinafter referred to as the "Company", as of August 1, 2002. The future net revenues and present worth values presented in this report were calculated using "Escalating Price" assumptions based on our opinion of the future crude oil, natural gas and natural gas product prices at July 1, 2002 and were presented in Canadian dollars before income tax.

The properties evaluated in this report were indicated to include essentially all of the Company's conventional petroleum and natural gas interests in Canada. The Company's principal crude oil properties are located in the Hayter and Thompson Lake areas in the province of Alberta. The principal natural gas property is located in the Thompson Lake area in the province of Alberta.

All of the Company's properties were evaluated in detail for this report, except for the Hayter and West Provost areas which were recently acquired from Anadarko Canada Corporation. These two properties were evaluated in detail by McDaniel & Associates for Anadarko as of June 1, 2002 and were mechanically updated to August 1, 2002 for this evaluation with no changes to the evaluation parameters.

The Company's share of proved remaining and probable additional crude oil, natural gas and natural gas products reserves as of August 1, 2002 and the respective present worth values assigned to these reserves based on "Escalating Price" assumptions were estimated to be as follows:

ESTIMATED COMPANY SHARE OF REMAINING RESERVES
AS OF AUGUST 1, 2002
MMCF, MBBL

	Proved Producing	Proved Non-Producing	Proved Undeveloped	Total Proved	Probable Additional	Total
Crude Oil						
Gross (1)	9,177	36	1,867	11,081	2,526	13,607
Net (2)	8,169	33	1,532	9,734	2,212	11,946
Natural Gas						
Gross (1)	1,348	298	-	1,646	340	1,986
Net (2)	1,079	233	-	1,312	266	1,578
Natural Gas Liquids						
Gross (1)	73	-	-	73	18	91
Net (2)	56	-	-	56	14	69

ESTIMATED COMPANY SHARE OF PRESENT WORTH VALUES BEFORE INCOME TAX
AS OF AUGUST 1, 2002
$1000 (3) (4)

	Discounted At				
	0%	10%	12%	15%	20%
Proved Developed Producing Reserves	99,174	83,660	81,234	77,911	73,079
Proved Developed Non-Producing Reserves	1,205	935	892	833	748
Proved Undeveloped Reserves	17,173	13,481	12,881	12,049	10,819
Total Proved Reserves	117,553	98,076	95,007	90,793	84,646
Probable Additional Reserves-Unrisked	30,401	20,879	19,569	17,854	15,526
Total Proved & Probable Reserves-Unrisked	**147,954**	**118,955**	**114,576**	**108,647**	**100,172**
Probable Additional Reserves-Risked (5)	15,201	10,440	9,785	8,927	7,763
Total Proved & Probable Reserves-Risked (5)	**132,753**	**108,515**	**104,791**	**99,720**	**92,409**

(1) Gross reserves are defined as the aggregate of the Company's working interest and royalty interest reserves before deductions of royalties payable to others.
(2) Net reserves are gross reserves less all royalties payable to others.
(3) Financial matters such as prepayments, take or pay payments, general obligations, etc. were not included.
(4) Based on "Escalating Price" assumptions at July 1, 2002 (see Price Schedules).
(5) Includes a 50 percent reduction in the probable present worth values to account for the risk associated with the probable additional reserves.

The Company's share of remaining reserves and present worth values are presented on a total Company basis in the summary section of this report. The location of the Company's properties and a graphical summary of the forecast production, net income and reserve distributions are also presented in this section. Tables summarizing the reserves, production and revenues for the various reserve classes are presented in Appendices 1 to 7. A summary of the Company's interests and encumbrances in each property is presented in Appendix 8. Discussions of the assumptions and methodology employed to prepare the reserve estimates and revenue forecasts are also contained in the "Evaluation Methodology" section.

Detailed reserve estimates and revenue forecasts and other supporting data for each of the properties that were reviewed in detail were provided in the detailed property report. Property discussions and a detailed description of the economic factors employed to derive the cash flow forecasts were also included therein.

The extent and character of all factual information supplied by the Company including ownership, well data, production, prices, revenues, operating costs, contracts, and other relevant data were relied upon by us in preparing this report and has been accepted as represented without independent verification. In view of the generality of the assignment the opinions expressed are not intended to provide a stand alone analysis of any specific property but to relate to an overall evaluation of the reserves of the Company.

This report was prepared by McDaniel & Associates Consultants Ltd. for the exclusive use of Coyote Energy Inc. and is not to be reproduced, distributed or made available, in whole or in part, to any person, company or organization other than Coyote Energy Inc. without the knowledge and consent of McDaniel & Associates Consultants Ltd. We reserve the right to revise any estimates provided herein if any relevant data existing prior to preparation of this report was not made available or if any data provided was found to be erroneous.

Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by B. H. Emslie"

B. H. Emslie, P. Eng.

"signed by R. Ott"

R. Ott, P. Geol.

BHE/RO:po
[02-421]

PERMIT TO PRACTICE
McDANIEL & ASSOCIATES CONSULTANTS LTD.

Signature "signed by B. H. Emslie"

Date Wednesday, August 21, 2002

PERMIT NUMBER: P 3145

The Association of Professional Engineers, Geologists and Geophysicists of Alberta

CERTIFICATE OF QUALIFICATION

I, Bryan Howard Emslie, Petroleum Engineer of 2200, 255 - 5th Avenue S.W., Calgary, Alberta, Canada hereby certify:

1. That I am a Senior Vice President of McDaniel & Associates Consultants Ltd. which Company did prepare, at the request of Coyote Energy Inc., the report entitled "Coyote Energy Inc., Evaluation of Oil & Gas Reserves, Based on Escalating Price Assumptions, As of August 1, 2002", dated August 21, 2002; and that I was involved in the preparation of this report.

2. That I attended the University of Alberta in the years 1973 to 1980 and that I graduated with Bachelor of Science Degree in Mechanical Engineering, that I am a registered Professional Engineer of the Association of Professional Engineers, Geologists & Geophysicists of Alberta and that I have in excess of twenty years experience in oil and gas reservoir studies and evaluations.

3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Coyote Energy Inc., any associate or affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

"signed by B. H. Emslie"

B. H. Emslie, P. Eng.

Calgary, Alberta
Dated: August 21, 2002

CERTIFICATE OF QUALIFICATION

I, Ronald Ott, Petroleum Geologist of 2200, 255 - 5th Avenue, S.W., Calgary, Alberta, Canada hereby certify:

1. That I am Chief Geologist of McDaniel & Associates Consultants Ltd. which Company did prepare, at the request of Coyote Energy Inc., the report entitled "Coyote Energy Inc., Evaluation of Oil & Gas Reserves, Based on Escalating Price Assumptions, As of August 1, 2002", dated August 21, 2002, and that I was involved in the preparation of this report.

2. That I attended University of Calgary in the years 1984 to 1988, graduating with a Bachelor of Science degree in Geology; that I am a member of the Canadian Society of Petroleum Geologists; that I am a registered Professional Geologist of the Association of Professional Engineers, Geologists & Geophysicists of Alberta and that I have in excess of eight years experience in oil and gas reservoir studies and evaluations.

3. That McDaniel & Associates Consultants Ltd., its officers or employees, have no direct or indirect interest, nor do they expect to receive any direct or indirect interest in any properties or securities of Coyote Energy Inc., any associate or affiliate thereof.

4. That the aforementioned report was not based on a personal field examination of the properties in question, however, such an examination was not deemed necessary in view of the extent and accuracy of the information available on the properties in question.

"signed by R. Ott"

R. Ott, P. Geol.

Calgary, Alberta
Dated: August 21, 2002

Coyote Energy Inc.

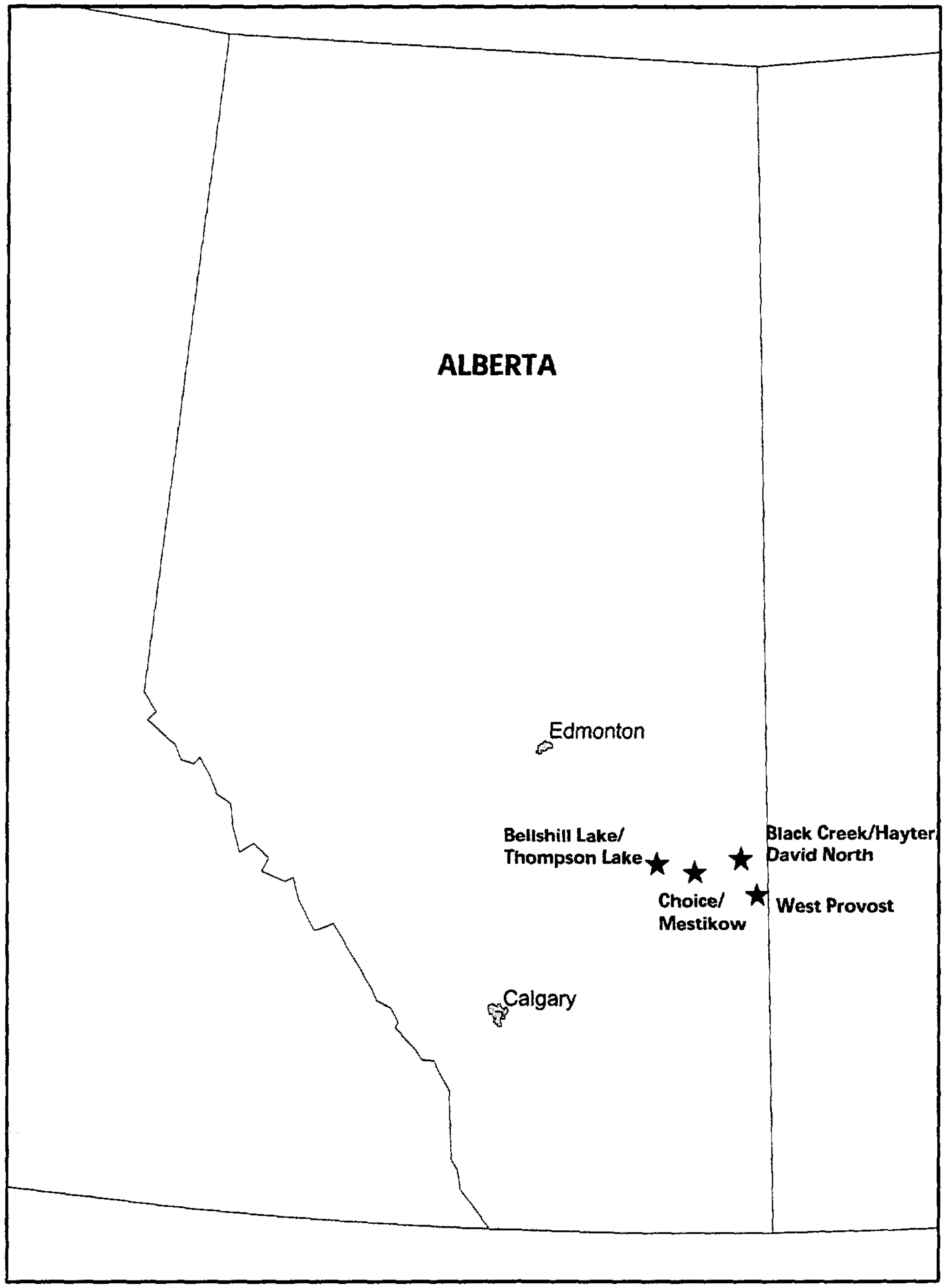
Total Company Reserves and Present Worth Values
Escalating Prices as of August 1, 2002
Proved & Probable Reserves - Unrisked

Total Of All Areas

	Company Share of Remaining Reserves (mbbl,mmcf,mlt)		Company Share of Present Worth Values Before Income Tax (4)(5)(6) (M$)				
	Gross (1)	Net (2)	@0.0%	@10.0%	@12.0%	@15.0%	@20.0%
Proved Producing Reserves							
Crude Oil	9,177.4	8,169.2	94,609.1	80,130.8	77,856.3	74,735.3	70,188.6
Natural Gas	1,348.3	1,078.8	3,187.3	2,441.1	2,333.9	2,191.1	1,991.5
Natural Gas Liquids	73.4	55.6	1,378.1	1,088.1	1,044.0	984.1	898.7
Total			**99,174.4**	**83,660.0**	**81,234.2**	**77,910.5**	**73,078.8**
Proved Non-Producing Reserves							
Crude Oil	36.2	32.8	517.9	384.8	364.1	335.9	295.4
Natural Gas	298.1	232.9	687.1	549.8	527.6	497.0	451.9
Natural Gas Liquids	0.0	0.0	0.4	0.3	0.3	0.2	0.2
Total			**1,205.3**	**934.9**	**892.0**	**833.1**	**747.5**
Proved Undeveloped Reserves							
Crude Oil	1,867.3	1,532.3	17,172.7	13,480.5	12,880.8	12,049.0	10,819.3
Total			**17,172.7**	**13,480.5**	**12,880.8**	**12,049.0**	**10,819.3**
Total Proved Reserves							
Crude Oil	11,080.8	9,734.2	112,299.7	93,996.2	91,101.2	87,120.3	81,303.3
Natural Gas	1,646.4	1,311.7	3,874.4	2,990.9	2,861.6	2,688.1	2,443.4
Natural Gas Liquids	73.4	55.7	1,378.4	1,088.4	1,044.2	984.4	898.9
Total			**117,552.5**	**98,075.5**	**95,007.0**	**90,792.7**	**84,645.5**
Total Probable Reserves							
Crude Oil	2,526.1	2,212.1	29,222.3	20,153.8	18,903.6	17,265.5	15,039.1
Natural Gas	339.7	266.1	838.4	527.4	486.1	432.9	362.0
Natural Gas Liquids	18.0	13.6	340.3	197.9	179.4	155.8	125.1
Total			**30,401.1**	**20,879.0**	**19,569.1**	**17,854.2**	**15,526.2**
Total Proved & Probable Reserves							
Crude Oil	13,606.9	11,946.3	141,522.0	114,150.0	110,004.7	104,385.8	96,342.4
Natural Gas	1,986.1	1,577.8	4,712.8	3,518.4	3,347.7	3,120.9	2,805.4
Natural Gas Liquids	91.4	69.3	1,718.7	1,286.3	1,223.6	1,140.2	1,024.0
Total			**147,953.5**	**118,954.6**	**114,576.0**	**108,647.0**	**100,171.9**
BOE Reserves & PWV/BOE (3)							
Proved Producing	9,475.5	8,404.6	10.47	8.83	8.57	8.22	7.71
Proved Non-Producing	85.8	71.6	14.04	10.89	10.39	9.70	8.71
Proved Undeveloped	1,867.3	1,532.3	9.20	7.22	6.90	6.45	5.79
Total Proved	11,428.6	10,008.5	10.29	8.58	8.31	7.94	7.41
Total Probable	2,600.7	2,270.0	11.69	8.03	7.52	6.87	5.97
Total Proved & Probable	14,029.3	12,278.5	10.55	8.48	8.17	7.74	7.14

(1) Before royalty deductions.
(2) After royalty deductions.
(3) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE based on Gross BOE reserves.
(4) No allowance was made for the degree of risk associated with any of the reserve categories.
(5) Before allowance for Alberta Royalty Tax Credit
(6) Costs associated with extraction of natural gas products have in most cases been deducted from the natural gas revenues.

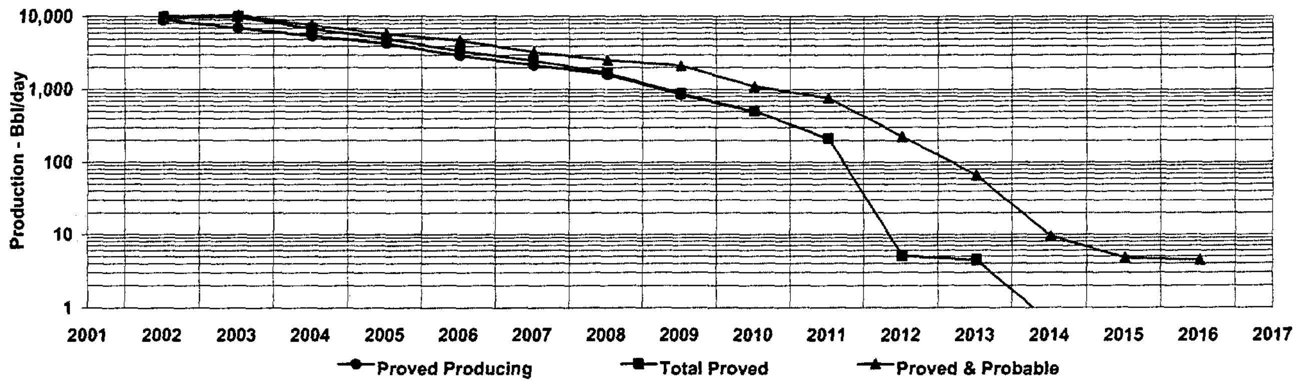
Coyote Energy Inc.
Location of Properties



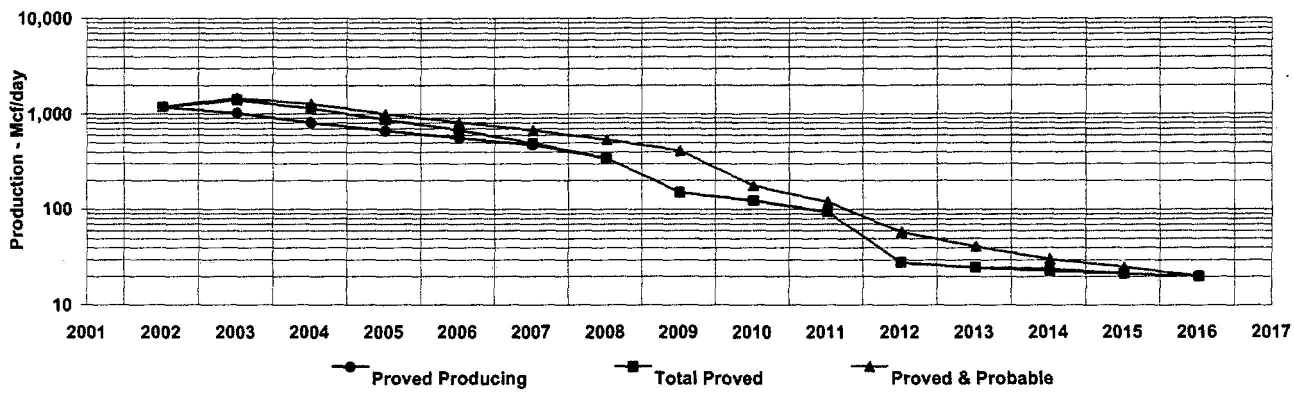
McDaniel & Associates Consultants Ltd.

Coyote Energy Inc.
Escalating Prices
Total Company
Company Share

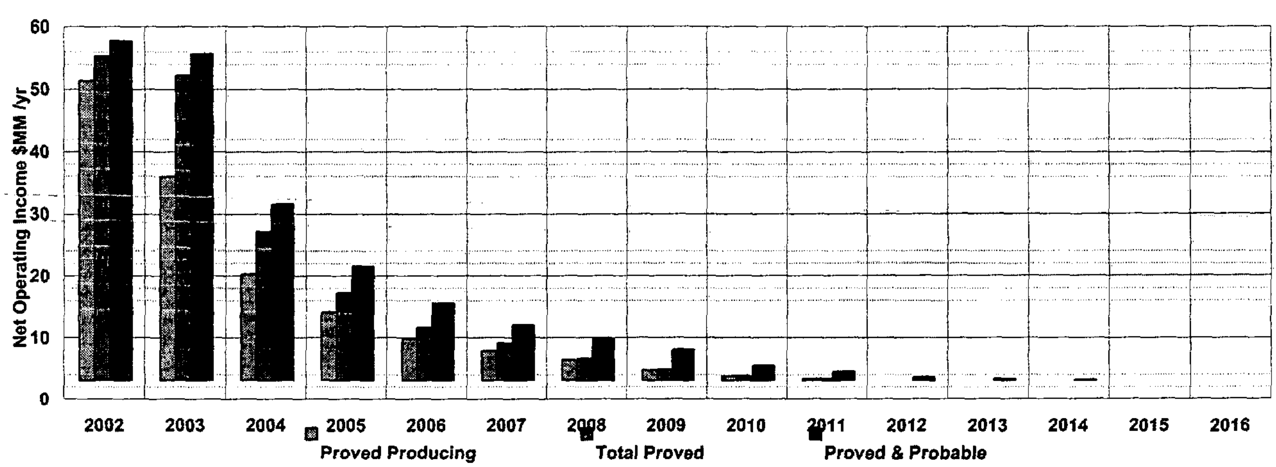
Crude Oil Production Profile



Natural Gas Production Profile



Before Tax Net Operating Income Profile



McDaniel & Associates
Consultants Ltd.

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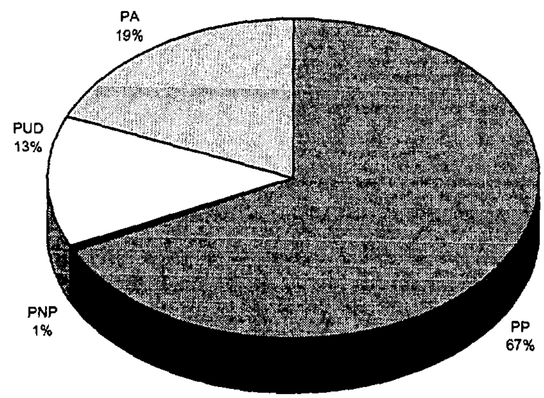
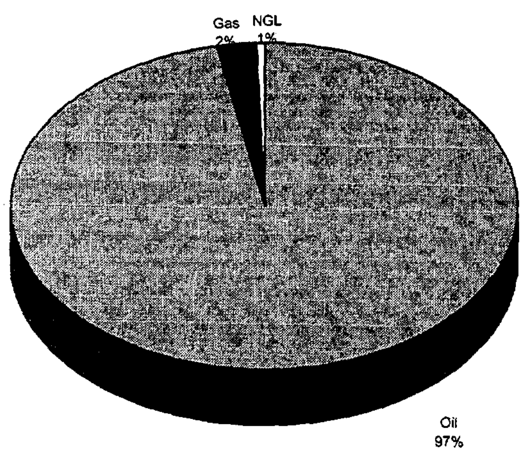
Coyote Energy Inc.
Escalating Prices
Reserve Distribution by Reserve Class and Product

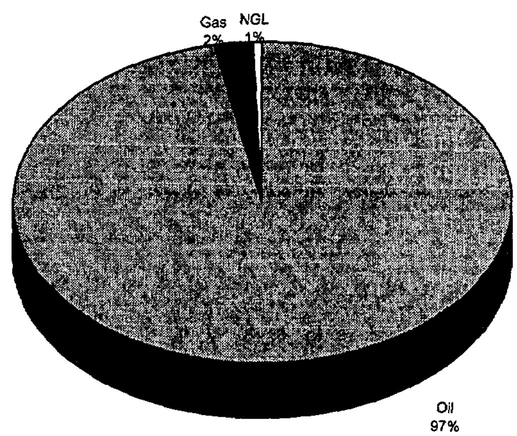
Reserve Distribution by Reserve Class



Reserve Distribution by Product Total Proved Reserves

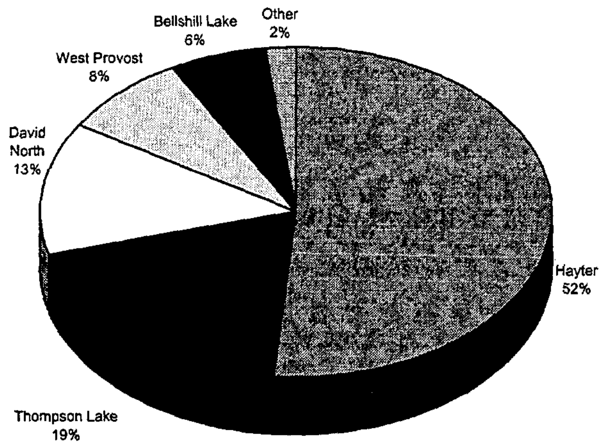


Reserve Distribution by Product Proved & Probable Reserves

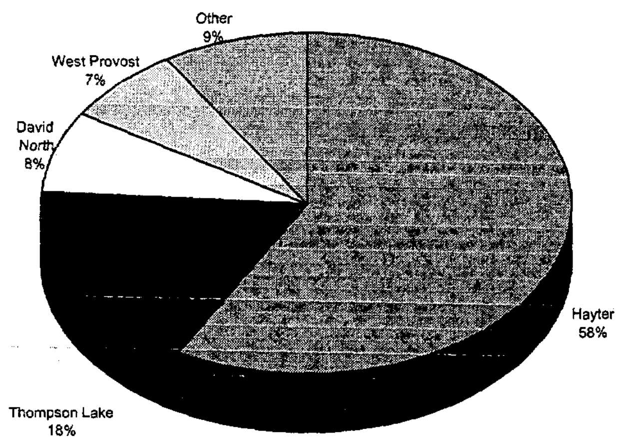


Coyote Energy Inc.
Escalating Prices
Reserve and Present Worth Value Distribution For Major Properties
Total Proved Reserves

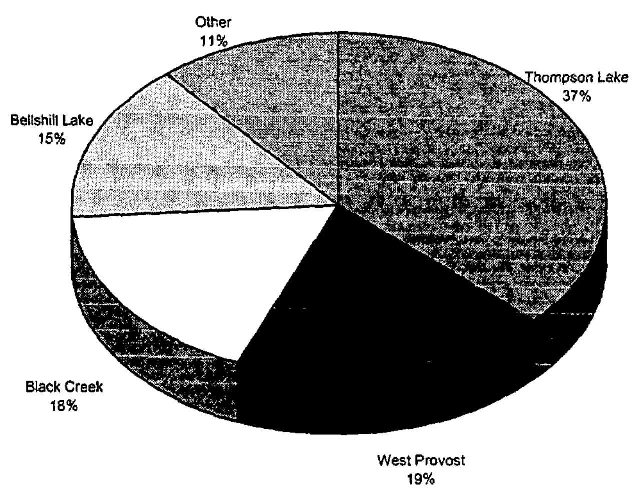
Top 5 Properties by 15% PWV



Top 4 Crude Oil Properties



Top 4 Natural Gas Properties



McDaniel & Associates
Consultants Ltd.

2421EscGraphs8/21/02

Table 1

McDaniel & Associates Consultants Ltd.

Summary of Price Forecasts

July 1, 2002

Year	WTI Crude Oil $US/BBL (1)	Edmonton Light Crude Oil $C/BBL (2)	Bow River Medium Crude Oil $C/BBL (3)	Heavy Crude Oil $C/BBL (4)	Alberta Average Natural Gas $C/Mmbtu (5)	Edmonton Cond. & Natural Gasolines $/Bbl	Edmonton Propane $/Bbl	Edmonton Butanes $/Bbl	Edmonton NGL Mix $/Bbl (6)	Sulphur $/LT	Inflation %	US/CAN Exchange Rate $US/$CAN
History												
1986	15.00	20.50	15.11	na	2.35	20.10	13.96	17.30	16.40	129.40	4.2	0.719
1987	19.30	24.30	20.79	na	1.64	23.80	9.98	16.80	15.10	89.20	4.4	0.755
1988	16.00	18.70	14.41	na	1.44	18.30	8.19	12.95	11.90	75.95	4.0	0.812
1989	19.60	22.20	18.09	na	1.47	21.80	8.14	10.35	11.60	72.00	5.0	0.844
1990	24.50	27.60	21.06	16.00	1.45	27.00	13.67	16.21	17.20	59.60	4.8	0.857
1991	21.40	23.40	15.07	9.05	1.18	22.90	11.91	15.25	15.30	54.15	5.6	0.873
1992	20.55	23.50	17.52	12.95	1.22	23.00	10.55	14.05	14.30	21.00	1.5	0.828
1993	18.60	21.90	16.70	13.30	1.89	21.50	14.10	13.55	15.40	-4.90	1.8	0.775
1994	17.20	22.20	18.43	15.00	1.83	21.75	12.50	13.45	14.70	11.65	0.2	0.732
1995	18.45	24.25	20.80	17.25	1.18	23.76	13.90	13.80	15.80	24.64	2.2	0.729
1996	22.10	29.35	25.11	20.05	1.50	28.75	22.20	17.15	21.70	12.63	1.6	0.733
1997	20.55	27.80	21.22	14.40	1.85	31.10	18.60	19.05	21.30	11.41	1.6	0.722
1998	14.40	20.35	14.60	9.40	1.90	21.85	10.95	11.90	13.50	8.54	1.0	0.687
1999	19.25	27.60	23.35	19.65	2.60	27.60	15.45	17.73	18.70	14.67	1.7	0.673
2000	30.31	44.72	34.35	27.80	5.20	46.25	31.55	35.00	35.70	15.00	2.7	0.674
2001	25.97	39.60	25.07	17.97	5.25	42.42	29.15	28.45	30.85	na	2.0	0.646
2002 (6mo)	23.95	37.25	29.45	25.45	3.53	37.20	16.35	21.95	22.35	na	2.0	0.635
Forecast												
2002 (6 mo)	25.00	37.50	31.50	25.00	4.50	37.50	25.20	24.70	27.50	0.00	2.0	0.650
2003	23.50	35.10	30.10	24.10	4.70	35.10	24.70	23.10	26.20	0.00	2.0	0.650
2004	21.80	32.00	27.00	21.00	4.55	32.00	23.10	21.10	24.20	0.00	2.0	0.660
2005	22.20	32.10	27.10	21.10	4.50	32.10	23.00	21.20	24.20	0.00	2.0	0.670
2006	22.60	32.20	27.20	21.20	4.45	32.20	23.00	21.20	24.20	0.00	2.0	0.680
2007	23.10	32.90	27.90	21.90	4.50	32.90	23.40	21.70	24.70	2.50	2.0	0.680
2008	23.60	33.60	28.60	22.60	4.50	33.60	23.60	22.20	25.10	5.00	2.0	0.680
2009	24.10	34.30	29.30	23.30	4.55	34.30	24.00	22.60	25.60	7.50	2.0	0.680
2010	24.60	35.00	30.00	24.00	4.65	35.00	24.50	23.10	26.10	10.00	2.0	0.680
2011	25.10	35.70	30.70	24.70	4.75	35.70	25.00	23.50	26.60	10.00	2.0	0.680
2012	25.60	36.40	31.40	25.40	4.85	36.40	25.50	24.00	27.20	10.00	2.0	0.680
2013	26.10	37.10	32.10	26.10	4.95	37.10	26.10	24.50	27.70	10.00	2.0	0.680
2014	26.60	37.80	32.80	26.80	5.00	37.80	26.40	24.90	28.20	10.00	2.0	0.680
2015	27.10	38.60	33.60	27.60	5.10	38.60	27.00	25.50	28.80	10.00	2.0	0.680
2016	27.60	39.30	34.30	28.30	5.20	39.30	27.50	25.90	29.30	10.00	2.0	0.680
2017	28.20	40.10	35.10	29.10	5.35	40.10	28.20	26.40	30.00	10.00	2.0	0.680
2018	28.80	41.00	36.00	30.00	5.45	41.00	28.70	27.00	30.60	10.00	2.0	0.680
2019	29.40	41.80	36.80	30.80	5.55	41.80	29.30	27.60	31.20	10.00	2.0	0.680
2020	30.00	42.70	37.70	31.70	5.65	42.70	29.90	28.20	31.90	10.00	2.0	0.680
2021	30.60	43.50	38.50	32.50	5.80	43.50	30.50	28.70	32.50	10.00	2.0	0.680
Thereafter	30.60	43.50	38.50	32.50	5.80	43.50	30.50	28.70	32.50	10.00	0.0	0.680

(1) West Texas Intermediate at Cushing Oklahoma
(2) Edmonton price for 40 API, 0.5% sulphur crude
(3) Bow River 26 degrees/2.1% sulphur crude oil at Hardisty Alberta
(4) Heavy crude oil 12 degrees at Hardisty Alberta
(5) Average Alberta field price
(6) NGL Mix based on 45 percent propane, 35 percent butane and 20 percent natural gasolines.

G020701 - Effective July 1, 2002

Table 2

McDaniel & Associates Consultants Ltd.

Summary of Natural Gas Price Forecasts

July 1, 2002

Year	U.S. Henry Hub Gas Price $US/Mmbtu	AECO Spot Price $C/GJ	Alberta Average Plantgate $C/Mmbtu (1)	Aggregator Plantgate $C/Mmbtu	Alberta Spot Sales Plantgate $C/Mmbtu	Sask. Prov. Gas Plantgate $C/Mmbtu	Sask. Spot Sales Plantgate $C/Mmbtu	British Columbia CanWest Plantgate $C/Mmbtu	British Columbia CanWest Wellhead $C/Mcf	B.C. Spot Sales Plantgate $C/Mmbtu
History										
1986	1.75	-	2.35	2.59	-	2.51	-	-	-	-
1987	1.50	-	1.64	1.82	-	1.86	-	-	-	-
1988	1.85	-	1.44	1.66	1.21	1.86	-	-	-	-
1989	1.68	-	1.47	1.57	1.28	1.60	-	-	-	-
1990	1.67	-	1.45	1.64	1.20	1.67	-	-	-	-
1991	1.54	-	1.18	1.31	0.97	1.61	-	-	-	1.13
1992	1.79	-	1.22	1.30	1.04	1.51	-	1.47	1.11	1.10
1993	2.13	-	1.89	1.60	2.16	2.16	-	1.73	1.37	2.13
1994	1.92	1.88	1.83	1.81	1.86	1.92	-	1.81	1.45	1.87
1995	1.62	1.12	1.18	1.23	1.02	1.35	-	1.29	0.90	1.12
1996	2.50	1.39	1.54	1.63	1.34	1.52	-	1.51	1.14	1.47
1997	2.59	1.71	1.84	1.86	1.67	1.85	-	1.78	1.43	1.98
1998	2.06	1.96	1.90	1.88	1.84	2.05	-	1.94	1.59	2.00
1999	2.28	2.79	2.60	2.46	2.78	2.82	2.96	2.52	2.19	2.77
2000	4.31	5.32	5.20	4.57	5.38	4.78	4.83	5.27	5.05	4.88
2001	3.98	5.15	5.25	5.25	5.25	5.70	6.15	6.75	6.58	6.30
2002 (6mo)	2.98	3.53	3.53	3.38	3.75	3.70	3.75	3.29	2.99	3.80
Forecast										
2002 (6 mo)	3.36	4.39	4.50	4.50	4.50	4.65	4.65	4.40	4.16	4.50
2003	3.53	4.62	4.70	4.70	4.70	4.85	4.85	4.60	4.36	4.70
2004	3.46	4.44	4.55	4.55	4.55	4.71	4.71	4.45	4.20	4.55
2005	3.48	4.40	4.50	4.50	4.50	4.66	4.66	4.40	4.13	4.50
2006	3.51	4.36	4.45	4.45	4.45	4.61	4.61	4.35	4.07	4.45
2007	3.54	4.40	4.50	4.50	4.50	4.67	4.67	4.40	4.12	4.50
2008	3.58	4.44	4.50	4.50	4.50	4.67	4.67	4.40	4.11	4.50
2009	3.62	4.48	4.55	4.55	4.55	4.72	4.72	4.45	4.15	4.55
2010	3.69	4.57	4.65	4.65	4.65	4.83	4.83	4.55	4.24	4.65
2011	3.77	4.67	4.75	4.75	4.75	4.93	4.93	4.65	4.34	4.75
2012	3.84	4.76	4.85	4.85	4.85	5.03	5.03	4.75	4.43	4.85
2013	3.92	4.85	4.95	4.95	4.95	5.14	5.14	4.85	4.53	4.95
2014	3.99	4.94	5.00	5.00	5.00	5.19	5.19	4.90	4.57	5.00
2015	4.07	5.04	5.10	5.10	5.10	5.29	5.29	5.00	4.66	5.10
2016	4.14	5.13	5.20	5.20	5.20	5.40	5.40	5.10	4.76	5.20
2017	4.23	5.24	5.35	5.35	5.35	5.55	5.55	5.25	4.90	5.35
2018	4.32	5.35	5.45	5.45	5.45	5.66	5.66	5.35	4.99	5.45
2019	4.41	5.47	5.55	5.55	5.55	5.76	5.76	5.45	5.09	5.55
2020	4.50	5.58	5.65	5.65	5.65	5.86	5.86	5.55	5.18	5.65
2021	4.59	5.69	5.80	5.80	5.80	6.02	6.02	5.70	5.32	5.80
Thereafter	4.59	5.69	5.80	5.80	5.80	6.02	6.02	5.70	5.32	5.80

(1) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the crown royalty calculations.

Evaluation Methodology

INTRODUCTION

Estimates of the crude oil, natural gas and natural gas products reserves and the associated present worth values before income taxes attributable to the Canadian properties of the Company have been presented in this report as of August 1, 2002. Reserve estimates were prepared for 8 individual properties in which the Company was indicated to have an interest in Western Canada based on detailed studies of the reservoir and performance characteristics as well as historical revenues and costs.

The basic information employed in the preparation of this report was obtained from the Company's files, published sources and from our own files. Detailed reserve estimates and revenue forecasts and other supporting data for each of the properties that were reviewed in detail were provided in the detailed property report. Property discussions and a detailed description of the economic factors employed to derive the cash flow forecasts were also included therein.

The effective date of this report is August 1, 2002. The reserve estimates presented herein were based on the operating and economic conditions and development status as of that date except for changes planned for the immediate future or in the process of implementation. The assumptions and methodology employed in the preparation of this report conform with generally accepted petroleum engineering and evaluation principles. A brief review of the methodology employed in arriving at the reserves and present worth value estimates is presented in this section.

RESERVE ESTIMATES

Crude Oil

The crude oil reserve estimates presented in this report were based on a study of the volumetric data and performance characteristics of the individual wells and reservoirs in question. The oil-in-place estimates were based on individual well pore volume interpretations, geological studies of pool configurations as well as unitization studies and published estimates. In those cases where indicative oil production decline and/or increasing gas-oil and water-oil ratio trends were evident, the remaining reserves were determined by extrapolating these trends to economic limiting conditions. Where definitive production information was not yet available, the reserve estimates were based on analogy with similar wells or reservoirs or on theoretical studies of recovery efficiencies. The cumulative production figures were taken from published sources or from records of the Company and estimated for those recent periods where such data were not available.

Natural Gas and Products

The natural gas reserve estimates were based on a study of the volumetric data and performance characteristics of the individual wells and reservoirs in question. Volumetric estimates of the gas-in-place were based on individual well pore volume interpretations, geological studies of the pools and areas and on unitization studies and published estimates. Material balance estimates of the gas-in-place were employed where such information was available. The reserves recoverable from the currently producing properties were estimated from studies of performance characteristics and/or reservoir pressure histories. In cases of competitive drainage in multi-well pools the reserves were based on an analysis of the relevant factors relating to the future pool depletion by existing and possible future wells. The recovery factors for the non-producing properties were estimated from a consideration of test rates, reservoir pressures and by analogy with similar wells or reservoirs.

The natural gas products reserve estimates for the producing properties were predicated on a study of historical and anticipated future recoveries of these products from the natural gas reserves. The natural gas products recoveries from the non-producing natural gas reserves were estimated from gas analyses, well test information and from analogy with similar reservoirs. Natural gas products reserves were only assigned to non-producing properties in those cases where, in all likelihood the gas production would be processed through existing facilities capable of extracting these products or where such a facility will be available in the near future.

RESERVE CLASSIFICATION

The crude oil, natural gas and natural gas products reserves of the Company were classified into proved and probable additional categories. The proved reserves were considered to be those reserves estimated as recoverable under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir. Probable reserves are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future. A more detailed description of the factors considered in making these reserve assignments is presented in the "Reserve Definitions" at the end of this section.

The proved reserves have been further subdivided into proved producing, proved non-producing and proved undeveloped categories. Reserves were considered to be producing if these reserves are currently being produced or if definitive steps are being taken to begin production of these reserves in the immediate future. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area. Non-producing reserves recoverable from existing wells that require relatively minor capital expenditures to produce were classified as proved non-producing. Reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure is required were classified as proved undeveloped.

In all cases the crude oil and natural gas liquids reserves were expressed in barrels being equal to 34.972 Imperial gallons. The natural gas reserves were presented in thousands of standard cubic feet (MCF) and calculated at a base pressure of 14.65 psia and a base temperature of 60 degrees Fahrenheit.

Company Share of Reserves

The Company's net share of reserves was obtained by employing the Company's indicated gross working and royalty interests in the various properties in question less all royalties owned by others. In estimating net reserves the applicable Crown royalties were based on the regulations in effect as of August 1, 2002.

PRESENT WORTH VALUE ESTIMATES

The present worth values of the crude oil, natural gas and natural gas products reserves were obtained by employing future production and revenue analyses. The future crude oil production was in each instance predicated on a forecast of allowable rates and/or anticipated performance characteristics of the individual wells and reservoirs in question. The future natural gas production was predicated on the provisions of the natural gas purchase contracts where such contracts were available with consideration to the historical producing rates and the estimated deliverability. In those areas where shut-in natural gas reserves exist commencement of production was based on the proximity to a pipeline connection and the relevant factors relating to the future marketing of the reserves. Solution gas production was based on the forecast of the oil producing rates and producing gas-oil ratios. The natural gas products production forecasts were based on the anticipated recoveries of these products from the produced natural gas.

The Company's gross share of future crude oil revenue was derived by employing the Company's gross share of production and the forecast reference Edmonton crude oil prices less the historical quality and transportation price differential for each respective field. The forecast natural gas prices with an adjustment for the heating value of the gas were employed to calculate the gross share of future natural gas revenues. The forecast Edmonton natural gas products prices with adjustments to reflect historical price differentials realized by the Company in each respective property were employed to calculate the gross share of natural gas products revenues. Royalties and mineral taxes payable to the Crown were estimated based on the methods in effect as of August 1, 2002. Overriding royalties payable to others were estimated based on the indicated applicable rates. In those cases where a proportionate share of the natural gas gathering and processing charges were indicated to be payable by the Crown or royalties owned by others, these charges have been deducted in determining the net royalties payable.

In all cases, estimates of the applicable capital expenditures and operating costs with an allowance for inflation were deducted in arriving at the Company's share of future net revenues. No allowance for future well abandonment costs was made for any of the Company's working interest wells or for the abandonment of any facilities. The present worth values were then obtained by employing 10, 12, 15 and 20 percent nominal annual discount rates compounded annually.

The estimated present worth values of the proved plus probable additional reserves were obtained by employing future production and revenue analyses on a total proved plus probable reserve basis. All additional costs required to recover the probable additional reserves were included in the revenue forecasts. It should be pointed out that no allowance was made for any risk associated with the probable reserves in this report other than in the present worth value summary in the covering letter.

Summaries of the Company's share of remaining reserves together with forecast future revenues, royalties, taxes, operating and capital costs, cash flow and present worth values are presented in detailed tabulations in Appendices 1 to 7.

RESERVE DEFINITIONS

Crude Oil

A mixture, consisting mainly of pentanes and heavier hydrocarbons that may contain sulphur compounds, that is liquid at the conditions under which its volume is measured or estimated, but excluding such liquids obtained from the processing of natural gas.

Synthetic Oil

Oil derived from the upgrading of crude bitumen or by chemical modification of coal or other materials and which is largely interchangeable with conventional crude oil as a refinery feedstock.

Natural Gas

The lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions is essentially a gas, but which may contain liquids. The natural gas reserve estimates are reported on a marketable basis, that is the gas which is available to a transmission line after removal of certain hydrocarbons and non-hydrocarbon compounds present in the raw natural gas and which meets specifications for use as a domestic, commercial or industrial fuel.

Natural Gas Liquids

Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus, or a combination thereof.

Sulphur

Elemental sulphur removed from the produced natural gas by processing through an extraction plant.

Remaining Reserves

Remaining reserves are those quantities of crude oil, natural gas, natural gas liquids and sulphur remaining after deducting those quantities produced up to the reference date of the study.

Gross Reserves

The total of the Company's working interests and/or royalty interests share of reserves before deducting royalties owned by others.

Net Reserves

The total of the Company's working interests and/or royalty interests share of reserves after deducting the amounts attributable to the royalties owned by others.

Royalties

The term royalties, as used in this report, refers to royalties paid to others. The royalties deducted from the reserves are based on the royalty percentage calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling price the price forecasts for the individual properties in question has been employed.

Proved Reserves

Those reserves estimated as recoverable under current technology and existing economic conditions, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area.

Comments:

1. Where reserves are clearly known to exist in a reservoir and would be physically recoverable but cannot be termed "proved reserves" because they are not commercially recoverable due to their remote location (i.e. frontier reserves), these reserves are itemized separately in the report and their special circumstances fully explained.
2. Zones which have not been completed but which are interpreted to be productive from well logs (or core analyses) and which have conclusive drill stem tests or other production tests indicating economic producing rates are considered to be proved providing there is a high degree of certainty that these reserves will be produced.
3. Zones interpreted to be productive from well logs (or core analyses) either completed or behind pipe but which have not been tested or have inconclusive tests are considered proved only if offsetting wells indicate favorable tests or productive characteristics from this zone and there is a high degree of certainty that these reserves will be produced because of favorable reservoir characteristics.
4. The proved recovery efficiencies for presently shut-in reserves are estimated from theoretical considerations or by analogy to the nearest similar zone or area. In all cases the productive capacities of the individual wells or reservoirs in question are taken into account.
5. The proved natural gas reserves may be based on the assumption that additional compressor horsepower will be installed to achieve lower abandonment pressures providing there is a high degree of certainty that such action will be taken.
6. An allowance for increased recoveries in enhanced recovery (water-flood, solvent-flood, etc.) projects is made only on the basis of demonstrated more favorable performance from the project in question or from similar projects in like reservoirs. Increased proved recoveries may be assigned prior to the installation of the facilities if in our opinion there is a high degree of certainty that such facilities will be installed in the future. A gradual transfer of reserves from a probable additional to a proved category is usually made in such projects as more performance history is obtained. The assignment of higher recovery factors to these projects by regulatory authorities does not necessarily provide a basis for increased proved recoveries since such assignments must often be made prior to obtaining indicative performance history in order to provide sufficient incentives to institute such schemes.

7. Natural gas liquids and sulphur reserves are based on the recoveries of these products from the proved natural gas reserves and are dependent on current plant efficiencies. In the case of shut-in wells the reserves are based on analyses of the raw natural gas and anticipated extraction efficiencies.

Proved Producing Reserves

Those proved reserves that are actually on production, or if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner. An illustration of such a situation is where a well or zone is capable but is shut-in because its deliverability is not required to meet contract commitments. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to the Company's reserves in the area.

Proved Non-Producing Reserves

Those non-producing proved reserves recoverable from existing wells that require relatively minor capital expenditures to produce.

Proved Undeveloped Reserves

Those reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure will be required.

Probable Additional Reserves

Those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and existing economic conditions, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

Comments:

1. The probable additional natural gas reserves are based on the potential productive areas of the natural gas reservoirs in question which could not be deemed proved at this time as well as those solution gas reserves commercially recoverable from the probable additional crude oil reserves.
2. The probable additional reserves of natural gas liquids and sulphur were considered to be those reserves recoverable from the probable additional natural gas reserves.
3. Portions of the zones which have questionable potential based on well log interpretations (or core analyses) and which have not been indicated productive by conclusive tests are considered to be probable additional.

Coyote Energy Inc.

Table 1

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Total Proved Reserves

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids				
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Total Other Revenues M$	Gross Revenue M$
2002	423.4	1270.3	27.77	35279.6	136.5	4.50	614.3	7.5	27.64	207.0	22.2	36123.2
2003	428.4	3115.8	26.32	82016.0	389.9	4.70	1832.7	15.9	26.17	416.8	36.0	84301.5
2004	414.7	2177.0	23.55	51266.0	316.5	4.55	1440.1	13.4	24.19	324.1	32.0	53062.1
2005	386.6	1603.5	23.91	38339.7	240.8	4.50	1083.8	11.5	24.20	277.8	29.0	39730.3
2006	317.2	1079.9	24.58	26549.0	188.4	4.45	838.6	10.0	24.20	241.3	25.0	27653.9
2007	266.0	793.1	25.60	20300.9	135.5	4.50	609.9	8.7	24.74	216.0		21126.8
2008	188.3	534.3	26.44	14124.8	94.8	4.50	427.0	5.5	25.22	138.7		14690.5
2009	83.9	276.6	26.23	7254.7	41.5	4.55	189.1	0.3	27.41	8.8		7452.6
2010	57.3	159.4	27.77	4425.3	34.0	4.65	158.0	0.2	28.27	6.2		4589.6
2011	29.1	67.4	28.54	1925.0	26.0	4.75	123.3	0.1	33.07	4.6		2053.0
2012	1.5	1.6	31.94	50.5	7.8	4.85	37.7			0.0		88.2
2013	1.5	1.4	32.67	47.0	6.9	4.95	34.0					81.0
2014	0.8	0.2	33.75	8.1	6.4	5.00	32.0					40.1
2015	0.7				6.0	5.10	30.4					30.4
2016	0.7				5.6	5.20	29.0					29.0
REM.	0.7				9.7	5.40	52.2					52.2
TOTAL		**11080.5**	**25.41**	**281586.4**	**1646.3**	**4.58**	**7532.2**	**73.2**	**25.16**	**1841.3**	**144.2**	**291104.5**

	Crown Royalties			Freehold Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	1159.6	3.8	1155.8	3204.4	0.6	3203.8	319.3	0.1	319.2	724.3	5403.2	14.97
2003	2309.7	41.1	2268.7	8294.6	1.3	8293.2	720.8	0.1	720.7	1846.3	13128.9	15.58
2004	1240.4	33.1	1207.3	4691.7	1.3	4690.4	489.2	0.1	489.1	797.8	7184.5	13.55
2005	824.1	19.9	804.3	3355.7	1.2	3354.5	372.8	0.1	372.7	392.8	4924.4	12.40
2006	586.6	12.6	573.9	1978.3	1.1	1977.3	274.3	0.1	274.2	212.6	3038.1	11.00
2007	427.8	3.6	424.2	1395.1	1.0	1394.1	227.9	0.1	227.8	144.4	2190.5	10.37
2008	287.1	1.5	285.7	852.6	1.0	851.6	188.3	0.1	188.3	96.2	1421.7	9.68
2009	88.0	0.2	87.8	500.2	0.9	499.3	155.4	0.1	155.3	62.6	805.0	10.80
2010	62.5	0.1	62.5	204.0	0.9	203.1	125.0	0.0	124.9	32.1	422.6	9.21
2011	21.6	0.0	21.5	37.0	0.8	36.3	93.3	0.0	93.3	15.7	166.9	8.13
2012	0.1	0.0	0.1	18.5	0.8	17.7	0.2	0.0	0.2	0.6	18.6	21.11
2013	0.1	0.0	0.1	17.4	0.7	16.7	0.2	0.0	0.2	0.6	17.5	21.54
2014	0.1	0.0	0.1	8.2	0.7	7.5	0.2	0.0	0.2	0.4	8.1	20.30
2015	0.1	0.0	0.1	6.1	0.6	5.4	0.2	0.0	0.1	0.3	6.0	19.58
2016	0.1	0.0	0.1	5.8	0.6	5.2	0.2	0.0	0.1	0.3	5.7	19.57
REM.	0.1	0.0	0.1	10.4	1.0	9.4	0.3	0.0	0.3	0.5	10.2	19.57
TOTAL	**7008.1**	**116.0**	**6892.1**	**24579.8**	**14.4**	**24565.4**	**2967.3**	**0.9**	**2966.4**	**4327.5**	**38751.9**	**13.32**

			Capital Costs			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Drilling & Compl M$	Equip & Facility M$	Total Capital M$	Annual M$	Cum M$	PWV @15.0% M$
2002	8944.7	21775.3	9046.0		9046.0	12729.3	12729.3	12364.0
2003	22052.9	49119.6	3470.7	229.5	3700.2	45419.5	58148.8	39957.7
2004	21806.6	24071.0	5.2		5.2	24065.8	82214.5	18410.3
2005	20615.6	14190.3	5.3		5.3	14185.0	96399.6	9436.1
2006	15995.3	8620.5				8620.4	105020.0	4986.4
2007	12899.7	6036.6				6036.6	111056.6	3036.3
2008	9666.2	3602.6				3602.5	114659.1	1575.7
2009	4832.0	1815.6				1815.5	116474.6	690.5
2010	3419.8	747.1				747.1	117221.7	247.0
2011	1626.0	260.1				260.1	117481.8	74.8
2012	48.9	20.7				20.7	117502.5	5.2
2013	49.6	14.0				14.0	117516.5	3.0
2014	21.8	10.2				10.2	117526.6	1.9
2015	16.2	8.3				8.3	117534.9	1.4
2016	16.3	7.0				7.0	117541.9	1.0
REM.	31.6	10.4				10.4	117552.3	1.2
TOTAL	**122043.1**	**130309.1**	**12527.2**	**229.5**	**12756.7**	**117552.3**		**90792.5**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	Gross	Net	@10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	11080.8	9734.2	93996.2	91101.2	87120.3	81303.3
Natural Gas (mmcf)	1646.4	1311.7	2990.9	2861.6	2688.1	2443.4
Natural Gas Liquids (mbbl)	73.4	55.7	1088.4	1044.2	984.4	898.9
Total			**98075.5**	**95007.0**	**90792.7**	**84645.5**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves: Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$): @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
Fixed Battery Costs	P-100.000		NRA	-	-	-	-	-3372.9	-3132.8	-2822.7
00/04-05-041-12-W4	W-100.000	ELL	PP	10.2	48.79	0.05	-	539.6	510.3	471.9
02/04-05-041-12-W4	W-100.000	ELL	PP	19.6	50.39	0.09	-	590.1	558.7	517.5
03/04-05-041-12-W4	W-100.000	ELL	PP	1.2	5.15	0.00	-	48.8	48.3	47.5
00/05-05-041-12-W4	W-100.000	ELL	PP	11.6	52.20	0.05	-	598.0	566.4	524.9
04/05-05-041-12-W4	W-100.000	ELL	PP	12.6	38.11	0.05	-	389.9	369.2	341.9
B0/05-05-041-12-W4	W-100.000	ELL	PP	12.7	60.50	0.06	-	722.2	684.0	633.7
00/06-05-041-12-W4	W- 40.000	GLAUC L	PP	42.6	-	0.21	-	113.7	112.0	109.7
02/10-05-041-12-W4	W-100.000	ELL	PNP	1.9	21.09	0.01	-	226.0	214.7	199.4
00/12-05-041-12-W4	W-100.000	ELL	PP	19.4	49.69	0.09	-	578.0	547.4	507.1
00/13-05-041-12-W4	W-100.000	ELL	PP	0.8	5.62	0.00	-	39.9	39.4	38.6
B0/14-05-041-12-W4	W-100.000	ELL	PP	10.8	51.43	0.05	-	607.0	577.6	538.8
C0/14-05-041-12-W4	W-100.000	ELL	PP	8.2	40.48	0.04	-	416.5	394.6	365.7
00/15-05-041-12-W4	W-100.000	ELL	PNP	3.6	15.06	0.01	-	169.9	159.8	146.1
02/15-05-041-12-W4	W-100.000	ELL	PP	2.1	7.81	0.01	-	113.0	111.3	108.7
A2/15-05-041-12-W4	W-100.000	ELL	PP	4.6	34.14	0.02	-	423.2	407.4	385.9
B2/15-05-041-12-W4	W-100.000	ELL	PP	17.1	59.88	0.08	-	722.2	683.8	633.3
02/16-05-041-12-W4	W-100.000	ELL	PP	3.8	15.81	0.02	-	225.9	221.0	214.2
00/01-06-041-12-W4	W-100.000	ELL	PP	11.7	19.53	0.05	-	142.9	137.0	129.1
00/02-06-041-12-W4	W-100.000	ELL	PP	8.7	38.81	0.04	-	429.5	406.8	376.9
02/07-06-041-12-W4	W-100.000	ELL	PP	4.4	26.91	0.02	-	247.5	236.1	221.0
02/08-06-041-12-W4	W-100.000	ELL	PP	11.4	21.09	0.05	-	277.2	268.4	256.2
03/08-06-041-12-W4	W-100.000	ELL	PP	14.2	29.67	0.06	-	302.4	287.0	266.7
05/08-06-041-12-W4	W-100.000	ELL	PP	12.1	47.46	0.06	-	566.6	537.0	498.0
02/09-06-041-12-W4	W-100.000	ELL	PP	8.8	43.31	0.04	-	475.7	446.7	408.9
02/15-15-041-12-W4	R- 3.750	ELL	PP	-	0.22	-	-	5.0	4.8	4.7
04/15-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
02/16-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
05/16-15-041-12-W4	R- 3.750	ELL	PP	-	0.05	-	-	1.3	1.3	1.2
Subtotal				**254.2**	**783.22**	**1.15**	-	**5599.0**	**5397.9**	**5124.9**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	PNP	292.6	-	-	-	539.1	517.5	487.6
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PP	47.2	-	0.19	-	163.6	155.6	145.1
00/11-05-040-08-W4	R- 15.000	VIK	PP	5.0	-	0.02	-	20.1	19.6	18.9
00/07-07-040-08-W4	R- 6.250	CLY	PP	2.2	-	0.01	-	9.4	9.3	9.1
00/10-07-040-08-W4	R- 15.000	VIK	PP	18.3	-	0.07	-	60.5	57.1	52.6
Subtotal				**72.6**	-	**0.29**	-	**253.6**	**241.6**	**225.6**
David North										
Lloydminster O Unit	W-100.000	LLOYD	PP	40.4	403.99	2.02	-	6270.5	6049.7	5750.3
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PP	52.5	429.37	2.62	-	6153.9	5925.3	5618.8
00/10-27-040-03-W4	W-100.000	LLOYD	PP	-	14.09	-	-	139.3	134.9	128.9
02/10-27-040-03-W4	W-100.000	LLOYD	PP	-	24.26	-	-	371.8	359.2	342.1
02/15-27-040-03-W4	W-100.000	LLOYD	PP	-	22.92	-	-	235.5	227.3	216.1
Subtotal				**92.9**	**894.64**	**4.64**	-	**13171.0**	**12696.5**	**12056.0**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	PP	-	71.94	-	-	415.2	404.5	389.8
N-24-40-1W4 1999 Wells	W- 93.750	DINA	PP	-	47.39	-	-	347.4	341.6	333.3
N-24-40-1W4 2002 Wells	W- 93.750	DINA	PP	-	202.69	-	-	2053.2	2002.0	1931.3
N-24-40-1W4 Future Locations	W- 93.750	DINA	PUD	-	168.75	-	-	991.8	922.4	828.2
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	PP	-	1276.76	-	-	9388.2	9049.1	8590.4
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	PP	-	98.02	-	-	703.0	681.7	652.6
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	PP	-	128.94	-	-	1096.8	1075.8	1046.1
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	PP	-	414.57	-	-	3982.6	3917.2	3824.3

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Hayter (cont'd)										
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	PP	-	155.50	-	-	1682.7	1656.3	1618.6
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	PP	-	380.08	-	-	4800.0	4661.9	4472.7
Sec 25-40-1W4 Future Locations	W- 94.517	DINA	PUD	-	1361.04	-	-	10692.9	10273.8	9689.4
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	PP	-	75.39	-	-	413.7	407.6	398.8
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	PP	-	23.79	-	-	220.4	217.3	212.8
Sec 34-40-1W4 2000 Wells	W- 75.000	DINA	PP	-	9.84	-	-	53.5	52.6	51.3
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	PP	-	647.94	-	-	2769.6	2716.8	2642.2
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	PP	-	8.57	-	-	65.4	64.7	63.7
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	PP	-	31.36	-	-	265.3	260.5	253.8
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	PP	-	151.76	-	-	1559.0	1530.6	1490.5
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	PP	-	306.60	-	-	2748.9	2702.2	2636.0
NW-35-40-1W4 Pre-2000 Wells	W- 75.000	DINA	PP	-	116.69	-	-	407.5	394.8	377.4
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	PP	-	117.50	-	-	1026.8	1009.8	985.8
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	PP	-	232.37	-	-	2138.4	2095.3	2034.9
NW-35-40-1W4 Future Locations	W- 75.000	DINA	PUD	-	337.50	-	-	1795.8	1684.5	1531.3
S-36-40-1W4 GOR Wells	R- 7.500	DINA	PP	-	2.26	-	-	50.4	49.6	48.5
00/09-34-040-01-W4	W- 75.000	SPKY	PP	-	10.16	-	-	98.7	96.0	92.3
00/15-34-040-01-W4	W- 75.000	SPKY	PP	-	7.08	-	-	69.7	68.2	66.2
00/01-03-041-01-W4	W- 75.000	SPKY	PP	-	27.99	-	-	210.0	199.6	186.0
Subtotal				-	**6412.48**	-	-	**50046.8**	**48536.5**	**46448.2**
Mestikow										
All Company Wells	W-100.000	DINA	PP	-	170.34	-	-	1414.4	1372.1	1314.0
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	PP	612.5	2011.52	67.37	-	18895.0	18321.1	17531.5
04/10-29-040-11-W4	W- 25.000	VIK	PP	1.6	-	-	-	2.2	2.1	2.1
Subtotal				**614.1**	**2011.52**	**67.37**	-	**18897.1**	**18323.3**	**17533.6**
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PP	27.9	379.18	-	-	3450.4	3331.6	3170.1
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PP	8.3	79.23	-	-	730.6	704.5	669.0
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PP	21.7	206.44	-	-	2182.6	2136.7	2072.0
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PP	4.3	55.63	-	-	615.2	606.9	595.0
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PP	0.4	6.96	-	-	71.2	70.2	68.7
Sec 16-38-3W4	W-100.000	DINA	PP	10.1	57.55	-	-	520.5	511.1	497.8
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PP	16.6	23.65	-	-	264.4	258.7	250.7
00/11-24-037-02-W4	W- 37.500	VIK	PP	0.5	-	-	-	0.2	0.2	0.2
00/07-27-037-02-W4	W- 42.188	VIK	PP	55.5	-	-	-	59.0	54.3	48.6
02/06-11-038-03-W4	W- 28.125	VIK	NRA	-	-	-	-	-	-	-
00/14-12-038-03-W4	W- 37.500	CLY	PP	13.1	-	-	-	18.7	18.2	17.5
00/07-13-038-03-W4	W- 37.500	VIK	PP	34.2	-	-	-	52.2	49.9	46.8
00/06-14-038-03-W4	W- 37.500	VIK	NRA	-	-	-	-	-	-	-
00/07-15-038-03-W4	W- 37.500	VIK	PP	7.3	-	-	-	9.1	9.0	8.7
00/07-17-038-03-W4	W- 37.500	VIK	PP	6.0	-	-	-	1.6	1.6	1.5
00/07-18-038-03-W4	W- 37.500	VIK	PP	24.0	-	-	-	30.1	28.8	27.1
00/14-07-039-01-W4	W- 29.371	MCLAR	PP	90.1	-	-	-	121.5	113.5	103.3
Bodo Compression Facility	P-100.000	ALL ZONES	NRA	-	-	-	-	27.1	26.6	25.8

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
West Provost (cont'd)										
Wells with NRA		ALL ZONES	NRA	-	-	-	-	-	-	-
Subtotal				**320.0**	**808.64**	-	-	**8154.5**	**7921.6**	**7602.7**
Subtotal Alberta				**1646.5**	**11080.83**	**73.45**	-	**98075.6**	**95007.0**	**90792.7**
TOTAL				**1646.5**	**11080.83**	**73.45**	-	**98075.6**	**95007.0**	**90792.7**

Coyote Energy Inc.

Summary of Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved Reserves

Area	Company Interest Reserves Gas bcf	Company Interest Reserves Oil mbbl	Company Interest Reserves NGL mbbl	Company Interest Reserves Sulphur mlt	Net Reserves After Royalty Gas bcf	Net Reserves After Royalty Oil mbbl	Net Reserves After Royalty NGL mbbl	Net Reserves After Royalty Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%	@20.0%
Alberta												
Bellshill Lake	0.25	783.2	1.2	-	0.21	716.0	0.9	-	5599.0	5397.9	5124.9	4733.3
Black Creek	0.29	-	-	-	0.23	-	-	-	539.1	517.5	487.6	443.8
Choice	0.07	-	0.3	-	0.07	-	0.3	-	253.6	241.6	225.6	203.5
David North	0.09	894.6	4.6	-	0.09	847.8	4.4	-	13171.0	12696.5	12056.0	11145.7
Hayter	-	6412.5	-	-	-	5329.9	-	-	50046.8	48536.5	46448.2	43371.5
Mestikow	-	170.3	-	-	-	159.4	-	-	1414.4	1372.1	1314.0	1229.3
Thompson Lake	0.61	2011.5	67.4	-	0.46	1922.7	50.0	-	18897.1	18323.3	17533.6	16379.5
West Provost	0.32	808.6	-	-	0.26	758.5	-	-	8154.5	7921.6	7602.7	7139.1
Subtotal Alberta	**1.65**	**11080.8**	**73.5**	**-**	**1.31**	**9734.3**	**55.7**	**-**	**98075.6**	**95007.0**	**90792.7**	**84645.6**
TOTAL	**1.65**	**11080.8**	**73.5**	**-**	**1.31**	**9734.3**	**55.7**	**-**	**98075.6**	**95007.0**	**90792.7**	**84645.6**

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Sorted By Company Oil Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company Oil Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	6412.5	-	-	6412.5	50046.8	48536.5	46448.2	57.87	57.87
2	Thompson Lake	0.61	2011.5	67.4	-	2181.2	18897.1	18323.3	17533.6	18.15	76.02
3	David North	0.09	894.6	4.6	-	914.8	13171.0	12696.5	12056.0	8.07	84.10
4	West Provost	0.32	808.6	-	-	862.0	8154.5	7921.6	7602.7	7.30	91.39
5	Bellshill Lake	0.25	783.2	1.2	-	826.7	5599.0	5397.9	5124.9	7.07	98.46
6	Mestikow	-	170.3	-	-	170.3	1414.4	1372.1	1314.0	1.54	100.00
7	Black Creek	0.29	-	-	-	48.8	539.1	517.5	487.6	-	100.00
8	Choice	0.07	-	0.3	-	12.4	253.6	241.6	225.6	-	100.00
	Total	**1.65**	**11080.8**	**73.5**	**-**	**11428.7**	**98075.6**	**95007.0**	**90792.7**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Sorted By Company Gas Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company Gas Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Thompson Lake	0.61	2011.5	67.4	-	2181.2	18897.1	18323.3	17533.6	37.30	37.30
2	West Provost	0.32	808.6	-	-	862.0	8154.5	7921.6	7602.7	19.43	56.73
3	Black Creek	0.29	-	-	-	48.8	539.1	517.5	487.6	17.77	74.50
4	Bellshill Lake	0.25	783.2	1.2	-	826.7	5599.0	5397.9	5124.9	15.44	89.94
5	David North	0.09	894.6	4.6	-	914.8	13171.0	12696.5	12056.0	5.64	95.59
6	Choice	0.07	-	0.3	-	12.4	253.6	241.6	225.6	4.41	100.00
7	Hayter	-	6412.5	-	-	6412.5	50046.8	48536.5	46448.2	-	100.00
8	Mestikow	-	170.3	-	-	170.3	1414.4	1372.1	1314.0	-	100.00
	Total	**1.65**	**11080.8**	**73.5**	**-**	**11428.7**	**98075.6**	**95007.0**	**90792.7**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Sorted By Company BOE Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company BOE Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0%	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	6412.5	-	-	6412.5	50046.8	48536.5	46448.2	56.11	56.11
2	Thompson Lake	0.61	2011.5	67.4	-	2181.2	18897.1	18323.3	17533.6	19.09	75.19
3	David North	0.09	894.6	4.6	-	914.8	13171.0	12696.5	12056.0	8.00	83.20
4	West Provost	0.32	808.6	-	-	862.0	8154.5	7921.6	7602.7	7.54	90.74
5	Bellshill Lake	0.25	783.2	1.2	-	826.7	5599.0	5397.9	5124.9	7.23	97.97
6	Mestikow	-	170.3	-	-	170.3	1414.4	1372.1	1314.0	1.49	99.46
7	Black Creek	0.29	-	-	-	48.8	539.1	517.5	487.6	0.43	99.89
8	Choice	0.07	-	0.3	-	12.4	253.6	241.6	225.6	0.11	100.00
	Total	**1.65**	**11080.8**	**73.5**	**-**	**11428.7**	**98075.6**	**95007.0**	**90792.7**	**100.00**	**-**

1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Sorted By @15.0% Present Worth Value

		Company Interest Reserves					Present Worth Value Before Tax (M$)			@15.0% Present Worth Value	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	6412.5	-	-	6412.5	50046.8	48536.5	46448.2	51.16	51.16
2	Thompson Lake	0.61	2011.5	67.4	-	2181.2	18897.1	18323.3	17533.6	19.31	70.47
3	David North	0.09	894.6	4.6	-	914.8	13171.0	12696.5	12056.0	13.28	83.75
4	West Provost	0.32	808.6	-	-	862.0	8154.5	7921.6	7602.7	8.37	92.12
5	Bellshill Lake	0.25	783.2	1.2	-	826.7	5599.0	5397.9	5124.9	5.64	97.77
6	Mestikow	-	170.3	-	-	170.3	1414.4	1372.1	1314.0	1.45	99.21
7	Black Creek	0.29	-	-	-	48.8	539.1	517.5	487.6	0.54	99.75
8	Choice	0.07	-	0.3	-	12.4	253.6	241.6	225.6	0.25	100.00
	Total	**1.65**	**11080.8**	**73.5**	**-**	**11428.7**	**98075.6**	**95007.0**	**90792.7**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

First Year Production, Revenue and Expenses by Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

2002 Summary

	Production					Revenue and Expenses				Average Values $/BOE (1)			
Area	Oil bopd	Gas mcf/d	NGL bpd	Sulphur lt/d	BOE (1) boepd	Gross Revenue $M	Encumb. $M	Oper. Exp $M	Net Rev. (2) $M	Gross Revenue	Encumb.	Oper Exp	Net Rev (2)
Alberta													
Bellshill Lake	382.4	189.2	0.7	-	413.9	1803	211	585	1007	28.64	3.35	9.29	16.00
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	46.6	0.2	-	7.8	33	-	-	33	27.37	-	-	27.37
David North	697.4	73.1	3.6	-	713.1	3448	227	572	2649	31.80	2.10	5.27	24.43
Hayter	5168.5	-	-	-	5168.5	19990	4130	3887	11973	25.43	5.25	4.95	15.23
Mestikow	123.9	-	-	-	123.9	514	46	153	316	27.27	2.42	8.10	16.75
Thompson Lake	1341.3	416.0	44.9	-	1455.5	7082	479	2749	3854	31.99	2.16	12.42	17.41
West Provost	639.7	173.2	-	-	668.1	3254	311	999	1944	32.02	3.06	9.83	19.13
Subtotal Alberta	**8353.2**	**898.1**	**49.4**	-	**8551.0**	**36123**	**5403**	**8945**	**21775**	**27.78**	**4.15**	**6.88**	**16.74**
TOTAL	**8353.2**	**898.1**	**49.4**	-	**8551.0**	**36123**	**5403**	**8945**	**21775**	**27.78**	**4.15**	**6.88**	**16.74**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE based on Gross BOE reserves.
(2) Excludes capital and abandonment expenses.

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Oil Production Forecast (mbbl) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	58	125	115	104	88	76	63	55	52	47	783	-	783
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	106	200	148	114	91	74	62	51	30	19	895	-	895
Hayter	786	2125	1358	924	513	331	199	129	42	2	6409	3	6413
Mestikow	19	38	30	25	21	18	16	4	-	-	170	-	170
Thompson Lake	204	435	372	321	280	247	153	-	-	-	2012	-	2012
West Provost	97	193	155	116	87	48	41	37	35	-	809	-	809
Subtotal Alberta	**1270**	**3116**	**2177**	**1604**	**1080**	**793**	**534**	**277**	**159**	**67**	**11078**	**3**	**11081**
TOTAL	**1270**	**3116**	**2177**	**1604**	**1080**	**793**	**534**	**277**	**159**	**67**	**11078**	**3**	**11081**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Gas Production Forecast (mmcf) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	29	58	36	28	24	21	17	15	14	13	254	-	254
Black Creek	-	108	92	55	33	5	-	-	-	-	293	-	293
Choice	7	15	12	10	7	6	5	4	4	3	72	0	73
David North	11	21	15	12	9	8	6	5	3	2	93	-	93
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	63	133	113	98	85	75	47	-	-	-	614	-	614
West Provost	26	55	49	39	30	22	20	16	13	8	278	42	320
Subtotal Alberta	**137**	**390**	**317**	**241**	**188**	**136**	**95**	**42**	**34**	**26**	**1604**	**42**	**1647**
TOTAL	**137**	**390**	**317**	**241**	**188**	**136**	**95**	**42**	**34**	**26**	**1604**	**42**	**1647**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

NGL Production Forecast (mstb) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	0	0	0	0	0	0	0	0	0	0	1	-	1
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	0	0	0	0	0	0	0	0	0	0	0	-	0
David North	1	1	1	1	0	0	0	0	0	0	5	-	5
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	7	15	12	11	9	8	5	-	-	-	67	-	67
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**8**	**16**	**13**	**12**	**10**	**9**	**6**	**0**	**0**	**0**	**73**	**-**	**73**
TOTAL	**8**	**16**	**13**	**12**	**10**	**9**	**6**	**0**	**0**	**0**	**73**	**-**	**73**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Gross Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1803	3681	2933	2648	2237	1985	1689	1516	1446	1357	21294	-	21294
Black Creek	-	507	419	248	146	21	-	-	-	-	1341	-	1341
Choice	33	70	55	44	32	28	24	20	18	13	336	2	338
David North	3448	6226	4131	3203	2563	2147	1832	1558	946	592	26648	-	26648
Hayter	19990	52138	29128	19921	11134	7408	4610	3072	1048	54	148503	106	148608
Mestikow	514	973	681	562	476	421	378	94	-	-	4098	-	4098
Thompson Lake	7082	14500	11196	9707	8501	7669	4871	-	-	-	63525	-	63525
West Provost	3254	6206	4518	3398	2564	1449	1288	1192	1132	38	25038	213	25252
Subtotal Alberta	**36123**	**84302**	**53062**	**39730**	**27654**	**21127**	**14691**	**7453**	**4590**	**2053**	**290784**	**321**	**291105**
TOTAL	**36123**	**84302**	**53062**	**39730**	**27654**	**21127**	**14691**	**7453**	**4590**	**2053**	**290784**	**321**	**291105**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Encumbrance Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	211	413	316	276	221	193	163	143	135	124	2194	-	2194
Black Creek	-	106	64	24	8	1	-	-	-	-	203	-	203
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	227	403	262	200	158	131	110	90	48	23	1654	-	1654
Hayter	4130	10690	5509	3612	1995	1329	787	504	182	12	28751	24	28776
Mestikow	46	73	45	33	25	22	18	4	-	-	266	-	266
Thompson Lake	479	948	695	579	489	429	270	-	-	-	3890	-	3890
West Provost	311	495	292	201	142	86	73	64	58	7	1729	42	1771
Subtotal Alberta	**5403**	**13129**	**7185**	**4924**	**3038**	**2191**	**1422**	**805**	**423**	**167**	**38686**	**66**	**38752**
TOTAL	**5403**	**13129**	**7185**	**4924**	**3038**	**2191**	**1422**	**805**	**423**	**167**	**38686**	**66**	**38752**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Capital Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	-	-	5	5	-	-	-	-	-	-	11	-	11
Black Creek	-	230	-	-	-	-	-	-	-	-	230	-	230
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	-	-	-	-	-	-	-	-	-	-	-	-	-
Hayter	9046	3471	-	-	-	-	-	-	-	-	12517	-	12517
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	-	-	-	-	-	-	-	-	-	-	-	-	-
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**9046**	**3700**	**5**	**5**	-	-	-	-	-	-	**12757**	-	**12757**
TOTAL	**9046**	**3700**	**5**	**5**	-	-	-	-	-	-	**12757**	-	**12757**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Operating Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	585	1399	1395	1357	1317	1291	1219	1193	1208	1211	12175	-	12175
Black Creek	-	68	68	52	42	7	-	-	-	-	236	-	236
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	572	1274	1173	1088	1012	940	869	802	557	367	8653	-	8653
Hayter	3887	10095	10137	9588	5566	3533	2479	1801	684	32	47802	72	47874
Mestikow	153	364	325	325	326	290	293	74	-	-	2150	-	2150
Thompson Lake	2749	6422	6231	6071	5950	5845	3859	-	-	-	37127	-	37127
West Provost	999	2431	2478	2135	1783	994	948	961	970	16	13716	112	13828
Subtotal Alberta	**8945**	**22053**	**21807**	**20616**	**15995**	**12900**	**9666**	**4832**	**3420**	**1626**	**121859**	**184**	**122043**
TOTAL	**8945**	**22053**	**21807**	**20616**	**15995**	**12900**	**9666**	**4832**	**3420**	**1626**	**121859**	**184**	**122043**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved Reserves

Net Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1007	1869	1217	1010	700	501	306	179	103	22	6915	-	6915
Black Creek	-	104	287	172	97	13	-	-	-	-	672	-	672
Choice	33	70	55	44	32	28	24	20	18	13	336	2	338
David North	2649	4549	2696	1914	1393	1077	852	667	341	202	16341	-	16341
Hayter	2927	27881	13481	6721	3573	2546	1345	767	182	9	59433	9	59442
Mestikow	316	536	310	205	125	109	67	15	-	-	1683	-	1683
Thompson Lake	3854	7129	4270	3057	2062	1394	742	-	-	-	22508	-	22508
West Provost	1944	3281	1748	1062	638	368	266	167	103	14	9593	59	9653
Subtotal Alberta	**12729**	**45419**	**24066**	**14185**	**8620**	**6037**	**3603**	**1816**	**747**	**260**	**117482**	**70**	**117552**
TOTAL	**12729**	**45419**	**24066**	**14185**	**8620**	**6037**	**3603**	**1816**	**747**	**260**	**117482**	**70**	**117552**

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Total Proved & Probable Reserves - Unrisked

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids				
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Total Other Revenues M$	Gross Revenue M$
2002	423.4	1320.8	27.72	36616.1	138.2	4.50	622.0	7.6	27.60	209.8	22.2	37470.1
2003	428.4	3286.8	26.30	86457.8	405.0	4.70	1903.6	16.5	26.18	432.3	36.0	88829.7
2004	415.7	2413.9	23.48	56681.8	353.5	4.55	1608.3	14.3	24.20	346.3	32.0	58668.4
2005	400.4	1868.3	23.82	44504.7	276.4	4.50	1243.8	12.5	24.19	303.3	29.0	46080.8
2006	371.1	1506.3	24.06	36236.2	224.7	4.45	1000.1	11.1	24.17	268.8	25.0	37530.1
2007	298.0	1047.8	25.30	26506.8	185.5	4.50	834.5	9.9	24.76	245.1		27586.5
2008	254.6	805.1	26.27	21148.2	148.7	4.50	669.2	8.9	25.14	223.8		22041.2
2009	234.0	668.8	27.21	18196.7	114.0	4.55	518.8	8.0	25.66	206.3		18921.8
2010	108.4	347.2	27.20	9444.5	49.0	4.65	227.8	1.6	26.44	41.2		9713.6
2011	76.8	243.0	27.79	6751.2	32.9	4.75	156.2	0.3	29.97	8.7		6916.1
2012	35.4	71.6	31.25	2236.3	16.1	4.85	77.9	0.2	27.23	6.0		2320.2
2013	14.5	20.8	32.62	677.6	11.4	4.95	56.5	0.1	26.38	3.4		737.5
2014	2.5	3.0	33.37	101.4	8.5	5.00	42.4	0.0	21.00	0.4		144.3
2015	1.5	1.5	34.31	52.5	7.0	5.10	35.8			0.1		88.4
2016	1.5	1.4	35.08	49.8	5.6	5.20	29.0					78.8
REM.	0.8	0.3	36.35	11.3	9.7	5.40	52.2					63.5
TOTAL		**13606.7**	**25.40**	**345672.9**	**1986.0**	**4.57**	**9078.0**	**91.1**	**25.18**	**2295.4**	**144.2**	**357190.9**

	Crown Royalties			Freehold Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	1226.6	3.9	1222.7	3368.7	0.6	3368.1	327.4	0.1	327.3	779.7	5697.9	15.22
2003	2546.6	39.6	2507.0	8799.3	1.3	8797.9	746.7	0.1	746.6	2006.5	14058.0	15.83
2004	1459.6	36.1	1423.5	5302.2	1.3	5300.9	523.4	0.1	523.3	980.6	8228.3	14.03
2005	1056.1	23.7	1032.4	3901.6	1.2	3900.5	408.6	0.1	408.5	530.1	5871.5	12.75
2006	759.4	16.4	743.1	3140.1	1.1	3139.0	336.5	0.1	336.5	351.8	4570.3	12.19
2007	584.5	11.6	573.0	1994.9	1.0	1993.8	265.4	0.1	265.3	218.2	3050.4	11.06
2008	450.7	7.2	443.6	1498.4	1.0	1497.4	223.9	0.1	223.8	157.6	2322.4	10.54
2009	378.4	2.0	376.4	1139.6	0.9	1138.7	188.5	0.1	188.5	119.5	1823.1	9.63
2010	138.5	0.4	138.1	637.9	0.9	637.1	158.6	0.0	158.5	75.1	1008.9	10.39
2011	70.0	0.0	70.0	476.1	0.8	475.3	139.9	0.0	139.9	56.7	742.0	10.73
2012	25.7	0.0	25.7	98.4	0.8	97.6	21.3	0.0	21.3	10.6	155.2	6.69
2013	0.1	0.0	0.1	38.5	0.7	37.8	2.7	0.0	2.7	4.1	44.7	6.06
2014	0.1	0.0	0.1	20.2	0.7	19.5	0.4	0.0	0.3	0.8	20.8	14.40
2015	0.1	0.0	0.1	17.9	0.6	17.3	0.2	0.0	0.1	0.5	18.0	20.36
2016	0.1	0.0	0.1	17.0	0.6	16.4	0.2	0.0	0.1	0.5	17.1	21.68
REM.	0.1	0.0	0.1	12.9	1.0	11.9	0.3	0.0	0.3	0.5	12.8	20.16
TOTAL	**8696.6**	**140.9**	**8555.8**	**30463.6**	**14.4**	**30449.2**	**3344.0**	**0.9**	**3343.1**	**5292.9**	**47641.3**	**13.34**

			Capital Costs			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Drilling & Compl M$	Equip & Facility M$	Total Capital M$	Annual M$	Cum M$	PWV @15.0% M$
2002	8955.4	22816.8	9046.0		9046.0	13770.8	13770.8	13375.5
2003	22119.3	52652.3	3470.7	229.5	3700.2	48952.2	62722.9	43065.6
2004	21987.6	28452.3	5.2		5.2	28447.2	91170.1	21762.1
2005	21757.5	18451.8	5.3		5.3	18446.5	109616.6	12270.8
2006	20416.7	12543.1				12543.0	122159.6	7255.4
2007	15441.5	9094.5				9094.5	131254.1	4574.5
2008	12914.3	6804.5				6804.5	138058.5	2976.2
2009	12076.2	5022.6				5022.5	143081.0	1910.2
2010	6252.1	2452.5				2452.5	145533.6	811.0
2011	4701.4	1472.7				1472.7	147006.3	423.5
2012	1559.0	605.9				605.9	147612.2	151.5
2013	431.6	261.1				261.2	147873.4	56.8
2014	82.5	40.9				40.9	147914.3	7.8
2015.	51.1	19.3				19.3	147933.6	3.2
2016	51.9	9.8				9.8	147943.4	1.4
REM.	40.7	10.0				10.0	147953.4	1.2
TOTAL	**148838.9**	**160710.0**	**12527.2**	**229.5**	**12756.7**	**147953.4**		**108646.6**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	**Gross**	**Net**	**@10.0%**	**@12.0%**	**@15.0%**	**@20.0%**
Crude Oil (mbbl)	13606.9	11946.3	114150.0	110004.7	104385.8	96342.4
Natural Gas (mmcf)	1986.1	1577.8	3518.4	3347.7	3120.9	2805.4
Natural Gas Liquids (mbbl)	91.4	69.3	1286.3	1223.6	1140.2	1024.0
Total			**118954.6**	**114576.0**	**108647.0**	**100171.9**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
Fixed Battery Costs	P-100.000		NRA	-	-	-	-	-3372.9	-3132.8	-2822.7
00/04-05-041-12-W4	W-100.000	ELL	P	10.2	48.79	0.05	-	539.6	510.3	471.9
02/04-05-041-12-W4	W-100.000	ELL	P	19.6	50.39	0.09	-	590.1	558.7	517.5
03/04-05-041-12-W4	W-100.000	ELL	P	1.2	5.15	0.00	-	48.8	48.3	47.5
00/05-05-041-12-W4	W-100.000	ELL	P	11.6	52.20	0.05	-	598.0	566.4	524.9
04/05-05-041-12-W4	W-100.000	ELL	P	12.6	38.11	0.05	-	389.9	369.2	341.9
B0/05-05-041-12-W4	W-100.000	ELL	P	12.7	60.50	0.06	-	722.2	684.0	633.7
00/06-05-041-12-W4	W- 40.000	GLAUC L	P	52.0	-	0.25	-	136.2	133.9	130.6
02/10-05-041-12-W4	W-100.000	ELL	NP	2.3	26.09	0.01	-	274.1	259.0	238.7
00/12-05-041-12-W4	W-100.000	ELL	P	19.4	49.69	0.09	-	578.0	547.4	507.1
00/13-05-041-12-W4	W-100.000	ELL	P	0.8	5.62	0.00	-	39.9	39.4	38.6
B0/14-05-041-12-W4	W-100.000	ELL	P	10.8	51.43	0.05	-	607.0	577.6	538.8
C0/14-05-041-12-W4	W-100.000	ELL	P	8.2	40.48	0.04	-	416.5	394.6	365.7
00/15-05-041-12-W4	W-100.000	ELL	NP	4.8	20.06	0.02	-	221.8	207.7	188.7
02/15-05-041-12-W4	W-100.000	ELL	P	2.1	7.81	0.01	-	113.0	111.3	108.7
A2/15-05-041-12-W4	W-100.000	ELL	P	4.6	34.14	0.02	-	423.2	407.4	385.9
B2/15-05-041-12-W4	W-100.000	ELL	P	17.1	59.88	0.08	-	722.2	683.8	633.3
02/16-05-041-12-W4	W-100.000	ELL	P	3.8	15.81	0.02	-	225.9	221.0	214.2
00/01-06-041-12-W4	W-100.000	ELL	P	11.7	19.53	0.05	-	142.9	137.0	129.1
00/02-06-041-12-W4	W-100.000	ELL	P	8.7	38.81	0.04	-	429.5	406.8	376.9
02/07-06-041-12-W4	W-100.000	ELL	P	4.4	26.91	0.02	-	247.5	236.1	221.0
02/08-06-041-12-W4	W-100.000	ELL	P	11.4	21.09	0.05	-	277.2	268.4	256.2
03/08-06-041-12-W4	W-100.000	ELL	P	14.2	29.67	0.06	-	302.4	287.0	266.7
05/08-06-041-12-W4	W-100.000	ELL	P	12.1	47.46	0.06	-	566.6	537.0	498.0
02/09-06-041-12-W4	W-100.000	ELL	P	8.8	43.31	0.04	-	475.7	446.7	408.9
02/15-15-041-12-W4	R- 3.750	ELL	P	-	0.22	-	-	5.0	4.8	4.7
04/15-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
02/16-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
05/16-15-041-12-W4	R- 3.750	ELL	P	-	0.05	-	-	1.3	1.3	1.2
Subtotal				**265.4**	**793.22**	**1.21**	-	**5721.5**	**5512.0**	**5227.6**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	NP	409.4	-	-	-	768.2	731.7	681.9
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	P	64.1	-	0.26	-	204.0	191.5	175.4
00/11-05-040-08-W4	R- 15.000	VIK	P	5.0	-	0.02	-	20.1	19.6	18.9
00/07-07-040-08-W4	R- 6.250	CLY	P	2.2	-	0.01	-	9.4	9.3	9.1
00/10-07-040-08-W4	R- 15.000	VIK	P	18.3	-	0.07	-	60.5	57.1	52.6
Subtotal				**89.5**	-	**0.36**	-	**294.0**	**277.4**	**255.9**
David North										
Lloydminster O Unit	W-100.000	LLOYD	P	53.2	531.85	2.65	-	7889.8	7537.1	7069.4
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	P	64.8	529.37	3.23	-	7422.2	7090.8	6654.6
00/10-27-040-03-W4	W-100.000	LLOYD	P	-	14.09	-	-	139.3	134.9	128.9
02/10-27-040-03-W4	W-100.000	LLOYD	P	-	29.26	-	-	430.7	413.7	390.7
02/15-27-040-03-W4	W-100.000	LLOYD	P	-	27.92	-	-	274.3	263.0	247.8
Subtotal				**118.0**	**1132.49**	**5.89**	-	**16156.3**	**15439.3**	**14491.4**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	P	-	90.67	-	-	485.7	470.9	450.5
N-24-40-1W4 1999 Wells	W- 93.750	DINA	P	-	66.05	-	-	450.5	440.6	426.8
N-24-40-1W4 2002 Wells	W- 93.750	DINA	P	-	256.67	-	-	2525.8	2452.4	2352.1
N-24-40-1W4 Future Locations	W- 93.750	DINA	UND	-	206.25	-	-	1370.6	1274.8	1146.7
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	P	-	1559.43	-	-	11186.8	10702.5	10058.6
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	P	-	121.57	-	-	835.5	805.4	764.6
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	P	-	175.69	-	-	1427.3	1392.7	1344.5
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	P	-	506.83	-	-	4782.7	4691.1	4562.1

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Hayter (cont'd)										
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	P	-	201.07	-	-	2115.9	2076.7	2021.3
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	P	-	489.82	-	-	5981.5	5776.7	5500.5
Sec 25-40-1W4 Future Locations	W- 94.517	DINA	UND	-	1663.50	-	-	13604.6	12989.9	12146.4
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	P	-	112.79	-	-	541.5	530.8	515.8
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	P	-	31.20	-	-	275.9	271.1	264.3
Sec 34-40-1W4 2000 Wells	W- 75.000	DINA	P	-	9.84	-	-	53.5	52.6	51.3
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	P	-	797.73	-	-	3242.0	3165.6	3059.0
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	P	-	13.50	-	-	93.8	92.5	90.6
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	P	-	41.24	-	-	338.5	330.8	320.1
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	P	-	200.64	-	-	1993.2	1948.8	1886.7
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	P	-	404.96	-	-	3499.0	3426.6	3324.8
NW-35-40-1W4 Pre-2000 Wells	W- 75.000	DINA	P	-	116.69	-	-	407.5	394.8	377.4
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	P	-	155.30	-	-	1311.8	1285.7	1248.9
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	P	-	305.18	-	-	2744.9	2677.0	2582.9
NW-35-40-1W4 Future Locations	W- 75.000	DINA	UND	-	412.50	-	-	2527.8	2374.1	2164.8
S-36-40-1W4 GOR Wells	R- 7.500	DINA	P	-	2.26	-	-	50.4	49.6	48.5
00/09-34-040-01-W4	W- 75.000	SPKY	P	-	10.16	-	-	98.7	96.0	92.3
00/15-34-040-01-W4	W- 75.000	SPKY	P	-	7.08	-	-	69.7	68.2	66.2
00/01-03-041-01-W4	W- 75.000	SPKY	P	-	35.48	-	-	249.2	234.3	215.2
Subtotal				-	**7994.13**	-	-	**62264.2**	**60072.3**	**57082.8**
Mestikow										
All Company Wells	W-100.000	DINA	P	-	195.31	-	-	1585.1	1531.7	1459.0
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	P	763.2	2506.50	83.95	-	22631.8	21789.7	20648.8
04/10-29-040-11-W4	W- 25.000	VIK	P	1.6	-	-	-	2.2	2.1	2.1
Subtotal				**764.8**	**2506.50**	**83.95**	-	**22634.0**	**21791.8**	**20650.9**
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	P	33.4	454.00	-	-	3968.4	3811.6	3600.8
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	P	10.3	97.94	-	-	865.0	827.8	778.3
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	P	25.6	243.69	-	-	2517.2	2456.0	2370.7
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	P	5.7	74.11	-	-	800.6	786.8	767.3
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	P	0.6	10.69	-	-	101.5	99.5	96.5
Sec 16-38-3W4	W-100.000	DINA	P	13.6	77.54	-	-	661.4	645.7	623.8
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	P	19.2	27.38	-	-	297.6	290.5	280.5
00/11-24-037-02-W4	W- 37.500	VIK	P	0.5	-	-	-	0.2	0.2	0.2
00/07-27-037-02-W4	W- 42.188	VIK	P	55.5	-	-	-	59.0	54.3	48.6
02/06-11-038-03-W4	W- 28.125	VIK	NRA	-	-	-	-	-	-	-
00/14-12-038-03-W4	W- 37.500	CLY	P	13.1	-	-	-	18.7	18.2	17.5
00/07-13-038-03-W4	W- 37.500	VIK	P	34.2	-	-	-	52.2	49.9	46.8
00/06-14-038-03-W4	W- 37.500	VIK	NRA	-	-	-	-	-	-	-
00/07-15-038-03-W4	W- 37.500	VIK	P	7.3	-	-	-	9.1	9.0	8.7
00/07-17-038-03-W4	W- 37.500	VIK	P	6.0	-	-	-	1.6	1.6	1.5
00/07-18-038-03-W4	W- 37.500	VIK	P	24.0	-	-	-	30.1	28.8	27.1
00/14-07-039-01-W4	W- 29.371	MCLAR	P	90.1	-	-	-	121.5	113.5	103.3
Bodo Compression Facility	P-100.000	ALL ZONES	NRA	-	-	-	-	27.1	26.6	25.8

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
West Provost (cont'd)										
Wells with NRA		ALL ZONES	NRA	-	-	-	-	-	-	-
Subtotal				**339.1**	**985.34**	**-**	**-**	**9531.3**	**9220.0**	**8797.5**
Subtotal Alberta				**1986.1**	**13606.99**	**91.40**	**-**	**118954.6**	**114576.1**	**108647.0**
TOTAL				**1986.1**	**13606.99**	**91.40**	**-**	**118954.6**	**114576.1**	**108647.0**

Coyote Energy Inc.

Summary of Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

	Company Interest Reserves				Net Reserves After Royalty				Present Worth Value Before Tax (M$)			
Area	Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	@10.0%	@12.0%	@15.0%	@20.0%
Alberta												
Bellshill Lake	0.27	793.2	1.2	-	0.22	725.1	1.0	-	5721.5	5512.0	5227.6	4820.4
Black Creek	0.41	-	-	-	0.32	-	-	-	768.2	731.7	681.9	610.2
Choice	0.09	-	0.4	-	0.09	-	0.4	-	294.0	277.4	255.9	227.0
David North	0.12	1132.5	5.9	-	0.11	1073.5	5.6	-	16156.3	15439.3	14491.4	13182.3
Hayter	-	7994.1	-	-	-	6646.6	-	-	62264.2	60072.3	57082.8	52764.8
Mestikow	-	195.3	-	-	-	182.7	-	-	1585.1	1531.7	1459.0	1354.4
Thompson Lake	0.76	2506.5	83.9	-	0.57	2394.4	62.3	-	22634.0	21791.8	20650.9	19021.2
West Provost	0.34	985.3	-	-	0.27	924.1	-	-	9531.3	9220.0	8797.5	8191.5
Subtotal Alberta	**1.99**	**13607.0**	**91.4**	**-**	**1.58**	**11946.3**	**69.3**	**-**	**118954.6**	**114576.1**	**108647.0**	**100171.9**
TOTAL	**1.99**	**13607.0**	**91.4**	**-**	**1.58**	**11946.3**	**69.3**	**-**	**118954.6**	**114576.1**	**108647.0**	**100171.9**

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By Company Oil Reserves

		Company Interest Reserves					Present Worth Value			Company Oil Reserves	
		Gas	Oil	NGL	Sulphur	BOE (1)	Before Tax (M$)			% of	Cumulative
Rank		bcf	mbbl	mbbl	mlt	mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	Total	%
1	Hayter	-	7994.1	-	-	7994.1	62264.2	60072.3	57082.8	58.75	58.75
2	Thompson Lake	0.76	2506.5	83.9	-	2717.9	22634.0	21791.8	20650.9	18.42	77.17
3	David North	0.12	1132.5	5.9	-	1158.0	16156.3	15439.3	14491.4	8.32	85.49
4	West Provost	0.34	985.3	-	-	1041.9	9531.3	9220.0	8797.5	7.24	92.74
5	Bellshill Lake	0.27	793.2	1.2	-	838.7	5721.5	5512.0	5227.6	5.83	98.56
6	Mestikow	-	195.3	-	-	195.3	1585.1	1531.7	1459.0	1.44	100.00
7	Black Creek	0.41	-	-	-	68.2	768.2	731.7	681.9	-	100.00
8	Choice	0.09	-	0.4	-	15.3	294.0	277.4	255.9	-	100.00
	Total	**1.99**	**13607.0**	**91.4**	**-**	**14029.4**	**118954.6**	**114576.1**	**108647.0**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By Company Gas Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company Gas Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Thompson Lake	0.76	2506.5	83.9	-	2717.9	22634.0	21791.8	20650.9	38.51	38.51
2	Black Creek	0.41	-	-	-	68.2	768.2	731.7	681.9	20.62	59.12
3	West Provost	0.34	985.3	-	-	1041.9	9531.3	9220.0	8797.5	17.07	76.19
4	Bellshill Lake	0.27	793.2	1.2	-	838.7	5721.5	5512.0	5227.6	13.36	89.55
5	David North	0.12	1132.5	5.9	-	1158.0	16156.3	15439.3	14491.4	5.94	95.49
6	Choice	0.09	-	0.4	-	15.3	294.0	277.4	255.9	4.51	100.00
7	Hayter	-	7994.1	-	-	7994.1	62264.2	60072.3	57082.8	-	100.00
8	Mestikow	-	195.3	-	-	195.3	1585.1	1531.7	1459.0	-	100.00
	Total	**1.99**	**13607.0**	**91.4**	**-**	**14029.4**	**118954.6**	**114576.1**	**108647.0**	**100.00**	**-**

1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By Company BOE Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company BOE Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	7994.1	-	-	7994.1	62264.2	60072.3	57082.8	56.98	56.98
2	Thompson Lake	0.76	2506.5	83.9	-	2717.9	22634.0	21791.8	20650.9	19.37	76.35
3	David North	0.12	1132.5	5.9	-	1158.0	16156.3	15439.3	14491.4	8.25	84.61
4	West Provost	0.34	985.3	-	-	1041.9	9531.3	9220.0	8797.5	7.43	92.03
5	Bellshill Lake	0.27	793.2	1.2	-	838.7	5721.5	5512.0	5227.6	5.98	98.01
6	Mestikow	-	195.3	-	-	195.3	1585.1	1531.7	1459.0	1.39	99.40
7	Black Creek	0.41	-	-	-	68.2	768.2	731.7	681.9	0.49	99.89
8	Choice	0.09	-	0.4	-	15.3	294.0	277.4	255.9	0.11	100.00
	Total	**1.99**	**13607.0**	**91.4**	**-**	**14029.4**	**118954.6**	**114576.1**	**108647.0**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By @15.0% Present Worth Value

		Company Interest Reserves					Present Worth Value Before Tax (M$)			@15.0% Present Worth Value	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	7994.1	-	-	7994.1	62264.2	60072.3	57082.8	52.54	52.54
2	Thompson Lake	0.76	2506.5	83.9	-	2717.9	22634.0	21791.8	20650.9	19.01	71.55
3	David North	0.12	1132.5	5.9	-	1158.0	16156.3	15439.3	14491.4	13.34	84.89
4	West Provost	0.34	985.3	-	-	1041.9	9531.3	9220.0	8797.5	8.10	92.98
5	Bellshill Lake	0.27	793.2	1.2	-	838.7	5721.5	5512.0	5227.6	4.81	97.79
6	Mestikow	-	195.3	-	-	195.3	1585.1	1531.7	1459.0	1.34	99.14
7	Black Creek	0.41	-	-	-	68.2	768.2	731.7	681.9	0.63	99.76
8	Choice	0.09	-	0.4	-	15.3	294.0	277.4	255.9	0.24	100.00
	Total	**1.99**	**13607.0**	**91.4**	-	**14029.4**	**118954.6**	**114576.1**	**108647.0**	**100.00**	-

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Table 4
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Coyote Energy Inc.

First Year Production, Revenue and Expenses by Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

2002 Summary

	Production					Revenue and Expenses				Average Values $/BOE (1)			
Area	Oil bopd	Gas mcf/d	NGL bpd	Sulphur lt/d	BOE (1) boepd	Gross Revenue $M	Encumb. $M	Oper. Exp $M	Net Rev. (2) $M	Gross Revenue	Encumb.	Oper Exp	Net Rev (2)
Alberta													
Bellshill Lake	382.4	191.0	0.7	-	414.2	1804	211	585	1008	28.64	3.35	9.29	16.00
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	47.1	0.2	-	7.9	33	-	-	33	27.47	-	-	27.47
David North	714.4	74.9	3.7	-	730.6	3533	234	575	2724	31.79	2.11	5.17	24.51
Hayter	5447.9	-	-	-	5447.9	21068	4392	3887	12789	25.43	5.30	4.69	15.44
Mestikow	125.5	-	-	-	125.5	521	47	153	321	27.28	2.45	8.02	16.81
Thompson Lake	1358.0	421.1	45.5	-	1473.7	7170	488	2757	3926	31.99	2.18	12.30	17.52
West Provost	657.5	175.0	-	-	686.1	3341	326	999	2016	32.02	3.13	9.57	19.32
Subtotal Alberta	**8685.7**	**909.0**	**50.1**	**-**	**8885.8**	**37470**	**5698**	**8955**	**22817**	**27.73**	**4.22**	**6.63**	**16.88**
TOTAL	**8685.7**	**909.0**	**50.1**	**-**	**8885.8**	**37470**	**5698**	**8955**	**22817**	**27.73**	**4.22**	**6.63**	**16.88**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE based on Gross BOE reserves.
(2) Excludes capital and abandonment expenses.

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Oil Production Forecast (mbbl) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	58	125	115	105	89	80	66	55	52	47	793	-	793
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	109	215	166	133	109	91	78	66	57	50	1074	59	1132
Hayter	829	2255	1539	1112	863	499	346	262	161	111	7977	17	7994
Mestikow	19	39	32	27	23	20	17	16	3	-	195	-	195
Thompson Lake	207	450	395	349	311	279	252	228	36	-	2507	-	2507
West Provost	100	203	167	142	110	78	46	42	38	36	962	23	985
Subtotal Alberta	**1321**	**3287**	**2414**	**1868**	**1506**	**1048**	**805**	**669**	**347**	**243**	**13508**	**99**	**13607**
TOTAL	**1321**	**3287**	**2414**	**1868**	**1506**	**1048**	**805**	**669**	**347**	**243**	**13508**	**99**	**13607**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Gas Production Forecast (mmcf) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	29	60	43	28	24	21	18	15	14	13	265	-	265
Black Creek	-	114	110	76	53	37	20	-	-	-	409	-	409
Choice	7	15	13	11	8	7	6	6	5	4	82	8	90
David North	11	22	17	14	11	9	8	7	6	5	111	7	118
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	64	137	120	106	95	85	77	69	11	-	765	-	765
West Provost	27	57	50	42	34	26	20	17	13	11	295	44	339
Subtotal Alberta	**138**	**405**	**354**	**276**	**225**	**185**	**149**	**114**	**49**	**33**	**1928**	**58**	**1986**
TOTAL	**138**	**405**	**354**	**276**	**225**	**185**	**149**	**114**	**49**	**33**	**1928**	**58**	**1986**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

NGL Production Forecast (mstb) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	0	0	0	0	0	0	0	0	0	0	1	-	1
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	0	0	0	0	0	0	0	0	0	0	0	0	0
David North	1	1	1	1	1	0	0	0	0	0	6	0	6
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	*7*	*15*	*13*	*12*	*10*	*9*	*8*	*8*	*1*	-	*84*	-	*84*
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**8**	**17**	**14**	**13**	**11**	**10**	**9**	**8**	**2**	**0**	**91**	**0**	**91**
TOTAL	**8**	**17**	**14**	**13**	**11**	**10**	**9**	**8**	**2**	**0**	**91**	**0**	**91**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Gross Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1804	3689	2976	2675	2271	2090	1773	1516	1446	1357	21595	-	21595
Black Creek	-	534	501	343	235	164	91	-	-	-	1868	-	1868
Choice	33	73	59	48	38	33	29	26	23	18	381	39	420
David North	3533	6697	4658	3743	3083	2644	2301	1998	1774	1576	32007	1926	33933
Hayter	21068	55311	32998	23980	18712	11179	8004	6251	3947	2797	184248	497	184745
Mestikow	521	1005	718	602	516	461	417	381	81	-	4701	-	4701
Thompson Lake	7170	14996	11897	10561	9442	8675	8006	7427	1206	-	79380	-	79380
West Provost	3341	6526	4861	4128	3234	2340	1421	1324	1237	1168	29580	970	30550
Subtotal Alberta	**37470**	**88830**	**58668**	**46081**	**37530**	**27587**	**22041**	**18922**	**9714**	**6916**	**353758**	**3433**	**357191**
TOTAL	**37470**	**88830**	**58668**	**46081**	**37530**	**27587**	**22041**	**18922**	**9714**	**6916**	**353758**	**3433**	**357191**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Encumbrance Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	211	415	321	281	225	201	172	143	135	124	2228	-	2228
Black Creek	-	118	92	48	24	12	5	-	-	-	299	-	299
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	234	438	300	237	193	164	142	118	103	90	2020	92	2111
Hayter	4392	11475	6379	4371	3353	2011	1441	1052	634	468	35577	102	35678
Mestikow	47	77	50	37	28	25	21	18	3	-	306	-	306
Thompson Lake	488	995	755	649	563	506	457	416	68	-	4896	-	4896
West Provost	326	541	331	249	184	131	85	75	66	60	2048	75	2123
Subtotal Alberta	**5698**	**14058**	**8228**	**5871**	**4570**	**3050**	**2322**	**1823**	**1009**	**742**	**47373**	**269**	**47642**
TOTAL	**5698**	**14058**	**8228**	**5871**	**4570**	**3050**	**2322**	**1823**	**1009**	**742**	**47373**	**269**	**47642**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Capital Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	-	-	5	5	-	-	-	-	-	-	11	-	11
Black Creek	-	230	-	-	-	-	-	-	-	-	230	-	230
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	-	-	-	-	-	-	-	-	-	-	-	-	-
Hayter	9046	3471	-	-	-	-	-	-	-	-	12517	-	12517
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	-	-	-	-	-	-	-	-	-	-	-	-	-
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**9046**	**3700**	**5**	**5**	-	-	-	-	-	-	**12757**	-	**12757**
TOTAL	**9046**	**3700**	**5**	**5**	-	-	-	-	-	-	**12757**	-	**12757**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Operating Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	585	1400	1406	1359	1319	1326	1253	1193	1208	1211	12260	-	12260
Black Creek	-	71	77	62	52	45	31	-	-	-	336	-	336
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	575	1290	1193	1110	1033	960	888	820	821	788	9477	1087	10564
Hayter	3887	10095	10205	10256	9493	5240	3639	3008	2216	1717	59756	316	60072
Mestikow	153	366	328	327	328	293	295	298	75	-	2463	-	2463
Thompson Lake	2757	6467	6303	6160	6049	5950	5861	5796	962	-	46304	-	46304
West Provost	999	2431	2478	2484	2143	1628	948	961	970	985	16027	814	16841
Subtotal Alberta	**8955**	**22119**	**21988**	**21758**	**20417**	**15442**	**12914**	**12076**	**6252**	**4701**	**146622**	**2217**	**148839**
TOTAL	**8955**	**22119**	**21988**	**21758**	**20417**	**15442**	**12914**	**12076**	**6252**	**4701**	**146622**	**2217**	**148839**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Escalating Prices as of August 1, 2002
Total Proved & Probable Reserves

Net Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	*1008*	*1874*	*1243*	*1030*	*726*	*562*	349	179	*103*	22	7096	-	7096
Black Creek	-	116	333	233	159	107	55	-	-	-	1004	-	1004
Choice	33	73	59	48	38	33	29	26	23	18	381	39	420
David North	2724	4970	3165	2396	1857	1521	1272	1060	850	697	20511	747	21258
Hayter	3743	30270	16414	9353	5866	3928	2924	2190	1097	612	76398	79	76477
Mestikow	321	562	341	239	159	143	101	65	2	-	1932	-	1932
Thompson Lake	3926	7533	4839	3752	2830	2219	1688	1216	177	-	28180	-	28180
West Provost	2016	3554	2052	1395	908	581	387	288	200	123	11505	81	11586
Subtotal Alberta	**13771**	**48952**	**28447**	**18447**	**12543**	**9095**	**6805**	**5023**	**2453**	**1473**	**147006**	**947**	**147954**
TOTAL	**13771**	**48952**	**28447**	**18447**	**12543**	**9095**	**6805**	**5023**	**2453**	**1473**	**147006**	**947**	**147954**

Coyote Energy Inc.

Table 1

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Total Probable Reserves - Unrisked

Total Of All Areas

Year	No.Of Wells	Crude Oil			Natural Gas			Natural Gas Liquids			Gross Revenue M$
		Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	
2002		50.5	26.45	1336.4	1.7	4.52	7.6	0.1	27.60	2.8	1346.9
2003		170.9	25.98	4441.8	15.1	4.70	70.9	0.6	26.14	15.4	4528.2
2004	1.0	236.9	22.86	5415.8	36.9	4.55	168.2	0.9	24.10	22.2	5606.2
2005	13.8	264.8	23.28	6165.0	35.5	4.50	160.0	1.0	24.49	25.5	6350.5
2006	53.9	426.3	22.72	9687.2	36.3	4.45	161.4	1.1	24.37	27.5	9876.2
2007	32.0	254.7	24.37	6205.9	49.9	4.50	224.6	1.2	24.90	29.1	6459.7
2008	66.3	270.9	25.93	7023.5	53.8	4.50	242.2	3.4	25.15	85.0	7350.7
2009	150.0	392.2	27.90	10942.0	72.5	4.55	329.7	7.7	25.62	197.5	11469.2
2010	51.1	187.9	26.72	5019.3	15.0	4.65	69.8	1.3	26.13	35.0	5124.0
2011	47.6	175.6	27.49	4826.2	6.9	4.75	32.9	0.2	27.13	4.1	4863.1
2012	34.0	70.0	31.24	2185.8	8.3	4.85	40.2	0.2	27.05	5.9	2232.0
2013	13.0	19.3	32.60	630.5	4.5	4.95	22.5	0.1	26.38	3.4	656.5
2014	1.7	2.8	33.33	93.3	2.1	5.00	10.4	0.0	19.50	0.4	104.2
2015	0.8	1.5	34.31	52.5	1.0	5.10	5.4			0.1	58.0
2016	0.8	1.4	35.08	49.8							49.8
REM.	0.8	0.3	36.35	11.3							11.3
TOTAL		**2526.0**	**25.37**	**64086.4**	**339.6**	**4.55**	**1545.8**	**17.9**	**25.36**	**454.0**	**66086.3**

Year	Crown Royalties			Freehold Royalties			Overriding Royalties			Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$			
2002	67.0	0.1	66.9	164.3		164.3	8.1		8.1	55.4	294.7	21.88
2003	236.9	-1.5	238.3	504.7		504.7	25.9		25.9	160.2	929.1	20.52
2004	219.1	2.9	216.2	610.5		610.5	34.2		34.2	182.9	1043.8	18.62
2005	231.9	3.8	228.1	545.9		545.9	35.8		35.8	137.2	947.1	14.91
2006	172.8	3.7	169.1	1161.7		1161.7	62.2		62.2	139.1	1532.2	15.51
2007	156.7	7.9	148.8	599.8		599.8	37.5	-0.0	37.5	73.8	859.9	13.31
2008	163.6	5.7	157.9	645.8		645.8	35.6	0.0	35.6	61.3	900.6	12.25
2009	290.4	1.8	288.7	639.4	0.0	639.4	33.2	-0.0	33.2	56.8	1018.1	8.88
2010	75.9	0.3	75.7	433.9		433.9	33.6		33.6	43.0	586.3	11.44
2011	48.4		48.4	439.1		439.1	46.6		46.6	41.0	575.1	11.83
2012	25.6		25.6	79.9		79.9	21.1		21.1	10.0	136.6	6.12
2013				21.1	0.0	21.1	2.5		2.5	3.5	27.2	4.15
2014				12.0		12.0	0.2		0.2	0.5	12.6	12.13
2015				11.8		11.8				0.2	12.0	20.77
2016				11.2		11.2				0.2	11.4	22.90
REM.				2.5		2.5				0.0	2.6	22.89
TOTAL	**1688.4**	**24.8**	**1663.7**	**5883.6**	**0.0**	**5883.6**	**376.6**	**-0.0**	**376.6**	**965.3**	**8889.4**	**13.45**

Year	Operating Costs M$	Net Op. Income M$	Net Revenues After Costs		
			Annual M$	Cum M$	PWV @15.0% M$
2002	10.7	1041.4	1041.4	1041.4	1011.5
2003	66.4	3532.6	3532.7	4574.1	3107.8
2004	181.0	4381.4	4381.3	8955.4	3351.8
2005	1141.9	4261.5	4261.5	13216.9	2834.8
2006	4421.4	3922.6	3922.6	17139.5	2269.0
2007	2541.9	3057.9	3057.9	20197.4	1538.1
2008	3248.1	3201.9	3201.9	23399.3	1400.4
2009	7244.1	3207.0	3207.0	26606.3	1219.8
2010	2832.3	1705.4	1705.4	28311.7	564.0
2011	3075.4	1212.6	1212.6	29524.3	348.7
2012	1510.1	585.2	585.2	30109.6	146.3
2013	382.1	247.2	247.2	30356.7	53.8
2014	60.8	30.8	30.8	30387.5	5.8
2015	34.9	11.0	11.0	30398.5	1.8
2016	35.6	2.8	2.8	30401.3	0.4
REM.	9.1	-0.4	-0.4	30400.9	-0.0
TOTAL	**26795.8**	**30400.9**	**30400.9**		**17854.0**

Product	Remaining Reserves		Remaining Present Worth Value - M$			
	Gross	Net	@10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	2526.1	2212.1	20153.8	18903.6	17265.5	15039.1
Natural Gas (mmcf)	339.7	266.1	527.4	486.1	432.9	362.0
Natural Gas Liquids (mbbl)	18.0	13.6	197.9	179.4	155.8	125.1
Total			**20879.0**	**19569.1**	**17854.2**	**15526.2**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves: Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$): @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
00/06-05-041-12-W4	W- 40.000	GLAUC L	PA	9.5	-	0.05	-	22.5	21.8	20.9
02/10-05-041-12-W4	W-100.000	ELL	PA	0.4	5.00	0.00	-	48.1	44.3	39.3
00/15-05-041-12-W4	W-100.000	ELL	PA	1.2	5.00	0.01	-	51.9	47.9	42.5
Subtotal				**11.1**	**10.00**	**0.05**	-	**122.5**	**114.0**	**102.7**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	PA	116.8	-	-	-	229.2	214.2	194.3
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PA	16.9	-	0.07	-	40.3	35.8	30.3
David North										
Lloydminster O Unit	W-100.000	LLOYD	PA	12.8	127.86	0.64	-	1619.3	1487.3	1319.2
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PA	12.2	100.00	0.61	-	1268.3	1165.4	1035.8
02/10-27-040-03-W4	W-100.000	LLOYD	PA	-	5.00	-	-	58.9	54.4	48.6
02/15-27-040-03-W4	W-100.000	LLOYD	PA	-	5.00	-	-	38.8	35.7	31.7
Subtotal				**25.0**	**237.85**	**1.25**	-	**2985.3**	**2742.9**	**2435.3**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	PA	-	18.72	-	-	70.5	66.3	60.8
N-24-40-1W4 1999 Wells	W- 93.750	DINA	PA	-	18.66	-	-	103.1	99.0	93.5
N-24-40-1W4 2002 Wells	W- 93.750	DINA	PA	-	53.99	-	-	472.6	450.4	420.7
N-24-40-1W4 Future Locations	W- 93.750	DINA	PA	-	37.50	-	-	378.8	352.4	318.4
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	PA	-	282.67	-	-	1798.6	1653.5	1468.2
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	PA	-	23.55	-	-	132.5	123.6	112.0
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	PA	-	46.75	-	-	330.5	316.9	298.4
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	PA	-	92.26	-	-	800.1	774.0	737.8
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	PA	-	45.58	-	-	433.2	420.4	402.7
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	PA	-	109.74	-	-	1181.5	1114.8	1027.8
Sec 25-40-1W4 Future Locations	W- 94.517	DINA	PA	-	302.45	-	-	2911.7	2716.1	2457.0
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	PA	-	37.40	-	-	127.8	123.2	116.9
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	PA	-	7.40	-	-	55.5	53.8	51.5
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	PA	-	149.79	-	-	472.4	448.8	416.8
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	PA	-	4.93	-	-	28.4	27.8	26.9
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	PA	-	9.88	-	-	73.2	70.3	66.3
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	PA	-	48.88	-	-	434.2	418.2	396.3
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	PA	-	98.36	-	-	750.1	724.3	688.7
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	PA	-	37.81	-	-	285.0	275.8	263.1
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	PA	-	72.81	-	-	606.5	581.7	548.0
NW-35-40-1W4 Future Locations	W- 75.000	DINA	PA	-	75.00	-	-	732.0	689.6	633.5
00/01-03-041-01-W4	W- 75.000	SPKY	PA	-	7.50	-	-	39.2	34.7	29.2
Subtotal				-	**1581.65**	-	-	**12217.5**	**11535.7**	**10634.6**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Total Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Mestikow										
All Company Wells	W-100.000	DINA	PA	-	24.98	-	-	170.6	159.6	145.0
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	PA	150.7	494.98	16.58	-	3736.9	3468.6	3117.3
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PA	5.5	74.81	-	-	518.0	480.0	430.7
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PA	2.0	18.71	-	-	134.3	123.3	109.3
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PA	3.9	37.25	-	-	334.6	319.4	298.7
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PA	1.4	18.48	-	-	185.3	179.9	172.4
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PA	0.2	3.72	-	-	30.3	29.3	27.8
Sec 16-38-3W4	W-100.000	DINA	PA	3.5	20.00	-	-	141.0	134.6	126.0
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PA	2.6	3.73	-	-	33.2	31.8	29.8
Subtotal				**19.1**	**176.70**	**-**	**-**	**1376.8**	**1298.3**	**1194.8**
Subtotal Alberta				**339.7**	**2526.16**	**17.95**	**-**	**20879.0**	**19569.1**	**17854.3**
TOTAL				**339.7**	**2526.16**	**17.95**	**-**	**20879.0**	**19569.1**	**17854.3**

Coyote Energy Inc.

Table 1

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Proved Producing Reserves

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids				
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Total Other Revenues M$	Gross Revenue M$
2002	420.4	1182.5	27.95	33048.6	136.5	4.50	614.3	7.5	27.64	207.0	22.2	33892.3
2003	406.9	2236.7	27.04	60469.6	282.0	4.70	1325.7	15.9	26.17	416.8	36.0	62248.1
2004	391.9	1743.5	24.07	41961.1	223.7	4.55	1017.6	13.4	24.18	324.0	32.0	43334.8
2005	362.9	1387.4	24.25	33650.9	183.2	4.50	824.6	11.5	24.20	277.6	29.0	34782.1
2006	293.5	933.7	25.02	23362.0	153.9	4.45	685.0	10.0	24.18	241.1	25.0	24313.1
2007	243.9	681.4	26.11	17794.5	130.3	4.50	586.3	8.7	24.74	215.9		18596.7
2008	184.8	513.9	26.57	13654.4	94.8	4.50	427.0	5.5	25.22	138.7		14220.2
2009	82.1	268.0	26.31	7050.1	41.5	4.55	189.1	0.3	27.41	8.8		7248.0
2010	57.3	159.4	27.77	4425.3	34.0	4.65	158.0	0.2	28.27	6.2		4589.6
2011	29.1	67.4	28.54	1925.0	26.0	4.75	123.3	0.1	33.07	4.6		2053.0
2012	1.5	1.6	31.94	50.5	7.8	4.85	37.7			0.0		88.2
2013	1.5	1.4	32.67	47.0	6.9	4.95	34.0					81.0
2014	0.8	0.2	33.75	8.1	6.4	5.00	32.0					40.1
2015	0.7				6.0	5.10	30.4					30.4
2016	0.7				5.6	5.20	29.0					29.0
REM.	0.7				9.7	5.40	52.2					52.2
TOTAL		**9177.1**	**25.87**	**237447.2**	**1348.2**	**4.57**	**6166.3**	**73.2**	**25.16**	**1840.9**	**144.2**	**245598.8**

	Crown Royalties			*Freehold Royalties*			*Overriding Royalties*					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	1077.0	3.8	1073.2	2856.1	0.6	2855.5	305.6	0.1	305.5	624.2	4858.4	14.34
2003	1723.5	7.1	1716.5	4964.6	1.3	4963.3	577.6	0.1	577.5	874.6	8131.9	13.07
2004	1012.3	4.1	1008.2	3278.8	1.3	3277.5	409.1	0.1	409.0	448.6	5143.3	11.88
2005	698.2	2.9	695.3	2672.3	1.2	2671.1	331.1	0.1	331.0	302.4	3999.9	11.51
2006	525.4	2.5	522.9	1510.8	1.1	1509.7	244.8	0.1	244.7	171.0	2448.3	10.08
2007	400.3	2.2	398.1	1015.8	1.0	1014.7	206.0	0.1	205.9	118.0	1736.8	9.34
2008	270.9	1.5	269.4	791.9	1.0	790.9	186.9	0.1	186.8	92.8	1339.9	9.42
2009	75.2	0.2	75.0	500.2	0.9	499.3	155.2	0.1	155.1	62.6	792.1	10.93
2010	62.5	0.1	62.5	204.0	0.9	203.1	125.0	0.0	124.9	32.1	422.6	9.21
2011	21.6	0.0	21.5	37.0	0.8	36.3	93.3	0.0	93.3	15.7	166.9	8.13
2012	0.1	0.0	0.1	18.5	0.8	17.7	0.2	0.0	0.2	0.6	18.6	21.11
2013	0.1	0.0	0.1	17.4	0.7	16.7	0.2	0.0	0.2	0.6	17.5	21.54
2014	0.1	0.0	0.1	8.2	0.7	7.5	0.2	0.0	0.2	0.4	8.1	20.30
2015	0.1	0.0	0.1	6.1	0.6	5.4	0.2	0.0	0.1	0.3	6.0	19.58
2016	0.1	0.0	0.1	5.8	0.6	5.2	0.2	0.0	0.1	0.3	5.7	19.57
REM.	0.1	0.0	0.1	10.4	1.0	9.4	0.3	0.0	0.3	0.5	10.2	19.57
TOTAL	**5867.5**	**24.5**	**5843.1**	**17897.8**	**14.4**	**17883.4**	**2635.7**	**0.9**	**2634.8**	**2744.6**	**29106.1**	**11.86**

			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Annual M$	Cum M$	PWV @15.0% M$
2002	8899.4	20134.4	20134.4	20134.4	19556.6
2003	21223.2	32893.1	32893.1	53027.5	28937.6
2004	20916.5	17275.0	17275.0	70302.5	13215.3
2005	19682.0	11100.2	11100.1	81402.6	7384.0
2006	15063.3	6801.5	6801.5	88204.1	3934.2
2007	12022.1	4837.8	4837.8	93041.8	2433.3
2008	9526.8	3353.4	3353.3	96395.2	1466.7
2009	4754.5	1701.5	1701.4	98096.6	647.1
2010	3419.8	747.1	747.1	98843.7	247.0
2011	1626.0	260.1	260.1	99103.8	74.8
2012	48.9	20.7	20.7	99124.5	5.2
2013	49.6	14.0	14.0	99138.5	3.0
2014	21.8	10.2	10.2	99148.6	1.9
2015	16.2	8.3	8.3	99156.9	1.4
2016	16.3	7.0	7.0	99163.9	1.0
REM.	31.6	10.4	10.4	99174.3	1.2
TOTAL	**117317.9**	**99174.3**	**99174.3**		**77910.3**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	**Gross**	**Net**	**@10.0%**	**@12.0%**	**@15.0%**	**@20.0%**
Crude Oil (mbbl)	9177.4	8169.2	80130.8	77856.3	74735.3	70188.6
Natural Gas (mmcf)	1348.3	1078.8	2441.1	2333.9	2191.1	1991.5
Natural Gas Liquids (mbbl)	73.4	55.6	1088.1	1044.0	984.1	898.7
Total			**83660.0**	**81234.2**	**77910.5**	**73078.8**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Proved Producing Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
Fixed Battery Costs	P-100.000		NRA	-	-	-	-	-3372.9	-3132.8	-2822.7
00/04-05-041-12-W4	W-100.000	ELL	PP	10.2	48.79	0.05	-	539.6	510.3	471.9
02/04-05-041-12-W4	W-100.000	ELL	PP	19.6	50.39	0.09	-	590.1	558.7	517.5
03/04-05-041-12-W4	W-100.000	ELL	PP	1.2	5.15	0.00	-	48.8	48.3	47.5
00/05-05-041-12-W4	W-100.000	ELL	PP	11.6	52.20	0.05	-	598.0	566.4	524.9
04/05-05-041-12-W4	W-100.000	ELL	PP	12.6	38.11	0.05	-	389.9	369.2	341.9
B0/05-05-041-12-W4	W-100.000	ELL	PP	12.7	60.50	0.06	-	722.2	684.0	633.7
00/06-05-041-12-W4	W- 40.000	GLAUC L	PP	42.6	-	0.21	-	113.7	112.0	109.7
00/12-05-041-12-W4	W-100.000	ELL	PP	19.4	49.69	0.09	-	578.0	547.4	507.1
00/13-05-041-12-W4	W-100.000	ELL	PP	0.8	5.62	0.00	-	39.9	39.4	38.6
B0/14-05-041-12-W4	W-100.000	ELL	PP	10.8	51.43	0.05	-	607.0	577.6	538.8
C0/14-05-041-12-W4	W-100.000	ELL	PP	8.2	40.48	0.04	-	416.5	394.6	365.7
02/15-05-041-12-W4	W-100.000	ELL	PP	2.1	7.81	0.01	-	113.0	111.3	108.7
A2/15-05-041-12-W4	W-100.000	ELL	PP	4.6	34.14	0.02	-	423.2	407.4	385.9
B2/15-05-041-12-W4	W-100.000	ELL	PP	17.1	59.88	0.08	-	722.2	683.8	633.3
02/16-05-041-12-W4	W-100.000	ELL	PP	3.8	15.81	0.02	-	225.9	221.0	214.2
00/01-06-041-12-W4	W-100.000	ELL	PP	11.7	19.53	0.05	-	142.9	137.0	129.1
00/02-06-041-12-W4	W-100.000	ELL	PP	8.7	38.81	0.04	-	429.5	406.8	376.9
02/07-06-041-12-W4	W-100.000	ELL	PP	4.4	26.91	0.02	-	247.5	236.1	221.0
02/08-06-041-12-W4	W-100.000	ELL	PP	11.4	21.09	0.05	-	277.2	268.4	256.2
03/08-06-041-12-W4	W-100.000	ELL	PP	14.2	29.67	0.06	-	302.4	287.0	266.7
05/08-06-041-12-W4	W-100.000	ELL	PP	12.1	47.46	0.06	-	566.6	537.0	498.0
02/09-06-041-12-W4	W-100.000	ELL	PP	8.8	43.31	0.04	-	475.7	446.7	408.9
02/15-15-041-12-W4	R- 3.750	ELL	PP	-	0.22	-	-	5.0	4.8	4.7
04/15-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
02/16-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
05/16-15-041-12-W4	R- 3.750	ELL	PP	-	0.05	-	-	1.3	1.3	1.2
Subtotal				**248.7**	**747.07**	**1.13**	-	**5203.1**	**5023.4**	**4779.4**
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PP	47.2	-	0.19	-	163.6	155.6	145.1
00/11-05-040-08-W4	R- 15.000	VIK	PP	5.0	-	0.02	-	20.1	19.6	18.9
00/07-07-040-08-W4	R- 6.250	CLY	PP	2.2	-	0.01	-	9.4	9.3	9.1
00/10-07-040-08-W4	R- 15.000	VIK	PP	18.3	-	0.07	-	60.5	57.1	52.6
Subtotal				**72.6**	-	**0.29**	-	**253.6**	**241.6**	**225.6**
David North										
Lloydminster O Unit	W-100.000	LLOYD	PP	40.4	403.99	2.02	-	6270.5	6049.7	5750.3
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PP	52.5	429.37	2.62	-	6153.9	5925.3	5618.8
00/10-27-040-03-W4	W-100.000	LLOYD	PP	-	14.09	-	-	139.3	134.9	128.9
02/10-27-040-03-W4	W-100.000	LLOYD	PP	-	24.26	-	-	371.8	359.2	342.1
02/15-27-040-03-W4	W-100.000	LLOYD	PP	-	22.92	-	-	235.5	227.3	216.1
Subtotal				**92.9**	**894.64**	**4.64**	-	**13171.0**	**12696.5**	**12056.0**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	PP	-	71.94	-	-	415.2	404.5	389.8
N-24-40-1W4 1999 Wells	W- 93.750	DINA	PP	-	47.39	-	-	347.4	341.6	333.3
N-24-40-1W4 2002 Wells	W- 93.750	DINA	PP	-	202.69	-	-	2053.2	2002.0	1931.3
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	PP	-	1276.76	-	-	9388.2	9049.1	8590.4
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	PP	-	98.02	-	-	703.0	681.7	652.6
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	PP	-	128.94	-	-	1096.8	1075.8	1046.1
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	PP	-	414.57	-	-	3982.6	3917.2	3824.3
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	PP	-	155.50	-	-	1682.7	1656.3	1618.6
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	PP	-	380.08	-	-	4800.0	4661.9	4472.7
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	PP	-	75.39	-	-	413.7	407.6	398.8

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Escalating Prices as of August 1, 2002
Proved Producing Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves: Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$): @10.0%	@12.0%	@15.0%
Hayter (cont'd)										
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	PP	-	23.79	-	-	220.4	217.3	212.8
Sec 34-40-1W4 2000 Wells	W- 75.000	DINA	PP	-	9.84	-	-	53.5	52.6	51.3
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	PP	-	647.94	-	-	2769.6	2716.8	2642.2
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	PP	-	8.57	-	-	65.4	64.7	63.7
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	PP	-	31.36	-	-	265.3	260.5	253.8
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	PP	-	151.76	-	-	1559.0	1530.6	1490.5
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	PP	-	306.60	-	-	2748.9	2702.2	2636.0
NW-35-40-1W4 Pre-2000 Wells	W- 75.000	DINA	PP	-	116.69	-	-	407.5	394.8	377.4
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	PP	-	117.50	-	-	1026.8	1009.8	985.8
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	PP	-	232.37	-	-	2138.4	2095.3	2034.9
S-36-40-1W4 GOR Wells	R- 7.500	DINA	PP	-	2.26	-	-	50.4	49.6	48.5
00/09-34-040-01-W4	W- 75.000	SPKY	PP	-	10.16	-	-	98.7	96.0	92.3
00/15-34-040-01-W4	W- 75.000	SPKY	PP	-	7.08	-	-	69.7	68.2	66.2
00/01-03-041-01-W4	W- 75.000	SPKY	PP	-	27.99	-	-	210.0	199.6	186.0
Subtotal				**-**	**4545.18**	**-**	**-**	**36566.2**	**35655.8**	**34399.2**
Mestikow										
All Company Wells	W-100.000	DINA	PP	-	170.34	-	-	1414.4	1372.1	1314.0
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	PP	612.5	2011.52	67.37	-	18895.0	18321.1	17531.5
04/10-29-040-11-W4	W- 25.000	VIK	PP	1.6	-	-	-	2.2	2.1	2.1
Subtotal				**614.1**	**2011.52**	**67.37**	**-**	**18897.1**	**18323.3**	**17533.6**
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PP	27.9	379.18	-	-	3450.4	3331.6	3170.1
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PP	8.3	79.23	-	-	730.6	704.5	669.0
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PP	21.7	206.44	-	-	2182.6	2136.7	2072.0
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PP	4.3	55.63	-	-	615.2	606.9	595.0
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PP	0.4	6.96	-	-	71.2	70.2	68.7
Sec 16-38-3W4	W-100.000	DINA	PP	10.1	57.55	-	-	520.5	511.1	497.8
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PP	16.6	23.65	-	-	264.4	258.7	250.7
00/11-24-037-02-W4	W- 37.500	VIK	PP	0.5	-	-	-	0.2	0.2	0.2
00/07-27-037-02-W4	W- 42.188	VIK	PP	55.5	-	-	-	59.0	54.3	48.6
02/06-11-038-03-W4	W- 28.125	VIK	NRA	-	-	-	-	-	-	-
00/14-12-038-03-W4	W- 37.500	CLY	PP	13.1	-	-	-	18.7	18.2	17.5
00/07-13-038-03-W4	W- 37.500	VIK	PP	34.2	-	-	-	52.2	49.9	46.8
00/06-14-038-03-W4	W- 37.500	VIK	NRA	-	-	-	-	-	-	-
00/07-15-038-03-W4	W- 37.500	VIK	PP	7.3	-	-	-	9.1	9.0	8.7
00/07-17-038-03-W4	W- 37.500	VIK	PP	6.0	-	-	-	1.6	1.6	1.5
00/07-18-038-03-W4	W- 37.500	VIK	PP	24.0	-	-	-	30.1	28.8	27.1
00/14-07-039-01-W4	W- 29.371	MCLAR	PP	90.1	-	-	-	121.5	113.5	103.3
Bodo Compression Facility	P-100.000	ALL ZONES	NRA	-	-	-	-	27.1	26.6	25.8
Wells with NRA		ALL ZONES	NRA	-	-	-	-	-	-	-
Subtotal				**320.0**	**808.64**	**-**	**-**	**8154.5**	**7921.6**	**7602.7**
Subtotal Alberta				**1348.4**	**9177.38**	**73.43**	**-**	**83660.1**	**81234.2**	**77910.6**
TOTAL				**1348.4**	**9177.38**	**73.43**	**-**	**83660.1**	**81234.2**	**77910.6**

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Escalating Prices as of August 1,2002

Proved Non-Producing Reserves

Total Of All Areas

Year	No.Of Wells	Crude Oil Annual Volume mbbl	Crude Oil Sales Price $/bbl	Crude Oil Sales Revenue M$	Natural Gas Annual Volume mmcf	Natural Gas Sales Price $/mcf	Natural Gas Sales Revenue M$	Natural Gas Liquids Annual Volume mbbl	Natural Gas Liquids Sales Price $/bbl	Natural Gas Liquids Sales Revenue M$	Gross Revenue M$
2003	1.0				107.9	4.70	507.0				507.0
2004	2.0	7.9	24.11	191.4	92.8	4.55	422.4			0.1	613.9
2005	3.0	14.2	24.17	343.0	57.6	4.50	259.2	0.0	24.00	0.2	602.5
2006	3.0	9.5	24.22	230.8	34.5	4.45	153.6			0.2	384.6
2007	1.8	4.5	24.84	111.3	5.3	4.50	23.7			0.0	135.0
TOTAL		**36.1**	**24.25**	**876.5**	**298.1**	**4.58**	**1366.0**	**0.0**	**24.00**	**0.5**	**2243.0**

Year	Crown Royalties Unadj. Royalty M$	Crown Royalties Royalty Adj. M$	Crown Royalties Adj. Royalty M$	Overriding Royalties Unadj. Royalty M$	Overriding Royalties Royalty Adj. M$	Overriding Royalties Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2003	140.0	34.0	106.0					106.0	20.91
2004	93.2	29.0	64.2	19.5		19.5	4.5	88.1	14.35
2005	64.6	17.0	47.7	14.2		14.2	2.4	64.3	10.67
2006	26.9	10.1	16.8	11.2		11.2	1.5	29.5	7.68
2007	4.9	1.4	3.5	7.1		7.1	0.8	11.4	8.44
TOTAL	**329.6**	**91.5**	**238.1**	**52.0**		**52.0**	**9.3**	**299.4**	**13.35**

Year	Operating Costs M$	Net Op. Income M$	Capital Costs Drilling & Compl M$	Capital Costs Equip & Facility M$	Capital Costs Total Capital M$	Net Revenues After Costs Annual M$	Net Revenues After Costs Cum M$	Net Revenues After Costs PWV @15.0% M$
2003	67.9	333.1		229.5	229.5	103.6	103.6	91.2
2004	113.0	412.8	5.2		5.2	407.6	511.2	311.8
2005	141.0	397.2	5.3		5.3	391.9	903.1	260.7
2006	123.5	231.5				231.5	1134.7	133.9
2007	52.9	70.7				70.6	1205.3	35.5
TOTAL	**498.3**	**1445.3**	**10.5**	**229.5**	**240.0**	**1205.3**		**833.2**

Product	Remaining Reserves Gross	Remaining Reserves Net	Remaining Present Worth Value - M$ @10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	36.2	32.8	384.8	364.1	335.9	295.4
Natural Gas (mmcf)	298.1	232.9	549.8	527.6	497.0	451.9
Natural Gas Liquids (mbbl)	0.0	0.0	0.3	0.3	0.2	0.2
Total			**934.9**	**892.0**	**833.1**	**747.5**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Total Proved Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
West Provost (cont'd)										
Wells with NRA		ALL ZONES	NRA	-	-	-	-	-	-	-
Subtotal				**320.0**	**808.64**	-	-	**10226.5**	**9875.9**	**9399.8**
Subtotal Alberta				**1647.1**	**11084.31**	**73.45**	-	**121619.3**	**117289.8**	**111379.8**
TOTAL				**1647.1**	**11084.31**	**73.45**	-	**121619.3**	**117289.8**	**111379.8**

Coyote Energy Inc.

Summary of Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Total Proved Reserves

Area	Company Interest Reserves				Net Reserves After Royalty				Present Worth Value Before Tax (M$)			
	Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	@10.0%	@12.0%	@15.0%	@20.0%
Alberta												
Bellshill Lake	0.25	786.7	1.2	-	0.21	718.0	0.9	-	7703.6	7355.1	6889.2	6236.5
Black Creek	0.29	-	-	-	0.23	-	-	-	533.2	511.5	481.6	437.5
Choice	0.07	-	0.3	-	0.07	-	0.3	-	250.4	238.5	222.6	200.7
David North	0.09	894.6	4.6	-	0.09	847.8	4.4	-	15251.7	14654.7	13851.4	12714.7
Hayter	-	6412.5	-	-	-	5327.9	-	-	61035.7	59001.4	56200.7	52102.3
Mestikow	-	170.3	-	-	-	158.9	-	-	1873.3	1805.0	1711.9	1578.0
Thompson Lake	0.61	2011.5	67.4	-	0.46	1918.9	50.0	-	24744.8	23847.8	22622.5	20851.7
West Provost	0.32	808.6	-	-	0.26	755.2	-	-	10226.5	9875.9	9399.8	8716.7
Subtotal Alberta	**1.65**	**11084.3**	**73.5**	**-**	**1.31**	**9726.6**	**55.7**	**-**	**121619.3**	**117289.8**	**111379.8**	**102838.3**
TOTAL	**1.65**	**11084.3**	**73.5**	**-**	**1.31**	**9726.6**	**55.7**	**-**	**121619.3**	**117289.8**	**111379.8**	**102838.3**

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Sorted By Company Oil Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company Oil Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	6412.5	-	-	6412.5	61035.7	59001.4	56200.7	57.85	57.85
2	Thompson Lake	0.61	2011.5	67.4	-	2181.2	24744.8	23847.8	22622.5	18.15	76.00
3	David North	0.09	894.6	4.6	-	914.8	15251.7	14654.7	13851.4	8.07	84.07
4	West Provost	0.32	808.6	-	-	862.0	10226.5	9875.9	9399.8	7.30	91.37
5	Bellshill Lake	0.25	786.7	1.2	-	830.3	7703.6	7355.1	6889.2	7.10	98.46
6	Mestikow	-	170.3	-	-	170.3	1873.3	1805.0	1711.9	1.54	100.00
7	Black Creek	0.29	-	-	-	48.8	533.2	511.5	481.6	-	100.00
8	Choice	0.07	-	0.3	-	12.4	250.4	238.5	222.6	-	100.00
	Total	**1.65**	**11084.3**	**73.5**	**-**	**11432.3**	**121619.3**	**117289.8**	**111379.8**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Sorted By Company Gas Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company Gas Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Thompson Lake	0.61	2011.5	67.4	-	2181.2	24744.8	23847.8	22622.5	37.28	37.28
2	West Provost	0.32	808.6	-	-	862.0	10226.5	9875.9	9399.8	19.43	56.71
3	Black Creek	0.29	-	-	-	48.8	533.2	511.5	481.6	17.76	74.47
4	Bellshill Lake	0.25	786.7	1.2	-	830.3	7703.6	7355.1	6889.2	15.47	89.95
5	David North	0.09	894.6	4.6	-	914.8	15251.7	14654.7	13851.4	5.64	95.59
6	Choice	0.07	-	0.3	-	12.4	250.4	238.5	222.6	4.41	100.00
7	Hayter	-	6412.5	-	-	6412.5	61035.7	59001.4	56200.7	-	100.00
8	Mestikow	-	170.3	-	-	170.3	1873.3	1805.0	1711.9	-	100.00
	Total	**1.65**	**11084.3**	**73.5**	**-**	**11432.3**	**121619.3**	**117289.8**	**111379.8**	**100.00**	**-**

1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Sorted By Company BOE Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company BOE Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	6412.5	-	-	6412.5	61035.7	59001.4	56200.7	56.09	56.09
2	Thompson Lake	0.61	2011.5	67.4	-	2181.2	24744.8	23847.8	22622.5	19.08	75.17
3	David North	0.09	894.6	4.6	-	914.8	15251.7	14654.7	13851.4	8.00	83.17
4	West Provost	0.32	808.6	-	-	862.0	10226.5	9875.9	9399.8	7.54	90.71
5	Bellshill Lake	0.25	786.7	1.2	-	830.3	7703.6	7355.1	6889.2	7.26	97.98
6	Mestikow	-	170.3	-	-	170.3	1873.3	1805.0	1711.9	1.49	99.47
7	Black Creek	0.29	-	-	-	48.8	533.2	511.5	481.6	0.43	99.89
8	Choice	0.07	-	0.3	-	12.4	250.4	238.5	222.6	0.11	100.00
	Total	**1.65**	**11084.3**	**73.5**	**-**	**11432.3**	**121619.3**	**117289.8**	**111379.8**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Sorted By @10.0% Present Worth Value

Rank		Company Interest Reserves Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	Present Worth Value Before Tax (M$) @ 10.0 %	@ 12.0 %	@ 15.0 %	@10.0% Present Worth Value % of Total	Cumulative %
1	Hayter	-	6412.5	-	-	6412.5	61035.7	59001.4	56200.7	50.19	50.19
2	Thompson Lake	0.61	2011.5	67.4	-	2181.2	24744.8	23847.8	22622.5	20.35	70.53
3	David North	0.09	894.6	4.6	-	914.8	15251.7	14654.7	13851.4	12.54	83.07
4	West Provost	0.32	808.6	-	-	862.0	10226.5	9875.9	9399.8	8.41	91.48
5	Bellshill Lake	0.25	786.7	1.2	-	830.3	7703.6	7355.1	6889.2	6.33	97.82
6	Mestikow	-	170.3	-	-	170.3	1873.3	1805.0	1711.9	1.54	99.36
7	Black Creek	0.29	-	-	-	48.8	533.2	511.5	481.6	0.44	99.79
8	Choice	0.07	-	0.3	-	12.4	250.4	238.5	222.6	0.21	100.00
	Total	**1.65**	**11084.3**	**73.5**	**-**	**11432.3**	**121619.3**	**117289.8**	**111379.8**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

First Year Production, Revenue and Expenses by Area
Constant Prices as of August 1, 2002
Total Proved Reserves

2002 Summary

	Production					Revenue and Expenses				Average Values $/BOE (1)			
Area	Oil bopd	Gas mcf/d	NGL bpd	Sulphur lt/d	BOE (1) boepd	Gross Revenue $M	Encumb. $M	Oper. Exp $M	Net Rev. (2) $M	Gross Revenue	Encumb.	Oper Exp	Net Rev (2)
Alberta													
Bellshill Lake	382.4	189.2	0.7	-	413.9	1803	211	585	1007	28.64	3.35	9.29	16.00
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	46.6	0.2	-	7.8	33	-	-	33	27.37	-	-	27.37
David North	697.4	73.1	3.6	-	713.1	3448	227	572	2649	31.80	2.10	5.27	24.43
Hayter	5168.5	-	-	-	5168.5	19990	4130	3887	11973	25.43	5.25	4.95	15.23
Mestikow	123.9	-	-	-	123.9	514	46	153	316	27.27	2.42	8.10	16.75
Thompson Lake	1341.3	416.0	44.9	-	1455.5	7082	479	2749	3854	31.99	2.16	12.42	17.41
West Provost	639.7	173.2	-	-	668.1	3254	311	999	1944	32.02	3.06	9.83	19.13
Subtotal Alberta	**8353.2**	**898.1**	**49.4**	**-**	**8551.0**	**36123**	**5403**	**8945**	**21775**	**27.78**	**4.15**	**6.88**	**16.74**
TOTAL	**8353.2**	**898.1**	**49.4**	**-**	**8551.0**	**36123**	**5403**	**8945**	**21775**	**27.78**	**4.15**	**6.88**	**16.74**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE based on Gross BOE reserves.
(2) Excludes capital and abandonment expenses.

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Oil Production Forecast (mbbl) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	58	125	115	106	89	76	63	55	52	47	787	-	787
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	106	200	148	114	91	74	62	51	30	19	895	-	895
Hayter	786	2125	1358	924	513	331	199	129	42	2	6409	3	6413
Mestikow	19	38	30	25	21	18	16	4	-	-	170	-	170
Thompson Lake	204	435	372	321	280	247	153	-	-	-	2012	-	2012
West Provost	97	193	155	116	87	48	41	37	35	-	809	-	809
Subtotal Alberta	**1270**	**3116**	**2177**	**1605**	**1081**	**793**	**534**	**277**	**159**	**67**	**11081**	**3**	**11084**
TOTAL	**1270**	**3116**	**2177**	**1605**	**1081**	**793**	**534**	**277**	**159**	**67**	**11081**	**3**	**11084**

(1) *Company gross share of production before royalty deductions*

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Gas Production Forecast (mmcf) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	29	58	36	28	24	21	17	15	14	13	255	-	255
Black Creek	-	108	92	55	33	5	-	-	-	-	293	-	293
Choice	7	15	12	10	7	6	5	4	4	3	72	0	73
David North	11	21	15	12	9	8	6	5	3	2	93	-	93
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	63	133	113	98	85	75	47	-	-	-	614	-	614
West Provost	26	55	49	39	30	22	20	16	13	8	278	42	320
Subtotal Alberta	**137**	**390**	**317**	**241**	**189**	**136**	**95**	**42**	**34**	**26**	**1605**	**42**	**1647**
TOTAL	**137**	**390**	**317**	**241**	**189**	**136**	**95**	**42**	**34**	**26**	**1605**	**42**	**1647**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

NGL Production Forecast (mstb) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	0	0	0	0	0	0	0	0	0	0	1	-	1
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	0	0	0	0	0	0	0	0	0	0	0	-	0
David North	1	1	1	1	0	0	0	0	0	0	5	-	5
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	7	15	12	11	9	8	5	-	-	-	67	-	67
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**8**	**16**	**13**	**12**	**10**	**9**	**6**	**0**	**0**	**0**	**74**	**-**	**74**
TOTAL	**8**	**16**	**13**	**12**	**10**	**9**	**6**	**0**	**0**	**0**	**74**	**-**	**74**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Gross Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1803	3851	3469	3182	2675	2281	1894	1659	1546	1417	23777	-	23777
Black Creek	-	485	415	248	148	21	-	-	-	-	1317	-	1317
Choice	33	68	55	44	33	28	24	20	17	12	332	2	334
David North	3448	6502	4794	3703	2953	2413	2009	1669	990	605	29085	-	29085
Hayter	19990	54038	34542	23504	13070	8420	5080	3285	1089	55	163071	104	163176
Mestikow	514	1029	822	678	573	494	432	105	-	-	4647	-	4647
Thompson Lake	7082	15093	12890	11138	9720	8557	5310	-	-	-	69789	-	69789
West Provost	3254	6464	5210	3903	2935	1618	1404	1271	1179	36	27272	188	27461
Subtotal Alberta	**36123**	**87529**	**62197**	**46399**	**32107**	**23831**	**16152**	**8008**	**4820**	**2125**	**319291**	**294**	**319585**
TOTAL	**36123**	**87529**	**62197**	**46399**	**32107**	**23831**	**16152**	**8008**	**4820**	**2125**	**319291**	**294**	**319585**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Encumbrance Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	211	433	376	336	267	223	185	158	145	131	2466	-	2466
Black Creek	-	101	64	24	8	1	-	-	-	-	198	-	198
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	227	421	304	231	182	147	121	96	50	23	1802	-	1802
Hayter	4130	11081	6557	4274	2350	1515	870	540	189	13	31517	24	31541
Mestikow	46	80	59	42	32	27	22	5	-	-	313	-	313
Thompson Lake	479	992	810	675	570	488	301	-	-	-	4316	-	4316
West Provost	311	530	360	247	175	103	85	72	64	7	1955	37	1993
Subtotal Alberta	**5403**	**13637**	**8530**	**5830**	**3585**	**2505**	**1584**	**872**	**449**	**174**	**42569**	**61**	**42630**
TOTAL	**5403**	**13637**	**8530**	**5830**	**3585**	**2505**	**1584**	**872**	**449**	**174**	**42569**	**61**	**42630**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Capital Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	-	-	5	5	-	-	-	-	-	-	10	-	10
Black Creek	-	225	-	-	-	-	-	-	-	-	225	-	225
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	-	-	-	-	-	-	-	-	-	-	-	-	-
Hayter	9046	3403	-	-	-	-	-	-	-	-	12449	-	12449
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	-	-	-	-	-	-	-	-	-	-	-	-	-
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**9046**	**3628**	**5**	**5**	-	-	-	-	-	-	**12684**	-	**12684**
TOTAL	**9046**	**3628**	**5**	**5**	-	-	-	-	-	-	**12684**	-	**12684**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Operating Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	585	1372	1346	1323	1247	1170	1082	1039	1031	1014	11209	-	11209
Black Creek	-	67	65	49	39	6	-	-	-	-	226	-	226
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	572	1249	1127	1025	935	851	772	698	476	307	8012	-	8012
Hayter	3887	9897	9743	9035	5142	3200	2201	1568	584	27	45285	59	45344
Mestikow	153	357	313	306	301	263	260	65	-	-	2017	-	2017
Thompson Lake	2749	6297	5989	5721	5497	5294	3426	-	-	-	34974	-	34974
West Provost	999	2383	2382	2014	1650	901	842	837	828	13	12849	87	12936
Subtotal Alberta	**8945**	**21621**	**20967**	**19473**	**14811**	**11684**	**8584**	**4207**	**2919**	**1361**	**114571**	**145**	**114716**
TOTAL	**8945**	**21621**	**20967**	**19473**	**14811**	**11684**	**8584**	**4207**	**2919**	**1361**	**114571**	**145**	**114716**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved Reserves

Net Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1007	2047	1742	1518	1160	888	627	462	369	272	10093	-	10093
Black Creek	-	93	285	175	101	14	-	-	-	-	668	-	668
Choice	33	68	55	44	33	28	24	20	17	12	332	2	334
David North	2649	4832	3363	2446	1836	1415	1116	875	464	274	19271	-	19271
Hayter	2927	29656	18242	10196	5578	3706	2009	1176	316	16	73821	22	73842
Mestikow	316	593	450	330	240	204	150	35	-	-	2317	-	2317
Thompson Lake	3854	7804	6090	4741	3653	2774	1582	-	-	-	30499	-	30499
West Provost	1944	3550	2468	1642	1110	614	477	361	287	15	12468	64	12532
Subtotal Alberta	**12729**	**48643**	**32695**	**21091**	**13711**	**9642**	**5984**	**2929**	**1452**	**590**	**149468**	**88**	**149555**
TOTAL	**12729**	**48643**	**32695**	**21091**	**13711**	**9642**	**5984**	**2929**	**1452**	**590**	**149468**	**88**	**149555**

Coyote Energy Inc.

Table 1

Forecast of Production and Revenue - Company Share
Constant Prices as of August 1,2002

Total Proved & Probable Reserves - Unrisked

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids				
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Total Other Revenues M$	Gross Revenue M$
2002	423.4	1320.8	27.72	36616.1	138.2	4.50	622.0	7.6	27.60	209.8	22.2	37470.1
2003	428.4	3286.8	27.36	89916.3	405.0	4.50	1822.6	16.5	27.48	453.7	36.0	92228.6
2004	415.9	2414.1	27.65	66759.4	353.5	4.50	1590.9	14.3	27.50	393.5	32.0	68775.9
2005	401.8	1870.2	27.91	52198.5	276.7	4.50	1245.5	12.5	27.48	344.7	29.0	53817.7
2006	372.1	1507.6	28.05	42289.8	224.9	4.50	1012.2	11.1	27.47	305.5	25.0	43632.4
2007	298.0	1047.8	28.64	30008.3	185.5	4.50	834.5	9.9	27.56	272.9		31115.8
2008	254.6	805.1	28.93	23291.1	148.7	4.50	669.2	8.9	27.54	245.1		24205.5
2009	234.0	668.8	29.18	19517.6	114.0	4.50	513.1	8.0	27.56	221.6		20252.3
2010	108.4	347.2	28.48	9888.9	49.0	4.50	220.4	1.6	27.86	43.5		10152.9
2011	76.8	243.0	28.40	6900.8	32.9	4.50	147.9	0.3	30.86	8.9		7057.8
2012	35.4	71.6	31.20	2232.6	16.1	4.50	72.3	0.2	27.50	6.1		2310.9
2013	14.5	20.8	31.92	663.1	11.4	4.50	51.3	0.1	26.23	3.4		717.8
2014	2.5	3.0	31.94	97.1	8.5	4.50	38.2	0.0	20.50	0.4		135.7
2015	1.5	1.5	32.07	49.1	7.0	4.50	31.6			0.1		80.8
2016	1.5	1.4	32.11	45.6	5.6	4.50	25.1					70.7
REM.	0.8	0.3	32.52	10.1	9.7	4.50	43.5					53.6
TOTAL		**13610.2**	**27.96**	**380484.2**	**1986.6**	**4.50**	**8940.3**	**91.1**	**27.53**	**2509.1**	**144.2**	**392078.2**

	Crown Royalties			Freehold Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	1226.6	3.9	1222.7	3368.7	0.6	3368.1	327.4	0.1	327.3	779.7	5697.9	15.22
2003	2662.9	38.9	2624.0	9122.3	1.3	9121.0	778.4	0.1	778.3	2079.6	14602.9	15.84
2004	1758.9	35.0	1723.9	6272.1	1.2	6270.9	619.0	0.1	618.8	1157.7	9771.3	14.21
2005	1281.1	22.8	1258.2	4590.8	1.1	4589.7	486.7	0.1	486.6	621.9	6956.4	12.93
2006	923.3	15.6	907.7	3676.0	1.0	3674.9	398.7	0.1	398.6	410.3	5391.5	12.36
2007	691.9	10.9	681.0	2261.1	0.9	2260.2	303.1	0.1	303.1	246.3	3490.6	11.22
2008	521.7	6.7	515.0	1647.6	0.9	1646.8	249.3	0.1	249.2	172.8	2583.7	10.67
2009	428.7	1.7	427.0	1217.2	0.8	1216.4	204.6	0.0	204.6	127.3	1975.3	9.75
2010	155.6	0.3	155.3	662.4	0.7	661.6	168.0	0.0	168.0	78.1	1063.0	10.47
2011	78.2	0.0	78.2	480.9	0.7	480.2	144.8	0.0	144.8	57.4	760.6	10.78
2012	28.3	0.0	28.3	97.3	0.6	96.6	21.3	0.0	21.3	10.4	156.6	6.78
2013	0.1	0.0	0.1	37.2	0.6	36.6	2.6	0.0	2.6	3.9	43.3	6.03
2014	0.1	0.0	0.1	19.0	0.5	18.4	0.3	0.0	0.3	0.8	19.6	14.45
2015	0.1	0.0	0.1	16.4	0.5	15.9	0.1	0.0	0.1	0.5	16.6	20.54
2016	0.1	0.0	0.1	15.3	0.4	14.8	0.1	0.0	0.1	0.4	15.4	21.82
REM.	0.1	0.0	0.1	10.9	0.8	10.2	0.2	0.0	0.2	0.5	10.9	20.39
TOTAL	**9757.6**	**136.0**	**9621.6**	**33495.0**	**12.7**	**33482.4**	**3704.7**	**0.8**	**3703.9**	**5747.6**	**52555.7**	**13.41**

			Capital Costs			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Drilling & Compl M$	Equip & Facility M$	Total Capital M$	Annual M$	Cum M$	PWV @10.0% M$
2002	8955.4	22816.8	9046.0		9046.0	13770.8	13770.8	13500.0
2003	21686.2	55939.4	3402.6	225.0	3627.6	52311.7	66082.5	47935.2
2004	21140.5	37863.9	5.0		5.0	37858.9	103941.5	31537.8
2005	20549.0	26312.2	5.0		5.0	26307.2	130248.7	19922.6
2006	18895.7	19345.1				19345.1	149593.8	13318.3
2007	13986.5	13638.6				13638.6	163232.4	8535.9
2008	11468.3	10153.4				10153.4	173385.8	5777.0
2009	10513.8	7763.2				7763.2	181149.0	4015.5
2010	5336.5	3753.4				3753.4	184902.3	1764.9
2011	3934.2	2363.0				2363.0	187265.3	1010.1
2012	1279.1	875.2				875.2	188140.5	340.1
2013	347.2	327.3				327.3	188467.8	115.6
2014	65.1	51.0				51.0	188518.8	16.4
2015	39.5	24.6				24.6	188543.4	7.2
2016	39.3	15.9				15.9	188559.3	4.2
REM.	30.0	12.6				12.6	188572.0	3.0
TOTAL	**138266.4**	**201255.6**	**12458.7**	**225.0**	**12683.7**	**188572.0**		**147803.7**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	Gross	Net	@10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	13610.4	11934.9	142863.8	137028.7	129160.4	117987.9
Natural Gas (mmcf)	1986.8	1578.4	3540.6	3365.2	3132.4	2808.8
Natural Gas Liquids (mbbl)	91.4	69.3	1399.5	1330.4	1238.4	1110.2
Total			**147803.8**	**141724.3**	**133531.2**	**121906.9**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
Fixed Battery Costs	P-100.000		NRA	-	-	-	-	-3106.5	-2892.7	-2615.9
00/04-05-041-12-W4	W-100.000	ELL	P	10.2	48.79	0.05	-	649.2	612.3	563.9
02/04-05-041-12-W4	W-100.000	ELL	P	19.6	50.39	0.09	-	702.9	663.7	612.3
03/04-05-041-12-W4	W-100.000	ELL	P	1.5	6.36	0.00	-	60.6	59.7	58.4
00/05-05-041-12-W4	W-100.000	ELL	P	11.6	52.20	0.05	-	714.2	674.6	622.7
04/05-05-041-12-W4	W-100.000	ELL	P	12.6	38.11	0.05	-	479.5	452.4	416.9
B0/05-05-041-12-W4	W-100.000	ELL	P	12.7	60.50	0.06	-	854.5	807.3	745.4
00/06-05-041-12-W4	W- 40.000	GLAUC L	P	52.0	-	0.25	-	133.0	130.8	127.5
02/10-05-041-12-W4	W-100.000	ELL	NP	2.3	26.09	0.01	-	357.3	337.6	310.9
00/12-05-041-12-W4	W-100.000	ELL	P	19.4	49.69	0.09	-	689.7	651.4	601.0
00/13-05-041-12-W4	W-100.000	ELL	P	1.2	7.89	0.00	-	58.0	56.7	54.9
B0/14-05-041-12-W4	W-100.000	ELL	P	10.8	51.43	0.05	-	721.9	684.9	636.0
C0/14-05-041-12-W4	W-100.000	ELL	P	8.2	40.48	0.04	-	510.3	481.8	444.4
00/15-05-041-12-W4	W-100.000	ELL	NP	4.8	20.06	0.02	-	281.6	263.6	239.4
02/15-05-041-12-W4	W-100.000	ELL	P	2.1	7.81	0.01	-	125.3	123.2	120.3
A2/15-05-041-12-W4	W-100.000	ELL	P	4.6	34.14	0.02	-	506.3	485.9	458.2
B2/15-05-041-12-W4	W-100.000	ELL	P	17.1	59.88	0.08	-	852.9	805.6	743.5
02/16-05-041-12-W4	W-100.000	ELL	P	3.8	15.81	0.02	-	259.8	253.8	245.3
00/01-06-041-12-W4	W-100.000	ELL	P	11.7	19.53	0.05	-	198.7	188.7	175.5
00/02-06-041-12-W4	W-100.000	ELL	P	8.7	38.81	0.04	-	521.1	491.9	453.6
02/07-06-041-12-W4	W-100.000	ELL	P	4.4	26.91	0.02	-	317.4	301.1	279.5
02/08-06-041-12-W4	W-100.000	ELL	P	11.4	21.09	0.05	-	332.0	320.3	304.3
03/08-06-041-12-W4	W-100.000	ELL	P	14.2	29.67	0.06	-	377.9	357.1	329.7
05/08-06-041-12-W4	W-100.000	ELL	P	12.1	47.46	0.06	-	672.9	636.0	587.5
02/09-06-041-12-W4	W-100.000	ELL	P	8.8	43.31	0.04	-	574.5	538.3	491.2
02/15-15-041-12-W4	R- 3.750	ELL	P	-	0.22	-	-	5.4	5.3	5.1
04/15-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
02/16-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
05/16-15-041-12-W4	R- 3.750	ELL	P	-	0.05	-	-	1.3	1.3	1.3
Subtotal				**266.0**	**796.70**	**1.21**	-	**7851.7**	**7492.5**	**7012.7**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	NP	409.4	-	-	-	766.6	729.5	679.0
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	P	64.1	-	0.26	-	200.5	188.3	172.6
00/11-05-040-08-W4	R- 15.000	VIK	P	5.0	-	0.02	-	19.8	19.3	18.6
00/07-07-040-08-W4	R- 6.250	CLY	P	2.2	-	0.01	-	9.2	9.1	8.9
00/10-07-040-08-W4	R- 15.000	VIK	P	18.3	-	0.07	-	59.8	56.4	52.0
Subtotal				**89.5**	-	**0.36**	-	**289.3**	**273.1**	**252.0**
David North										
Lloydminster O Unit	W-100.000	LLOYD	P	53.2	531.85	2.65	-	9057.4	8630.7	8065.7
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	P	64.8	529.37	3.23	-	8595.1	8186.1	7648.9
00/10-27-040-03-W4	W-100.000	LLOYD	P	-	14.09	-	-	173.0	166.8	158.2
02/10-27-040-03-W4	W-100.000	LLOYD	P	-	29.26	-	-	499.0	477.8	449.3
02/15-27-040-03-W4	W-100.000	LLOYD	P	-	27.92	-	-	330.2	315.0	294.9
Subtotal				**118.0**	**1132.49**	**5.89**	-	**18654.7**	**17776.4**	**16616.9**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	P	-	90.67	-	-	703.8	676.7	639.7
N-24-40-1W4 1999 Wells	W- 93.750	DINA	P	-	66.05	-	-	595.5	579.3	556.8
N-24-40-1W4 2002 Wells	W- 93.750	DINA	P	-	256.67	-	-	2932.8	2834.7	2701.4
N-24-40-1W4 Future Locations	W- 93.750	DINA	UND	-	206.25	-	-	1661.2	1548.9	1398.8
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	P	-	1559.43	-	-	13997.9	13320.9	12424.3
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	P	-	121.57	-	-	1070.5	1025.0	963.8
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	P	-	175.69	-	-	1765.7	1713.6	1641.7
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	P	-	506.83	-	-	5654.8	5526.0	5345.7

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves: Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$): @10.0%	@12.0%	@15.0%
Hayter (cont'd)										
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	P	-	201.07	-	-	2438.9	2386.4	2312.7
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	P	-	489.82	-	-	6704.1	6457.3	6125.1
Sec 25-40-1W4 Future Locations	W- 94.517	DINA	UND	-	1663.50	-	-	16314.8	15574.3	14560.1
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	P	-	112.79	-	-	803.3	781.6	751.2
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	P	-	31.20	-	-	331.0	324.3	314.8
Sec 34-40-1W4 2000 Wells	W- 75.000	DINA	P	-	9.84	-	-	72.9	71.3	69.1
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	P	-	797.73	-	-	5025.6	4862.4	4637.0
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	P	-	13.50	-	-	112.2	110.4	107.9
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	P	-	41.24	-	-	417.0	405.5	389.6
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	P	-	200.64	-	-	2343.0	2282.3	2197.9
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	P	-	404.96	-	-	4245.1	4138.0	3988.7
NW-35-40-1W4 Pre-2000 Wells	W- 75.000	DINA	P	-	116.69	-	-	639.7	613.5	577.9
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	P	-	155.30	-	-	1553.8	1517.1	1465.7
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	P	-	305.18	-	-	3202.3	3110.0	2982.9
NW-35-40-1W4 Future Locations	W- 75.000	DINA	UND	-	412.50	-	-	3104.7	2921.6	2672.6
S-36-40-1W4 GOR Wells	R- 7.500	DINA	P	-	2.26	-	-	52.8	51.9	50.8
00/09-34-040-01-W4	W- 75.000	SPKY	P	-	10.16	-	-	127.9	123.6	117.8
00/15-34-040-01-W4	W- 75.000	SPKY	P	-	7.08	-	-	89.2	86.9	83.7
00/01-03-041-01-W4	W- 75.000	SPKY	P	-	35.48	-	-	312.5	292.0	265.8
Subtotal				-	**7994.13**	-	-	**76273.0**	**73335.6**	**69343.8**
Mestikow										
All Company Wells	W-100.000	DINA	P	-	195.31	-	-	2106.9	2021.3	1905.8
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	P	763.2	2506.50	83.95	-	29804.0	28507.5	26763.5
04/10-29-040-11-W4	W- 25.000	VIK	P	1.6	-	-	-	2.1	2.1	2.1
Subtotal				**764.8**	**2506.50**	**83.95**	-	**29806.2**	**28509.6**	**26765.6**
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	P	33.4	454.00	-	-	5097.1	4855.4	4535.0
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	P	10.3	97.94	-	-	1104.5	1049.1	976.0
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	P	25.6	243.69	-	-	3167.4	3073.6	2944.0
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	P	5.7	74.11	-	-	975.5	955.4	927.0
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	P	0.6	10.69	-	-	128.9	125.7	121.3
Sec 16-38-3W4	W-100.000	DINA	P	13.6	77.54	-	-	880.3	854.6	819.0
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	P	19.2	27.38	-	-	372.8	361.9	347.0
00/11-24-037-02-W4	W- 37.500	VIK	P	0.5	-	-	-	0.2	0.2	0.2
00/07-27-037-02-W4	W- 42.188	VIK	P	55.5	-	-	-	61.4	56.4	50.2
02/06-11-038-03-W4	W- 28.125	VIK	NRA	-	-	-	-	-	-	-
00/14-12-038-03-W4	W- 37.500	CLY	P	13.1	-	-	-	19.0	18.5	17.7
00/07-13-038-03-W4	W- 37.500	VIK	P	34.2	-	-	-	54.5	51.9	48.5
00/06-14-038-03-W4	W- 37.500	VIK	NRA	-	-	-	-	-	-	-
00/07-15-038-03-W4	W- 37.500	VIK	P	7.3	-	-	-	9.0	8.8	8.6
00/07-17-038-03-W4	W- 37.500	VIK	P	6.0	-	-	-	1.8	1.7	1.7
00/07-18-038-03-W4	W- 37.500	VIK	P	24.0	-	-	-	32.1	30.6	28.6
00/14-07-039-01-W4	W- 29.371	MCLAR	P	90.1	-	-	-	124.1	115.6	105.0
Bodo Compression Facility	P-100.000	ALL ZONES	NRA	-	-	-	-	27.1	26.6	25.8

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
West Provost (cont'd)										
Wells with NRA		ALL ZONES	NRA	-	-	-	-	-	-	-
Subtotal				**339.1**	**985.34**	**-**	**-**	**12055.5**	**11586.2**	**10955.4**
Subtotal Alberta				**1986.8**	**13610.47**	**91.40**	**-**	**147803.8**	**141724.3**	**133531.2**
TOTAL				**1986.8**	**13610.47**	**91.40**	**-**	**147803.8**	**141724.3**	**133531.2**

Coyote Energy Inc.

Summary of Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

	Company Interest Reserves				Net Reserves After Royalty				Present Worth Value Before Tax (M$)			
	Gas	Oil	NGL	Sulphur	Gas	Oil	NGL	Sulphur				
Area	bcf	mbbl	mbbl	mlt	bcf	mbbl	mbbl	mlt	@10.0%	@12.0%	@15.0%	@20.0%
Alberta												
Bellshill Lake	0.27	796.7	1.2	-	0.22	727.0	1.0	-	7851.7	7492.5	7012.7	6340.7
Black Creek	0.41	-	-	-	0.32	-	-	-	766.6	729.5	679.0	606.5
Choice	0.09	-	0.4	-	0.09	-	0.4	-	289.3	273.1	252.0	223.7
David North	0.12	1132.5	5.9	-	0.11	1073.5	5.6	-	18654.7	17776.4	16616.9	15019.5
Hayter	-	7994.1	-	-	-	6643.5	-	-	76273.0	73335.6	69343.8	63610.0
Mestikow	-	195.3	-	-	-	182.0	-	-	2106.9	2021.3	1905.8	1741.9
Thompson Lake	0.76	2506.5	83.9	-	0.57	2389.1	62.3	-	29806.2	28509.6	26765.6	24301.2
West Provost	0.34	985.3	-	-	0.27	919.8	-	-	12055.5	11586.2	10955.4	10063.4
Subtotal Alberta	**1.99**	**13610.5**	**91.4**	**-**	**1.58**	**11934.9**	**69.3**	**-**	**147803.8**	**141724.3**	**133531.2**	**121906.9**
TOTAL	**1.99**	**13610.5**	**91.4**	**-**	**1.58**	**11934.9**	**69.3**	**-**	**147803.8**	**141724.3**	**133531.2**	**121906.9**

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By Company Oil Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company Oil Reserves	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0%	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	7994.1	-	-	7994.1	76273.0	73335.6	69343.8	58.74	58.74
2	Thompson Lake	0.76	2506.5	83.9	-	2717.9	29806.2	28509.6	26765.6	18.42	77.15
3	David North	0.12	1132.5	5.9	-	1158.0	18654.7	17776.4	16616.9	8.32	85.47
4	West Provost	0.34	985.3	-	-	1041.9	12055.5	11586.2	10955.4	7.24	92.71
5	Bellshill Lake	0.27	796.7	1.2	-	842.2	7851.7	7492.5	7012.7	5.85	98.56
6	Mestikow	-	195.3	-	-	195.3	2106.9	2021.3	1905.8	1.44	100.00
7	Black Creek	0.41	-	-	-	68.2	766.6	729.5	679.0	-	100.00
8	Choice	0.09	-	0.4	-	15.3	289.3	273.1	252.0	-	100.00
	Total	**1.99**	**13610.5**	**91.4**	**-**	**14033.0**	**147803.8**	**141724.3**	**133531.2**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By Company Gas Reserves

Rank		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company Gas Reserves	
		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Thompson Lake	0.76	2506.5	83.9	-	2717.9	29806.2	28509.6	26765.6	38.49	38.49
2	Black Creek	0.41	-	-	-	68.2	766.6	729.5	679.0	20.61	59.10
3	West Provost	0.34	985.3	-	-	1041.9	12055.5	11586.2	10955.4	17.07	76.17
4	Bellshill Lake	0.27	796.7	1.2	-	842.2	7851.7	7492.5	7012.7	13.39	89.56
5	David North	0.12	1132.5	5.9	-	1158.0	18654.7	17776.4	16616.9	5.94	95.49
6	Choice	0.09	-	0.4	-	15.3	289.3	273.1	252.0	4.51	100.00
7	Hayter	-	7994.1	-	-	7994.1	76273.0	73335.6	69343.8	-	100.00
8	Mestikow	-	195.3	-	-	195.3	2106.9	2021.3	1905.8	-	100.00
	Total	**1.99**	**13610.5**	**91.4**	**-**	**14033.0**	**147803.8**	**141724.3**	**133531.2**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By Company BOE Reserves

		Company Interest Reserves					Present Worth Value Before Tax (M$)			Company BOE Reserves	
		Gas	Oil	NGL	Sulphur	BOE (1)				% of	Cumulative
Rank		bcf	mbbl	mbbl	mlt	mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	Total	%
1	Hayter	-	7994.1	-	-	7994.1	76273.0	73335.6	69343.8	56.97	56.97
2	Thompson Lake	0.76	2506.5	83.9	-	2717.9	29806.2	28509.6	26765.6	19.37	76.33
3	David North	0.12	1132.5	5.9	-	1158.0	18654.7	17776.4	16616.9	8.25	84.59
4	West Provost	0.34	985.3	-	-	1041.9	12055.5	11586.2	10955.4	7.42	92.01
5	Bellshill Lake	0.27	796.7	1.2	-	842.2	7851.7	7492.5	7012.7	6.00	98.01
6	Mestikow	-	195.3	-	-	195.3	2106.9	2021.3	1905.8	1.39	99.40
7	Black Creek	0.41	-	-	-	68.2	766.6	729.5	679.0	0.49	99.89
8	Choice	0.09	-	0.4	-	15.3	289.3	273.1	252.0	0.11	100.00
	Total	**1.99**	**13610.5**	**91.4**	**-**	**14033.0**	**147803.8**	**141724.3**	**133531.2**	**100.00**	**-**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

Reserves and Present Worth Values By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Sorted By @10.0% Present Worth Value

		Company Interest Reserves					Present Worth Value Before Tax (M$)			@10.0% Present Worth Value	
Rank		Gas bcf	Oil mbbl	NGL mbbl	Sulphur mlt	BOE (1) mbbl	@ 10.0 %	@ 12.0 %	@ 15.0 %	% of Total	Cumulative %
1	Hayter	-	7994.1	-	-	7994.1	76273.0	73335.6	69343.8	51.60	51.60
2	Thompson Lake	0.76	2506.5	83.9	-	2717.9	29806.2	28509.6	26765.6	20.17	71.77
3	David North	0.12	1132.5	5.9	-	1158.0	18654.7	17776.4	16616.9	12.62	84.39
4	West Provost	0.34	985.3	-	-	1041.9	12055.5	11586.2	10955.4	8.16	92.55
5	Bellshill Lake	0.27	796.7	1.2	-	842.2	7851.7	7492.5	7012.7	5.31	97.86
6	Mestikow	-	195.3	-	-	195.3	2106.9	2021.3	1905.8	1.43	99.29
7	Black Creek	0.41	-	-	-	68.2	766.6	729.5	679.0	0.52	99.80
8	Choice	0.09	-	0.4	-	15.3	289.3	273.1	252.0	0.20	100.00
	Total	**1.99**	**13610.5**	**91.4**	-	**14033.0**	**147803.8**	**141724.3**	**133531.2**	**100.00**	-

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE base

Coyote Energy Inc.

First Year Production, Revenue and Expenses by Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

2002 Summary

	Production					Revenue and Expenses				Average Values $/BOE (1)			
Area	Oil bopd	Gas mcf/d	NGL bpd	Sulphur lt/d	BOE (1) boepd	Gross Revenue $M	Encumb. $M	Oper. Exp $M	Net Rev. (2) $M	Gross Revenue	Encumb.	Oper Exp	Net Rev (2)
Alberta													
Bellshill Lake	382.4	191.0	0.7	-	414.2	1804	211	585	1008	28.64	3.35	9.29	16.00
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	47.1	0.2	-	7.9	33	-	-	33	27.47	-	-	27.47
David North	714.4	74.9	3.7	-	730.6	3533	234	575	2724	31.79	2.11	5.17	24.51
Hayter	5447.9	-	-	-	5447.9	21068	4392	3887	12789	25.43	5.30	4.69	15.44
Mestikow	125.5	-	-	-	125.5	521	47	153	321	27.28	2.45	8.02	16.81
Thompson Lake	1358.0	421.1	45.5	-	1473.7	7170	488	2757	3926	31.99	2.18	12.30	17.52
West Provost	657.5	175.0	-	-	686.1	3341	326	999	2016	32.02	3.13	9.57	19.32
Subtotal Alberta	**8685.7**	**909.0**	**50.1**	**-**	**8885.8**	**37470**	**5698**	**8955**	**22817**	**27.73**	**4.22**	**6.63**	**16.88**
TOTAL	**8685.7**	**909.0**	**50.1**	**-**	**8885.8**	**37470**	**5698**	**8955**	**22817**	**27.73**	**4.22**	**6.63**	**16.88**

(1) Barrels of Oil Equivalent based on 6.0:1 for Natural Gas, 1.00:1 for Condensate and C5+, 1.00:1 for Ethane, 1.00:1 for Propane, 1.00:1 for Butanes, 1.00:1 for NGL Mix, 1.00:1 for Sulphur. PWV/BOE based on Gross BOE reserves.
(2) Excludes capital and abandonment expenses.

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Oil Production Forecast (mbbl) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	58	125	115	107	91	80	66	55	52	47	797	-	797
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	109	215	166	133	109	91	78	66	57	50	1074	59	1132
Hayter	829	2255	1539	1112	863	499	346	262	161	111	7977	17	7994
Mestikow	19	39	32	27	23	20	17	16	3	-	195	-	195
Thompson Lake	207	450	395	349	311	279	252	228	36	-	2507	-	2507
West Provost	100	203	167	142	110	78	46	42	38	36	962	23	985
Subtotal Alberta	**1321**	**3287**	**2414**	**1870**	**1508**	**1048**	**805**	**669**	**347**	**243**	**13512**	**99**	**13610**
TOTAL	**1321**	**3287**	**2414**	**1870**	**1508**	**1048**	**805**	**669**	**347**	**243**	**13512**	**99**	**13610**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Gas Production Forecast (mmcf) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	29	60	43	28	24	21	18	15	14	13	266	-	266
Black Creek	-	114	110	76	53	37	20	-	-	-	409	-	409
Choice	7	15	13	11	8	7	6	6	5	4	82	8	90
David North	11	22	17	14	11	9	8	7	6	5	111	7	118
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	64	137	120	106	95	85	77	69	11	-	765	-	765
West Provost	27	57	50	42	34	26	20	17	13	11	295	44	339
Subtotal Alberta	**138**	**405**	**354**	**277**	**225**	**185**	**149**	**114**	**49**	**33**	**1929**	**58**	**1987**
TOTAL	**138**	**405**	**354**	**277**	**225**	**185**	**149**	**114**	**49**	**33**	**1929**	**58**	**1987**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

NGL Production Forecast (mstb) (1)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	0	0	0	0	0	0	0	0	0	0	1	-	1
Black Creek	-	-	-	-	-	-	-	-	-	-	-	-	-
Choice	0	0	0	0	0	0	0	0	0	0	0	0	0
David North	1	1	1	1	1	0	0	0	0	0	6	0	6
Hayter	-	-	-	-	-	-	-	-	-	-	-	-	-
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	7	15	13	12	10	9	8	8	1	-	84	-	84
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**8**	**17**	**14**	**13**	**11**	**10**	**9**	**8**	**2**	**0**	**91**	**0**	**91**
TOTAL	**8**	**17**	**14**	**13**	**11**	**10**	**9**	**8**	**2**	**0**	**91**	**0**	**91**

(1) Company gross share of production before royalty deductions

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Gross Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1804	3858	3513	3215	2715	2402	1988	1659	1546	1417	24116	-	24116
Black Creek	-	511	495	343	237	164	91	-	-	-	1843	-	1843
Choice	33	70	59	49	38	33	29	26	22	17	376	36	412
David North	3533	6994	5406	4328	3552	2971	2523	2139	1855	1610	34910	1909	36819
Hayter	21068	57326	39132	28294	21968	12708	8820	6682	4098	2823	202918	481	203399
Mestikow	521	1063	867	727	622	541	477	425	88	-	5328	-	5328
Thompson Lake	7170	15609	13697	12117	10796	9679	8728	7910	1255	-	86961	-	86961
West Provost	3341	6797	5608	4746	3705	2618	1550	1412	1289	1191	32257	944	33201
Subtotal Alberta	**37470**	**92229**	**68776**	**53818**	**43632**	**31116**	**24205**	**20252**	**10153**	**7058**	**388709**	**3369**	**392078**
TOTAL	**37470**	**92229**	**68776**	**53818**	**43632**	**31116**	**24205**	**20252**	**10153**	**7058**	**388709**	**3369**	**392078**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Encumbrance Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	211	435	382	343	273	234	194	158	145	131	2505	-	2505
Black Creek	-	112	91	49	25	13	5	-	-	-	295	-	295
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	234	457	347	274	222	184	155	127	108	92	2200	91	2291
Hayter	4392	11894	7595	5176	3949	2293	1592	1128	660	473	39152	98	39250
Mestikow	47	84	64	48	37	32	26	21	4	-	363	-	363
Thompson Lake	488	1042	883	759	659	578	511	455	72	-	5446	-	5446
West Provost	326	579	409	308	227	157	100	86	74	65	2333	73	2406
Subtotal Alberta	**5698**	**14603**	**9771**	**6956**	**5392**	**3491**	**2584**	**1975**	**1063**	**761**	**52294**	**262**	**52556**
TOTAL	**5698**	**14603**	**9771**	**6956**	**5392**	**3491**	**2584**	**1975**	**1063**	**761**	**52294**	**262**	**52556**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Capital Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	-	-	5	5	-	-	-	-	-	-	10	-	10
Black Creek	-	225	-	-	-	-	-	-	-	-	225	-	225
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	-	-	-	-	-	-	-	-	-	-	-	-	-
Hayter	9046	3403	-	-	-	-	-	-	-	-	12449	-	12449
Mestikow	-	-	-	-	-	-	-	-	-	-	-	-	-
Thompson Lake	-	-	-	-	-	-	-	-	-	-	-	-	-
West Provost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal Alberta	**9046**	**3628**	**5**	**5**	**-**	**-**	**-**	**-**	**-**	**-**	**12684**	**-**	**12684**
TOTAL	**9046**	**3628**	**5**	**5**	**-**	**-**	**-**	**-**	**-**	**-**	**12684**	**-**	**12684**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Operating Expense Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	585	1373	1356	1325	1250	1201	1112	1039	1031	1014	11286	-	11286
Black Creek	-	69	74	58	48	40	27	-	-	-	316	-	316
Choice	-	-	-	-	-	-	-	-	-	-	-	-	-
David North	575	1265	1147	1046	954	869	788	713	701	660	8718	885	9602
Hayter	3887	9897	9809	9664	8770	4746	3232	2619	1892	1437	55953	253	56206
Mestikow	153	358	315	308	303	265	262	260	64	-	2289	-	2289
Thompson Lake	2757	6340	6058	5805	5588	5390	5205	5046	821	-	43009	-	43009
West Provost	999	2383	2382	2342	1982	1475	842	837	828	825	14895	662	15558
Subtotal Alberta	**8955**	**21686**	**21141**	**20549**	**18896**	**13987**	**11468**	**10514**	**5337**	**3934**	**136467**	**1800**	**138267**
TOTAL	**8955**	**21686**	**21141**	**20549**	**18896**	**13987**	**11468**	**10514**	**5337**	**3934**	**136467**	**1800**	**138267**

Coyote Energy Inc.

Ten Year Production, Revenues and Expenses By Area
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Net Revenue Forecast (M$)

Area	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Subtotal	Remainder	Total
Alberta													
Bellshill Lake	1008	2051	1770	1542	1192	967	682	462	369	272	10315	-	10315
Black Creek	-	105	331	236	165	111	58	-	-	-	1006	-	1006
Choice	33	70	59	49	38	33	29	26	22	17	376	36	412
David North	2724	5272	3912	3008	2375	1918	1580	1299	1047	859	23993	933	24926
Hayter	3743	32132	21729	13453	9248	5668	3996	2935	1546	913	95365	129	95494
Mestikow	321	620	487	371	282	244	189	144	20	-	2677	-	2677
Thompson Lake	3926	8227	6756	5554	4549	3712	3012	2408	362	-	38506	-	38506
West Provost	2016	3834	2816	2096	1496	985	608	489	387	301	15029	209	15237
Subtotal Alberta	**13771**	**52312**	**37859**	**26307**	**19345**	**13639**	**10153**	**7763**	**3753**	**2363**	**187265**	**1307**	**188572**
TOTAL	**13771**	**52312**	**37859**	**26307**	**19345**	**13639**	**10153**	**7763**	**3753**	**2363**	**187265**	**1307**	**188572**

Coyote Energy Inc.

Table 1

Forecast of Production and Revenue - Company Share
Constant Prices as of August 1,2002

Total Probable Reserves - Unrisked

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids			
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Gross Revenue M$
2002		50.5	26.45	1336.4	1.7	4.52	7.6	0.1	27.60	2.8	1346.9
2003		170.9	27.00	4615.1	15.1	4.50	67.9	0.6	27.44	16.2	4699.2
2004	1.0	236.9	26.97	6387.6	36.9	4.50	166.4	0.9	27.39	25.2	6579.1
2005	13.8	264.8	27.30	7229.4	35.5	4.50	160.0	1.0	27.82	28.9	7418.3
2006	53.9	426.3	26.58	11331.0	36.3	4.50	163.3	1.1	27.69	31.3	11525.6
2007	32.0	254.7	27.60	7028.2	49.9	4.50	224.6	1.2	27.73	32.4	7285.3
2008	66.3	270.9	28.49	7717.8	53.8	4.50	242.2	3.4	27.55	93.1	8053.2
2009	150.0	392.2	29.84	11706.0	72.5	4.50	326.1	7.7	27.52	212.2	12244.2
2010	51.1	187.9	27.83	5228.5	15.0	4.50	67.5	1.3	27.53	36.9	5332.9
2011	47.6	175.6	27.90	4897.9	6.9	4.50	31.2	0.2	28.07	4.2	4933.3
2012	34.0	70.0	31.19	2182.1	8.3	4.50	37.3	0.2	27.36	6.0	2225.5
2013	13.0	19.3	31.91	617.1	4.5	4.50	20.4	0.1	26.23	3.4	640.9
2014	1.7	2.8	31.91	89.4	2.1	4.50	9.4	0.0	19.00	0.4	99.1
2015	0.8	1.5	32.07	49.1	1.0	4.50	4.7			0.1	53.9
2016	0.8	1.4	32.11	45.6							45.6
REM.	0.8	0.3	32.52	10.1							10.1
TOTAL		**2526.0**	**27.90**	**70471.2**	**339.6**	**4.50**	**1528.6**	**17.9**	**27.54**	**493.2**	**72492.9**

	Crown Royalties			Freehold Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	67.0	0.1	66.9	164.3		164.3	8.1	0.0	8.1	55.3	294.7	21.88
2003	248.0	-1.4	249.4	523.2		523.2	26.9	-0.0	26.9	166.1	965.6	20.55
2004	264.4	2.8	261.7	723.1	-0.0	723.1	40.4		40.4	216.4	1241.4	18.87
2005	283.2	3.6	279.6	643.1	-0.0	643.1	42.1	0.0	42.1	161.5	1126.3	15.18
2006	211.3	3.5	207.8	1362.9		1362.9	72.9	-0.0	72.9	162.9	1806.6	15.67
2007	186.0	7.6	178.4	681.1		681.1	42.7		42.7	83.7	985.9	13.53
2008	187.7	5.4	182.3	710.7		710.7	39.3		39.3	67.3	999.7	12.41
2009	325.9	1.5	324.3	683.0		683.0	35.7		35.7	60.4	1103.4	9.01
2010	83.8	0.2	83.6	450.8		450.8	35.1		35.1	44.6	614.2	11.52
2011	54.3		54.3	443.6		443.6	47.4	0.0	47.4	41.4	586.6	11.89
2012	28.2		28.2	79.3	0.0	79.3	21.1		21.1	9.8	138.4	6.22
2013				20.6		20.6	2.5		2.5	3.4	26.6	4.14
2014				11.5		11.5	0.2		0.2	0.4	12.1	12.19
2015				11.0		11.0				0.2	11.3	20.88
2016				10.3		10.3				0.2	10.4	22.92
REM.				2.3		2.3				0.0	2.3	22.82
TOTAL	**1939.8**	**23.3**	**1916.5**	**6520.8**	**-0.0**	**6520.8**	**414.4**	**0.0**	**414.4**	**1073.8**	**9925.6**	**13.69**

			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Annual M$	Cum M$	PWV @10.0% M$
2002	10.7	1041.4	1041.4	1041.4	1020.9
2003	65.1	3668.4	3668.4	4709.8	3361.5
2004	174.0	5163.6	5163.6	9873.4	4301.5
2005	1076.1	5216.0	5215.9	15089.4	3950.1
2006	4084.8	5634.1	5634.1	20723.5	3878.9
2007	2302.3	3997.0	3997.0	24720.5	2501.6
2008	2884.4	4169.0	4169.0	28889.5	2372.1
2009	6306.9	4833.9	4833.9	33723.4	2500.3
2010	2417.5	2301.2	2301.2	36024.5	1082.1
2011	2573.6	1773.1	1773.1	37797.6	758.0
2012	1238.9	848.1	848.1	38645.7	329.6
2013	307.3	307.0	307.0	38952.7	108.5
2014	47.9	39.1	39.1	38991.9	12.6
2015	27.0	15.6	15.6	39007.5	4.6
2016	27.0	8.1	8.1	39015.6	2.2
REM.	6.8	1.0	1.0	39016.7	0.3
TOTAL	**23550.4**	**39016.7**	**39016.7**		**26184.4**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	Gross	Net	@10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	2526.1	2208.3	25427.9	23740.5	21538.0	18561.8
Natural Gas (mmcf)	339.7	266.1	541.5	498.9	443.8	370.5
Natural Gas Liquids (mbbl)	18.0	13.6	215.1	195.1	169.6	136.4
Total			**26184.5**	**24434.5**	**22151.4**	**19068.7**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Total Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
00/06-05-041-12-W4	W- 40.000	GLAUC L	PA	9.5	-	0.05	-	22.4	21.7	20.8
02/10-05-041-12-W4	W-100.000	ELL	PA	0.4	5.00	0.00	-	60.9	56.1	49.7
00/15-05-041-12-W4	W-100.000	ELL	PA	1.2	5.00	0.01	-	64.8	59.7	53.0
Subtotal				**11.1**	**10.00**	**0.05**	-	**148.1**	**137.5**	**123.4**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	PA	116.8	-	-	-	233.4	218.0	197.5
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PA	16.9	-	0.07	-	38.9	34.6	29.4
David North										
Lloydminster O Unit	W-100.000	LLOYD	PA	12.8	127.86	0.64	-	1850.0	1696.9	1502.1
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PA	12.2	100.00	0.61	-	1436.5	1317.8	1168.6
02/10-27-040-03-W4	W-100.000	LLOYD	PA	-	5.00	-	-	69.3	63.8	56.8
02/15-27-040-03-W4	W-100.000	LLOYD	PA	-	5.00	-	-	47.1	43.2	38.1
Subtotal				**25.0**	**237.85**	**1.25**	-	**3402.9**	**3121.7**	**2765.5**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	PA	-	18.72	-	-	118.4	110.1	99.2
N-24-40-1W4 1999 Wells	W- 93.750	DINA	PA	-	18.66	-	-	158.5	151.3	141.4
N-24-40-1W4 2002 Wells	W- 93.750	DINA	PA	-	53.99	-	-	548.6	519.6	481.4
N-24-40-1W4 Future Locations	W- 93.750	DINA	PA	-	37.50	-	-	420.3	390.7	352.5
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	PA	-	282.67	-	-	2180.0	1993.8	1757.5
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	PA	-	23.55	-	-	172.3	159.4	142.6
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	PA	-	46.75	-	-	435.7	414.7	386.3
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	PA	-	92.26	-	-	1011.3	972.8	919.8
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	PA	-	45.58	-	-	533.2	515.0	489.9
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	PA	-	109.74	-	-	1327.5	1249.4	1147.8
Sec 25-40-1W4 Future Locations	W- 94.517	DINA	PA	-	302.45	-	-	3493.6	3256.5	2942.8
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	PA	-	37.40	-	-	248.1	237.0	221.7
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	PA	-	7.40	-	-	75.8	73.2	69.6
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	PA	-	149.79	-	-	884.8	832.5	762.0
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	PA	-	4.93	-	-	41.7	40.7	39.2
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	PA	-	9.88	-	-	96.2	91.7	85.7
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	PA	-	48.88	-	-	540.6	517.9	487.1
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	PA	-	98.36	-	-	980.8	940.6	885.6
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	PA	-	37.81	-	-	362.5	348.8	329.9
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	PA	-	72.81	-	-	724.5	691.0	646.1
NW-35-40-1W4 Future Locations	W- 75.000	DINA	PA	-	75.00	-	-	836.4	786.7	721.0
00/01-03-041-01-W4	W- 75.000	SPKY	PA	-	7.50	-	-	46.6	40.9	34.1
Subtotal				-	**1581.65**	-	-	**15237.2**	**14334.3**	**13143.1**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Total Probable Reserves

				Company Gross Interest Reserves				Present Worth Value Before Tax (M$)		
Area and Property	Company Interest %	Zones	Reserve Class	Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	@10.0%	@12.0%	@15.0%
Mestikow										
All Company Wells	W-100.000	DINA	PA	-	24.98	-	-	233.6	216.4	194.0
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	PA	150.7	494.98	16.58	-	5061.4	4661.8	4143.0
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PA	5.5	74.81	-	-	663.7	607.3	535.8
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PA	2.0	18.71	-	-	168.7	153.3	134.0
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PA	3.9	37.25	-	-	447.3	423.7	391.8
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PA	1.4	18.48	-	-	247.1	238.7	227.1
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PA	0.2	3.72	-	-	43.2	41.5	39.2
Sec 16-38-3W4	W-100.000	DINA	PA	3.5	20.00	-	-	213.6	202.7	187.9
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PA	2.6	3.73	-	-	45.4	43.0	39.9
Subtotal				**19.1**	**176.70**	**-**	**-**	**1829.0**	**1710.3**	**1555.6**
Subtotal Alberta				**339.7**	**2526.16**	**17.95**	**-**	**26184.5**	**24434.6**	**22151.4**
TOTAL				**339.7**	**2526.16**	**17.95**	**-**	**26184.5**	**24434.6**	**22151.4**

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Constant Prices as of August 1,2002

Proved Producing Reserves

Total Of All Areas

Year	No.Of Wells	Crude Oil Annual Volume mbbl	Crude Oil Sales Price $/bbl	Crude Oil Sales Revenue M$	Natural Gas Annual Volume mmcf	Natural Gas Sales Price $/mcf	Natural Gas Sales Revenue M$	Natural Gas Liquids Annual Volume mbbl	Natural Gas Liquids Sales Price $/bbl	Natural Gas Liquids Sales Revenue M$	Total Other Revenues M$	Gross Revenue M$
2002	420.4	1182.5	27.95	33048.7	136.5	4.50	614.3	7.5	27.64	207.0	22.2	33892.3
2003	406.9	2236.7	28.15	62970.6	282.0	4.50	1269.2	15.9	27.46	437.5	36.0	64713.4
2004	392.1	1743.8	28.29	49335.1	223.7	4.50	1006.8	13.4	27.48	368.2	32.0	50742.1
2005	364.3	1389.3	28.38	39433.0	183.6	4.50	826.3	11.5	27.50	315.4	29.0	40603.8
2006	294.5	935.0	29.11	27213.8	154.1	4.50	693.6	10.0	27.48	274.0	25.0	28206.3
2007	243.9	681.4	29.54	20128.5	130.3	4.50	586.3	8.7	27.54	240.4		20955.2
2008	184.8	513.9	29.30	15054.9	94.8	4.50	427.0	5.5	27.63	152.0		15634.0
2009	82.1	268.0	28.33	7592.9	41.5	4.50	187.0	0.3	29.47	9.4		7789.3
2010	57.3	159.4	29.24	4660.4	34.0	4.50	152.9	0.2	29.86	6.6		4820.0
2011	29.1	67.4	29.70	2002.9	26.0	4.50	116.8	0.1	33.93	4.8		2124.5
2012	1.5	1.6	31.93	50.5	7.8	4.50	35.0			0.0		85.4
2013	1.5	1.4	31.95	46.0	6.9	4.50	30.9					76.9
2014	0.8	0.2	32.29	7.8	6.4	4.50	28.8					36.5
2015	0.7				6.0	4.50	26.9					26.9
2016	0.7				5.6	4.50	25.1					25.1
REM.	0.7				9.7	4.50	43.5					43.5
TOTAL		**9180.6**	**28.49**	**261545.0**	**1348.8**	**4.50**	**6070.3**	**73.2**	**27.54**	**2015.3**	**144.2**	**269775.2**

Year	Crown Royalties Unadj. Royalty M$	Crown Royalties Royalty Adj. M$	Crown Royalties Adj. Royalty M$	Freehold Royalties Unadj. Royalty M$	Freehold Royalties Royalty Adj. M$	Freehold Royalties Adj. Royalty M$	Overriding Royalties Unadj. Royalty M$	Overriding Royalties Royalty Adj. M$	Overriding Royalties Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	1077.0	3.8	1073.1	2856.1	0.6	2855.5	305.6	0.1	305.5	624.2	4858.4	14.34
2003	1817.9	7.0	1810.9	5147.9	1.3	5146.6	603.0	0.1	602.9	906.4	8466.8	13.09
2004	1233.6	3.9	1229.7	3873.3	1.2	3872.1	483.5	0.1	483.4	527.2	6112.4	12.05
2005	849.6	2.7	846.8	3141.2	1.1	3140.1	395.4	0.1	395.3	353.7	4735.9	11.67
2006	639.3	2.3	637.0	1764.1	1.0	1763.1	291.0	0.1	290.9	198.4	2889.5	10.25
2007	473.0	2.0	471.0	1148.7	0.9	1147.8	235.5	0.1	235.4	132.6	1986.8	9.48
2008	314.9	1.3	313.6	870.1	0.9	869.2	208.4	0.1	208.3	101.6	1492.7	9.55
2009	88.4	0.2	88.2	534.2	0.8	533.4	168.6	0.0	168.6	66.9	857.2	11.00
2010	71.7	0.1	71.7	211.6	0.7	210.8	132.9	0.0	132.9	33.4	448.8	9.31
2011	23.9	0.0	23.9	37.3	0.7	36.7	97.4	0.0	97.4	16.0	174.0	8.19
2012	0.1	0.0	0.1	18.0	0.6	17.3	0.2	0.0	0.2	0.6	18.2	21.30
2013	0.1	0.0	0.1	16.5	0.6	15.9	0.2	0.0	0.2	0.5	16.7	21.71
2014	0.1	0.0	0.1	7.5	0.5	6.9	0.2	0.0	0.1	0.3	7.5	20.57
2015	0.1	0.0	0.1	5.4	0.5	4.9	0.1	0.0	0.1	0.3	5.3	19.88
2016	0.1	0.0	0.1	5.0	0.4	4.6	0.1	0.0	0.1	0.3	5.0	19.82
REM.	0.1	0.0	0.1	8.7	0.8	7.9	0.2	0.0	0.2	0.4	8.6	19.83
TOTAL	**6589.8**	**23.4**	**6566.3**	**19645.5**	**12.6**	**19632.8**	**2922.4**	**0.9**	**2921.5**	**2962.9**	**32083.8**	**11.90**

Year	Operating Costs M$	Net Op. Income M$	Net Revenues After Costs Annual M$	Net Revenues After Costs Cum M$	Net Revenues After Costs PWV @10.0% M$
2002	8899.4	20134.4	20134.4	20134.4	19738.6
2003	20807.7	35438.8	35438.8	55573.2	32473.9
2004	20110.9	24518.7	24518.7	80091.9	20424.9
2005	18593.2	17274.7	17274.7	97366.5	13082.2
2006	13949.8	11367.0	11367.1	108733.6	7825.7
2007	10889.3	8079.0	8079.0	116812.6	5056.3
2008	8460.1	5681.1	5681.1	122493.7	3232.4
2009	4139.4	2792.8	2792.8	125286.5	1444.5
2010	2919.0	1452.2	1452.2	126738.7	682.8
2011	1360.6	589.8	589.8	127328.5	252.1
2012	40.1	27.1	27.1	127355.6	10.5
2013	39.9	20.3	20.3	127376.0	7.2
2014	17.2	11.8	11.8	127387.8	3.8
2015	12.5	9.0	9.0	127396.8	2.6
2016	12.4	7.7	7.7	127404.5	2.1
REM.	23.3	11.6	11.6	127416.2	2.7
TOTAL	**110274.7**	**127416.2**	**127416.2**		**104242.4**

Product	Remaining Reserves Gross	Remaining Reserves Net	Remaining Present Worth Value - M$ @10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	9180.8	8162.5	100603.4	97202.2	92569.3	85894.4
Natural Gas (mmcf)	1349.0	1079.4	2454.9	2344.4	2197.5	1992.5
Natural Gas Liquids (mbbl)	73.4	55.6	1184.1	1135.0	1068.5	973.6
Total			**104242.4**	**100681.7**	**95835.3**	**88860.5**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Proved Producing Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves: Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$): @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
Fixed Battery Costs	P-100.000		NRA	-	-	-	-	-3106.5	-2892.7	-2615.9
00/04-05-041-12-W4	W-100.000	ELL	PP	10.2	48.79	0.05	-	649.2	612.3	563.9
02/04-05-041-12-W4	W-100.000	ELL	PP	19.6	50.39	0.09	-	702.9	663.7	612.3
03/04-05-041-12-W4	W-100.000	ELL	PP	1.5	6.36	0.00	-	60.6	59.7	58.4
00/05-05-041-12-W4	W-100.000	ELL	PP	11.6	52.20	0.05	-	714.2	674.6	622.7
04/05-05-041-12-W4	W-100.000	ELL	PP	12.6	38.11	0.05	-	479.5	452.4	416.9
B0/05-05-041-12-W4	W-100.000	ELL	PP	12.7	60.50	0.06	-	854.5	807.3	745.4
00/06-05-041-12-W4	W- 40.000	GLAUC L	PP	42.6	-	0.21	-	110.6	109.0	106.7
00/12-05-041-12-W4	W-100.000	ELL	PP	19.4	49.69	0.09	-	689.7	651.4	601.0
00/13-05-041-12-W4	W-100.000	ELL	PP	1.2	7.89	0.00	-	58.0	56.7	54.9
B0/14-05-041-12-W4	W-100.000	ELL	PP	10.8	51.43	0.05	-	721.9	684.9	636.0
C0/14-05-041-12-W4	W-100.000	ELL	PP	8.2	40.48	0.04	-	510.3	481.8	444.4
02/15-05-041-12-W4	W-100.000	ELL	PP	2.1	7.81	0.01	-	125.3	123.2	120.3
A2/15-05-041-12-W4	W-100.000	ELL	PP	4.6	34.14	0.02	-	506.3	485.9	458.2
B2/15-05-041-12-W4	W-100.000	ELL	PP	17.1	59.88	0.08	-	852.9	805.6	743.5
02/16-05-041-12-W4	W-100.000	ELL	PP	3.8	15.81	0.02	-	259.8	253.8	245.3
00/01-06-041-12-W4	W-100.000	ELL	PP	11.7	19.53	0.05	-	198.7	188.7	175.5
00/02-06-041-12-W4	W-100.000	ELL	PP	8.7	38.81	0.04	-	521.1	491.9	453.6
02/07-06-041-12-W4	W-100.000	ELL	PP	4.4	26.91	0.02	-	317.4	301.1	279.5
02/08-06-041-12-W4	W-100.000	ELL	PP	11.4	21.09	0.05	-	332.0	320.3	304.3
03/08-06-041-12-W4	W-100.000	ELL	PP	14.2	29.67	0.06	-	377.9	357.1	329.7
05/08-06-041-12-W4	W-100.000	ELL	PP	12.1	47.46	0.06	-	672.9	636.0	587.5
02/09-06-041-12-W4	W-100.000	ELL	PP	8.8	43.31	0.04	-	574.5	538.3	491.2
02/15-15-041-12-W4	R- 3.750	ELL	PP	-	0.22	-	-	5.4	5.3	5.1
04/15-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
02/16-15-041-12-W4	R- 3.750	ELL	NRA	-	-	-	-	-	-	-
05/16-15-041-12-W4	R- 3.750	ELL	PP	-	0.05	-	-	1.3	1.3	1.3
Subtotal				**249.4**	**750.55**	**1.13**	-	**7190.4**	**6869.6**	**6441.6**
Choice										
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PP	47.2	-	0.19	-	161.6	153.7	143.2
00/11-05-040-08-W4	R- 15.000	VIK	PP	5.0	-	0.02	-	19.8	19.3	18.6
00/07-07-040-08-W4	R- 6.250	CLY	PP	2.2	-	0.01	-	9.2	9.1	8.9
00/10-07-040-08-W4	R- 15.000	VIK	PP	18.3	-	0.07	-	59.8	56.4	52.0
Subtotal				**72.6**	-	**0.29**	-	**250.4**	**238.5**	**222.6**
David North										
Lloydminster O Unit	W-100.000	LLOYD	PP	40.4	403.99	2.02	-	7207.4	6933.8	6563.6
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PP	52.5	429.37	2.62	-	7158.5	6868.3	6480.3
00/10-27-040-03-W4	W-100.000	LLOYD	PP	-	14.09	-	-	173.0	166.8	158.2
02/10-27-040-03-W4	W-100.000	LLOYD	PP	-	24.26	-	-	429.8	414.0	392.5
02/15-27-040-03-W4	W-100.000	LLOYD	PP	-	22.92	-	-	283.0	271.9	256.8
Subtotal				**92.9**	**894.64**	**4.64**	-	**15251.7**	**14654.7**	**13851.4**
Hayter										
N-24-40-1W4 Pre-1999 Wells	W- 93.750	DINA	PP	-	71.94	-	-	585.4	566.6	540.5
N-24-40-1W4 1999 Wells	W- 93.750	DINA	PP	-	47.39	-	-	437.0	428.1	415.4
N-24-40-1W4 2002 Wells	W- 93.750	DINA	PP	-	202.69	-	-	2384.2	2315.0	2220.0
Sec 25-40-1W4 Pre-1998 Wells	W- 94.517	DINA	PP	-	1276.76	-	-	11817.9	11327.1	10666.8
Sec 25-40-1W4 1998 Wells	W- 94.517	DINA	PP	-	98.02	-	-	898.3	865.6	821.2
Sec 25-40-1W4 1999 Wells	W- 94.517	DINA	PP	-	128.94	-	-	1330.0	1298.9	1255.4
Sec 25-40-1W4 2000 Wells	W- 94.517	DINA	PP	-	414.57	-	-	4643.5	4553.3	4425.9
Sec 25-40-1W4 2001 Wells	W- 94.517	DINA	PP	-	155.50	-	-	1905.7	1871.4	1822.8
Sec 25-40-1W4 2002 Wells	W- 94.517	DINA	PP	-	380.08	-	-	5376.6	5207.9	4977.4
Sec 34-40-1W4 Pre-1999 Wells	W- 75.000	DINA	PP	-	75.39	-	-	555.2	544.6	529.5

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Proved Producing Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Hayter (cont'd)										
Sec 34-40-1W4 1999 Wells	W- 75.000	DINA	PP	-	23.79	-	-	255.3	251.1	245.2
Sec 34-40-1W4 2000 Wells	W- 75.000	DINA	PP	-	9.84	-	-	72.9	71.3	69.1
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	PP	-	647.94	-	-	4140.8	4029.9	3875.0
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	PP	-	8.57	-	-	70.5	69.7	68.6
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	PP	-	31.36	-	-	320.9	313.8	303.9
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	PP	-	151.76	-	-	1802.4	1764.3	1710.8
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	PP	-	306.60	-	-	3264.2	3197.3	3103.1
NW-35-40-1W4 Pre-2000 Wells	W- 75.000	DINA	PP	-	116.69	-	-	639.7	613.5	577.9
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	PP	-	117.50	-	-	1191.3	1168.3	1135.8
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	PP	-	232.37	-	-	2477.8	2418.9	2336.8
S-36-40-1W4 GOR Wells	R- 7.500	DINA	PP	-	2.26	-	-	52.8	51.9	50.8
00/09-34-040-01-W4	W- 75.000	SPKY	PP	-	10.16	-	-	127.9	123.6	117.8
00/15-34-040-01-W4	W- 75.000	SPKY	PP	-	7.08	-	-	89.2	86.9	83.7
00/01-03-041-01-W4	W- 75.000	SPKY	PP	-	27.99	-	-	265.9	251.1	231.8
Subtotal				**-**	**4545.18**	**-**	**-**	**44705.3**	**43390.3**	**41585.4**
Mestikow										
All Company Wells	W-100.000	DINA	PP	-	170.34	-	-	1873.3	1805.0	1711.9
Thompson Lake										
Thompson Lake Total Field	W- 99.045	GLAUC	PP	612.5	2011.52	67.37	-	24742.7	23845.7	22620.5
04/10-29-040-11-W4	W- 25.000	VIK	PP	1.6	-	-	-	2.1	2.1	2.1
Subtotal				**614.1**	**2011.52**	**67.37**	**-**	**24744.8**	**23847.8**	**22622.5**
West Provost										
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PP	27.9	379.18	-	-	4433.3	4248.1	3999.2
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PP	8.3	79.23	-	-	935.8	895.7	841.9
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PP	21.7	206.44	-	-	2720.1	2650.0	2552.2
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PP	4.3	55.63	-	-	728.4	716.7	699.9
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PP	0.4	6.96	-	-	85.7	84.2	82.1
Sec 16-38-3W4	W-100.000	DINA	PP	10.1	57.55	-	-	666.7	651.9	631.1
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PP	16.6	23.65	-	-	327.4	318.9	307.1
00/11-24-037-02-W4	W- 37.500	VIK	PP	0.5	-	-	-	0.2	0.2	0.2
00/07-27-037-02-W4	W- 42.188	VIK	PP	55.5	-	-	-	61.4	56.4	50.2
02/06-11-038-03-W4	W- 28.125	VIK	NRA	-	-	-	-	-	-	-
00/14-12-038-03-W4	W- 37.500	CLY	PP	13.1	-	-	-	19.0	18.5	17.7
00/07-13-038-03-W4	W- 37.500	VIK	PP	34.2	-	-	-	54.5	51.9	48.5
00/06-14-038-03-W4	W- 37.500	VIK	NRA	-	-	-	-	-	-	-
00/07-15-038-03-W4	W- 37.500	VIK	PP	7.3	-	-	-	9.0	8.8	8.6
00/07-17-038-03-W4	W- 37.500	VIK	PP	6.0	-	-	-	1.8	1.7	1.7
00/07-18-038-03-W4	W- 37.500	VIK	PP	24.0	-	-	-	32.1	30.6	28.6
00/14-07-039-01-W4	W- 29.371	MCLAR	PP	90.1	-	-	-	124.1	115.6	105.0
Bodo Compression Facility	P-100.000	ALL ZONES	NRA	-	-	-	-	27.1	26.6	25.8
Wells with NRA		ALL ZONES	NRA	-	-	-	-	-	-	-
Subtotal				**320.0**	**808.64**	**-**	**-**	**10226.5**	**9875.9**	**9399.8**
Subtotal Alberta				**1349.0**	**9180.86**	**73.43**	**-**	**104242.4**	**100681.7**	**95835.3**
TOTAL				**1349.0**	**9180.86**	**73.43**	**-**	**104242.4**	**100681.7**	**95835.3**

Table 1

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Constant Prices as of August 1,2002

Proved Non-Producing Reserves

Total Of All Areas

		Crude Oil			Natural Gas			Natural Gas Liquids			
Year	No.Of Wells	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Annual Volume mmcf	Sales Price $/mcf	Sales Revenue M$	Annual Volume mbbl	Sales Price $/bbl	Sales Revenue M$	Gross Revenue M$
2003	1.0				107.9	4.50	485.5				485.5
2004	2.0	7.9	28.72	228.0	92.8	4.50	417.8			0.1	645.9
2005	3.0	14.2	28.75	407.9	57.6	4.50	259.2	0.0	27.00	0.3	667.4
2006	3.0	9.5	28.75	274.0	34.5	4.50	155.3			0.2	429.5
2007	1.8	4.5	28.72	128.7	5.3	4.50	23.7			0.0	152.4
TOTAL		**36.1**	**28.74**	**1038.6**	**298.1**	**4.50**	**1341.5**	**0.0**	**27.00**	**0.6**	**2380.7**

	Crown Royalties			Overriding Royalties					
Year	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Unadj. Royalty M$	Royalty Adj. M$	Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2003	134.1	33.3	100.7					100.7	20.75
2004	92.2	28.3	63.9	23.1		23.1	5.3	92.3	14.30
2005	71.5	16.5	55.0	16.9		16.9	2.9	74.8	11.20
2006	29.6	9.8	19.8	13.3		13.3	1.8	34.9	8.12
2007	5.5	1.4	4.1	8.2	-0.0	8.2	0.9	13.3	8.71
TOTAL	**332.9**	**89.3**	**243.6**	**61.5**	**-0.0**	**61.5**	**10.9**	**316.0**	**13.27**

			Capital Costs			Net Revenues After Costs		
Year	Operating Costs M$	Net Op. Income M$	Drilling & Compl M$	Equip & Facility M$	Total Capital M$	Annual M$	Cum M$	PWV @10.0% M$
2003	66.5	318.2		225.0	225.0	93.2	93.2	85.4
2004	108.6	445.0	5.0		5.0	440.0	533.1	366.5
2005	132.9	459.8	5.0		5.0	454.8	987.9	344.4
2006	114.1	280.5				280.5	1268.4	193.1
2007	47.9	91.2				91.2	1359.6	57.1
TOTAL	**470.1**	**1594.6**	**10.0**	**225.0**	**235.0**	**1359.6**		**1046.4**

	Remaining Reserves		Remaining Present Worth Value - M$			
Product	Gross	Net	@10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	36.2	32.6	502.0	474.8	437.9	384.8
Natural Gas (mmcf)	298.1	232.9	544.2	521.9	491.1	445.8
Natural Gas Liquids (mbbl)	0.0	0.0	0.3	0.3	0.3	0.2
Total			**1046.5**	**997.0**	**929.2**	**830.8**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Proved Non-Producing Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves: Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$): @10.0%	@12.0%	@15.0%
Alberta										
Bellshill Lake										
02/10-05-041-12-W4	W-100.000	ELL	PNP	1.9	21.09	0.01	-	296.4	281.5	261.2
00/15-05-041-12-W4	W-100.000	ELL	PNP	3.6	15.06	0.01	-	216.8	203.9	186.4
Subtotal				**5.5**	**36.15**	**0.02**	-	**513.2**	**485.5**	**447.6**
Black Creek										
00/06-20-041-03-W4	W-100.000	MCLAR	PNP	292.6	-	-	-	533.2	511.5	481.6
Subtotal Alberta				**298.1**	**36.15**	**0.02**	-	**1046.5**	**997.0**	**929.2**
TOTAL				**298.1**	**36.15**	**0.02**	-	**1046.5**	**997.0**	**929.2**

Coyote Energy Inc.

Forecast of Production and Revenue - Company Share
Constant Prices as of August 1,2002

Proved Undeveloped Reserves

Total Of All Areas

Year	No.Of Wells	Crude Oil Annual Volume mbbl	Crude Oil Sales Price $/bbl	Crude Oil Sales Revenue M$	Gross Revenue M$
2002	15.1	87.8	25.40	2230.9	2230.9
2003	20.7	879.2	25.40	22330.6	22330.6
2004	20.7	425.5	25.40	10808.7	10808.7
2005	20.7	201.9	25.40	5128.2	5128.2
2006	20.7	136.6	25.40	3470.9	3470.9
2007	20.7	107.2	25.40	2723.0	2723.0
2008	3.4	20.4	25.41	518.3	518.3
2009	1.9	8.6	25.40	218.7	218.7
TOTAL		**1867.3**	**25.40**	**47429.3**	**47429.3**

Year	Crown Royalties Unadj. Royalty M$	Crown Royalties Royalty Adj. M$	Crown Royalties Adj. Royalty M$	Freehold Royalties Unadj. Royalty M$	Freehold Royalties Royalty Adj. M$	Freehold Royalties Adj. Royalty M$	Overriding Royalties Unadj. Royalty M$	Overriding Royalties Royalty Adj. M$	Overriding Royalties Adj. Royalty M$	Mineral Tax M$	Total Royalty & Taxes M$	Total Royalty & Taxes %
2002	82.7		82.7	348.3		348.3	13.7		13.7	100.1	544.8	24.42
2003	463.0		463.0	3451.1		3451.1	148.4		148.4	1007.1	5069.7	22.70
2004	168.6		168.6	1675.8		1675.8	71.9		71.9	408.9	2325.1	21.51
2005	76.8		76.8	806.5		806.5	32.4		32.4	103.9	1019.5	19.88
2006	43.0		43.0	549.0		549.0	21.5		21.5	47.1	660.6	19.03
2007	27.5		27.5	431.3		431.3	16.8		16.8	29.0	504.5	18.53
2008	19.1		19.1	66.8		66.8	1.6		1.6	3.8	91.3	17.61
2009	14.5		14.5				0.2		0.2		14.7	6.72
TOTAL	**895.1**		**895.1**	**7328.7**		**7328.7**	**306.4**		**306.4**	**1699.9**	**10230.1**	**21.57**

Year	Operating Costs M$	Net Op. Income M$	Capital Costs Drilling & Compl M$	Capital Costs Equip & Facility M$	Capital Costs Total Capital M$	Net Revenues After Costs Annual M$	Net Revenues After Costs Cum M$	Net Revenues After Costs PWV @10.0% M$
2002	45.2	1640.9	9046.0		9046.0	-7405.1	-7405.1	-7259.5
2003	746.9	16513.9	3402.6		3402.6	13111.3	5706.2	12014.4
2004	746.9	7736.7				7736.7	13442.9	6444.9
2005	746.9	3361.8				3361.8	16804.7	2545.9
2006	746.9	2063.4				2063.4	18868.1	1420.6
2007	747.0	1471.5				1471.5	20339.5	920.9
2008	123.8	303.3				303.3	20642.8	172.6
2009	67.5	136.5				136.5	20779.3	70.6
TOTAL	**3971.1**	**33228.0**	**12448.7**		**12448.7**	**20779.3**		**16330.4**

Product	Remaining Reserves Gross	Remaining Reserves Net	Remaining Present Worth Value - M$ @10.0%	@12.0%	@15.0%	@20.0%
Crude Oil (mbbl)	1867.3	1531.5	16330.4	15611.1	14615.3	13147.0
Total			**16330.4**	**15611.1**	**14615.3**	**13147.0**

Coyote Energy Inc.

Reserves and Present Worth Values by Property
Constant Prices as of August 1, 2002
Proved Undeveloped Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Company Gross Interest Reserves Gas mmcf	Oil mbbl	NGL mbbl	Sulphur mlt	Present Worth Value Before Tax (M$) @10.0%	@12.0%	@15.0%
Alberta										
Hayter										
N-24-40-1W4 Future Locations	W- 93.750	DINA	PUD	-	168.75	-	-	1240.8	1158.3	1046.4
Sec 25-40-1W4 Future Locations	W- 94.517	DINA	PUD	-	1361.04	-	-	12821.3	12317.8	11617.3
NW-35-40-1W4 Future Locations	W- 75.000	DINA	PUD	-	337.50	-	-	2268.3	2135.0	1951.7
Subtotal				-	**1867.29**	-	-	**16330.4**	**15611.1**	**14615.3**
Subtotal Alberta				-	**1867.29**	-	-	**16330.4**	**15611.1**	**14615.3**
TOTAL				-	**1867.29**	-	-	**16330.4**	**15611.1**	**14615.3**

Coyote Energy Inc.

Summary of Crude Oil Reserve Estimates
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Volumetric Factors: Area acre	Net Pay ft	Por. %	Sw %	Sg %	Oil Shr.	Property Gross Crude Oil Reserves: Orig. OIP mbbl	Rec. %	Orig. Res. mbbl	Cum. Prod. mbbl	Rem. Res. mbbl	Company Share: Rem. Res. mbbl	2002 Rate bopd	Reserves based on
Alberta																	
Bellshill Lake																	
00/04-05-041-12-W4/0	W-100.000	ELL	PR									383	334	48	48.8	21	Decl
02/04-05-041-12-W4/0	W-100.000	ELL	PR									360	309	50	50.4	23	Decl
03/04-05-041-12-W4/0	W-100.000	ELL	PR		16.4	27.0	30.0		0.93			107	100	6	6.4	9	Decl
00/05-05-041-12-W4/2	W-100.000	ELL	PR									339	286	52	52.2	24	Decl
04/05-05-041-12-W4/2	W-100.000	ELL	PR									225	187	38	38.1	16	Decl
B0/05-05-041-12-W4/0	W-100.000	ELL	PR									328	267	60	60.5	28	Decl
02/10-05-041-12-W4/0	W-100.000	ELL	PR									115	93	21	21.1		Decl
			PA											5	5.0		Decl
00/12-05-041-12-W4/2	W-100.000	ELL	PR									214	165	49	49.7	22	Decl
00/13-05-041-12-W4/0	W-100.000	ELL	PR		23.0	27.0	25.0					97	89	7	7.9	7	Decl
B0/14-05-041-12-W4/0	W-100.000	ELL	PR									220	168	51	51.4	27	Decl
C0/14-05-041-12-W4/0	W-100.000	ELL	PR									289	248	40	40.5	18	Decl
00/15-05-041-12-W4/0	W-100.000	ELL	PR									150	134	15	15.1		Decl
			PA											5	5.0		Decl
02/15-05-041-12-W4/2	W-100.000	ELL	PR									120	112	7	7.8	13	Decl
A2/15-05-041-12-W4/0	W-100.000	ELL	PR									145	110	34	34.1	23	Decl
B2/15-05-041-12-W4/0	W-100.000	ELL	PR									229	169	59	59.9	28	Decl
02/16-05-041-12-W4/0	W-100.000	ELL	PR		13.1	27.0	25.0		0.93			113	97	15	15.8	18	Decl
00/01-06-041-12-W4/0	W-100.000	ELL	PR									110	90	19	19.5	9	Decl

Coyote Energy Inc.

Summary of Crude Oil Reserve Estimates
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

				Volumetric Factors						Property Gross Crude Oil Reserves					Company Share		
Area and Property	Company Interest %	Zones	Reserve Class	Area acre	Net Pay ft	Por. %	Sw %	Sg %	Oil Shr.	Orig. OIP mbbl	Rec. %	Orig. Res. mbbl	Cum. Prod. mbbl	Rem. Res. mbbl	Rem. Res. mbbl	2002 Rate bopd	Reserves based on
00/02-06-041-12-W4/0	W-100.000	ELL	PR									101	62	38	38.8	17	Decl
02/07-06-041-12-W4/3	W-100.000	ELL	PR									140	113	26	26.9	13	Decl
02/08-06-041-12-W4/0	W-100.000	ELL	PR									126	104	21	21.1	16	Decl
03/08-06-041-12-W4/0	W-100.000	ELL	PR									178	148	29	29.7	13	Decl
05/08-06-041-12-W4/0	W-100.000	ELL	PR									181	133	47	47.5	23	Decl
02/09-06-041-12-W4/0	W-100.000	ELL	PR									239	196	43	43.3	15	Decl
02/15-15-041-12-W4/0	R- 3.750	ELL	PR									220	214	5	0.2	0	Decl
04/15-15-041-12-W4/0	R- 3.750	ELL	PR									8	8				
02/16-15-041-12-W4/0	R- 3.750	ELL	PR									79	79				
05/16-15-041-12-W4/0	R- 3.750	ELL	PR									21	19	1	0.0	0	
Subtotal			**PR**									**4837**	**4034**	**781**	**786.7**	**382**	
			PA											**10**	**10.0**		
David North																	
Lloydminster O Unit	W-100.000	LLOYD	PR									5764	5360	403	404.0	319	Decl
			PA											128	127.9	9	Decl
Sec 26 & NE-27-40-3W4	W-100.000	DINA/CUMM	PR									1600	1170	429	429.4	336	Decl
			PA											100	100.0	7	Decl
00/10-27-040-03-W4/0	W-100.000	LLOYD	PR									40	25	14	14.1	9	Decl
02/10-27-040-03-W4/0	W-100.000	LLOYD	PR									60	35	24	24.3	18	Perf
			PA											5	5.0	0	Perf
02/15-27-040-03-W4/0	W-100.000	LLOYD	PR									30	7	22	22.9	15	Perf
			PA											5	5.0	0	Perf
Subtotal			**PR**									**7494**	**6597**	**892**	**894.6**	**697**	
			PA											**238**	**237.9**	**17**	

Coyote Energy Inc.

Summary of Crude Oil Reserve Estimates
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

				Volumetric Factors						Property Gross Crude Oil Reserves					Company Share		
Area and Property	Company Interest %	Zones	Reserve Class	Area acre	Net Pay ft	Por. %	Sw %	Sg %	Oil Shr.	Orig. OIP mbbl	Rec. %	Orig. Res. mbbl	Cum. Prod. mbbl	Rem. Res. mbbl	Rem. Res. mbbl	2002 Rate bopd	Reserves based on
Hayter																	
N-24-40-1W4	W- 93.750	DINA	PR									780	703	76	71.9	52	Decl
Pre-1999 Wells			PA											20	18.7	1	Decl
N-24-40-1W4	W- 93.750	DINA	PR									320	269	50	47.4	57	Decl
1999 Wells			PA											20	18.7	2	Decl
N-24-40-1W4	W- 93.750	DINA	PR									270	53	216	202.7	255	
2002 Wells			PA											60	54.0	27	
N-24-40-1W4	W- 93.750	DINA	PR									180		180	168.8	338	
Future Locations			PA											40	37.5	5	
Sec 25-40-1W4	W- 94.517	DINA	PR									8800	7449	1350	1276.8	798	Decl
Pre-1998 Wells			PA											300	282.7	20	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									500	396	103	98.0	67	Decl
1998 Wells			PA											25	23.6	2	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									550	413	136	128.9	146	Decl
1999 Wells			PA											50	46.8	10	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									1700	1261	438	414.6	592	Decl
2000 Wells			PA											100	92.3	36	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									550	385	164	155.5	253	Decl
2001 Wells			PA											50	45.6	24	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									540	137	402	380.1	451	Decl
2002 Wells			PA											120	109.7	48	Decl
Sec 25-40-1W4	W- 94.517	DINA	PR									1440		1440	1361.0	1863	
Future Locations			PA											320	302.5		
Sec 34-40-1W4	W- 75.000	DINA	PR									1450	1349	100	75.4	93	Decl
Pre-1999 Wells			PA											50	37.4	2	Decl
Sec 34-40-1W4	W- 75.000	DINA	PR									150	118	31	23.8	38	Decl
1999 Wells			PA											10	7.4	2	Decl

Coyote Energy Inc.

Summary of Crude Oil Reserve Estimates
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Volumetric Factors: Area acre	Net Pay ft	Por. %	Sw %	Sg %	Oil Shr.	Property Gross Crude Oil Reserves: Orig. OIP mbbl	Rec. %	Orig. Res. mbbl	Cum. Prod. mbbl	Rem. Res. mbbl	Company Share: Rem. Res. mbbl	2002 Rate bopd	Reserves based on
Hayter (cont'd)																	
Sec 34-40-1W4 2000 Wells	W- 75.000	DINA	PR									45	31	13	9.8	11	Perf
S&NE-35-40-1W4 Pre-1998 Wells	W-100.000	DINA	PR									5200	4552	647	647.9	543	Decl
			PA											150	149.8	5	Decl
S&NE-35-40-1W4 1998 Wells	W-100.000	DINA	PR									65	56	8	8.6	20	Decl
			PA											5	4.9	1	Decl
S&NE-35-40-1W4 1999 Wells	W-100.000	DINA	PR									145	113	31	31.4	37	Decl
			PA											10	9.9	2	Decl
S&NE-35-40-1W4 2000 Wells	W-100.000	DINA	PR									575	423	151	151.8	209	Decl
			PA											50	48.9	18	Decl
S&NE-35-40-1W4 2001 Wells	W-100.000	DINA	PR									600	293	306	306.6	403	Decl
			PA											100	98.4	29	Decl
NW-35-40-1W4 Pre-2000 Wells	W- 75.000	DINA	PR									950	794	155	116.7	62	Decl
NW-35-40-1W4 2000 Wells	W- 77.500	DINA	PR									520	368	151	117.5	171	Decl
			PA											50	37.8	15	Decl
NW-35-40-1W4 2001 Wells	W- 75.000	DINA	PR									600	290	309	232.4	302	Decl
			PA											100	72.8	31	Decl
NW-35-40-1W4 Future Locations	W- 75.000	DINA	PR									450		450	337.5	684	
			PA											100	75.0	9	
S-36-40-1W4 GOR Wells	R- 7.500	DINA	PR									400	369	30	2.3	4	Decl
00/09-34-040-01-W4/2	W- 75.000	SPKY	PR		5.9	30.0	25.0		0.97			185	171	13	10.2	7	Decl
00/15-34-040-01-W4/2	W- 75.000	SPKY	PR									15	5	9	7.1	6	Decl
00/01-03-041-01-W4/2	W- 75.000	SPKY	PR		7.2	28.5	25.0		0.97			150	112	37	28.0	11	Decl
			PA						0.97					10	7.5	0	Decl
Subtotal			PR									27130	20110	6996	6412.5	7473	
			PA											1740	1581.6	291	

Coyote Energy Inc.

Summary of Crude Oil Reserve Estimates
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Volumetric Factors: Area acre	Net Pay ft	Por. %	Sw %	Sg %	Oil Shr.	Property Gross Crude Oil Reserves: Orig. OIP mbbl	Rec. %	Orig. Res. mbbl	Cum. Prod. mbbl	Rem. Res. mbbl	Company Share: Rem. Res. mbbl	2002 Rate bopd	Reserves based on
Mestikow																	
All Company Wells	W-100.000	DINA	PR									785	614	170	170.3	124	Decl
			PA											25	25.0	2	Decl
Thompson Lake																	
Thompson Lake Total Field	W- 99.045	GLAUC	PR									23500	21469	2030	2011.5	1340	Decl
			PA											500	495.0	17	Decl
West Provost																	
Secs 10 & 15-38-3W4 Pre 1995 Wells	W- 37.500	DINA	PR			29.0	20.0		0.95	17011	51.7	8800	7788	1011	379.2	216	Decl
			PA						0.95					200	74.8	4	Decl
Secs 10 & 15-38-3W4 1995 Wells	W- 37.500	DINA	PR			29.0	20.0		0.95	1706	58.6	1000	788	211	79.2	44	Decl
			PA						0.95					50	18.7	1	Decl
Secs 10 & 15-38-3W4 1996 Wells	W- 37.500	DINA	PR			29.0	20.0		0.95	6561	54.9	3600	3049	550	206.4	200	Decl
			PA						0.95					100	37.2	5	Decl
Secs 10 & 15-38-3W4 1997 Wells	W- 37.500	DINA	PR			29.0	20.0		0.95	2409	52.9	1275	1126	148	55.6	86	Decl
			PA						0.95					50	18.5	5	Decl
Secs 10 & 15-38-3W4 1998 Wells	W- 37.500	DINA	PR			29.0	20.0		0.95	391	51.1	200	181	18	7.0	10	Decl
			PA						0.95					10	3.7	1	Decl
Sec 16-38-3W4	W-100.000	DINA	PR			29.0	20.0		0.95	1181	45.7	540	482	57	57.5	61	Perf
			PA						0.95					20	20.0	1	Perf
Secs 10 & 15-38-3W4 Rex Wells	W- 37.500	REX	PR									400	336	63	23.7	23	Decl
			PA											10	3.7	0	Decl
Subtotal			PR							29259		15815	13750	2058	808.6	639	
			PA											440	176.7	18	
Subtotal Alberta			PR							29259		79561	66574	12927	11084.3	10656	
			PA											2953	2526.2	344	
TOTAL			PR							29259		79561	66574	12927	11084.3	10656	
			PA											2953	2526.2	344	

Coyote Energy Inc.

Summary of Natural Gas Reserve Estimates
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

				Volumetric Factors								Property Gross Natural Gas Reserves							Company Share		
Area and Property	Company Interest %	Zones	Reserve Class	Area acre	Net Pay ft	Por. %	Sw %	So %	Pres. psia	Temp. deg R	Z	Orig. Raw GIP mmcf	Rec. %	Orig. Raw Res. mmcf	Cum. Prod. mmcf	Rem. Raw. Res. mmcf	Surf. Loss %	Rem. Sales Res. mmcf	Rem. Sales Res. mmcf	2002 Rate mcf/d	Reserves based on
Alberta																					
Bellshill Lake																					
00/04-05-041-12-W4/0	W-100.000	ELL	PR																10.2	4	
02/04-05-041-12-W4/0	W-100.000	ELL	PR																19.6	9	
03/04-05-041-12-W4/0	W-100.000	ELL	PR																1.5	2	
00/05-05-041-12-W4/2	W-100.000	ELL	PR																11.6	5	
04/05-05-041-12-W4/2	W-100.000	ELL	PR																12.6	5	
B0/05-05-041-12-W4/0	W-100.000	ELL	PR																12.7	6	
00/06-05-041-12-W4/2	W- 40.000	GLAUC L	PR		7.2	22.0	30.0							1925	1813	112	5.0	107	42.6	84	Perf
			PA											25		25	5.0	24	9.5	2	Perf
02/10-05-041-12-W4/0	W-100.000	ELL	PR																1.9		
			PA																0.4		
00/12-05-041-12-W4/2	W-100.000	ELL	PR																19.4	9	
00/13-05-041-12-W4/0	W-100.000	ELL	PR																1.2	1	
B0/14-05-041-12-W4/0	W-100.000	ELL	PR																10.8	6	
C0/14-05-041-12-W4/0	W-100.000	ELL	PR																8.2	4	
00/15-05-041-12-W4/0	W-100.000	ELL	PR																3.6		
			PA																1.2		
02/15-05-041-12-W4/2	W-100.000	ELL	PR																2.1	3	
A2/15-05-041-12-W4/0	W-100.000	ELL	PR																4.6	3	
B2/15-05-041-12-W4/0	W-100.000	ELL	PR																17.1	8	

Coyote Energy Inc.

Summary of Natural Gas Reserve Estimates
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

				Volumetric Factors								Property Gross Natural Gas Reserves							Company Share		
Area and Property	Company Interest %	Zones	Reserve Class	Area acre	Net Pay ft	Por. %	Sw %	So %	Pres. psia	Temp. deg R	Z	Orig. Raw GIP mmcf	Rec. %	Orig. Raw Res. mmcf	Cum. Prod. mmcf	Rem. Raw. Res. mmcf	Surf. Loss %	Rem. Sales Res. mmcf	Rem. Sales Res. mmcf	2002 Rate mcf/d	Reserves based on
02/16-05-041-12-W4/0	W-100.000	ELL	PR																3.8	4	
00/01-06-041-12-W4/0	W-100.000	ELL	PR																11.7	5	
00/02-06-041-12-W4/0	W-100.000	ELL	PR																8.7	4	
02/07-06-041-12-W4/3	W-100.000	ELL	PR																4.4	2	
02/08-06-041-12-W4/0	W-100.000	ELL	PR																11.4	9	
03/08-06-041-12-W4/0	W-100.000	ELL	PR																14.2	6	
05/08-06-041-12-W4/0	W-100.000	ELL	PR																12.1	6	
02/09-06-041-12-W4/0	W-100.000	ELL	PR																8.8	3	
Subtotal			PR											1925	1813	112		107	254.9	189	
			PA											25		25		24	11.1	2	
Black Creek																					
00/06-20-041-03-W4	W-100.000	MCLAR	PR	160	13.1	29.0	50.0	5.0	708	540	0.900	616	50.0	308		308	5.0	293	292.6		Vol
			PA										20.0	123		123	5.0	117	116.8		Vol
Choice																					
Choice Viking Gas Unit No. 1	R- 7.107	VIK	PR											9250	8551	699	5.0	665	47.2	29	Decl
			PA											250		250	5.0	238	16.9	1	Decl
00/11-05-040-08-W4/0	R- 15.000	VIK	PR											760	725	35	5.0	33	5.0	5	Decl
00/07-07-040-08-W4/0	R- 6.250	CLY	PR	160	7.9	28.0	40.0		914	544	0.890	620		380	344	36	5.0	35	2.2	5	Decl
00/10-07-040-08-W4/0	R- 15.000	VIK	PR											950	822	128	5.0	122	18.3	8	Decl
Subtotal			PR									620		11340	10442	898		855	72.6	47	
			PA											250		250		238	16.9	1	

Coyote Energy Inc.

Summary of Natural Gas Reserve Estimates
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Volumetric Factors: Area acre	Net Pay ft	Por. %	Sw %	So %	Pres. psia	Temp. deg R	Z	Property Gross Natural Gas Reserves: Orig. Raw GIP mmcf	Rec. %	Orig. Raw Res. mmcf	Cum. Prod. mmcf	Rem. Raw. Res. mmcf	Surf. Loss %	Rem. Sales Res. mmcf	Company Share: Rem. Sales Res. mmcf	2002 Rate mcf/d	Reserves based on
David North																					
Lloydminster O Unit	W-100.000	LLOYD	PR																40.4	32	
			PA																12.8	1	
Sec 26 &	W-100.000	DINA/CUMM	PR																52.5	41	
NE-27-40-3W4			PA																12.2	1	
Subtotal			**PR**																**92.9**	**73**	
			PA																**25.0**	**2**	
Thompson Lake																					
Thompson Lake	W- 99.045	GLAUC	PR																612.5	408	
Total Field			PA																150.7	5	
04/10-29-040-11-W4/2	W- 25.000	VIK	PR											80	73	7	5.0	7	1.6	8	Decl
Subtotal			**PR**											**80**	**73**	**7**		**7**	**614.1**	**416**	
			PA																**150.7**	**5**	
West Provost																					
Secs 10 & 15-38-3W4	W- 37.500	DINA	PR																27.9	16	
Pre 1995 Wells			PA																5.5	0	
Secs 10 & 15-38-3W4	W- 37.500	DINA	PR																8.3	5	
1995 Wells			PA																2.0	0	
Secs 10 & 15-38-3W4	W- 37.500	DINA	PR																21.7	21	
1996 Wells			PA																3.9	1	
Secs 10 & 15-38-3W4	W- 37.500	DINA	PR																4.3	7	
1997 Wells			PA																1.4	0	
Secs 10 & 15-38-3W4	W- 37.500	DINA	PR																0.4	1	
1998 Wells			PA																0.2	0	
Sec 16-38-3W4	W-100.000	DINA	PR																10.1	11	
			PA																3.5	0	

Coyote Energy Inc.

Summary of Natural Gas Reserve Estimates
Constant Prices as of August 1, 2002
Total Proved & Probable Reserves

Area and Property	Company Interest %	Zones	Reserve Class	Volumetric Factors: Area acre	Net Pay ft	Por. %	Sw %	So %	Pres. psia	Temp. deg R	Z	Property Gross Natural Gas Reserves: Orig. Raw GIP mmcf	Rec. %	Orig. Raw Res. mmcf	Cum. Prod. mmcf	Rem. Raw. Res. mmcf	Surf. Loss %	Rem. Sales Res. mmcf	Company Share: Rem. Sales Res. mmcf	2002 Rate mcf/d	Reserves based on
West Provost (cont'd)																					
Secs 10 & 15-38-3W4	W- 37.500	REX	PR																16.6	16	
Rex Wells			PA																2.6	0	
00/11-24-037-02-W4/0	W- 37.500	VIK	PR		4.0	26.0	45.0		838	540	0.890			775	773	2	6.0	2	0.5	3	Perf
00/07-27-037-02-W4/0	W- 42.188	VIK	PR		3.3	22.0	50.0		673	540	0.894			525	385	140	6.0	131	55.5	13	Perf
02/06-11-038-03-W4/0	W- 28.125	VIK	PR		6.0	23.0	40.0		843	540	0.896			377	377						
00/14-12-038-03-W4/0	W- 37.500	CLY	PR		24.9	26.0	25.0		785	548	0.918			1600	1563	37	6.0	35	13.1	11	Perf
00/07-13-038-03-W4/0	W- 37.500	VIK	PR		4.9	24.0	40.0		810	531	0.875			1100	1003	97	6.0	91	34.2	17	Perf
00/06-14-038-03-W4/0	W- 37.500	VIK	PR		5.0	20.0	40.0		844	540	0.815			456	456						
00/07-15-038-03-W4/2	W- 37.500	VIK	PR											460	439	21	6.0	20	7.3	9	Perf
00/07-17-038-03-W4/0	W- 37.500	VIK	PR		3.0	21.0	40.0		802	540	0.875			360	343	17	6.0	16	6.0	6	Perf
00/07-18-038-03-W4/0	W- 37.500	VIK	PR		7.0	21.0	45.0		810	540	0.875			950	882	68	6.0	64	24.0	11	Perf
00/14-07-039-01-W4/0	W- 29.371	MCLAR	PR	213	18.7	30.0	30.0		800	540	0.900	2130	75.0	1598	1275	323	5.0	307	90.1	29	Perf
Bodo Compression Facility	P-100.000	ALL ZONES	PR																		
Subtotal			PR									2130		8201	7496	705		666	320.0	173	
			PA																19.1	2	
Subtotal Alberta			PR									3366		21854	19824	2030		1928	1647.1	897	
			PA											398		398		379	339.7	11	
TOTAL			PR									3366		21854	19824	2030		1928	1647.1	897	
			PA											398		398		379	339.7	11	

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Acreage Description	Ownership Information	
Alberta		
Bellshill Lake		
Fixed Battery Costs	OWNED BY COMPANY	
	Working Interest	100.00000 %
Northstar et al Hzl Bell 4-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Northstar et al Hzl 4C2 Bell 4-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Northstar ARC Hz 4C3 Bell 4-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Northstar etal Hzl Bell 5-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Northstar Hzl 5C2 Bell 5-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Northstar etal Hzl 5B Bell 5-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150 MIN 10.00 % MAX 15.00 %
Renaissance Bellh Lk 6-5-41-12 SW-5-41-12W4	OWNED BY COMPANY	
	Working Interest	40.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN

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Acreage Description	Ownership Information	
Northstar Hzl 10B Bell 10-5-41-12 NE-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar ARC Hz 12C Bell 12-5-41-12 NW-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar Hzl 13C2 Bell 13-5-41-12 NW-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar ARC 14B Bell 14-5-41-12 NW-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar Hzl 14C Bell 14-5-41-12 NW-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar Hzl 15A2 Bell 15-5-41-12 NE-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Government Royalty	 100.00000 % ALTA NEW CROWN
Northstar ARC Hz14C2 Bell 14-5-41-12 NE-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %
Northstar ARC 15A3 Bell 15-5-41-12 NE-5-41-12W4	OWNED BY COMPANY Working Interest ENCUMBRANCES Mineral Tax Gross Overriding Royalty	 100.00000 % ALTA MIN. TAX 1/150 MIN 10.00 % MAX 15.00 %

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Acreage Description	Ownership Information	
Bellshill Lake (cont'd)		
Northstar ARC 15B2	OWNED BY COMPANY	
Bell 15-5-41-12	Working Interest	100.00000 %
NE-5-41-12W4	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150
		MIN 10.00 %
		MAX 15.00 %
Northstar Hzl 16D	OWNED BY COMPANY	
Bell 16-5-41-12	Working Interest	100.00000 %
NE-5-41-12W4	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1/150
		MIN 10.00 %
		MAX 15.00 %
Northstar ARC 100 1C	OWNED BY COMPANY	
Bell 1-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 100 2A	OWNED BY COMPANY	
Bell 2-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 102 7D	OWNED BY COMPANY	
Bell 7-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 8C	OWNED BY COMPANY	
Bell 8-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 8D	OWNED BY COMPANY	
Bell 8-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 105 8C	OWNED BY COMPANY	
Bell 8-6-41-12	Working Interest	100.00000 %
SE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Northstar ARC 9D	OWNED BY COMPANY	
Bell 9-6-41-12	Working Interest	100.00000 %
NE-6-41-12W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Tiv et al Bell	OWNED BY COMPANY	
15-15BQ-41-12	Gross Overriding Royalty	1/150
Lsd 15-15-41-12W4		MIN 5.00 %
		MAX 15.00 %
	Percentage of production	75.00000 %
TIV et al 104 Bell	OWNED BY COMPANY	
15-15-41-12	Gross Overriding Royalty	1/150
NE-15-41-12W4		MIN 5.00 %
		MAX 15.00 %
	Percentage of production	75.00000 %

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Acreage Description	Ownership Information	
Bellshill Lake (cont'd)		
TIV et al Bell	OWNED BY COMPANY	
16B-15-41-12	Gross Overriding Royalty	1/150
NE-15-41-12W4		MIN 5.00 %
		MAX 15.00 %
	Percentage of production	75.00000 %
TIV et al 105 Bell	OWNED BY COMPANY	
16-15-41-12	Gross Overriding Royalty	1/150
NE-15-41-12W4		MIN 5.00 %
		MAX 15.00 %
	Percentage of production	75.00000 %
Black Creek		
Morrison et al	OWNED BY COMPANY	
Provost 6-20-41-3	Working Interest	100.00000 %
Sec 20-41-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Choice		
Choice Viking Gas	OWNED BY COMPANY	
Unit No. 1	Gross Overriding Royalty	7.10690 %
ACL Provost	OWNED BY COMPANY	
11-5-40-8	Gross Overriding Royalty	15.00000 %
Sec 5-40-8W4		
Husky Avid Provost	OWNED BY COMPANY	
7-7-40-8	Gross Overriding Royalty	6.25000 %
Sec 7-40-8W4		
ACL Provost	OWNED BY COMPANY	
10-7-40-8	Gross Overriding Royalty	15.00000 %
Sec 7-40-8W4		
David North		
Lloydminster O Unit	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	4.34000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1.47000 %
Sec 26 &	OWNED BY COMPANY	
NE-27-40-3W4	Working Interest	100.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	2.94000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.40000 %
Northstar Provost	OWNED BY COMPANY	
10-27-40-3	Working Interest	100.00000 %
Lsd-10-27-40-3W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1.47000 %

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Acreage Description	Ownership Information	
David North (cont'd)		
Northstar 10A	OWNED BY COMPANY	
Provost 10-27-40-3	Working Interest	100.00000 %
Lsd 10-27-40-3W4	ENCUMBRANCES	
	Freehold Royalty Payable	4.34000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	1.47000 %
Northstar 102	OWNED BY COMPANY	
Provost 15-27-40-3	Working Interest	100.00000 %
Lsd 15-27-40-3W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	7.90000 %
Hayter		
N-24-40-1W4	OWNED BY COMPANY	
Pre-1999 Wells	Working Interest	93.75000 %
N-24-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.10000 %
N-24-40-1W4	OWNED BY COMPANY	
1999 Wells	Working Interest	93.75000 %
N-24-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.10000 %
N-24-40-1W4	OWNED BY COMPANY	
2002 Wells	Working Interest	93.75000 %
N-24-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.10000 %
N-24-40-1W4	OWNED BY COMPANY	
Future Locations	Working Interest	93.75000 %
N-24-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.10000 %
Sec 25-40-1W4	OWNED BY COMPANY	
Pre-1998 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 25-40-1W4	OWNED BY COMPANY	
1998 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 25-40-1W4	OWNED BY COMPANY	
1999 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %

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Acreage Description	Ownership Information	
Hayter (cont'd)		
Sec 25-40-1W4	OWNED BY COMPANY	
2000 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 25-40-1W4	OWNED BY COMPANY	
2001 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 25-40-1W4	OWNED BY COMPANY	
2002 Wells	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 25-40-1W4	OWNED BY COMPANY	
Future Locations	Working Interest	94.51700 %
Sec 25-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
Sec 34-40-1W4	OWNED BY COMPANY	
Pre-1999 Wells	Working Interest	75.00000 %
Sec 34-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.50000 %
Sec 34-40-1W4	OWNED BY COMPANY	
1999 Wells	Working Interest	75.00000 %
Sec 34-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.50000 %
Sec 34-40-1W4	OWNED BY COMPANY	
2000 Wells	Working Interest	75.00000 %
Sec 34-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.50000 %
S&NE-35-40-1W4	OWNED BY COMPANY	
Pre-1998 Wells	Working Interest	100.00000 %
S&NE-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
S&NE-35-40-1W4	OWNED BY COMPANY	
1998 Wells	Working Interest	100.00000 %
S&NE-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %

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Acreage Description	Ownership Information	
Hayter (cont'd)		
S&NE-35-40-1W4	OWNED BY COMPANY	
1999 Wells	Working Interest	100.00000 %
S&NE-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
S&NE-35-40-1W4	OWNED BY COMPANY	
2000 Wells	Working Interest	100.00000 %
S&NE-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
S&NE-35-40-1W4	OWNED BY COMPANY	
2001 Wells	Working Interest	100.00000 %
S&NE-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	15.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.75000 %
NW-35-40-1W4	OWNED BY COMPANY	
Pre-2000 Wells	Working Interest	75.00000 %
NW-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	25.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.50000 %
NW-35-40-1W4		
2000 Wells		
14-35 wells	INTEREST NUMBER 1	
	OWNED BY COMPANY	
	Working Interest	75.00000 %
	Percentage of production	50.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	25.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.50000 %
03/12-35 well	INTEREST NUMBER 2	
	OWNED BY COMPANY	
	Working Interest	80.00000 %
	Percentage of production	50.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	23.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.50000 %
NW-35-40-1W4	OWNED BY COMPANY	
2001 Wells	Working Interest	75.00000 %
NW-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	25.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.50000 %
NW-35-40-1W4	OWNED BY COMPANY	
Future Locations	Working Interest	75.00000 %
NW-35-40-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	25.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.50000 %
S-36-40-1W4	OWNED BY COMPANY	
GOR Wells	Gross Overriding Royalty	7.50000 %
S-36-40-1W4		

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Acreage Description	Ownership Information	
Hayter (cont'd)		
Norcenlnt et al	OWNED BY COMPANY	
Hayter 9-34-40-1	Working Interest	75.00000 %
Lsd 9-34-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.50000 %
UPRI et al 15D	OWNED BY COMPANY	
Hayter 15-34-40-1	Working Interest	75.00000 %
NE-34-40-1W4	ENCUMBRANCES	
	Government Royalty	ALTA HEAVY CROWN
	Gross Overriding Royalty	0.50000 %
Norcenlnt CS Hayter	OWNED BY COMPANY	
1B-3-41-1	Working Interest	75.00000 %
SE-3-41-1W4	ENCUMBRANCES	
	Freehold Royalty Payable	22.50000 %
	Mineral Tax	ALTA MIN. TAX
Mestikow		
All Company Wells	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	2.00000 %
Thompson Lake		
Thompson Lake		
Total Field		
Lsds 1, 8-10, 15 & 16-	INTEREST NUMBER 1	
34-40-11W4	OWNED BY COMPANY	
Lsds 2-7, 10-15,-	Working Interest	98.83750 %
Lsds 1-8, 10 & 11-	Tract Factor	75.60000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Lsds 1, 4-6, 8, 13,	INTEREST NUMBER 2	
Lsds 3 & 4-1-41-11W4	OWNED BY COMPANY	
Lsds 1& 8-3-41-11W4	Working Interest	100.00000 %
NW-35-40-11W4	Tract Factor	17.66000 %
Lsds 2-36-40-11W4	ENCUMBRANCES	
	Freehold Royalty Payable	10.00000 %
	Mineral Tax	ALTA MIN. TAX
Lsd 10-25-40-11W4	INTEREST NUMBER 3	
	OWNED BY COMPANY	
	Working Interest	99.31270 %
	Tract Factor	0.49000 %
	Percentage of production	19.50000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Lsd 10-25-40-11W4	INTEREST NUMBER 4	
	OWNED BY COMPANY	
	Working Interest	99.31270 %
	Tract Factor	0.49000 %
	Percentage of production	80.50000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	10.00000 %
	Mineral Tax	ALTA MIN. TAX

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Acreage Description	Ownership Information	
Thompson Lake (cont'd)		
Lsd 15-25-40-11W4	INTEREST NUMBER 5	
	OWNED BY COMPANY	
	Working Interest	98.83750 %
	Tract Factor	6.25000 %
	Percentage of production	46.25000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	10.00000 %
	Mineral Tax	ALTA MIN. TAX
Lsd 15-25-40-11W4	INTEREST NUMBER 6	
	OWNED BY COMPANY	
	Working Interest	98.83750 %
	Tract Factor	6.25000 %
	Percentage of production	53.75000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Husky 104 Provost	OWNED BY COMPANY	
10-29-40-11	Working Interest	25.00000 %
Sec 29-40-11W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
West Provost		
Secs 10 & 15-38-3W4	OWNED BY COMPANY	
Pre 1995 Wells	Working Interest	37.50000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Secs 10 & 15-38-3W4	OWNED BY COMPANY	
1995 Wells	Working Interest	37.50000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Secs 10 & 15-38-3W4		
1996 Wells		
Lsds 9&16 Sec 10	INTEREST NUMBER 1	
	OWNED BY COMPANY	
	Working Interest	37.50000 %
	Percentage of production	97.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Remaining Lands	INTEREST NUMBER 2	
	OWNED BY COMPANY	
	Working Interest	37.50000 %
	Percentage of production	3.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Secs 10 & 15-38-3W4		
1997 Wells		
Lsds 9&16 Sec 10	INTEREST NUMBER 1	
	OWNED BY COMPANY	
	Working Interest	37.50000 %
	Percentage of production	97.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN

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Acreage Description	Ownership Information	
West Provost (cont'd)		
Remaining Lands	INTEREST NUMBER 2	
	OWNED BY COMPANY	
	Working Interest	37.50000 %
	Percentage of production	3.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Secs 10 & 15-38-3W4	OWNED BY COMPANY	
1998 Wells	Working Interest	37.50000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Sec 16-38-3W4	OWNED BY COMPANY	
	Working Interest	100.00000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Secs 10 & 15-38-3W4	OWNED BY COMPANY	
Rex Wells	Working Interest	37.50000 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcenint et al	OWNED BY COMPANY	
Provost 11C-24-37-2	Working Interest	37.50000 %
Sec 24-37-2W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcenint et al		
Provost 7-27-37-2		
S&NE-27-37-2W4	INTEREST NUMBER 1	
	OWNED BY COMPANY	
	Working Interest	42.18750 %
	Percentage of production	75.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	26.66667 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.44444 %
NW-27-37-2W4	INTEREST NUMBER 2	
	OWNED BY COMPANY	
	Working Interest	42.18750 %
	Percentage of production	25.00000 %
	ENCUMBRANCES	
	Mineral Tax	ALTA MIN. TAX
Norcenint Dome et al	OWNED BY COMPANY	
Prov. 6-11-38-3	Working Interest	28.12500 %
Sec 11-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Norcenint et al	OWNED BY COMPANY	
Provost 14D-12-38-3	Working Interest	37.50000 %
Sec 12-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %

Coyote Energy Inc.

List Of Interests and Encumbrances
Constant Prices as of August 1, 2002
Total Reserves

Acreage Description	Ownership Information	
West Provost (cont'd)		
Norcen et al Provost	OWNED BY COMPANY	
7-13-38-3	Working Interest	37.50000 %
Sec 13-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcenint et al	OWNED BY COMPANY	
Provost 6B-14-38-3	Working Interest	37.50000 %
Sec 14-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcenint et al	OWNED BY COMPANY	
Provost 7-15-38-3	Working Interest	37.50000 %
Sec 15-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
Norcen Int et al	OWNED BY COMPANY	
Provost 7-17-38-3	Working Interest	37.50000 %
Sec 17-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcenint et al	OWNED BY COMPANY	
Provost 7-18-38-3	Working Interest	37.50000 %
Sec 18-38-3W4	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	1.00000 %
Norcen et al Hayter		
14-7-39-1		
SE-7-39-1W4	INTEREST NUMBER 1	
	OWNED BY COMPANY	
	Working Interest	29.37100 %
	Percentage of production	25.00000 %
	ENCUMBRANCES	
	Freehold Royalty Payable	25.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.26667 %
SW-7-39-1W4	INTEREST NUMBER 2	
Frac NW-7-39-1W4	OWNED BY COMPANY	
(54.76 Ha)	Working Interest	29.37100 %
Frac NE-7-39-1W4	Percentage of production	68.18750 %
(55.8 Ha)	ENCUMBRANCES	
	Freehold Royalty Payable	20.00000 %
	Mineral Tax	ALTA MIN. TAX
	Gross Overriding Royalty	0.26667 %
	Gross Overriding Royalty	0.63838 %
Frac N-7-39-1W4	INTEREST NUMBER 3	
(17.44 Ha)	OWNED BY COMPANY	
	Working Interest	29.37100 %
	Percentage of production	6.81250 %
	ENCUMBRANCES	
	Government Royalty	ALTA NEW CROWN
	Gross Overriding Royalty	0.26667 %
Bodo Compression	OWNED BY COMPANY	
Facility	Working Interest	100.00000 %

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

Attention Business/Financial Editors:
Harvest Energy Trust Confirms March 17th, 2003 Cash Distribution of $0.20 Per Unit

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CALGARY, Feb. 18 /CNW/ - Harvest Energy Trust ("Harvest") (TSX: HTE.UN) announces that a cash distribution of $0.20 per trust unit will be paid on March 17th, 2003 to Unitholders of record on February 28th, 2003. The trust units of Harvest are expected to commence trading on an ex-distribution basis on February 26th, 2003. This distribution amount represents Distributable Cash earned in the month of February 2003.

Harvest Energy Trust is a Calgary based oil and natural gas trust that strives to deliver stable monthly cash distributions to its Unitholders through its strategy of acquiring, enhancing and producing crude oil, natural gas and natural gas liquids. Harvest's assets, comprised of high quality medium and heavy gravity crude oil properties in East Central Alberta, and its hands on operating strategy underpin Harvest's objective to deliver superior economic returns to Unitholders. Harvest's strategy is to retain up to 50% of its Cash Available for Distribution for capital reinvestment in the form of existing property enhancement and new property acquisitions while maintaining a high rate of cash distributions. Harvest currently operates approximately 99% of its production, enabling it to pursue additional asset growth through property optimization and enhancement.

ADVISORY: Certain information regarding Harvest Energy Trust and Harvest Operations Corp. including management's assessment of future plans and operations, may constitute forward-looking statements under applicable securities law and necessarily involve risks associated with oil and natural gas exploration, production, marketing and transportation such as loss of market, volatility of prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources; as a consequence, actual results may differ materially from those anticipated in the forward- looking statements.

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(HTE.UN)

CO: Harvest Energy Trust
ST: Alberta
IN: OIL
SU: DIV

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