U.S. Securities and Exchange Commission
Washington, D.C. 20549
Form 40-F

[ ] Registration statement pursuant to section 12 of the Securities Exchange Act of 1934

or

[X] Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended **December 31, 2002** Commission File Number **00-115124**

NCE PETROFUND
(Exact name of Registrant as specified in its charter)

Ontario, Canada
(Province or other jurisdiction of incorporation or organization)

1331
(Primary Standard Industrial Classification Code Number (if applicable))

Not Applicable
(I.R.S. Employer Identification Number (if applicable))

600, 444 – 7th Avenue S.W.

Calgary, Alberta Canada T2P 0X8

(403) 218-8625

(Address and telephone number of Registrant's principal executive offices)

CT Corporation System

1633 Broadway, New York, New York USA 10019

(212) 664-1666
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
Trust Units	**The American Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act.

__________________________**None**____________________________
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

______________________________**None**_____________________________
(Title of Class)

For annual reports, indicate by check mark the information filed with this Form:

[**X**] Annual information form [**X**] Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

______**54,107,764**_______

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the filing number assigned to the Registrant in connection with such Rule.

Yes _____ 82-________ No _**X**___

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes __**X**___ No_____

NCE PETROFUND

RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2002

MARCH 10, 2003

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1) INFORMATION PREPARED BY NCEP MANAGEMENT

The information contained in this annual information form has been prepared by NCEP Management in its capacity as manager of the Trust.

2) FORWARD-LOOKING STATEMENTS

Some of the statements contained herein including, without limitation, financial and business prospects and financial outlooks, may be forward-looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will" "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions have been used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, changes in general economic and market conditions and other risk factors. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, we cannot assure that actual results will be consistent with these forward looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and we assume no obligation to update or revise them to reflect new events or circumstances.

Forward-looking statements and other information contained herein concerning the oil and gas industries and our general expectations concerning these industries are based on estimates prepared by us using data from publicly available industry sources as well as from reserve report, market research and industry analysis and on assumptions based on data and knowledge of these industries which we believe to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While we are not aware of any misstatements regarding any industry data presented herein, the industries involve risks and uncertainties and are subject to change based on various factors.

3) CONSOLIDATION OF TRUST UNITS

On July 6, 2001, the Trust Units were consolidated on a one-for-three basis. All relevant figures, including Trust Units outstanding, net income per Trust Unit and distributions per Trust Unit, have been restated to reflect this consolidation.

4) DOLLAR AMOUNTS

Unless otherwise specified, all dollar amounts set out in this annual information form are in Canadian dollars.

5) GLOSSARY OF TERMS

The following terms used herein have the meanings set out below:

AECO:	The regional pricing hub for natural gas located at the storage facilities of Alberta Energy Company near Medicine Hat, Alberta.
bbl:	Barrel.
bcf:	Billions of cubic feet.
Board of Directors:	The board of directors of NCEP.
boe:	Barrels of oil equivalent, using a conversion factor of 6 mcf of gas being equivalent to one bbl of oil and one bbl of NGLs being equivalent to one bbl of oil.
boepd:	Barrels of oil equivalent per day.
bpd:	Barrels of oil or NGLs per day.
Established Reserves:	Proved reserves plus 50% of probable reserves.
Executive Committee:	The executive committee of the Board of Directors of NCEP, comprised of three members of the Board of Directors, of whom two are nominees of the Unitholders and one is a nominee of NCEP Management.
gj:	Gigajoule.
GLJ:	Gilbert Laustsen Jung Associates Ltd., independent oil and gas reservoir engineers of Calgary, Alberta.
GLJ Report:	The report prepared by GLJ dated March 3rd, 2003 with respect to the petroleum, natural gas and NGL reserves of NCEP effective as at December 31, 2002.
Internalization Transaction:	The proposed transaction to be considered at the annual and special meeting of Unitholders to be held on or about April 16, 2003 under which, if approved, management of the Trust would be internalized through the acquisition by NCEP of all of the issued and outstanding shares of NCEP Management and the consequent elimination of all management, acquisition and disposition fees payable to NCEP Management.
Management Agreement:	The amended and restated management, advisory and administration agreement made as of January 1, 2002 among NCEP, the Trust and NCEP Management.
mbbls:	Thousands of barrels.
mboe:	Thousands of barrels of oil equivalent.
mcf:	Thousands of cubic feet.
mcfpd:	Thousands of cubic feet per day.
mlt:	Thousand long tons.
mmboe:	Millions of barrels of oil equivalent.
mmcf:	Millions of cubic feet.
mmcfpd:	Millions of cubic feet per day.
NCEP:	NCE Petrofund Corp.
NCEP Management:	NCE Petrofund Management Corp.

netback:	The amount received from the sale of a barrel of oil or barrel of oil equivalent after deduction of operating costs and royalty payments.
NGLs:	Natural gas liquids.
NMSI:	NCE Management Services Inc.
properties:	The interests, including working interests and unit interests, in petroleum and natural gas rights held by NCEP.
Royalty Agreement:	The amended and restated royalty agreement dated as of May 31, 2002 between NCEP and the Trust.
Special Resolution:	A resolution approved in writing by Unitholders holding not less than 66 2/3% of the outstanding Trust Units or passed by a majority of not less than 66 2/3% of the votes cast, either in person or by proxy, at a meeting of the Unitholders called for the purpose of approving such resolution.
Tax Act:	Income Tax Act (Canada), as amended.
TSX:	Toronto Stock Exchange.
Trust:	NCE Petrofund.
Trustee:	Computershare Trust Company of Canada, as trustee of the Trust.
Trust Indenture:	The amended and restated trust indenture made as of May 31, 2002 between NCEP and Computershare Trust Company of Canada.
Trust Unit or Unit:	A trust unit created pursuant to the Trust Indenture and representing a fractional undivided interest in the Trust.
Unanimous Shareholder Agreement:	The unanimous shareholder agreement made as of November 1, 2000 among NCEP, the Trust and NCEP Management.
Unitholder:	A holder from time to time of Trust Units.

NCE PETROFUND
ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2002
DATED MARCH 10, 2003

NCE PETROFUND

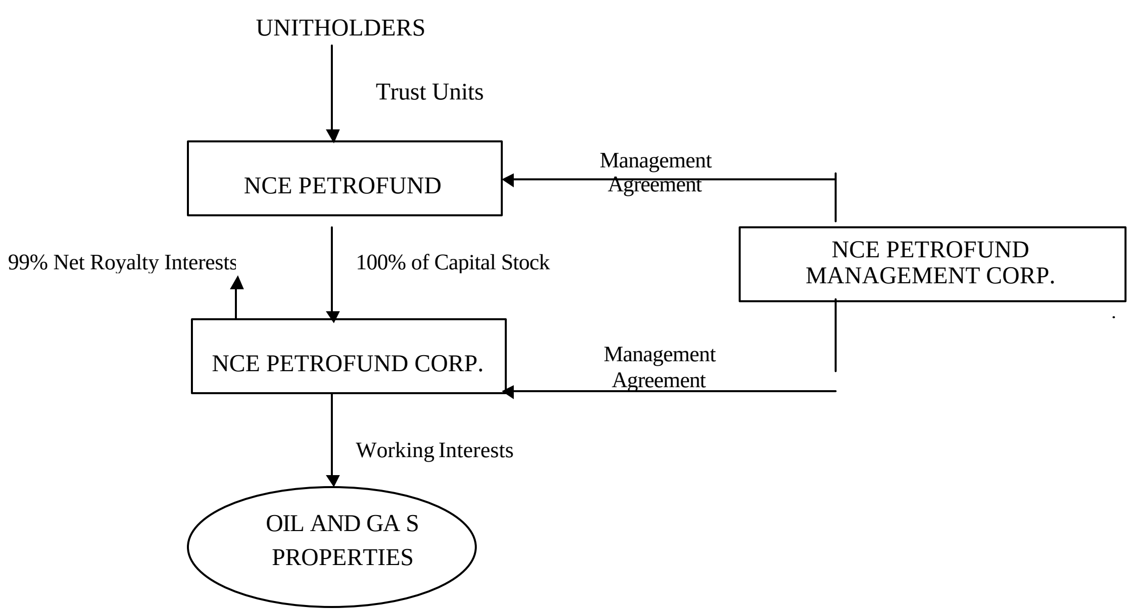
a. The Trust

The Trust is an open-ended investment trust created under the laws of the Province of Ontario on December 18, 1988 under the name "NCE Petrofund I". Active operations commenced March 3, 1989. On July 4, 1996, the name of the Trust was changed to its present name, "NCE Petrofund". Effective September 7, 2001, the Trustee became the trustee of the Trust. The Trust is currently governed by the Trust Indenture.

The executive office of the Trust is located at 130 King Street West, Suite 2850, Toronto, Ontario, M5X 1A4. The operations and head office of the Trust is located at Suite 600, 444 - 7th Avenue S.W., Calgary, Alberta, T2P 0X8. If the Internalization Transaction is completed, the Trust's operations will be consolidated and managed from the Trust's Calgary office following a transition period which will end on December 31, 2003.

The Trust's primary source of income is from 99% net royalty interests granted by NCEP, its wholly-owned subsidiary. NCEP is a corporation incorporated under the laws of Alberta. NCEP acquires, manages and disposes of petroleum and natural gas rights and royalties and related property rights and interests located primarily in western Canada. In addition, NCEP may acquire royalties or other property interests or securities of other resource issuers. The Trust may also purchase directly or indirectly securities of oil and gas companies, oil and gas properties and other related assets.

The following chart shows the structure of the Trust at the date hereof:



Each Trust Unit represents an equal undivided beneficial interest in the assets of the Trust. Historically, the Trust's activities have been focused on the acquisition of net royalties from NCEP. For each property for which a net royalty is granted by NCEP, the Trust receives 99% of the revenue generated by the property net of operating costs, management fees, debt service charges, general and administrative costs and certain other taxes and charges. The Trust distributes to its Unitholders a majority of its cash flow in the form of monthly distributions, part of which is on a tax-advantaged basis. Cash flow includes royalty income and may include cash flow generated by properties and interests not currently subject to the Trust's net royalty interests.

The Trust was initially formed as a closed-end royalty trust for the purposes of acquiring royalty interests from NCEP. Effective February 2, 1999, the Trust was converted to an open-ended investment trust. The Trust Indenture, Royalty Agreement and related agreements were amended to: (i) permit the Trust and NCEP to acquire, directly or indirectly, interests in resource issuers and/or resource properties and other related assets; (ii) remove certain financing restrictions applicable to the Trust and NCEP to permit the Trust and NCEP, subject to certain limitations, to raise or issue capital in connection with, or to finance, such acquisitions, either through the issuance of Trust Units or other equity or debt securities of the Trust or NCEP or through borrowing; and (iii) provide that Unitholders have the right to cause the Trust to redeem their Trust Units in certain circumstances.

Effective November 1, 2000, the Trust acquired all of the issued and outstanding shares of NCEP from a subsidiary of NCEP Management for nominal consideration, resulting in NCEP becoming a wholly-owned direct subsidiary of the Trust. This change simplified the structure of the Trust and related entities and allows the Trust to present consolidated financial statements which fully reflect the assets and liabilities of the Trust and NCEP.

In conjunction with NCEP becoming a wholly-owned subsidiary of the Trust, the corporate governance of the Trust was changed so that the stewardship of the Trust and NCEP is now undertaken by the Board of Directors of NCEP in consultation with NCEP Management, rather than by a subsidiary of NCEP Management in consultation with NCEP Management as was the case previously.

b. Management of the Trust

The Trust has entered into the Management Agreement, under which it has retained the services of NCEP Management to identify, assess and assist in the acquisition, disposition and ongoing management of the Trust's properties and to administer its net royalties and other assets. See "Governance of the Trust and NCEP - Management Agreement" and "Proposed Internalization of Management".

Proposed Internalization of Management

As announced on March 10, 2003, the Trust has entered into an agreement to internalize its management structure such that NCEP Management, the manager of the Trust, would become a wholly owned subsidiary of NCEP. Completion of the transaction is subject to unitholder and regulatory approval. If completed, all management, acquisition and disposition fees payable to NCEP Management would be eliminated effective January 1, 2003. The Internalization Transaction will cost approximately $29 million, subject to adjustment as described below, and will be effected in the following manner:

- Prior to the closing, NCEP Management will acquire NMSI (which employs all of the Calgary-based personnel who provide services to the trust and NCEP on behalf of NCEP Management).

- At the closing, NCEP will purchase all of the issued shares of NCEP Management from Petro Assets Inc. for $23.6 million, subject to adjustment. At closing, Petro Assets Inc. will be owned by the Driscoll Family Trust (a trust established for the family of John F. Driscoll, Chairman and Chief Executive Officer of NCEP) and by John F. Driscoll.

- The purchase price for the shares of NCEP Management will be satisfied by the issuance of 1,939,147 exchangeable shares of NCEP ("Exchangeable Shares"), plus a cash amount per Exchangeable Share equal to the distributions paid or payable per Trust Unit by the Trust to Unitholders of record from and after January 1, 2003 up to and including the closing date. Initially each Exchangeable Share will be exchangeable into one Trust Unit. The Exchange rate will be adjusted from time to time to reflect distributions paid on each Trust Unit after the closing date. Each Exchangeable Share was ascribed a value of $12.1703, representing the weighted average trading price of the Trust Units over the 10 trading days, ending on March 4, 2003 on the TSX.

- At closing, NCEP will pay $3.4 million in cash to fund the repayment of indebtedness owing by NCEP Management. In addition, it is a condition to the closing of the Internalization Transaction that NCEP will cause NMSI to deliver to certain senior executives of NCEP Management $780,000 in cash and 100,244 Trust Units (plus an amount per Trust Unit equal to the distributions per Trust Unit paid to holders of record of Trust Units during the period commencing on January 1, 2003 and ending on the closing date).

Upon the closing of the Internalization Transaction, the Trust's operations will be consolidated and managed from NCEP's offices in Calgary, Alberta. To ensure an orderly transition of the services currently provided by NCEP Management through its office in Toronto, Ontario, upon closing Sentry Select Capital Corp. ("Sentry") will enter into an agreement effective January 1, 2003, with the Trust, NCEP and NCEP Management to provide certain of these services to the Trust and NCEP at Sentry's cost until December 31, 2003, subject to a maximum cost of $2 million. After December 31, 2003, Sentry will no longer provide such services. Sentry is currently an affiliate of NCEP Management and is a company in which John F. Driscoll owns a controlling interest.

The elimination of the fees payable under the Management Agreement, along with the reduction in general and administrative costs expected from the consolidation of the ongoing management structure in Calgary, Alberta are expected to improve the long term operating cost structure of the Trust and NCEP.

c. Strategy

The Trust's objective is to maximize cash flow for distribution to its Unitholders. The Trust intends to execute its business strategy by:

- continuing to pursue selected acquisitions that meet its portfolio acquisition criteria;
- continuing to develop its existing properties to enhance production and increase reserves;
- maintaining a balanced portfolio of geographically and geologically diversified oil and gas properties;
- controlling costs through efficient operation of existing and acquired properties;
- maintaining a capital structure that provides flexibility in accessing debt and capital markets; and
- managing commodity price risk when appropriate through hedging agreements that will increase the level of predictability in prices for its oil and gas production.

d. Acquisition Criteria

The Royalty Agreement requires NCEP to comply with the following criteria and procedures before purchasing a property:

- Properties will be acquired with the objective of providing Unitholders with an average annual net yield after all costs but before income taxes of at least 15% over the first five years from the date of acquisition and at least a 15% internal rate of return over the life of the reserves after all costs but before income taxes.
- At least 70% of the purchase price of all gas and oil properties must be represented by proved reserves.
- At least 50% of the properties purchased will be estimated to be producing for 20 years following their acquisition, based on independent engineering reports.
- Generally accepted industry practices and procedures will be employed in investigating title to the properties.
- No property having an acquisition cost of $10 million or more will be acquired unless a report has been obtained from an independent engineering consultant.
- Where the acquisition price of a property has not been determined by arm's length negotiations, the price will be no greater than the fair market value of the property at the time of acquisition as determined by an independent engineering consultant.
- The amount of anticipated future capital expenditures for a property will not be significant and such expenditures will be of the type which are intended to maintain, realize or improve production from the properties.
- Properties may not be acquired from or sold to NCEP Management, its associates or affiliates or other funds managed by NCEP Management, except that NCEP may enter into farmout arrangements with NCEP Management, its associates or affiliates or other funds managed by NCEP Management or funds, partnerships or other entities managed by corporations or entities controlled by John F. Driscoll or The Driscoll Family Trust, so long as such farmout arrangements are completed on terms which are no less favourable to NCEP as those which could be obtained on arm's length terms and an independent oil consultant has provided a report confirming the same.

In addition to the above, the Trust's properties, in aggregate, must be geographically and geologically diversified. Not more than 25% of the asset value of all the Trust's properties may be attributable to a single reservoir. The Trust's properties will be located primarily in western Canada (namely, British Columbia, Alberta, Saskatchewan and Manitoba). At the time of each acquisition, after giving effect to the proposed acquisition, not more than 10% of the asset value of the Trust's properties may be represented by properties located outside of western Canada. All of the Trust's properties must be located in Canada. Asset value is the fair market value of the property as estimated by the Board of Directors based on the most recent independent engineering report respecting such property. If there is a material change to such property, a new report will be prepared and used to determine the fair market value of such property.

The foregoing acquisition criteria apply only to the Trust's property acquisitions. The foregoing criteria may only be amended by Special Resolution. Although the Trust is not required to apply these criteria when it acquires oil and gas companies, as a matter of policy, the Trust is generally guided by the same criteria. In addition, the Trust Indenture requires that any such acquisition will be subject to standard industry due diligence procedures and a favourable valuation report.

In the event of a sale of a property, the Board of Directors must make a determination as to whether the proceeds of the sale will be reinvested in additional properties or assets or will be distributed to the Unitholders, in each case after repayment of such portion of the outstanding indebtedness as NCEP may determine. A sale involving more than 35% of the asset value of all properties requires the approval of the Unitholders by Special Resolution.

e. Key Factors for Success

The success of the Trust in meeting its objectives lies in management's ability to positively influence three main factors:

6) Identify, pursue and acquire oil and gas properties and/or companies at prices which meet the acquisition criteria previously mentioned and add value to the Trust;
7) Cost effectively add or extend reserves with farmouts and internal development and drilling; and,
8) Manage and contain costs.

NCEP's ability to achieve these three factors depends mainly on the experience, knowledge, and capability of the management team. In addition to the factors over which management has influence, there are numerous other factors beyond management's control which will influence the success of the organization. These other potential risks are identified in the Risk Factors section of this document.

Outlook for Next Year

Looking ahead into 2003, we intend to continue with our acquisition strategy to add value through the purchase of long life production. It is our expectation that more properties will come available on the market as a result of non-core property divestitures by the larger E&P companies, and NCEP will participate in the review and evaluation process of these properties. We will also continue with our drilling, developme nt and optimization programs as a complement to our base strategy. We expect to continue to grow but we are more focused on providing good yields to our unitholders while, at the same time, maintaining unit value.

9) GENERAL DEVELOPMENT OF THE BUSINESS OF THE TRUST

a. Financings

The Trust was established in 1988 to raise funds for the purposes of acquiring royalties from NCEP. During the last three years, the Trust completed the following public offerings of Trust Units:

Date	Gross Proceeds
April, 2000	$27,500,000
August, 2000	51,750,000
April, 2001	74,800,000
August, 2001	51,750,000
November, 2001	40,800,000
March, 2002	59,800,000

b. Acquisitions

i. 2000

In 2000, NCEP expended approximately $89 million on new acquisitions. In addition, NCEP expended approximately $19 million to increase interests in existing properties.

1. Weyburn

Effective January 1, 2000, NCEP acquired a 7% working interest in the Weyburn Unit located in southeast Saskatchewan. The purchase price was $48.3 million ($46.9 million after adjustments) and was funded through a combination of available cash ($1 million), borrowings under NCEP's credit facilities ($42.6 million) and a property exchange with the vendor of the Weyburn property ($3.3 million). The acquisition added approximately 11.8 million boe of Established Reserves and 1,379 boepd of production.

2. Pacific Cassiar

On December 1, 2000, NCEP acquired Pacific Cassiar Limited, a public company, and three private companies that held interests in the same oil and gas properties as held by Pacific Cassiar. The purchase price was $32.5 million of which $323,000 was allocated to working capital and the balance to oil and gas properties. The acquisition was funded through NCEP's credit facility. The acquisition added approximately 2.4 million boe of Established Reserves and approximately 800 boepd of production.

3. Other

In addition, NCEP acquired property interests in six separate transactions that, in aggregate, added approximately 5 million boe of Established Reserves and 1,000 boepd of production. The cost of these acquisitions totalled $27.1 million. The majority of these acquisitions involved interests in properties where NCEP held existing interests.

ii. 2001

1. Apache Properties

Effective January 1, 2001, NCEP purchased a 50% interest in a diverse group of oil and gas producing properties from a major oil and gas company for $23.8 million. The acquisition added 3.7 mmboe of Established Reserves, at a cost of $6.40 per boe, and 702 boepd of production. The reserves and production were 57% gas.

2. Strachan

On March 6, 2001, NCEP closed the purchase of an interest in a gas producing property in Strachan, Alberta from a major Canadian oil and gas producer. The purchase price was $9.5 million. The acquisition added approximately 1.2 million boe of Established Reserves and 270 boepd of production.

3. Magin Energy Inc.

In July, 2001, NCEP completed the acquisition of Magin Energy Inc., a company listed on the TSX. The purchase price consisted of $58.6 million in cash and 8.5 million Trust Units. NCEP also assumed $43.7 million of debt, including negative working capital, the outstanding bank loan and capital leases, and incurred other transaction costs of $11.8 million (comprised principally of brokers' fees, severance costs and an acquisition fee of $4.4 million paid to NCEP Management) and received net stock option proceeds of $6.9 million. In consideration for the delivery of such Trust Units, the Trust received promissory notes of NCEP in the aggregate amount of $157.1 million. Magin Energy was amalgamated into NCEP and a royalty was granted in the Magin Energy properties in favour of the Trust. Cash flow from the Magin Energy properties are paid to the Trust as royalty income and as payment on the promissory notes.

Magin Energy was a Canadian oil and gas exploration and production company whose principal areas of operation were Alberta and Saskatchewan. Prior to the completion of the acquisition of Magin Energy, Magin Energy sold its interest in a property known as the Copton property.

As a result of the acquisition, NCEP acquired Established Reserves of 29 mmboe and production of 9,000 boepd at the time of the acquisition at an effective purchase price of $9.17 per Established Reserves boe. The reserves and production were 50% gas. The reserve life index for the Magin Energy properties at December 31, 2000 was 7.5 years. Over 90% of the Magin Energy properties were operated by Magin Energy, and are now operated by NCEP. The Magin Energy properties are located in areas with year round road access and this, along with the multiple geological zone potential, is expected to help keep development costs at or below the average for the area. As a result of the Magin Energy acquisition, NCEP also acquired undeveloped land of 345,080 net (460,287 gross) acres.

4. Swan Hills

On December 31, 2001, NCEP acquired a 1.4% interest in the Swan Hills Unit #1 in north central Alberta from a large independent U.S. oil and gas company for $7.5 million. The acquisition added approximately 2.2 million boe of Established Reserves and 300 boepd of production.

Effective November 1, 2001, NCEP acquired a 1.2% interest in the Swan Hills Unit #1 along with other minor interests in the Swan Hills area from a large independent U.S. oil and gas company. The transaction closed on February 26, 2002. The purchase price was $12.3 million. The acquisition added approximately 2.5 million boe of Established Reserves and 400 boepd of production.

2002

Central Alberta

Effective March 2002 NCEP acquired two gas properties and two oil properties in Central Alberta for $40.2 million. Three of the properties are unitized and one is operated. Net established reserves acquired were estimated at 8.8 million boe and net production at date of acquisition was approximately 1,800 boepd consisting of 67% oil. The properties had a reserve life index in excess of 13 years.

NCE Energy Trust

On May 30, 2002 NCEP completed the acquisition of NCE Energy Trust, a royalty trust listed on the TSX. The acquisition was completed through the exchange of 0.2325 units of NCEP for each unit of NCE Energy Trust. The total price of the transaction was $140.1 million comprised of 7.6 million Trust Units with an assigned value of $98.6 million, the assumption of $39.5 million of debt and negative working capital, and transaction costs of $2.0 million. A non-cash amount of $27.1 million was added to oil and gas properties to reflect the difference between the cost and the tax basis of the properties acquired.

As a result of the acquisition, NCEP acquired Established Reserves of 13.9 mmboe and production of 5,300 boepd at an effective purchase price of $10.08 per boe and $26,400 per boepd. The reserves and production were approximately 50% gas and the reserve life index for these properties was 7.2 years. The NCE Energy Trust properties are located in British Columbia, Alberta and Saskatchewan. Over 50% of the production was operated by NCE Energy Trust and is now operated by NCEP. Approximately 30% of the production and reserves in NCE Energy Trust were common with or adjacent to NCEP properties.

The Trust and NCE Energy Trust were managed by affiliated management companies. Although it was concluded that the acquisition was not a "related party transaction" within the meaning of certain Canadian securities laws, because of the fact that the Trust and NCE Energy Trust were managed by management companies that were under common control, the acquisition was effectively treated as a related party transaction. As such, certain valuation, disclosure and minority approval requirements were complied with. A valuation of each of the Trust and NCE Energy Trust was completed by Sayer Securities Limited. The valuation report, dated April 19, 2002, concluded that a reasonable range of the fair market value for the units of the Trust was a low of $11.39 and a high of $14.29 and that a reasonable range of the fair market value for the units of NCE Energy Trust was a low of $2.59 and a high of $3.29. The acquisition was negotiated on an arm's length basis on behalf of the Trust and NCE Energy Trust by a special committee of the board responsible for each respective entity.

ATCO

On December 31, 2002 NCEP acquired producing gas properties in the Fort Saskatchewan, Alberta area from ATCO Gas for $31.5 million. NCEP will operate the properties and holds an average 95% working interest. Current production net to NCEP is approximately 6 mmcfpd and the Established Reserves acquired were approximately 19 bcf.

10) BUSINESS AND PROPERTIES

NCEP acquires, manages and disposes of petroleum and natural gas property rights and interests. As of December 31, 2002, NCEP's principal properties were located in Alberta, British Columbia, Manitoba and Saskatchewan. NCEP primarily produces light and medium oil, natural gas and natural gas liquids. As at December 31, 2002, NCEP's asset base included Established Reserves (before royalties) of 46,701 mbbls of oil, 274 bcf of natural gas and 6,997 mbbls of natural gas liquids based on escalated prices and cost assumptions, and an inventory of undeveloped land totalling 676,943 gross (379,134 net) acres. See "Business and Properties - Gross and Net Reserves Summary" and "Business and Properties - Undeveloped Land".

One of NCEP's ongoing objectives is to enhance reserves and production through acquisitions. With respect to acquisitions, NCEP operates in a competitive environment with both large and small competitors.

In 2002, NCEP acquired new properties for a total purchase price of $185 million and expended approximately $35 million to increase interests in existing properties. NCEP disposed of properties for total proceeds of $30 million. In addition, NCEP incurred approximately $40 million mainly for drilling, well equipment and facility costs.

The following is a summary of NCEP's properties as at December 31, 2002:

i. Weyburn, Saskatchewan

NCEP owns a 7% working interest in the Weyburn Unit, which is operated by Encana Corporation. Located approximately 20 miles south of the city of Weyburn in southeast Saskatchewan, the Weyburn property is one of the largest oil pools in western Canada. This property has a very long reserve life index of greater than 20 years, and an economic life of greater than 40 years. Enhanced oil recovery through carbon dioxide injection and waterflooding are contributing to the long life of the pool. The Weyburn Unit has facilities to treat emulsion, inject produced water, inject produced gas and inject carbon dioxide. NCEP's working interest production from this property averaged 1,463 boepd in 2002. The Established Reserves for this property as at December 31, 2002 were 10,422 mboe, comprised of 10,287 mbbls of oil and 134 mbbls of NGLs.

ii. Pembina, Alberta

The Pembina area, which includes both operated and non-operated properties, is located approximately 60 miles southwest of Edmonton, centered around Drayton Valley. NCEP holds various working interests in the properties included in this area, ranging from 100% at Alder Flats to less than 1% in the Lobstick Cardium Unit. NCEP operated properties include Alder Flats, Cynthia, Lodgepole, Pembina, Rose Creek and Warburg. Partner operated properties include the North Pembina Cardium Unit (9.5%), Berrymoor Cardium Unit (11.8%), Pembina Cardium Unit #7 (19.3%), Pembina Easyford Cardium Unit #1 (9.9%), Lobstick Cardium Unit (0.8%) and the Pembina Knobhill Belly River Unit #2 (8.1%). Each of the units and properties have facilities to treat produced emulsion and dispose of produced water. The majority of the production from this area comes from the Cardium zone. The majority of these Cardium units are under waterflood. Operated properties account for 35% of the Pembina area production, with the majority of the remaining production coming from the non-operated units. NCEP acquired a 9.5% working interest in the North Pembina Cardium Unit effective January 1, 2002 adding approximately 365 bopd net to NCEP. Drilling activities in 2002 were mainly focused in the North Pembina Cardium Unit with 4 wells, which initially added 30 bopd net, stabilizing at 20 bopd net. An additional 4 to 6 locations are planned in 2003 for this unit. NCEP's net production from the Pembina area averaged 1,140 boepd in 2002. The Established Reserves for this area as of December 31, 2002 were 9,227 mboe, comprised of 7,365 mbbls of oil, 7.7 bcf of gas and 580 mbbls of NGLs.

iii. Strachan, Alberta

The Strachan area, which has been expanded to include the Caroline properties, is located approximately 100 miles northwest of Calgary and consists of operated and non-operated wells and units with NCEP's working interest varying from 7% to 90%. Strachan/Caroline is a very attractive oil and gas area with many producing horizons. Presently production is from the Leduc, Beaverhill Lake, Cardium, Viking, Ostracod, Glauconite and Mannville formations. Non-operated production is mainly from the Caroline Viking S Unit (25.8%), Caroline North Cardium 'R' Unit (6.7%) and the Chedderville Viking 'A' Unit (14.0%). Operated properties account for approximately 90% of the Strachan area production, with the majority of the remaining production coming from the non-operated wells. Effective January 1, 2002, NCEP acquired operatorship and approximately 72% working interest in the Strachan Leduc D-3 Gas Unit #1 along with a 7% ownership in the Strachan gas plant. The ownership in the Strachan gas plant also decreased the operating costs associated with the Sunchild property since 35% of the Sunchild gas is processed at the Strachan plant. In the first half of 2002, NCEP participated in the drilling of 2 Viking oil wells, which opened up a new play in the area for NCEP and partners. NCEP drilled and cased a third Viking well in sweet Glauconite gas well that was placed on production in December 2002 at 330 mcfpd net to NCEP. Additional drilling and workover activity is planned for early 2003. NCEP's net production from the Strachan area averaged 1,130 boepd in 2002. The Established Reserves for this area as of December 31, 2002 were 4,314 mboe, comprised of 329 mbbls of oil, 18.4 bcf of gas and 912 mbbls of NGLs.

iv. Ring Border, British Columbia

NCEP owns a 9.4% interest in the Border Bluesky-Gething-Montney Unit "B" located 120 miles northeast of Fort St. John in northeast British Columbia. NCEP has ownership in all related facilities, including the Border gas plant. Burlington Resources Canada Energy Ltd. is operator of both the unit and the producing facilities. NCEP's working interest production from this property averaged approximately 795 boepd in 2002. The Established Reserves for this property as at December 31, 2002 were 4,081 mboe, comprised of 21.7 bcf of gas and 466 mbbls of NGLs.

v. Swan Hills, Alberta

Swan Hills is located approximately 125 miles northwest of Edmonton. NCEP acquired a 2.6% working interest in the Swan Hills Unit #1 which Devon Canada operates. This field was discovered in 1957 and the Unit was formed in 1963. The reservoir is under waterflood and hydrocarbon miscible flood. NCEP also owns a 1.6% working interest in the Judy Creek West Beaverhill Lake Unit and a 0.7% working interest in the South Swan Hills Unit. Both of these Units are also under waterflood and hydrocarbon miscible flood. Each of the units include produced emulsion treating facilities and injection facilities. NCEP also owns various working interests in the components of the Judy Creek Gas Conservation Plant that is operated by Pengrowth. NCEP's average 2002 working interest production from the Swan Hills area was 548 boepd. The Established Reserves for this property as at December 31, 2002 were 3,959 mboe, comprised of 2,906 mbbls of oil, 1.8 bcf of gas and 756 mbbls of NGLs.

vi. July Lake, British Columbia

NCEP's July Lake gas property is located approximately 100 miles northeast of Fort Nelson in northeast British Columbia. NCEP holds an average 34% interest in 19 gas wells, several of which are horizontals, within a production sharing area operated by Canadian Natural Resources Limited. NCEP also owns 100% in nine additional operated gas wells. All gas production from this property comes from the Jean Marie formation. The natural gas is processed through a third party processing facility. NCEP's working interest production from this property averaged approximately 6.0 mmcfpd in 2002. The Established Reserves for this property as at December 31, 2002 were 21.6 bcf of gas.

vii. Swan Hills North, Alberta

The Swan Hills North area is located approximately 145 miles northwest of Edmonton. NCEP owns a 14.5% working interest in House Mountain Unit #1 which is operated by Apache Canada and is currently under waterflood. Six horizontal re-entry wells were drilled and two wells were successfully re-activated in the Unit in 2002. NCE invested approximately $1.4 million in this property in 2002. NCEP also owns a 3.7% working interest in Deer Mountain Unit #1 which is operated by Pengrowth. Each of the units include produced emulsion treating facilities and injection facilities. NCEP's average working interest production from the Swan Hills North area for 2002 was 672 boepd. The Established Reserves for this property as at December 31, 2002 were 3,581 mboe, comprised of 3,299 mbbls oil, 654 mmcf of gas and 172 mbbls of NGLs.

viii. Three Hills Creek, Alberta

Three Hills Creek is located 12 miles southeast of Red Deer Alberta. NCEP's average working interest in the property is 81% and the majority of the wells are operated by NCEP. NCEP did farm-outs with four separate companies in 2002 resulting in the drilling of six wells, two of which were abandoned and four cased and currently being evaluated. NCEP's internal evaluation of the area potential resulted in a successful recompletion of a Viking oil well and a tie-in of a standing gas well. NCEP 2003 activity includes a 3 well drilling program and further area optimization. NCEP holds 98% interest in two gas processing facilities and one oil treating facility. Current net production is approximately 1,100 boepd with an 80/20 gas/oil split on a boe basis. NCEP's Established Reserves for Three Hills Creek as of December 31, 2002 was 3,431 mboe, comprised of 463 mbbls of oil, 14.9 bcf of gas and 480 mbbls of NGLs.

ix. Fort Saskatchewan, Alberta

Effective January 1, 2003, NCEP purchased two main operated properties in Fort Saskatchewan and Beaverhill Lake, Alberta, located approximately 20 miles east of Edmonton. NCEP's working interest varies from 75% to 100%, averaging over 95%. The property consists of approximately 50 unit and non-unit relatively shallow gas wells producing from the Viking formation. The Viking zone forms a continuous pool, which extends approximately 50 miles from the northwest end of the Fort Saskatchewan field to the southeast end of the Beaverhill Lake field. NCEP acquired operatorship and a 95.55% working interest in the Beaverhill Lake Viking Gas Unit as well as 100% working interest in four compressor stations and the associated gathering systems. This property is currently producing over 6 mmcfpd. NCEP's Established Reserves for this area as of January 1, 2003 were 19.8 bcf of gas.

x. Sunchild, Alberta

Sunchild is a gas property located approximately 100 miles southwest of Edmonton and consists of operated and non-operated wells. NCEP's interests in the producing wells vary from overriding royalties to 100%. The majority of the production from this property is deep sour gas, coming mainly from the Pekisko and Shunda formations. Recently several wells have been drilled and completed for sweet gas in the Ostracod and Belly River formations. In 2002, NCEP participated in the drilling of 3 wells and farmed out two additional wells for an overriding royalty. These wells were tied in and placed on production around the first part of December 2001 and has increased NCEP's net production by over 2 mmcfpd. NCEP installed field dehydration and compression facilities in 2002, as well as expanded the major compression facility. Operated production accounts for 65% of the Sunchild area production, with the remaining production coming from the non-operated wells. NCEP and other partners plan further activity in the area for 2003. NCEP's net production from the Sunchild area averaged 1,121 boepd in 2002. The Established Reserves for this area as of December 31, 2002 were 3,007 mboe, comprised of 15.8 bcf of gas and 372 mbbls of NGLs.

xi. Minehead, Alberta

Minehead is a gas property located approximately 120 miles southwest of Edmonton and is operated by Shiningbank Energy. NCEP's working interest varies from 27.8% to 40% with the production mainly coming from the Belly River and Cardium formations. Effective January 1, 2002, NCEP acquired additional working interest in the area, increasing NCEP's net production by approximately by 300 boepd. Net production from the Minehead area averaged 343 boepd in 2002. The Established Reserves for this area as of December 31, 2002 were 2,901 mboe, comprised of 22 mbbls of oil, 13 bcf of gas and 715 mbbls of NGLs.

xii. Hatton, Saskatchewan

The Hatton gas property is located approximately 80 miles west of Swift Current in southwest Saskatchewan. NCEP holds an average 94% working interest in 189 Milk River/Medicine Hat gas wells. NCEP's working interest production from this property averaged approximately 3.1 mmcfpd in 2002. The Established Reserves for this property as at December 31, 2002 were 17.2 bcf of gas.

xiii. Kaybob, Alberta

NCEP owns a 42.7% working interest in the Kaybob Beaverhill Lake Unit #1 which is operated by Chevron Canada Ltd. The property is located approximately 150 miles northwest of Edmonton. NCEP also has ownership in the associated Kaybob gas plant that processes solution gas from the Unit. The working interest production from this property averaged 983 boepd in 2002. NCEP's Established

Reserves for this property as at December 31, 2002 were 2,637 mboe, comprised of 1,788 mbbls of oil, 2.9 bcf of gas and 363 mbbls of NGLs.

xiv. Waskada, Manitoba

NCEP's Waskada oil property is located 100 miles south of Brandon, in southwest Manitoba. NCEP holds an average 96% working interest in 152 active wells. NCEP also owns 100% of the central oil treating battery and 75% of the sales oil shipping terminal, as well as the 50 mile sales oil transmission pipeline running between Waskada and Cromer. NCEP's net production from this property averaged approximately 560 bopd in 2002. The Established Reserves for this property as at December 31, 2002 were 2,428 mbbls of oil.

xv. Blood-Magrath/McIntyre Ranch, Alberta

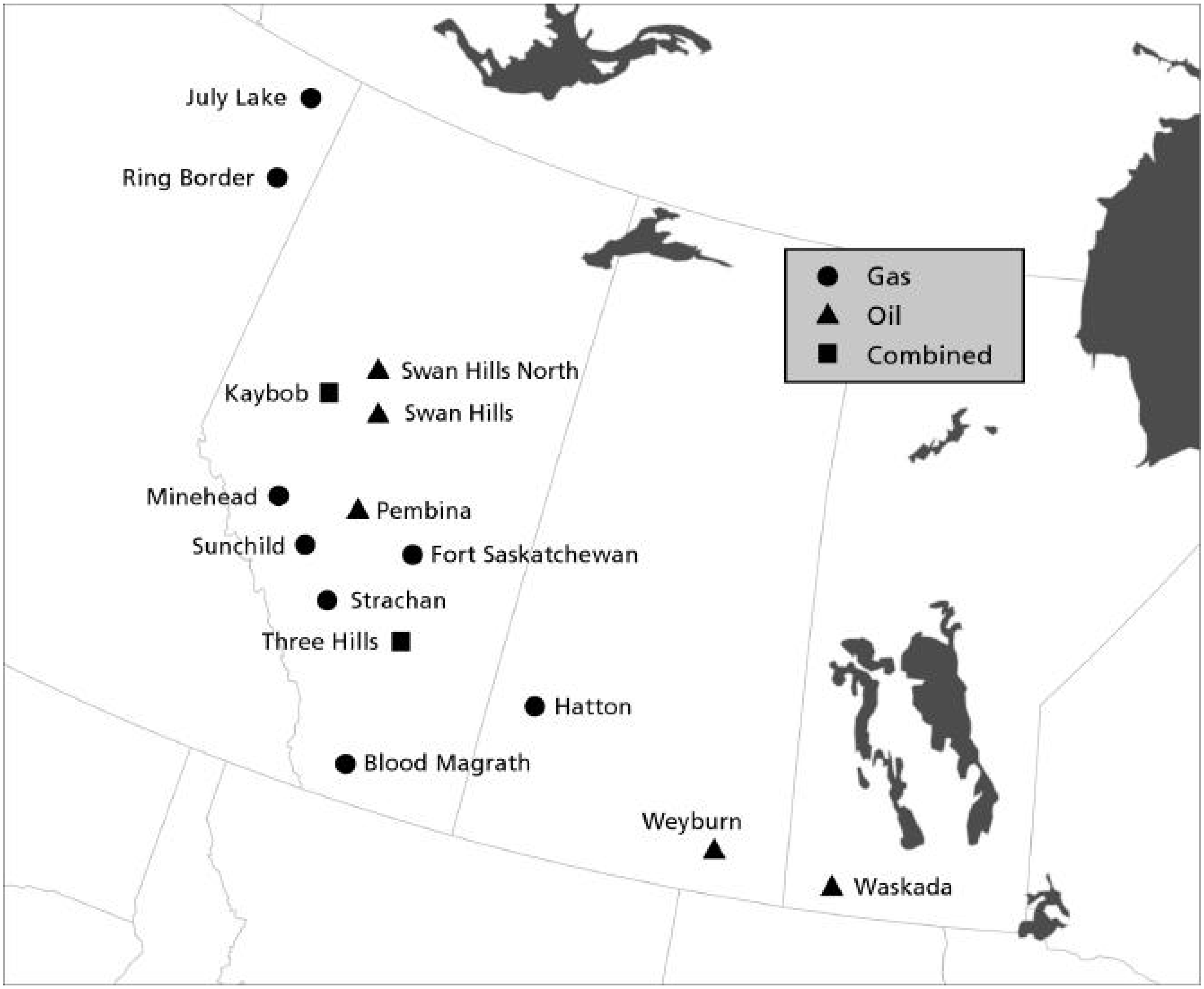
The NCEP operated Blood-Magrath/McIntyre Ranch gas property is located approximately 20 miles south of Lethbridge in southeastern Alberta. This gas property was acquired in December of 2000. NCEP holds an average 96% working interest in 37 producing gas wells and owns and operates an extensive gas gathering system along with 7 compressor stations. Production is mainly from the Bow Island zone. The average 2002 net production was approximately 4.2 mmcfd of gas. NCEP's Established Reserves for this property as at December 31, 2002 were 13.9 bcf of sales gas.

The above 15 properties account for about 62% of NCEP's total Established Reserves as at December 31, 2002.

xvi. Other Properties

NCEP has various interests in numerous other properties located in Alberta, British Columbia and Saskatchewan. NCEP's Established Reserves for these other properties as at December 31, 2002 amounted to approximately 37,290 mboe. In total, these properties represent approximately 38% of NCEP's Established Reserves as at December 31, 2002.

Below is a map which illustrates the approximate locations of NCEP's principal properties:



xvii. Gross and Net Reserves Summary

GLJ has prepared engineering reports evaluating all properties held by NCEP effective as at December 31, 2002.

The following summary of reserves includes all working interests held by NCEP at December 31, 2002, using both the escalated and constant price cases as evaluated by GLJ. Assumptions and qualifications contained in the GLJ Report relating to prices, costs and inflation are set forth in the notes to the tables.

All evaluations have been stated prior to any provision for income taxes and general and administrative costs. The estimated present worth values of net production revenue contained in the following tables may not be representative of the fair market value of the reserves. Readers are cautioned that where the present worth of estimated future net production revenue is based on escalating price and cost assumptions, there is no assurance that such price and cost assumptions will be attained and variances could be material. Actual reserves may be greater than or less than the estimates provided herein.

Petroleum and Natural Gas Reserves
Based on Escalated Price and Cost Assumptions [1]

	Natural Gas[10]		Natural Gas Liquids		Oil	
	Gross[2]	Net[2]	Gross[2]	Net[2]	Gross[2]	Net[2]
	(bcf)		(mmbbls)		(mmbbls)	
Proved Reserves [3]						
Producing[4]	205	158	5.0	3.5	33.0	29.2
Nonproducing[5]	28	22	0.9	0.7	5.8	5.3
Total Proved Reserves	233	180	5.9	4.2	38.8	34.5
Probable Additional Reserves [6]	82	64	2.2	1.6	15.8	13.6
Total Proved Plus Probable	315	244	8.1	5.8	54.6	48.1
Total Established Reserves [7]	274	212	7.0	5.0	46.7	41.3

The present worth of the estimated future net production revenue to be derived from the foregoing reserves is set out in the following table:

Present Worth of Estimated Future Net Production Revenue Before Income Taxes
Based on Escalated Price and Cost Assumptions [1][8][9][11][12][13][15]

		Discounted at the Rate of		
	Undiscounted	10%	15%	20%
Proved Reserves [3]	($millions)		($millions)	
Producing[4]	882	542	466	413
Nonproducing[5]	129	60	46	36
Total Proved Reserves	1,011	602	512	449
Probable Additional Reserves [6]	470	167	119	91
Total Proved Plus Probable	1,481	769	631	540
Total Established Reserves [7]	1,246	685	571	494

Petroleum and Natural Gas Reserves
Based on Constant Price and No Cost Escalation[1]

	Natural Gas[10]		Natural Gas Liquids		Oil	
	Gross[2]	Net[2]	Gross[2]	Net[2]	Gross[2]	Net[2]
	(bcf)		(mmbbls)		(mmbbls)	
Proved Reserves [3]						
Producing[4]	208	161	5.0	3.5	34.5	30.4
Nonproducing[5]	29	21	1.0	0.7	5.9	5.0
Total Proved Reserves	237	182	6.0	4.2	40.4	35.4
Probable Additional Reserves [6]	83	65	2.2	1.6	16.2	13.8
Total Proved Plus Probable	320	247	8.2	5.8	56.6	49.2
Total Established Reserves [7]	278	215	7.1	5.0	48.5	42.3

The present worth of the estimated future net production revenue to be derived from the foregoing reserves is set out in the following table:

Present Worth of Estimated Future Net Production Revenue Before Income Taxes
Based on Constant Price and No Cost Escalation[1][8][9][11][14][15]

		Discounted at the Rate of		
	Undiscounted	10%	15%	20%

Proved Reserves[3]	($millions)		($millions)	
Producing[4]	1,557	899	758	660
Nonproducing[5]	229	116	90	72
Total Proved Reserves	1,786	1,015	848	732
Probable Additional Reserves[6]	733	271	196	151
Total Proved Plus Probable	2,519	1,286	1,044	883
Total Established Reserves[7]	2,153	1,150	946	808

Notes:

1) As a result of rounding, certain column amounts may not add to the corresponding total amount set out in the tables.

2) "Gross Reserves" are the remaining reserves owned by NCEP before deduction of any royalties. "Net Reserves" are the gross remaining reserves owned by NCEP less all royalties and interests owned by others.

3) "Proved Reserves" are those reserves estimated as recoverable with a high degree of certainty under current technology and existing economic conditions in the case of constant price and cost analyses and anticipated economic conditions in the case of escalated price and cost analyses, 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.

4) "Proved Producing Reserves" are those reserves that are actually on production and could be recovered from existing wells and facilities or, if facilities have not been installed, that would involve a small investment relative to cash flow. In multi-well pools involving a competitive situation, reserves may be subdivided into producing and non-producing reserves in order to reflect allocation of reserves to specific wells and their respective development status.

5) "Proved Non-producing Reserves" are those reserves that are not classified as producing.

6) "Probable Reserves" are those reserves which analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved, but where such analysis suggest the likelihood of their existence and future recovery under current technology and existing or anticipated economic conditions. 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.

7) "Established Reserves" are proved reserves plus 50 percent of probable reserves.

8) "Net production revenue" is income derived from the sale of net reserves of oil, pipeline gas and gas by-products, less all capital and operating costs.

9) In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the ARC program. The ARC program is based on a price sensitive formula and the ARC rate currently varies between 75% at prices of oil below $100 per cubic metre and 25% at prices above $210 per cubic metre. The ARC 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 ARC will generally not be eligible for ARC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period. The Alberta government has announced that the credit will operate on a three-year rolling term. Any changes to the credit will be announced three years in advance. The estimated net production revenue does not reflect an anticipated reduction in aggregate net production revenue which may result from an anticipated reduction in ARC which may be claimed by NCEP for 2002 and subsequent years.

10) Natural gas reserves are reported to be a base pressure of 14.65 pounds per square inch and a base temperature of 60 degrees Fahrenheit.

11) Prices for oil F.O.B. Edmonton are based upon 40 degree API crude oil having less than 0.3 percent sulphur content. The actual wellhead price will vary with the quality of the crude and the cost of transportation from the wellhead to Edmonton. The natural gas prices were adjusted for heating value, where applicable, and the cost of service charges of the various natural gas shippers.

12) The escalated price and cost case assumes the continuance of current laws and regulations and any increases in selling prices also accounts for inflation. The product price forecasts used below are the current price forecasts published by GLJ. The product price forecasts used are as follows:

Natural Gas and Sulphur (Prices in Canadian Dollars)
F.O.B. Field Gate or Plant

Year	AECO - C Spot	Saskatchewan Spot Plant Gate	British Columbia Spot Plant Gate	Sulphur	Inflation Rate	Exchange Rate
	$/mmbtu	*$/mmbtu*	*$/mmbtu*	*$/lt*	*%/year*	*$US/$Cdn*
2003……	5.65	5.65	5.30	10.50	1.5	0.650
2004……	5.00	5.00	4.80	9.50	1.5	0.660
2005……	4.70	4.70	4.50	8.50	1.5	0.670
2006……	4.85	4.85	4.65	16.00	1.5	0.670
2007……	4.85	4.85	4.65	22.50	1.5	0.680
2008……	4.85	4.85	4.65	24.00	1.5	0.680
2009……	4.85	4.85	4.65	25.50	1.5	0.680
2010……	4.90	4.90	4.70	27.00	1.5	0.680
2011……	4.95	4.95	4.75	29.00	1.5	0.680
2012……	5.05	5.05	4.85	30.50	1.5	0.680
2013……	5.10	5.10	4.90	32.00	1.5	0.680

Escalation rate of 1.5% thereafter.

NGLs and Light Crude Oil (Prices in Canadian Dollars unless specified)
F.O.B. Field Gate or Plant

Year	Edmonton Propane	Edmonton Butane	Edmonton Pentanes Plus	WTI Cushing Oklahoma	Light Sweet Crude Oil at Edmonton 40 API, 0.3%S
	$/bbl	*$/bbl*	*$/bbl*	$US/bbl	$Cdn/bbl
2003………..	24.75	27.25	39.50	25.50	38.50
2004………..	19.75	21.50	33.00	22.00	32.50
2005………..	19.50	20.50	31.00	21.00	30.50
2006………..	19.50	20.50	31.00	21.00	30.50
2007………..	19.50	20.50	31.00	21.25	30.50
2008………..	19.75	21.00	31.50	21.75	31.00
2009………..	20.25	21.50	32.00	22.00	31.50
2010………..	20.50	22.00	32.50	22.25	32.00
2011………..	20.75	22.50	33.00	22.50	32.50
2012………..	21.00	23.00	33.50	23.00	33.00
2013………..	21.50	23.50	34.00	23.25	33.50

Escalation rate of 1.5% thereafter.

13) The undiscounted, unrisked capital expenditures for the escalated price and cost case in the GLJ Report are as follows:

Capital Expenditures related to	Amount ($000's)
Proved Producing Reserves	$ 35,600
Proved Nonproducing Reserves	62,400
Probable Reserves [(a)]	56,200
Total	$154,200

Note:
(a) Probable Reserves have not been risked.

Well abandonment costs have been scheduled in the last year of production for each well evaluated. No salvage value for facilities has been included in the GLJ Report. The GLJ Report assumes that $29.3 million and $31.8 million will be spent to recover Proved and Probable Reserves during 2003 and 2004, respectively.

14) The constant price case was based upon the actual prices received to December 31, 2002. The average prices adjusted for quality and market costs are as follows:

Oil	$45.34/bbl (Wellhead)
Natural Gas	$5.85/mcf (Plant Gate)
NGLs	$36.89/bbl

15) Includes the Alberta Gas Cost Allowance and the Jumping Pound Allowance.

b. Reconciliation of Reserves

The following table provides a reconciliation of NCEP's natural gas, NGLs and oil proved reserves for the year ended December 31, 2002.

	Natural Gas (mmcf)		NGLs (mbbls)		Crude Oil (mbbls)		Total (mboe)		Established Reserves (mboe)
	Proved	**Risked Probable**	**Proved**	**Risked Probable**	**Proved**	**Risked Probable**	**Proved**	**Risked Probable**	
Opening Reserves as at December 31, 2001	209,485	37,699	5,097	1,070	33,403	8,584	73,414	15,937	89,351
Production	(28,058)	-	(660)	-	(4,074)	-	(9,410)	-	(9,410)
Acquisitions	67,128	12,615	1,644	240	10,125	1,444	22,957	3,787	26,744
Divestments	(9,611)	(3,184)	(230)	(60)	(823)	(114)	(2,655)	(705)	(3,360)
Extensions & Additions	12,801	3,162	115	25	792	238	3,041	790	3,831
Revisions	(18,531)	(9,327)	(42)	(202)	(583)	(2,291)	(3,714)	(4,047)	(7,761)
Year-end Reserves as at December 31, 2002	233,214	40,965	5,924	1,073	38,840	7,861	83,633	15,762	99,395

c. Reserve Life Index

The following table provides the reserve life index of NCEP's natural gas, NGLs and oil on proven and a proven plus probable basis for the year ended December 31, 2002.

Reserve Life Index by Product
December 31, 2002

	Years	
	Proved	**Proved + Probable**
Crude Oil	9.5	13.4
Natural Gas	8.3	11.2
NGLs	9.0	12.2
TOTAL Oil Equivalent	8.9	12.2

d. Well Status

Approximately 80% of NCEP's wells are tied in and are producing. The remaining wells are either waiting for tie in or evaluation or are shut in for operational reasons.

e. Undeveloped Land

As at December 31, 2002, NCEP held total inventory of undeveloped land as follows:

Undeveloped Land Holdings

December 31, 2002

	Acres	
	Gross	**Net**
Alberta	455,359	277,007
British Columbia	118,958	42,733
Manitoba	1,679	1,659
Saskatchewan	100,947	57,735
TOTAL	676,943	379,134

The majority of NCEP's undeveloped land is in the vicinity of its properties.

f. Oil and Gas Wells

The following table sets forth the number and status of wells in which NCEP had a working interest as at December 31, 2002, which are producing or which are shut-in but which NCEP considers to be capable of production:

	Producing Oil		Producing Gas		Shut-in Oil(1)		Shut-in Gas(1)	
	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)
Alberta	2,463	615.0	851	264.7	870	277.5	209	124.4
British Columbia	77	17.6	234	34.9	59	6.9	62	11.4
Manitoba	114	86.3	0	0.0	58	55.9	0	0.0
Saskatchewan	1,157	437.0	541	505.0	107	24.0	10	5.0
Total	3,811	1,155.9	1,626	804.6	1,094	364.3	281	140.8

Notes:

(1) "Shut-in" means wells which have encountered and are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons. Shut-in natural gas wells in which NCEP has an interest are located no further than 10 kilometres from gathering systems, pipelines or other means of transportation.

(2) "Gross" wells are defined as the total number of wells in which NCEP has an interest.

(3) "Net" wells are defined as the aggregate of the numbers obtained by multiplying each gross well by NCEP's percentage working interest therein.

(4) Royalty interest wells have been assigned a net number of zero. The table does not include water injection wells.

g. Summary of Third Party Farmout Arrangements for 2002

During 2002, NCEP entered into farmout agreements with various industry partners achieving 51 well commitments which resulted in 43 wells being drilled in 2002 on NCEP's undeveloped land base. This drilling yielding 30 gas wells, 8 oil wells, and 5 abandoned wells. Although terms are slightly different for each farmout, they are generally structured such that NCEP is carried for the costs of each well and receives a gross overriding royalty before payout of such costs and an after payout working interest which generally equates to 50% of its pre-farmout interest.

h. Drilling Summary

Drilling activity during the two most recent years is summarized as follows:

NCE Drilling Summary

2002	Total Working Interest Wells	Oil Wells	Gas Wells	Drilled and Abandoned Wells
Gross (1)	334	40	290	4
Net (2)	86.6	10.6	72.7	3.3
	Total Farmout Wells (3)	Oil Wells	Gas Wells	Drilled and Abandoned Wells
	43	8	30	5

2001	Total Working Interest Wells	Oil Wells	Gas Wells	Drilled and Abandoned Wells
Gross (1)	98	60	36	2
Net (2)	17.19	10.54	4.65	2.00
	Total Farmout Wells (3)	Oil Wells	Gas Wells	Drilled and Abandoned Wells
	36	0	35	1

Notes:

(5) Refers to the total number of wells in which NCEP holds a working interest.
(6) Refers to the sum of NCEP's working interests in the gross wells.
(7) Farmout wells are wells in which NCEP currently has no working interest but holds an overriding royalty on any production.

i. Marketing

1. Natural Gas

In 2002 NCEP sold 38% of its production to aggregators at netback pricing, up from 31% in 2001 and 33% in 2000. NCEP sold the remaining 62% on daily and monthly spot market pricing in Alberta, Saskatchewan and British Columbia. Petrofund's average natural gas price in 2002 was $3.95/mcf, a decrease of $1.14 /mcf or 22% over the previous year.

As noted last year, NCEP intends to avoid new long-term, ex-Alberta transportation commitments whether directly or embedded through the sales portfolios of the various Canadian aggregators. In spite of this, NCEP's aggregator sales increased year over year as a result of development activity on previously unproductive lands, which are, included in these aggregator contracts. NCEP continues to evaluate these contracts closely for opportunities to reduce sales. NCEP is responding to changes in the energy marketing infrastructure by altering other aspects of our marketing strategy; specifically, we will be contracting increasingly with end users and decreasing sales to middlemen.

As always, NCEP puts a priority on maintaining sufficient intra-provincial firm transport for most of its daily sales and maintains a high load factor on all contracted transportation.

2. Crude Oil

During 2002, NCEP's average price was $34.68/bbl up marginally from the $34.37/bbl received in 2001. Hedging losses were $2.10/bbl. About 62% of NCEP's crude production is sold directly to refiners up from 37% a year ago. This reflects NCEP's strategy of reducing sales to marketers and middlemen to achieve higher levels of security for both credit and the actual physical delivery of the crude. The balance of the crude is delivered to marketers.

Crude differentials were relatively stable and tight during 2002. NCEP's actual differentials off Edmonton postings were $3.16/bbl versus $5.86/bbl the previous year excluding hedging activities. The

Fund anticipates tight differentials for its light products and wider, more volatile differentials for heavier crudes in 2003 as large non-conventional heavy oil projects are completed.

The Fund's crude portfolio is over 95% light and medium crudes.

3. Natural Gas Liquids

During 2002, the average price received by NCEP for the propane, butane and condensate mix was $28.30/bbl, down 13% from the $32.57/bbl price received in 2001. Markets for NCEP's NGLs production are well diversified, with the majority sold to two buyers under one-year contract terms at market sensitive pricing.

NGL netbacks lagged the recovery in crude prices during the year but rallied in the 4th quarter. NCEP expects NGL's to continue to return strong pricing for 2003 as propane prices track gas upwards and as condensate prices strengthen with increased heavy oil activity.

4. Hedging

As at December 31, 2002, NCEP has hedged 23.25 mmcfpd of gas and 1,985 bbl/d of crude for 2003. Approximately 5.1 mmcfpd of the hedged gas is subject to a price ceiling of $3.17/mcf acquired via an acquisition. The balance of the gas hedges are a combination of price collars guaranteeing an AECO price of at least $4.70/mcf on 18.2 mmcfpd and an average ceiling of $6.77/mcf. NCEP has collared the price of its crude for 1,660 bbl/d between $37.70-$45.55/bbl and has fixed the price on 325 bbl/d at $44.38/bbl. Approximately 40% of the collared volumes will not receive the floor price if WTI prices retreat below US$20.50/bbl. In this case, these volumes will receive a premium of an additional US$4.00/bbl ($6.31/bbl Canadian) on the posted price. For further details please see Note 12 to the Financial Statements.

NCEP implemented a formal risk management policy in 2001 which provides the Risk Management Committee with the ability to use specified price risk management strategies for its crude, natural gas and NGLs production including fixed price contracts, costless collars, the purchase of floor price options and other derivative financial instruments to reduce price volatility and ensure minimum prices to a maximum of 40% of its annual production for a maximum of two years beyond the current date.

j. Market Fundamentals

1. Crude Oil

Crude prices increased throughout 2002 as West Texas Intermediate (WTI) rose from a low of US$21.64 in the first quarter to a high of US$28.27 in the third quarter. In a year over year comparison, WTI was up US$0.18/bbl in 2002 averaging US$26.08. The fourth quarter of 2002 was down US$0.12 from the third quarter of 2002, at US$28.15, but up US$7.72 or nearly 38% from the same period a year ago. Prices in early 2003 have risen to levels well in excess of the fourth quarter levels.

Market fundamentals are not setting the price of crude currently but the fundamentals have improved substantially over the year. Non-OPEC supply increased during the year by an estimated 1.2 to 1.5 million barrels/day from Russia, Canada, Brazil and Angola. In addition, OPEC producers exceeded their quotas for most of the year, yet world demand absorbed these increases. Finally, the strike of Venezuelan oil workers has taken most of that nation's 3 million bbl/d of production out of the market, reducing supply at the peak of the heating season in the Northern Hemisphere. This has left crude inventories in the United States to 20-year lows. Rebuilding these inventories may take one or two years, or longer if these inventories decline further.

2. Natural Gas

AECO spot natural gas prices cycled up and down throughout the year ending the year on a strong note, closely following US natural gas prices. For the year, AECO prices averaged $4.07/mcf, down 35% from 2001. AECO prices performed strongly in the fourth quarter averaging $5.25/mcf, up $2.00/mcf from the third quarter and up $1.95/mcf (59%) from the fourth quarter of 2001. The fourth quarter was also the first quarter of 2002 in which prices exceeded those from the previous year.

The Trust believes the fundamentals underpinning natural gas markets are robust as well. Weak North American natural gas prices in the later part of 2001 and the first nine months of 2002 lead to weak drilling during the year. Currently there are 706 gas drilling rigs in the U.S., down from January rig counts of 747 in 2001 and 879 in 2000. On average there were 26% fewer gas directed rigs active in the U.S. in 2002 versus 2001. Canadian drilling rigs counts and gas well completions were similarly down. Gas production slid as a result and the Trust expects current price levels may help stabilize production declines later in 2003 but will likely not result in substantial increases in production in the medium term.

k. Hedge Valuations

1. Derivative Financial Instruments and Physical Contracts

NCEP enters into various pricing mechanisms to reduce price volatility and establish minimum prices for a portion of its oil and gas production. These include fixed price contracts and the use of derivative financial instruments.

The outstanding derivative financial instruments as at December 31, 2002, all of which constitute effective hedges, and the outstanding physical contracts as at December 31, 2002, and the related unrealized gains or losses, are summarized below:

l. Financial Gas Hedges

Natural Gas	Term	Volume mcfpd	Price $/mcf	Delivery Point	Unrealized Gain/(Loss) ($000's)
Collar	January 1, 2003 to March 31, 2003	14,212	$4.59-$7.97	AECO	$ (46)
Collar	January 1, 2003 to March 31, 2003	4,737	$4.59-$7.97	AECO	(6)
Call option (purchased)	July 1, 2001 to October 31, 2003	6,159	$4.91	AECO	2,400
Collar	January 1, 2003 to March 31, 2003	4,737	$5.17-$6.75	AECO	(55)
Collar	January 1, 2003 to March 31, 2003	4,737	$5.17-$7.07	AECO	(13)
Collar	April 1, 2003 to October 31, 2003	9,475	$4.64-$6.23	AECO	(1,051)
Collar	April 1, 2003 to	4,737	$4.64-$6.23	AECO	(510)

	October 31, 2003				
Collar	April 1, 2003 to October 31, 2003	4,737	$4.64-$6.24	AECO	(308)
Total					$ 411

m. **Financial Oil Hedges**

Oil	Term	Volume Bpd	Price $/bbl	Delivery Point	Unrealized Gain/(Loss) ($000's)
Fixed Price	January 1, to January 31, 2003	2,000	$44.49	Edmonton	$ (271)
Fixed Price	February 1, to February 28, 2003	2,000	$44.25	Edmonton	(193)
Collar	January 1, 2003 to June 30, 2003	2,000	$37.06-$45.34	Edmonton	(728)
Three Way Collar	March 1, 2003 to June 30, 2003	2,000	*(1)	Edmonton	(413)
Total					$(1,605)

*(1) At Prices above $45.87, Petrofund receives $45.87/bbl.
At Prices between $38.65 and $45.87/bbl, Petrofund receives the actual price.
At prices between $32.34 and $38.65, Petrofund receives $38.65.
At Prices below $38.65, Petrofund receives actual price plus $6.31/bbl.

n. **Physical Gas Contracts**

Natural Gas	Term	Volume mcfpd	Price $/mcf	Delivery Point	Unrealized Gain/(Loss) ($000's)
Capped	November 1, 1999 to October 31, 2003	6,159	$3.16	AECO	$(5,020)
Total					$(5,020)

The gains or losses are recognized on a monthly basis over the terms of the contracts and adjust the prices received.

Derivative financial instruments and physical hedge contracts involve a degree of credit risk, which the Trust controls through the use of financially sound counter parties. Market risk relating to changes in value or settlement cost of NCEP's derivative financial instruments is essentially offset by gains or losses on the underlying physical sales.

o. **Credit Facility**

NCEP has a revolving working capital operating facility of $25 million and a syndicated facility of $220 million. Interest on the working capital loan is at prime and interest on the syndicated facility depends on NCEP's debt to cash flow ratio and varies from prime to prime plus 50 basis points or, at the Trusts option, bankers acceptance plus a stamping fee. Substantially all of the credit facility is financed with banker's acceptances, resulting in an average reduction in interest rates of 0.50% per annum.

The limit of the syndicated facility is subject to adjustment from time to time to reflect changes in NCEP's asset base. NCEP had long-term debt outstanding of $212 million at December 31, 2002, compared to $129 million at the end of the prior year.

The revolving period on the syndicated facility ends on May 30, 2003 unless extended for a further 364 day period. There are no principal repayments required during the revolving period. NCEP may request the facility be extended no earlier than 90 days and no later than 60 days prior to the end of the revolving period at which time lenders may extend the facility for an additional one year period. If the revolving period is not extended, the loan will convert to a one year term with payments due in three consecutive quarterly amounts equal to one-twentieth of the loan amount with an additional payment due on the last day of the term period equal to the remaining balance outstanding. In the event that the revolving period is not extended, the Trust will prepay the required quarterly instalments into a reserve account.

The credit facility is secured by a debenture in the amount of $350 million under which a Canadian chartered bank, as principal and as agent for the other lenders, received a first ranking security interest on all of NCEP's assets. The loan is the legal obligation of NCEP. Unitholders have no direct liability to the lenders or to NCEP should the assets securing the loan generate insufficient cash flow to repay the obligation.

11) SELECTED FINANCIAL AND OPERATING INFORMATION

a. Consolidated Financial Information

The following is a summary of selected consolidated financial information of the Trust for the years indicated.

	December 31,		
	2002	**2001**	**2000**[(1)]
	(millions, except per unit amounts)		
Total revenues………………………………..	$270.7	$244.5	$184.8
Royalties, net of incentives…………………..	50.4	54.8	39.2
Lease operating costs…………………………	74.8	48.2	28.7
Proceeds on disposition of property interests…	30.0	3.7	6.5
Cash flow from operations……………………	112.6	110.2	95.5
Cash flow available for distribution…………..	103.1	110.6	96.0
per Unit – basic……………………..	2.07	3.50	5.05
per Unit – diluted[(2)]………………...	2.06	3.49	5.05
Net income……………………………………	24.4	54.0	62.9
Per Unit – basic……………………..	.49	1.71	3.31
Per Unit – diluted [(2)]………………..	.49	1.71	3.30
Working Capital (deficit)……………………..	(6.9)	(20.6)	(13.2)
Total assets……………………………………	890.6	699.3	305.7
Total long-term debt[(3)]………………………	219.2	145.0	114.6
Unitholders' equity……………………………	480.1	398.7	136.8
Weighted average number of Units outstanding			
Basic ………………………………..	49.9	31.6	19.0
Diluted………………………………	49.9	31.6	19.0

Notes:

(8) Effective November 1, 2000, the Trust acquired all of the issued and outstanding shares of NCEP for nominal consideration, resulting in NCEP becoming a wholly owned subsidiary of the Trust. At the same time, the Unitholders of the Trust approved organizational changes to the Trust and NCEP such that the Unitholders have representation on the Board of Directors of NCEP and elect a majority of the members of the Executive Committee of NCEP. As a result, consolidated financial statements of the Trust and NCEP were prepared in the third quarter of 2000 and prior periods have been restated. Please refer to Note 3 to the Trust's audited consolidated financial statements.

(9) The Trust adopted the recommendations of the Canadian Institute of Chartered Accountants for the computation, presentation and disclosure of earnings per Unit in the fourth quarter of 2000. Under the new standard, the treasury stock method is used to determine the dilutive effect of "in the money" options. Prior period cash flow available for distribution per Unit - diluted and net income per Unit - diluted have been restated for this change.

(10) Although the Trust does not have any long term indebtedness, NCEP does have long term indebtedness, which is secured against all of NCEP's assets. The loan is the legal obligation of NCEP. While principal and interest payments are allowable deductions in the calculation of royalty income, the Unitholders of the Trust have no direct liability to NCEP's lenders or to NCEP should the assets securing the loan generate insufficient cash flow to repay the obligations.

b. Operating Information

The following summarizes operating information of the Trust for the periods indicated. The netbacks have been calculated as described below.

Oil Wells - solution gas produced with oil has been converted to oil with 6 mcf of gas deemed equivalent to one bbl of oil and one bbl of oil deemed equivalent to one bbl of NGLs.

Gas Wells - one bbl of liquid produced with the gas is deemed equal to 6 mcf of gas.

Average Daily Production

	Fiscal 2002 Three Months Ended			
	March 31	**June 30**	**Sept 30**	**Dec 31**
Oil (bpd)	10,217	10,589	11,718	12,096
Natural Gas (mmcfd)	70.7	75.3	81.4	79.9
NGLs (bpd)	1,645	2,015	1,625	1,947
BOE (6:1)	23,645	25,152	26,915	27,362

Average Daily Production

	Fiscal 2001 Three Months Ended			
	March 31	**June 30**	**Sept 30**	**Dec 31**
Oil (bpd)	5,963	6,297	10,364	9,932
Natural Gas (mmcfd)	60.8	61.0	71.2	75.6
NGLs (bpd)	1,410	1,349	1,372	1,674
BOE (6:1)	17,507	17,817	23,611	24,202

Gas Well Netbacks ($per mcf)

	Fiscal 2002 Three Months Ended			
	March 31	**June 30**	**Sept 30**	**Dec 31**
Sales revenue	$3.32	$4.17	$3.66	$5.21
Royalties	.67	.89	.77	1.22
Operating costs (1)	.87	1.00	.83	.83
Netback	$1.78	$2.28	$2.06	$3.16
Natural gas prices ($/mcf)	$3.22	$3.97	$3.36	$5.15
NGL prices ($/bbl)	$20.39	$27.12	$31.51	$33.34

Gas Well Netbacks ($per mcf)

	Fiscal 2001 Three Months Ended			
	March 31	**June 30**	**Sept 30**	**Dec 31**
Sales revenue	$8.42	$5.75	$3.56	$3.19
Royalties	2.21	1.49	0.69	0.43
Operating costs (1)	0.70	0.98	0.79	0.62
Netback	$5.51	$3.28	$2.08	$2.14
Natural gas prices ($/mcf)	$8.84	$5.89	$3.27	$3.23
NGL prices ($/bbl)	$40.34	$41.03	$27.43	$23.64

Oil Well Netbacks ($per bbl)

	Fiscal 2002 Three Months Ended			
	March 31	**June 30**	**Sept 30**	**Dec 31**
Sales revenue(2)	$28.53	$33.20	$34.57	$35.25
Royalties	4.72	5.81	6.41	6.83
Operating costs (1)	9.30	9.15	9.74	10.41
Netback	$14.51	$18.24	$18.42	$18.01
Oil price ($bbl)	$29.51	$34.60	$37.31	$36.48

Oil Well Netbacks ($per bbl)

	Fiscal 2001 Three Months Ended			
	March 31	**June 30**	**Sept 30**	**Dec 31**
Sales revenue(2)	$41.30	$37.28	$32.68	$27.66
Royalties	8.24	6.93	6.01	4.00
Operating costs (1)	7.71	8.12	9.40	7.04
Netback	$25.35	$22.23	$17.27	$16.62
Oil price ($bbl)	$38.04	$38.79	$33.64	$30.21

Notes:

(1) Operating costs are expenses incurred in the operation of producing properties and include items such as field staff costs, power, fuel, chemicals, repairs and maintenance, property taxes, lease rentals, processing and treating fees, overhead fees and other costs.

(2) Primarily light and medium conventional crude oil.

c. Sensitivity Analysis

In 2002, NCEP's cash flow from operating activities was $112.6 million, and net income was $24.4 million. The sensitivity of NCEP's cash flow and net income to oil price, gas price, $US/$CAN exchange rate, and the prime interest rate is listed below:

1) Oil Price – a $1.00 US per bbl change in WTI oil price changes cash flow from operations and net income by $5.865 million or $0.117 per unit (based on 1.52 exchange rate).
2) Gas Price – a $0.10 per mcf change in Canadian gas price changes cash flow from operations and net income by $2.217 million or $0.044 per unit.
3) $US/$CAN Exchange Rate – a change of $0.01 U.S. per Canadian dollar changes cash flow from operations and net income by $2.363 million or $0.047 per unit.
4) Prime Interest Rate – a 1% change in the prime interest rate changes cash flow from operations and net income by $1.710 million or $0.034 per unit.

d. **Finding and Development Costs**

In 2002, NCEP acquired 22,957 mboe proved reserves and divested of 2,655 mboe proved reserves for a net addition of 20,302 mboe proved reserves at a cost of $9.29/boe. Development activities added 3,040 mboe at a cost of $13.40/boe.

e. **Capital Expenditures**

The following table summarizes NCEP's capital expenditures for the periods indicated:

	Fiscal 2002 Three Months Ended			
	March 31	**June 30 ($000's)**	**Sept 30**	**Dec 31**
Property Acquisitions	$40,422.2	$141,829.8[(1)]	$1,942.0	$34,343.4
Land Acquisition	342.2	474.9	517.6	931.5
Seismic	166.2	95.0	189.5	104.8
Drilling and Completion	4,577.4	1,994.0	8,667.0	6,966.1
Production Facilities	4,479.7	2,122.9	3,470.6	5,651.3
Subtotal	49,987.7	146,516.6	14,786.7	47,997.1
Dispositions	3,130.7	(3.1)	3,004.0	23,886.8
Net Capital Expenditures	$46,857.0	$146,519.7	$11,782.7	$24,110.3

Note:

(1) Excludes the non-cash future income tax adjustment of $27.1 million for the difference between the cost and the tax basis of the assets acquired.

	Fiscal 2001 Three Months Ended			
	March 31	**June 30 ($000's)**	**Sept 30**	**Dec 31**
Property Acquisitions	$33,407.4	$158,064.2[(1)]	$(1,328.7)	$142,070.2
Land Acquisition	401.1	437.0	501.5	278.0
Seismic	106.3	102.0	65.7	184.1
Drilling and Completion	4,592.1	3,828.5	5,609.5	2,962.8
Production Facilities	1,845.5	2,629.4	1,781.8	1,593.7
Subtotal	40,352.4	165,061.1	6,629.8	147,088.8
Dispositions	175.3	(10.5)	(2.8)	3,574.2
Net Capital Expenditures	$40,177.1	$165,071.6	$6,632.6	$143,514.6

Note:

(11) Excludes the non-cash future income tax adjustment of $110 million for the difference between the cost and the tax basis of the assets acquired.

Development activities on NCEP's properties during 2003 are estimated to require capital expenditures of up to approximately $29.3 million, of which $20.8 million has a high probability of being incurred and $8.5 million is contingent upon prior successful activities.

f. Distributions

The following cash distributions per Trust Unit in respect of the quarters indicated have been made to Unitholders since 2000:

	Cash Distributions(1)		
	2002	**2001**	**2000**
First Quarter	$0.43	$1.26	$0.90
Second Quarter	0.41	1.32	0.99
Third Quarter	0.42	0.93	1.02
Fourth Quarter	0.45	0.73	1.08
Total Annual	$1.71	$4.24	$3.99

Note:

(12) Accrued Trust royalty income will vary from actual amounts distributed to Unitholders due to differences in the timing of actual receipt of Trust royalty income.

12) MANAGEMENT'S DISCUSSION AND ANALYSIS

The Trust's Management's Discussion and Analysis, filed with the Trust's audited consolidated financial statements for the year ended December 31, 2002, is incorporated by reference herein.

13) RISK FACTORS

The following are certain risk factors relating to the business of the Trust which prospective investors should carefully consider before deciding whether to purchase Trust Units.

Industry-Related Risks

a. Oil and Natural Gas Prices

The monthly cash distributions the Trust pays to Unitholders are highly dependent on the prices received for NCEP's oil and natural gas production. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and NCEP. These factors include, among others:

- political conditions throughout the world;
- worldwide economic conditions;
- weather conditions;
- the supply and price of foreign oil and natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation measures; and
- government regulations.

Declines in oil or natural gas prices will have an adverse effect on the Trust's operations, financial condition, reserves and ultimately on its ability to pay distributions to Unitholders.

Oil prices were fairly strong throughout the last two years averaging US$26.08 WTI in 2002 as compared to US$25.90 WTI in 2001. The only two quarters in the last two years that saw relatively low prices was the fourth quarter of 2001 when oil prices averaged US$20.43 WTI and the first quarter of 2002 when oil prices averaged US$21.64 WTI.

Monthly AECO prices averaged $4.25/mcf in 2002 as compared to $6.30/mcf in 2001, a decrease of 33%. In January of 2001, the monthly AECO price was $13.62/mcf, a level significantly higher than that experienced in recent years, and declined to $3.74/mcf in December 2001. The AECO gas price was weak throughout the first nine months of 2002 averaging $3.67/mcf; however, increased significantly to $5.26/mcf in the fourth quarter. The daily AECO price reached a high for the year of $6.75/mcf in December 2002.

b. Foreign Currency Exchange Rates

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact NCEP's net production revenue. To the extent that NCEP has engaged or in the future will engage in risk management activities related to commodity prices and foreign exchange rates, through entry into oil or natural gas price hedges and forward foreign exchange contracts or otherwise, NCEP will be subject to unfavourable price changes and credit risks associated with the counterparties with which it contracts.

c. Operations

NCEP's operations are subject to all of the risks normally associated with drilling for and the production and transportation of oil and gas. Such risks and hazards include encountering unexpected formations or pressures, blow-outs, craterings and fires, all of which could result in personal injury, loss of life, property damage and environmental damage. Although NCEP has safety and environmental policies in place to protect operators and employees, as well as to meet regulatory requirements, and although NCEP has liability insurance policies in place, NCEP cannot fully insure against all such risks, nor are all such risks insurable. NCEP may become liable for damages arising from such events against which it cannot insure or against which we 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 payments made by NCEP to the Trust.

d. Competition

There is strong competition relating to all aspects of the oil and gas industry. The Trust competes for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than 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 oil and other products on a world wide basis and as such have greater and more diverse resources to draw on.

e. Environmental Concerns

The oil and natural gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders. Such legislation may be changed to impose higher standards and potentially more costly obligations. Although NCEP has established a reclamation fund for the purpose of funding its estimated future environmental and reclamation obligations based on its current knowledge, there can be no assurance that NCEP will be able to satisfy its actual future environmental and reclamation obligations.

While NCEP has established a reserve for extraordinary and significant site reclamation or abandonment costs, actual abandonment costs incurred in the ordinary course of business during a specific period will reduce the amounts available for distribution to Unitholders.

Although NCEP maintains insurance coverage considered to be customary in the industry, it is not fully insured against certain environmental risks, either because such insurance is not available, or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (compared to sudden and catastrophic damages) is not available. Accordingly, NCEP's properties may be subject to liability due to hazards which cannot be insured against, or have not been insured against due to prohibitive premium costs or for other reasons. In such an event, these environmental obligations will be funded out of NCEP's cash flow and could therefore reduce distributable income payable to Unitholders.

Business-Related Risks

f. Reserves

The value of the Trust Units will depend upon, among other things, the reserves attributable to NCEP's properties. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for NCEP's properties will vary from estimates and those variations could be material. The reserve and cash flow information contained in this annual information form represent estimates only. Reserves and estimated future net cash flow from NCEP's properties have been independently evaluated at the dates indicated by independent firms of oil and gas reservoir engineers. These firms consider a number of factors and make assumptions when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices, production and development costs, severance and excise taxes, and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- timing and amount of capital expenditures;
- marketability of production;
- future prices of oil and natural gas;
- operating costs and royalties; and
- other government levies that may be imposed over the producing life of reserves.

These factors and assumptions were based on prices at the date the relevant evaluations were prepared. If these factors and assumptions prove to be inaccurate, the actual results may vary materially from the reserve estimates. Many of these factors are subject to change and are beyond the Trust's control. For example, evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. Actual reserves and estimated cash flows will be less than those contained in the evaluations to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations. Furthermore, cash flows may differ from those contained in the evaluations depending upon whether capital expenditures and operating costs differ from those estimated in the evaluations.

g. Depletion of Reserves

The Trust has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions by the Trust, absent commodity price increases or cost effective acquisition and development activities, will decline. The Trust will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent capital injections and acquisition and development activities, the Trust's production levels and reserves will decline.

NCEP's reserves and production, and therefore its cash flows, will be highly dependent upon its success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, NCEP's reserves and production will decline over time as reserves are exploited.

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, the Trust's ability to make the necessary capital investments to maintain or expand reserves will be impaired.

Even if the Trust does obtain the necessary capital, there is no assurance of success in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

h. Marketability of Production

The marketability of NCEP's production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as U.S. federal and state, regulation of oil and gas production and transportation, tax and energy policies, general economic conditions, and changes in supply and demand all could adversely affect NCEP's ability to produce and market oil and natural gas. If market factors dramatically change, the financial impact on the Trust's business could be substantial. The availability of markets is beyond NCEP's control.

i. Assessments of Value of Acquisitions

Acquisitions of resource issuers and resource assets will be based in large part on engineering and economic assessments made by independent engineers. These assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas 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 NCEP's control. In particular, the prices of and markets for resource products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based on reports by a firm of independent engineers that are not the same as the firm that NCEP uses for its year end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm used by NCEP. Any such instance may offset the return on and value of the Trust Units.

j. Reliance on Third Party Operators

Continuing production from a property and marketing of product produced from the property are dependent to a large extent on the ability of the operator of the property. NCEP currently operates properties that represent approximately 50% of its total daily production. To the extent the operator fails to perform these functions properly or becomes insolvent, revenue may be reduced.

k. Enforcement of Operating Agreements

Operations of the wells on properties not operated by NCEP are generally governed by operating agreements, which typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to NCEP, the Trust or the Unitholders. NCEP, as owner of working interests in properties not operated by it, will generally have a cause of action for damages arising from a breach of such duty. Although not established by definitive legal precedent, it is unlikely that the Trust or Unitholders would be entitled to bring suit against third-party operators to enforce the terms of the operating agreements; thus, Unitholders will be dependent on NCEP, as owner of the working interest, to enforce such rights.

l. Potential Conflicts of Interest

There may be circumstances in which the interests of NCEP Management, its affiliates or entities managed by them will conflict with those of the Trust and its Unitholders. NCEP Management or its affiliates may acquire oil and gas properties on its own behalf or on behalf of persons other than the Trust. NCEP Management or its affiliates may manage and administer such additional properties, as well as enter into other types of energy-related management, advisory and investment activities. Neither NCEP Management, nor its management or affiliates, carry on their full-time activities on behalf of the Trust and, when acting on their own behalf or on behalf of others, may at times act in competition with the interests of the Trust. Many of the directors and officers of NCEP Management are directors and officers of other entities that currently perform similar advisory functions for certain oil and gas partnerships. In the ordinary course of business, these other entities may acquire properties or explore other business opportunities for the benefit of such partnerships that may be suitable for the Trust. Part of the fees that NCEP Management receives for its services is a fee based on the acquisition and disposition costs of properties and other assets and hence the interests of NCEP Management may differ from the interests of the Trust and Unitholders. The management agreement under which NCEP Management has been engaged expressly provides that NCEP Management will not be liable in these circumstances so long as it exercises that degree of care, diligence and skill that a reasonably prudent person providing advice and management services relating to oil and gas properties in Canada would exercise in comparable circumstances.

Circumstances may arise where members of the board of directors of NCEP or NCEP Management are directors or officers of corporations which are in competition to the interests of NCEP and the trust. No assurances can be given that opportunities identified by such board members will be provided to NCEP and the Trust.

In the event that the Internalization Transaction is completed, NCEP Management would become a wholly-owned subsidiary of the Trust, thereby eliminating certain of the conflicts referred to above.

m. Borrowing

NCEP has secured credit facilities with variable interest rates. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount of NCEP's revenues required to be applied to its debt service before payment of any amounts to the Trust. Certain covenants contained in NCEP's agreements with its lenders may also limit the amounts paid to the Trust and the distributions paid by the Trust to Unitholders.

NCEP's lenders have been provided with security over substantially all of the assets of NCEP. If NCEP becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell NCEP's properties. The proceeds of any such sale would be applied to satisfy amounts owed to NCEP's lenders and other creditors and only the remainder, if any, would be available to the Trust.

Although NCEP believes that the credit facilities are sufficient, there is no assurance that the amounts available thereunder will be adequate for its future obligations or that additional funds can be obtained. The syndicated facility is available on a one year revolving basis. If the revolving period at which the lenders may extend the facility is not renewed for an additional one year period, the loan will convert to a one year term with payments due in three consecutive quarterly amounts equal to one-twentieth of the loan amount with an additional payment due on the last day of the term equal to the balance outstanding. If this occurs, NCEP will have to arrange alternate financing. There is no assurance that such financing will be available or be available on favourable terms. Trust distributions may be materially reduced in these circumstances and the failure to obtain suitable replacement financing may have a material adverse effect on the Trust.

n. Delays in Distributions

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of NCEP's properties, and by those operators to NCEP, payments between any of these 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 the properties or the establishment by the operator of reserves for such expenses. Any of these delays could adversely affect Trust distributions.

o. Unforeseen Title Defects

Although title reviews are conducted prior to any purchase of resource issuers or resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise to defeat NCEP's title to certain assets. A reduction of the distributable cash flow of the Trust and possible reduction of capital could result from such defects.

p. Potential for Write-Downs

Under Canadian accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" which is based, in part, upon estimated future net cash flows from reserves. If the net capitalized costs exceed this limit, the Trust must charge the amount of the excess against earnings. As oil and gas prices decline, the Trust's net capitalized cost may approach and, in certain circumstances, exceed this cost ceiling resulting in a charge against earnings. While these write-downs would not affect cash flow, the charge to earnings could be viewed unfavourably in the market or could limit NCEP's ability to borrow funds or comply with covenants contained in its current or future credit agreements or other debt instruments.

Risks Related to the Securities Markets and the Ownership of Trust Units

q. Nature of Trust Units

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 NCEP. The Trust Units are also dissimilar to conventional debt instruments in that there is no principal amount owing directly to Unitholders. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders do 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.

r. Trading Price of Trust Units

The price per Trust Unit is a function of anticipated Trust Unit distributions, the properties acquired by the Trust and its ability to effect long-term growth in the value of the Trust. 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.

Trust Units will have no value when reserves from the properties can no longer be economically produced or marketed and, as a result, cash distributions do not represent a "yield" in the traditional sense as they represent both return of capital and return on investment. Investors in Trust Units will have to obtain the return of capital invested out of cash flow derived from their investments in the Trust Units during the period when reserves can be economically recovered. Accordingly, there is no assurance that the distributions Unitholders receive over the life of their investment will meet or exceed their initial capital investment.

s. Reliance on NCEP Management and Others

Unitholders are entirely dependent on the management of NCEP and NCEP Management with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters relating to properties and the administration of the Trust. The loss of the services of key individuals who currently comprise the management team of NCEP and NCEP Management could have a detrimental effect on the Trust. NCEP currently operates properties that represent approximately 50% of its total daily production. Investors who are not willing to rely on the management of NCEP and NCEP Management should not invest in the Trust Units.

t. Unitholder Limited Liability

Because of uncertainties in the law relating to investment trusts there is a risk that a Unitholder could be held personally liable for obligations of the Trust (to the extent that claims are not satisfied by the Trust) in respect of contracts or undertakings which the Trust enters into and for certain liabilities arising otherwise than out of contract including claims in tort, claims for taxes and possibly certain other statutory liabilities. The Trust Indenture requires that the operations of the Trust be conducted in such a way as to minimize any such risk and, in particular, where feasible, every written contract or commitment of the Trust must contain an express disavowal of liability upon the Unitholders and a limitation of liability to Trust property. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent as a shareholder is protected from the liabilities of a corporation. It is unlikely, however, that personal liability will attach in Canada to the holders of Trust Units for claims arising out of any agreement or contract containing such a disavowal and limitation of liability. It is also considered unlikely that personal liability will attach in Canada to the holders of Trust Units for claims in tort, claims for taxes and possibly certain other statutory liabilities. In the event that a Unitholder is required to satisfy any obligation of the Trust, such Unitholder will be entitled to reimbursement from any available assets in the Trust.

u. Retraction Right

Cash payments for Trust Units surrendered for retraction are subject to limitations and any notes issued in lieu of a cash payment will not be listed on any stock exchange and no market is expected to develop for such notes.

v. Future Dilution

An objective of the Trust is to continually add to its reserves through acquisitions and through development, and because the Trust does not reinvest its cash flow, the success of the Trust is in part dependent on its ability to raise capital from time to time. Holders of Trust Units may also suffer dilution in connection with future issuances of Trust Units, whether issued pursuant to a financing or acquisition or otherwise.

w. Changes in Legislation

There can be no assurance that income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as the status of mutual fund trusts and resource allowance, will not be changed in a manner which will adversely affect the Trust and Unitholders. There can be no assurance that tax authorities having jurisdiction will agree with how the Trust calculates its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of the Trust or the Unitholders.

x. Changes in the Trust's Status under Tax Laws

It is intended that the Trust continue to qualify as a mutual fund trust for purposes of the Tax Act. However, should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise. The material consequences of losing mutual fund trust status are as follows: (1) Trust Units would not constitute qualified investments for RRSPs, RRIFs, RESPs and DPSPs ("Exempt Plans") upon the Trust ceasing to be a mutual fund trust. 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. An RRSP or RRIF holding Trust Units that are not qualified investments would become taxable on income attributable to the Trust Units while they are not qualified investments. RESPs which hold Trust Units that are not qualified investments may have their registration revoked by the Canada Customs and Revenue Agency; (2) The Trust would be required to pay a tax under Part XII.2 of the Tax Act in respect of amounts distributed to non-resident persons if it ceases to be a mutual fund trust. The payment of Part XII.2 tax by the Trust may have adverse income tax consequences for certain unitholders, since the amount of cash available for distribution would be reduced by the amount of the tax; (3) The Trust would cease being eligible for the capital gains refund mechanism available under the Tax Act upon ceasing to be a mutual fund trust; (4) Units held by Unitholders that are not residents of Canada would become taxable Canadian property upon the Trust ceasing to be a mutual fund trust. Such holders would be subject to Canadian income tax on any gains realized on a disposition of Units constituting taxable Canadian property; and (5) The Trust would be subject to alternative minimum tax under Part I of the Tax Act.

14) GOVERNANCE OF THE TRUST AND NCEP

a. Trust Indenture

1. General

The Trust is an investment trust created pursuant to the Trust Indenture and governed by the laws of the Province of Ontario. The Trust has been established for the purpose of holding royalties granted by NCEP and acquiring, directly and indirectly, securities and royalties of oil and gas companies, oil and gas properties and other related assets.

An unlimited number of Trust Units are issuable pursuant to the Trust Indenture. As at December 31, 2002, 54.1 million Trust Units were issued and outstanding. Each Trust Unit represents an equal undivided beneficial interest in the assets of the Trust. Each outstanding Trust Unit is entitled to an equal share of distributions by the Trust and, in the event of termination of the Trust, the net assets of the Trust. All Trust Units rank equally. Each Trust Unit entitles the holder thereof to one vote at all meetings of Unitholders.

2. Trustee

The Trust Indenture provides that the Trustee is required 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, will exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The Trustee, where it has met its standard of care, will be indemnified out of the assets of the Trust for any actions, suits or proceedings commenced against the Trustee in respect of the Trust and for costs, taxes and other liabilities incurred by the Trustee in respect of the administration or termination of the Trust but will have no additional recourse against Unitholders. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

3. Issuance of Trust Units

The Trust Indenture provides that Trust Units may be issued whether fully paid or in the context of an offering, on an instalment basis, subject to the approval of the NCEP Board of Directors, for the purposes of, among other things, acquiring, or raising capital to acquire, net royalty interests, securities of oil and gas companies and oil and gas properties and related assets. The Trust Indenture also provides that the NCEP Board of Directors may also authorize the creation and issuance from time to time of rights, warrants or options to subscribe for Trust Units or other securities convertible or exchangeable into Trust Units.

4. Distributions

The Trust makes monthly cash distributions of the distributable cash flow received by the Trust in each month. Distributions are made on the last business day of each month to Unitholders of record as at the close of business on the tenth business day preceding each such distribution date.

5. Retraction Right in Respect of Trust Units

Trust Units are retractable 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 requesting retraction. Upon receipt of the retraction request by the Trust, all rights to and under the Trust Units tendered for retraction shall be surrendered and the holder thereof shall be entitled to receive a price per Trust Unit (the "Retraction Price") equal to the lesser of: (i) 85% 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 were surrendered for retraction (the "Retraction Date"); and (ii) the "closing market price" on the principal market on which the Trust Units are quoted for trading on the Retraction Date.

The aggregate Retraction Price payable by the Trust in respect of any Trust Units surrendered for retraction during any calendar month shall be satisfied by way of a cash payment on the last day of the following month; provided that the entitlement of Unitholders to receive cash upon the retraction of their Trust Units is subject to the limitations that: (i) the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for retraction in the same calendar month shall not exceed $100,000 (provided that such limitation may be waived in the discretion of NCEP Management; (ii) at the time such Trust Units are tendered for retraction the outstanding Trust Units shall be listed for trading on a Canadian exchange or traded or quoted on any other market which NCEP Management considers, in its sole discretion, provides representative fair market value prices for the Trust Units; and (iii) the normal trading of Trust Units is not suspended or halted on any stock exchange on which the Trust Units are listed (or, if not listed on a stock exchange, on any market on which the Trust Units are quoted for trading) on the Retraction Date or for more than five trading days during the 10 day trading period commencing immediately after the Retraction Date.

If a Unitholder is not entitled to receive cash upon the retraction of Trust Units as a result of the foregoing limitations, then the Retraction Price shall, subject to any applicable regulatory approvals, be paid and satisfied by way of a distribution in specie of debt securities of NCEP then held by the Trust (the "NCEP Notes") having a rate of interest which is no less than the highest rate of interest charged by the Trust to NCEP. If the Trust does not hold NCEP Notes having a sufficient principal amount outstanding to effect such payment, the Trust will be entitled to create and, subject to any applicable regulatory approvals, issue in satisfaction of the Retraction Price its own debt securities (the "Trust Retraction Notes") having such terms and conditions as NCEP Management may determine and with recourse of the holder limited to the assets of the Trust.

The retraction right described above will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. The NCEP Notes, Trust Retraction Notes or other assets which may be distributed in specie to Unitholders in connection with a retraction will not be listed on any stock exchange and no market is expected to develop in such NCEP Notes or Trust Retraction Notes.

6. Meetings of Unitholders

The Trust Indenture provides that the following must be approved by Special Resolution: (i) removing or appointing the Trustee (subject to exceptions such as the Trustee failing to qualify to act as trustee and insolvency-related events); (ii) amendments to the Trust Indenture (except as described under "Governance of the Trust and NCEP - Trust Indenture - Amendments to the Trust Indenture"); (iii) amendments to the Royalty Agreement; (iv) subdivisions or consolidations of Trust Units; (v) the termination of the Trust; (vi) any matter required to be approved by Special Resolution under the Royalty Agreement, the Management Agreement or the Unanimous Shareholder Agreement; (vii) the sale of the property of the Trust as an entirety or substantially as an entirety; (viii) directing the Trustee to exercise, or refrain from exercising, any power under the Trust Indenture; (ix) directing the Trustee with respect to legal proceedings in connection with the Trust; and (x) approving the disposition of properties having a value in excess of 35% of the asset value of the properties of the Trust.

The Trust holds meetings of Unitholders on an annual basis for the purposes of electing three directors of NCEP and two such individuals as members of the Executive Committee and for the purposes of appointing auditors. See "Governance of the Trust and NCEP - NCEP Unanimous Shareholder Agreement".

A meeting of Unitholders may be convened at any time and for any purpose by the Trustee and must be convened if requested by the holders of not less than 25% of the Trust Units then outstanding by a written requisition. A requisition must specify the purpose for which the meeting is to be called.

7. Amendments to the Trust Indenture

Except as specifically provided otherwise, the Trust Indenture may only be amended by Special Resolution.

The Trustee is entitled to make certain amendments to the Trust Indenture without the approval of the Unitholders if authorized to do so by the board of directors of NCEP Management. These include amendments for the purposes of ensuring compliance with applicable laws, ensuring the Trust satisfies the requirements of the Tax Act to be a unit trust and mutual fund trust, providing additional protection for Unitholders, removing conflicts or inconsistencies (if such amendment is not detrimental to the interests of the Unitholders) and correcting ambiguities or errors (provided the rights of the Trustee and the Unitholders are not prejudiced thereby).

8. Limitation of Non-Resident Ownership

The Trust, by or through NCEP Management, is required to take all necessary steps to monitor the ownership of Trust Units to carry out the intention that the Trust qualify as a unit trust and a mutual fund trust under the Tax Act. If at any time the Trust or NCEP Management becomes aware that the beneficial owners of 50% or more of the Trust Units then outstanding are or may be non-residents of Canada (as defined in the Tax Act) or that such a situation is imminent, the Trust, by or through NCEP Management, shall take such action as may be necessary to carry out such intention.

9. Termination of the Trust

Unless the Trust is terminated earlier, the Trustee will commence to wind up the affairs of the Trust on December 31, 2066. If, in the opinion of the Board of Directors and the Executive Committee of NCEP, it would be in the best interests of the Unitholders to wind up the Trust, the Trust will be wound up. In addition, the Unitholders may, by Special Resolution, decide to terminate the Trust. Upon a decision to terminate the Trust, the Trustee will sell the assets of the Trust and distribute the net proceeds to Unitholders, or wind up the Trust as otherwise directed by the Unitholders or the Board of Directors.

10. Borrowing

The Trust and NCEP may finance the acquisition of securities and royalties of oil and gas companies, oil and gas properties and related assets and capital expenditures in respect thereof through the issuance of equity or debt securities.

The Trust and NCEP are also permitted to borrow funds and to grant security in respect of their assets, in priority to the royalty granted by NCEP, for the purposes of financing the purchase of oil and gas properties and related assets, capital expenditures in respect thereof or the purchase of securities and royalties of oil and gas companies or to facilitate the repurchase of Trust Units.

The maximum amount which may be borrowed for such purposes shall not exceed 40% of the aggregate Asset Value of all properties and other resource assets (including, where applicable, those being acquired) held by Petrofund, NCEP and their subsidiaries and 40% of the net asset value of non-reserve based assets. "Asset Value" is defined as the present worth of all of the estimated pre-tax net cash flow from the proved reserves and 50% of the estimated pre-tax net cash flow from the probable reserves shown in the most recent engineering report relating thereto, discounted at an annual rate equal to the then current annual yield of long term (10 year) Government of Canada bonds plus 400 basis points, subject to a maximum rate of 10% and using escalating price and cost assumptions.

In calculating the 40% borrowing restriction, amounts borrowed by the Trust or NCEP which the Trust or NCEP has the right to effectively repay or cause to be repaid through the issuance of Trust Units will not form part of the 40% borrowing restriction provided the Trust or NCEP, as applicable, has agreed to cause payment of such indebtedness to be made through the issuance of Trust Units prior to the maturity of such indebtedness to the extent necessary to ensure that the aggregate borrowings of the Trust and NCEP do not then exceed the 40% borrowing restriction.

b. NCEP Unanimous Shareholder Agreement

The following is a summary of the material terms of the Unanimous Shareholder Agreement.

1. Directors of NCEP

The Unanimous Shareholder Agreement provides that the Board of Directors of NCEP shall consist of six directors and that the Unitholders are entitled to nominate three of such directors and NCEP Management is entitled to nominate three of such directors. The Trust is to hold meetings on an annual basis for the purposes of implementing the appointment of such directors.

In the event that the Internalization Transaction is completed, the Unanimous Shareholder Agreement will be terminated and Unitholders will have the right to designate all of the nominees to be elected to the Board of Directors of NCEP.

2. Executive Committee

The Unanimous Shareholder Agreement provides for the establishment of the Executive Committee of the Board of Directors of NCEP comprised of three members, two of whom will be directors of NCEP nominated by Unitholders and one of whom will be a director nominated by NCEP Management. Any decision with respect to the following matters must be approved by the Board of Directors and the Executive Committee to be effective:

i. any acquisition or disposition of oil and gas properties or other assets by the Trust or NCEP in excess of $10 million;

ii. any borrowing of funds or granting of security in oil and gas properties or other assets held by the Trust or NCEP; and

iii. any related party transaction proposed to be entered into by the Trust or NCEP, including any amendment to or other matter involving the Management Agreement.

In the event that the Internalization Transaction is completed, it is expected that the Board will no longer have an Executive Committee.

3. *Distribution Policy*

The Unanimous Shareholder Agreement provides that NCEP will, subject to applicable law, on the last business day of each month distribute to the Trust the royalties payable under the Royalty Agreement in respect of the second calendar month immediately preceding such distribution date and all other cash flow available for distribution. Such distributions by NCEP may take the form of dividends or other distributions or payments in respect of its shares or other securities outstanding from time to time, interest and principal payments in respect of indebtedness owing by NCEP to the Trust or royalty income in respect of royalties held by the Trust.

c. Royalty Agreement

Under the Royalty Agreement, NCEP grants net royalties to the Trust of 99% of the revenue received in respect of each property held by NCEP net of certain related costs and expenses.

The net royalty consists of a 99% share of the royalty income from NCEP's properties. Net royalty income is gross production revenue less the following amounts:

- operating costs;
- debt service charges;
- general and administrative costs;
- management fees;
- taxes or other charges payable by NCEP; and
- amounts paid into the cash reserve established by NCEP to fund the payment of operating costs, capital expenditures, reclamation obligations, general and administrative costs, management fees and debt service charges.

Gross production revenues essentially consist of cash proceeds from the sale of oil, natural gas and other substances produced from NCEP's properties, any drilling credits resulting from any expenditures made on the properties (other than drilling credits applied to capital expenditures), amounts arising out of "take or pay" contracts for oil, gas and other products and any other consideration received by NCEP as a result of its ownership of the properties with the exception of revenues from the rental, sale or exchange of tangible assets and the proceeds from any unitization or pooling equalization payments relating to tangible assets and excluding the proceeds from the sale of any properties.

Operating costs are all expenditures from or allocated to a property made in connection with the maintenance of a property or any activities related to producing, gathering, treating, storing, compressing, processing and transporting oil, gas and other substances including, without limitation, overriding royalties and lessors' royalties.

NCEP is required to pay the royalty on the last business day of each month.

The properties in respect of which the Trust has net royalties may be encumbered by security granted by NCEP to secure its loan obligations. The obligations of NCEP to pay net royalties to the Trust are not secured. Borrowings are subject to the 40% borrowing restriction referred to under "Governance of the Trust and NCEP - Trust Indenture - Borrowing".

The Royalty Agreement provides that the sale of a property and the royalty thereto shall be approved by the NCEP Board of Directors, if the sale proceeds exceed $10,000,000.

d. Management Agreement

NCEP Management is incorporated under the laws of Ontario. The principal office of NCEP Management is located at Suite 600, 444 - 7th Avenue S.W., Calgary, Alberta, T2P 0X8 and the corporate office is located at 130 King Street West, Suite 2850, Toronto, Ontario, M5X 1A4. As of the date hereof, the sole shareholder of NCEP Management is Petro Assets Inc., a company beneficially owned by The Driscoll Family Trust, a trust established for the benefit of the family of John F. Driscoll, an officer and director of NCEP and NCEP Management.

Under the Management Agreement, NCEP and the Trust have engaged NCEP Management to, among other things, identify, assess and assist in the acquisition, disposition and ongoing management of NCEP's properties, to administer all matters relating to the net royalties granted by NCEP to the Trust and to manage and administer the Trust and all matters relating to the Trust Units.

The current term of the Management Agreement expires on March 3, 2003. It is to be automatically renewed for successive three-year terms unless terminated by either NCEP Management or the Trust:

i. if the asset value of all properties is less than $200 million, upon not less than two years' notice given in writing prior to the next expiry date of the Management Agreement;

ii. if the asset value of all properties is $200 million or more but less than $500 million, upon not less than three years' notice given in writing; and

iii. if the asset value of all properties is $500 million or more, upon not less than five years' notice given in writing.

Asset value for this purpose is defined as the present worth of all of the estimated pre-tax net cash flow from the proved reserves and 50% of the estimated pre-tax net cash flow from the probable reserves shown in the most recent engineering report relating thereto, discounted at an annual rate equal to the then current annual yield of long term (10 year) Government of Canada bonds plus 400 basis points, subject to a maximum rate of 10% and using escalating price and cost assumptions. If there is a material change to such property, a new report will be prepared and used to determine the fair market value of such property. Termination of the Management Agreement by the Trust requires the approval of the Unitholders by Special Resolution.

In addition, the Management Agreement may be terminated in the event that NCEP Management institutes bankruptcy proceedings, seeks relief under bankruptcy laws, appoints a receiver, makes an assignment for the benefit of its creditors, suspends transaction of its usual business, is declared bankrupt or insolvent or defaults in the performance of a material obligation under the Management Agreement which default is not remedied within 30 days following receipt of notice of the default.

In exercising its powers and discharging its duties under the Management Agreement, NCEP Management is required to exercise that degree of care, diligence and skill that a reasonably prudent person providing advice and management services relating to oil and gas properties in Canada would exercise in comparable circumstances. NCEP Management is indemnified by NCEP and the Trust against all liabilities and expenses arising from or related in any manner to the Management Agreement, unless NCEP Management has not acted in accordance with the foregoing standard of care.

The Management Agreement provides that NCEP Management is to receive monthly management fees equal to 3.25% (reduced from 3.75%, effective January 1, 2002) of net production revenue less Crown royalties and other Crown charges attributable to each property for the applicable period. As a matter of practice, the management fee has historically been paid on a quarterly basis. Net production revenue is gross production revenue less operating costs. Total management fees paid to NCEP Management for the fiscal year ended December 31, 2002 were $4.7 million.

NCEP Management receives acquisition fees equal to 1.5% (reduced from 1.75%, effective January 1, 2002) of the purchase costs of all oil and gas properties, oil and gas companies and other related assets acquired by NCEP, but excluding the cost of such fee paid. In the event that oil and gas properties, oil and gas companies or other related assets are sold, NCEP Management also receives disposition fees of 1.25% (reduced from 1.5%, effective January 1, 2002) of the sale price of the assets sold. In the event that the Trust acquires a royalty interest directly from a person other than NCEP, such fees are calculated as though NCEP had acquired the property and granted the royalty interest in respect of the property. No fees are payable to NCEP Management in connection with the acquisition of replacement properties. Total acquisition fees paid to NCEP Management for the fiscal year ended December 31, 2002 were $1.3 million. NCEP Management also received $116,000 in respect of dispositions.

NCEP Management is entitled to be reimbursed by NCEP for general and administrative costs and by the Trust for trust expenses. In no event is NCEP responsible for the payment in any fiscal year of the Trust of general and administrative costs in excess of the greater of (a) 5% of the gross production revenue for such fiscal year and (b) $240,000. To the extent that general and administrative costs for any fiscal year of the Trust exceed such maximum amount NCEP is entitled to set off and deduct such excess amount from its liability to pay management fees to NCEP Management. If any fiscal year is less than 12 months, such calculations are pro rated.

NCEP Management has retained NMSI to provide non-exclusive administrative services, including accounting, treasury, income tax, information system, Unitholder reporting and communication and legal and human relations services on its behalf to NCEP and the Trust. NMSI is wholly owned by John Driscoll, an officer and director of NCEP and NCEP Management.

During the period ended December 31, 2002, NMSI received $11.7 million for accounting and administrative services, which is included in general and administrative expenses of the Trust, $0.8 million for project sourcing and evaluation services, which have been capitalized to oil and gas properties, and $300,000 for marketing and other related equity issue costs. Such amounts were reimbursed to NCEP Management under the Management Agreement.

If the Internalization Transaction is completed, all management, acquisition and disposition fees payable to NCEP Management would be eliminated effective January 1, 2003. It is contemplated that

NSMI would be acquired by NCEP Management immediately prior to completion of the Internalization Transaction.

15) UNITHOLDER PROTECTION RIGHTS PLAN

The Trust has entered into an agreement with Montreal Trust Company of Canada dated May 14, 1999 creating a unitholder protection rights plan (the "Rights Plan"). The Rights Plan was approved by the Unitholders at a meeting held on November 12, 1999.

The Rights Plan utilizes the mechanism of the Permitted Bid (as hereinafter described), to ensure that a person seeking control of the Trust gives the Trust sufficient time in which to evaluate the bid, negotiate with the initial bidder and encourage competing bids to emerge. The purpose of the Rights Plan is to protect Unitholders by requiring all potential bidders to comply with the conditions specified in the Permitted Bid provisions failing which such bidders will become subject to the dilutive features of the Rights Plan.

Generally, to qualify as a Permitted Bid, a bid must be made to all of the Unitholders of the Trust and must be open for 60 days after the bid is made. If more than 50% of the Units held by Independent Unitholders (being Unitholders other than the bidder, its affiliates and persons acting jointly or in concert with it) are deposited or tendered to the bid and not withdrawn, the bidder may take up and pay for such Units. The take-over bid must then be extended for a further period of 10 business days on the same terms to allow those Unitholders who did not initially tender their Units to tender to the take-over bid if they so choose. Thus, there is no coercion to tender during the initial 60-day period because the bid must be open for acceptance for at least 10 days after the expiry of the initial tender period.

The term of the Rights Plan is five years from the date of the Rights Plan, May 14, 1999, at which time the right to exercise a right will terminate, unless it is previously terminated in accordance with the terms of the Rights Plan.

On May 14, 1999, one right (a "Right") was issued for each Unit outstanding which is, until the Separation Time (as defined below), evidenced by a legend imprinted on a certificate for the Units. One Right will also attach to any subsequently issued Units. The initial exercise price of the Rights is $60.00 per Unit (the "Exercise Price"), subject to appropriate anti-dilution adjustments.

The Rights will separate from the Units to which they are respectively attached and will become exercisable at the time (the "Separation Time") which is 10 days after the earlier of (i) the announcement that a person has become the beneficial owner of 20% or more of the Units, other than by an acquisition pursuant to a Permitted Bid, or (ii) the commencement or announcement date, or such later date as may be determined by the directors of NCEP Management in respect of a take-over bid to acquire 20% or more of the Units, other than by an acquisition pursuant to a Permitted Bid. After the Separation Time and prior to the occurrence of a Flip-in Event (as defined below), each Right will entitle the holder thereof to purchase, upon payment of the Exercise Price, one Unit, subject to anti-dilution adjustments.

The acquisition by a person (an "Acquiring Person"), including others acting in concert, of 20% or more of the Units, other than by way of a Permitted Bid, is referred to as a "Flip-in Event". Any Rights held by an Acquiring Person on or after the earlier of the Separation Time or the first date of public announcement by the Trust or an Acquiring Person that an Acquiring Person has become such, will become void upon the occurrence of a Flip-in Event. Ten trading days after the occurrence of the Flip-in Event, the Rights (other than those held by the Acquiring Person) will permit the holder to purchase, upon payment of the Exercise Price of $60.00, Units with a total market value of $120.00 (i.e., at a 50% discount).

Until a Right is exercised, the holder of such Right, as such, will have no rights as a Unitholder of the Trust.

16) DISTRIBUTION REINVESTMENT AND UNIT PURCHASE PLAN

The Trust has a distribution reinvestment and unit purchase plan (the "Plan"). The Plan allows Unitholders resident in Canada to acquire additional Trust Units by reinvesting their cash distributions or by making optional cash payments.

Under the Plan, Unitholders may direct the Trust to reinvest cash distributions on the Trust Units to acquire, in the discretion of NCEP Management, existing Trust Units through the facilities of the TSX or newly issued Trust Units from treasury. In addition, Unitholders may purchase newly issued Trust Units directly from the Trust by making cash payments to the Trust, subject to a minimum of $100 and a maximum of $1,000 per calendar quarter.

Cash distributions will be applied to the purchase of Trust Units on the TSX at prevailing market prices for a period of 10 trading days following the distribution date. The cost of such Trust Units to participants will be the average cost of the Trust Units purchased. If insufficient Trust Units are purchased during the said 10 trading day period, the uninvested portion will be applied to purchase Trust Units from treasury.

Optional cash payments will be applied to the purchase of newly-issued Trust Units on the cash distribution date following receipt.

In 2002, the Trust issued 288,981 Trust Units under the Plan.

17) DIRECTORS AND OFFICERS

a. NCEP

Information concerning the directors and officers of NCEP as of the date hereof is set out below:

Name and Municipality of Residence	Position	Director Since
John F. Driscoll[(1)] Toronto, Ontario	Chairman, Chief Executive Officer and Director	July 15, 1988
Jeffery E. Errico Calgary, Alberta	President and Chief Operating Officer	
Glen C. Fischer Calgary, Alberta	Senior Vice-President, Operations	
Vince P. Moyer Calgary, Alberta	Senior Vice-President, Finance	
Jeffrey D. Newcommon Calgary, Alberta	Senior Vice-President, Exploration and Land	
Gordon Thompson Toronto, Ontario	Senior Vice-President, Corporate Development	
Noel Cronin Calgary, Alberta	Vice-President, Production	
John Vooglaid King City, Ontario	Secretary-Treasurer and Vice-President, Finance	

Sandra S. Cowan(2) Toronto, Ontario	Director	January 17, 2002
John Nestor Mississauga, Ontario	Director	September 27, 1988
Frank Potter(1)(2) Toronto, Ontario	Director	November 1, 2000
Peter N. Thomson(1)(2) Nassau, Bahamas	Director	November 1, 2000
Richard Zarzeczny Stouffville, Ontario	Director	October 5, 1995

Notes:

(13) Member of the Executive Committee.

(14) Member of the Audit Committee.

Set forth below are the particulars of the principal occupations of each director and officer of NCEP for the past several years.

John F. Driscoll founded and has been President of J.F. Driscoll Investment Corp., Toronto, since 1981 and is the founder and Chairman and Chief Executive Officer of the NCE Resources Group in Toronto. He specializes in oil and gas investments and petroleum related advisory, management and consulting services. Mr. Driscoll received his Bachelor of Science degree from the Boston College Business School in 1964 and in 1967 attended the New York Institute of Finance. Resource issuers of which Mr. Driscoll is or has been an officer and/or director, or in respect of which he is or has been an officer and/or director of the manager or general partner, have invested or managed the investment of more than $1.3 billion in the acquisition, development and exploration of resource properties and securities of resource issuers.

Jeffery E. Errico is a Professional Engineer who received a Bachelor of Science degree in Chemical Engineering from the University of British Columbia in 1973. He has over 20 years experience in the oil and gas industry, serving as Vice-President, Operations of Deminex Canada Limited prior to joining NCE Resources Group in April, 1995.

Glen C. Fischer is a Professional Engineer who received a Degree in Mechanical Engineering from the University of Calgary. He has over 20 years of engineering and management experience in the oil and gas industry and from 1984 to 1996 was Manager, Engineering & Operations for ATCOR Ltd. and its successor Canadian Forest Oil Ltd. Mr. Fischer joined the NCE Resources Group in July, 1996.

Vince P. Moyer received his Chartered Accountant's designation in 1975 and a Master of Business Administration degree in 1972 from the University of Manitoba, majoring in finance. From 1981 to 1991 he held various positions with Enron Oil Canada Ltd., including most recently as Vice-President, Finance and Administration from 1986 to 1991. Mr. Moyer joined the NCE Resources Group in June, 1991.

Jeffrey D. Newcommon received his Bachelor of Arts degree in Finance and Economics from the University of Western Ontario in 1983. From 1984 to 1995 he held various positions with Canadian Hunter Exploration Ltd., including, most recently, Land Manager. He joined the NCE Resources Group in April, 1995.

Gordon Thompson, FICB, has 35 years experience in the financial services sector. From 1997 to 2000, Mr. Thompson was a Director at the CIT Group (formerly Newcourt Capital Inc.) where he was responsible for developing asset financing opportunities in the public and private sectors across Canada. From 1995 to 1997 Mr. Thompson was a key player in the successful growth of Newcourt Credit Group as Vice-President Business Development. Mr. Thompson is the former President and CEO of the Canadian Finance and Leasing Association and was Vice-President, Toronto District with the Bank of Montreal. He is also a director of a number of not-for-profit organizations, and recently served as co-chair of the Toronto Waterfront Revitalization Task Force.

Noel Cronin is a Professional Engineer with over 20 years of diversified experience in the petroleum industry in western Canada, including reservoir management/exploitation, economic evaluations, joint interests and production operations. He has worked for various Calgary-based oil and gas producers during his career and joined the NCE Resources Group as Production Manager in 1997.

John Vooglaid received his Chartered Accountant's designation in 1982. Since June, 1986, he has been a Vice-President of the NCE Resources Group. From 1978 to June, 1986, he was with the resource audit group of a major public accountancy firm. He earned a Bachelor of Arts (Honours) degree in Economics from the University of Toronto in 1977.

Sandra S. Cowan has been Partner and General Counsel of EdgeStone Capital Partners since January 15, 2002. From August, 1999 to January 15, 2002, Ms. Cowan was a partner in the law firm of Goodman and Carr LLP in Toronto, and prior to August, 1999, Ms. Cowan was a partner in the law firm of Aird & Berlis in Toronto.

John Nestor has been President of John Nestor & Associates Ltd., a firm of management consultants, since 1972 and is a director of a number of publicly-listed corporations. He also serves as a director of a number of other corporations in the NCE Resources Group. Mr. Nestor received a Bachelor of Applied Science degree in Engineering Physics, specializing in geophysics, in 1959 from the University of Toronto. He received his Master of Business Administration degree with honours in 1961 from the University of Toronto, majoring in marketing and finance.

Frank Potter has been the Chairman since 1995 of Emerging Markets Advisors, Inc., a Toronto-based consultancy that assists corporations in making and managing direct investments internationally. Prior thereto, Mr. Potter was executive director of The World Bank Group in Washington, and was subsequently senior advisor at the federal Department of Finance. Mr. Potter is a director of a number of public and private corporations and public service organizations.

Peter Nesbitt Thomson has been the Chairman of the Board of the West Indies Power Corporation Limited for over 10 years. He attended Lower Canada College and Sir George Williams College. He received an honorary Doctorate of Laws Degree from St. Thomas University, Fredericton, New Brunswick. Beginning his professional career in Montreal with investment dealer Nesbitt Thomson, he later was Chairman, President and Chief Executive Officer of Power Corporation of Canada. He has served as a director of numerous Canadian companies, including Petrofina Canada Limited and Norcen Energy Resources Ltd.

Richard J. Zarzeczny is principal and founder of Canadian Enerdata Limited (established in 1984), an energy and economic consulting firm specializing in oil and gas industry analysis and forecasting. He publishes The Natural Gas Market Report, the leading Canadian newsletter covering natural gas markets, including regular price and market activity surveys. He also serves as a director of a number of other corporations in the NCE Resources Group. Mr. Zarzeczny graduated from Simon Fraser University in 1980 with a Master of Arts degree in Economics specializing in econometrics and in 1975 received a Master of Arts degree in Mathematics from the University of Regina.

b. NCEP Management

Information concerning the directors and officers of NCEP Management as of the date hereof is set out below:

Name and Municipality of Residence	Position	Director Since
John F. Driscoll Toronto, Ontario	Chairman, Chief Executive Officer and Director	July 26, 1988
Jeffery E. Errico Calgary, Alberta	President and Chief Operating Officer	
Glen C. Fischer Calgary, Alberta	Senior Vice-President, Operations	
Vince P. Moyer Calgary, Alberta	Senior Vice-President, Finance	
Jeffrey D. Newcommon Calgary, Alberta	Senior Vice-President, Exploration and Land	
Gordon Thompson Toronto, Ontario	Senior Vice-President, Corporate Development	
Noel Cronin Calgary, Alberta	Vice-President, Production	
John Vooglaid King City, Ontario	Secretary-Treasurer and Vice-President, Finance	

Details concerning the principal occupations of each director and officer of NCEP Management are set out under "Directors and Officers - NCEP".

The term of office of each director of NCEP and NCEP Management listed above is from the date elected until the next annual meeting, or until his or her successor is elected or appointed.

c. Ownership of Trust Units by Directors and Officers

As at December 31, 2002, the directors and executive officers of NCEP and NCEP Management beneficially owned, directly or indirectly, 261,502 Trust Units representing less than 1% of the issued and outstanding Trust Units.

18) MARKET FOR SECURITIES

The Trust Units are listed and posted for trading on the TSX under the symbol "NCF.UN" and the American Stock Exchange under the symbol "NCN".

19) CONFLICTS OF INTEREST

NCEP Management, a member of the NCE Resources Group, was formed for the purpose of acting as manager of the Trust and NCEP. The NCE Resources Group provides consulting and management services to a number of private and public entities which are involved in the oil and natural gas business, some of which employ management, operational, exploitation and development strategies similar to those used by the Trust. As a result, there may be situations in which the interest of certain members of the NCE Resources Group will conflict with those of the Trust. As well, it is possible that NCEP Management may acquire oil and gas properties on behalf of entities other than the Trust and may establish other private or public entities which carry on businesses substantially similar to that of the

Trust. NMSI, which provides services to NCEP Management, provides similar services to other members of the NCE Resources Group. Certain of the directors and officers of NCEP Management and NCEP are also directors and officers of other members of the NCE Resources Group. As well, the executive officers of NCEP Management, NCEP and NMSI are not full time employees of either NCEP or NCEP Management and will be providing services to other members of the NCE Resources Group and other entities. Directors of NCEP Management and NCEP devote such amounts of time to the affairs of such corporations as is reasonably required to fulfil their duties as directors. The officers of NCEP Management and NCEP are also officers of other entities in the NCE Resources Group and, as a group, devote approximately 75% of their time to the affairs of the Trust and NCEP.

At the present time, both the Trust and one or more other members of the NCE Resources Group have access to capital resources which are expected to be used to fund acquisition programmes. It is a policy of NCEP, NCEP Management and the NCE Resources Group that in the event that opportunities become available to the NCE Resources Group which meet the objectives and criteria of a number of members thereof, including the Trust, each qualifying member will be entitled to participate with the other members in the opportunity on a pro-rata basis based on the funds available for expenditure upon the opportunity by each member which is permitted and elects to make such an investment based on its investment criteria and any time constraints on the investment of its funds.

Generally, all conflicts of interest are dealt with on a basis consistent with the objectives of each member of the NCE Resources Group and the duty to deal honestly, fairly and in good faith with each entity.

In the event that the Internalization Transaction is completed, NCEP Management would become a wholly-owned subsidiary of the Trust, thereby eliminating certain of the conflicts referred to above.

20) ADDITIONAL INFORMATION

Additional financial information is provided in the Trust's audited consolidated financial statements for the year ended December 31, 2002.

The Trust will provide to any person, upon request to NCEP Management, the manager of the Trust:

i. when the securities of the Trust are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities,

    1. one copy of the annual information form of the Trust, together with one copy of any document, or the pertinent pages of any document, incorporated by reference therein,

    2. one copy of the comparative financial statements of the Trust for its most recently completed financial year together with the accompanying report of the auditor and one copy of any interim financial statements of the Trust subsequent to the financial

statements for its most recently completed financial year,

3. one copy of the information circular of the Trust in respect of its most recent annual meeting of Unitholders that involved the election of directors or one copy of any annual filing prepared in lieu of that information circular, as appropriate, and

4. one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

ii. at any other time, one copy of any other documents referred to in (a)(i), (ii) and (iii) above, provided the Trust may require the payment of a reasonable charge if the request is made by a person who is not a security holder of the Trust.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the issuer's securities, options to purchase securities and interests of insiders in material transactions, if applicable, is contained in the issuer's information circular for its most recent annual meeting of Unitholders that involved the election of directors, and additional financial information is provided in the issuer's comparative financial statements for its most recently completed financial year.

For additional copies of this annual information form please contact:

NCE Petrofund Management Corp.
444 - 7th Avenue, S.W.
Suite 600
Calgary, Alberta
T2P 0X8

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

NCE Petrofund (the "Registrant") undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the staff of the Securities and Exchange Commission ("SEC"), and to furnish promptly, when requested to do so by the SEC staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

B. Consent to Service of Process

The Registrant has previously filed with the SEC a Form F-X in connection with the Trust Units.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.
DATED: March , 2003

NCE PETROFUND, by NCE PETROFUND MANAGEMENT CORP., As manager of NCE PETROFUND

By: /s/ John Vooglaid
Name: John Vooglaid
Title: Chief Financial Officer

CERTIFICATION

I, John Vooglaid, chief financial officer of NCE Petrofund Management Corp. (the "Manager"), the manager of NCE Petrofund (the "Trust"), certify for the Manager on behalf of the Trust that:

1. I have reviewed this annual report on Form 40-F of the Trust;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Trust as of, and for, the periods presented in this annual report;

4. The Trust's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Trust and have:

   (a) Designed such disclosure controls and procedures to ensure that material information relating to the Trust, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Evaluated the effectiveness of the Trust's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

   (c) Presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Trust's other certifying officers and I have disclosed, based on our most recent evaluation, to the Trust's auditors and the audit committee of the board of directors (and persons performing the equivalent function):

   (a) All significant deficiencies in the design or operation of internal controls which could adversely affect the Trust's ability to record, process, summarize and report financial data and have identified for the Trust's auditors any material weaknesses in internal controls; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the Trust's internal controls; and

6. The Trust's other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

By: /s/ John Vooglaid
Title: V.P. Finance, Secretary-Treasurer
Date: March 20, 2003.

CERTIFICATION

I, John Driscoll, chief executive officer of NCE Petrofund Management Corp. (the “Manager”), the manager of NCE Petrofund (the “Trust”), certify for the Manager on behalf of the Trust that:

1. I have reviewed this annual report on Form 40-F of the Trust;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the Trust as of, and for, the periods presented in this annual report;

4. The Trust’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the Trust and have:

   (a) Designed such disclosure controls and procedures to ensure that material information relating to the Trust, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

   (b) Evaluated the effectiveness of the Trust’s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the “Evaluation Date”); and

   (c) Presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The Trust’s other certifying officers and I have disclosed, based on our most recent evaluation, to the Trust’s auditors and the audit committee of the board of directors (and persons performing the equivalent function):

   (d) All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant’s ability to record, process, summarize and report financial data and have identified for the registrant’s auditors any material weaknesses in internal controls; and

   (e) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal controls; and

6. The registrant’s other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

By: /s/ John Driscoll
Title: Chief Executive Officer
Date: March 20, 2003.

EXHIBIT INDEX

Exhibits	Description
1	Management's Discussion and Analysis For the Year Ended December 31, 2002
2	Audited Consolidated Financial Statements, Including the Notes thereto, December 31, 2002 and 2001 and for the years ended December 31, 2002, 2001 and 2000, together with the Auditor's Report thereon
3	Consent of Deloitte & Touche LLP.

EXHIBIT 1

Management's Discussion & Analysis

As discussed in Note 3 (d) to the financial statements, NCE Petrofund (the "Trust") and NCE Petrofund Corp. ("NCEP") were consolidated on November 1, 2000 and the prior years have been restated to conform to the revised presentation. On July 6, 2001, the Trust units were consolidated on a one-for-three basis. All unit-related numbers including units outstanding, options outstanding and option prices, net income per unit and distributions per unit have been restated for all prior periods to reflect this consolidation.

The following discussion and analysis of financial results should be read in conjunction with the audited consolidated financial statements of the Trust for the fiscal years ended December 31, 2002 and 2001 presented below. This commentary is based on information available to March 10, 2003.

Where amounts and volumes are expressed on a barrel of oil equivalent (boe) basis, gas volumes have been converted to barrels of oil at 6,000 cubic feet per barrel.

The year 2002 was very successful from a growth standpoint with production increasing 24% to 25,782 barrels of oil equivalent per day (boe/d) in 2002 from 20,810 boe/d in 2001. Production for the second half of 2002 averaged 27,139 boe/d. The growth was due to $60 million of property acquisitions completed at the end of 2001 and in the first quarter of 2002, and the acquisition of NCE Energy Trust ("NCE Energy") effective May 31, 2002.

One of the key objectives of management was to acquire and amalgamate NCE Energy into NCE Petrofund as the Trusts had similar mandates and strategies and were already under common management. The NCE Energy purchase significantly increased the market capitalization of NCE Petrofund, eliminated duplicate reporting costs, corporate expenses, transfer agent and other costs, and simplified operations. The acquisition also increased the percentage of operated properties and, therefore, provided more control over costs and the timing of capital projects.

Oil prices were fairly strong throughout the past two years, averaging US$26.08 on the benchmark West Texas Intermediate (WTI) barrel in 2002 compared to US$25.90 in 2001. In the past two years, there were two quarters of relative price weakness, the fourth quarter of 2001 when oil averaged US$20.43 and the first quarter of 2002 when the price averaged US$21.64.

Monthly AECO prices averaged $4.25 per mcf in 2002, compared to $6.30 per mcf in 2001, a decrease of 33%. Over the course of 2001, the AECO price declined from an average of $13.62 per mcf in January (a level significantly higher than experienced in recent years) to $3.74 per mcf in December. The AECO gas price remained weak through the first nine months of 2002, averaging $3.67 per mcf, before rising significantly to $5.26 per mcf in the fourth quarter. The daily AECO price reached its high for the year of $6.75 per mcf in December 2002.

Cash flow from operating activities increased from $110.2 million in 2001 to $112.6 million in 2002. The 24% increase in production on a boe basis was largely offset by the lower gas prices.

Significant Financial Transactions

On January 17, 2002, NCE Petrofund announced the acquisition of two property packages for $19.8 million. The acquisition costs were reflected in the 2001 year-end financial statements and the results of operations from the properties are reflected in this report, effective January 1, 2002.

The acquired properties had a reserve life index of 18.1 years and consisted mainly of unitized production. The most significant unit interest acquired was in Swan Hills Unit #1. Production at the date of acquisition was approximately 700 boe/d, of which 95% was oil. According to independent engineering estimates, established reserves were 4.7 million boe.

On March 5, 2002, NCE Petrofund announced the purchase of two gas-producing properties and two oil-producing properties in central Alberta for $40.2 million. Three of the properties are unitized and one is operated. Net established reserves acquired were estimated at 8.8 million boe and net production at the date of acquisition was 1,800 boe/d, consisting of 67% oil. The properties had a reserve life index in excess of 13 years.

On March 28, 2002, NCE Petrofund closed a “bought deal” financing of Trust units raising gross proceeds of $59.8 million. A total of 4.6 million units were issued at $13.00 per unit.

On April 19, 2002, NCE Petrofund signed an agreement whereby NCE Petrofund would acquire NCE Energy on the basis of 0.2325 of an NCE Petrofund Trust unit for each NCE Energy unit on a tax-free rollover basis. On May 31, 2002, NCE Petrofund completed the acquisition for $140.1 million. The total price consisted of the issue of 7.6 million Petrofund units with an assigned value of $98.6 million, the assumption of $39.5 million of debt and negative working capital, as well as transaction costs of $2.0 million. The purchase price of $140.1 million does not include the $27.1 million added to oil and gas properties to reflect the difference between the cost and the tax basis of the properties acquired. Production from the properties at the time of acquisition was approximately 5,300 boe/d, representing a cost of $26,500 per boe/d, excluding the non-cash component of the purchase price. Approximately 50% of the production was gas.

On December 31, 2002, NCEP acquired producing gas properties in the Fort Saskatchewan, Alberta area from ATCO Gas for $31.5 million. NCEP will operate the properties and holds an average 95% working interest. Current production net to NCEP is approximately 6 mmcf/d and the established reserves acquired were approximately 19 bcf.

During the year, the Trust also spent $40.8 million for exploratory and development drilling, well-equipping costs, facilities and tie-ins. The Trust drilled 290 gross (72.7 net) gas wells, 40 gross (10.6 net) oil wells and had 4 gross (3.3 net) dry holes for an overall success rate of 96%. The drilling added approximately 1,750 boe/d of production at $23,500 per boe/d and established reserves of 3.8 million boe at a cost of $10.64 per boe, including equipping and facility costs. A significant portion of the capital expenditures were incurred to convert proved undeveloped reserves to developed and, therefore, did not add reserves.

In total, the Trust incurred net capital expenditures of $229.3 million in 2002, excluding future income taxes of $27.1 million, and replaced 206% of its 2002 production. Established reserves of 19.4 million boe, net of revisions were added. The cost was $8.42 per boe excluding the reserve revisions and $11.79 per boe after giving effect to the revision. A number of minor non-core properties with short reserve life indexes and high operating costs were sold for $30.0 million at a price of $8.94 per boe.

Cash Distributions
Trust unitholders who held their units throughout 2002 received cash distributions of $1.71 per unit as compared to $4.24 per unit in 2001, and $3.99 in 2000. During the first two months of 2003, the Trust distributed $0.31 per unit.

The Trust generated cash flow available for distributions of $103.1 million in 2002. The cash flow was reduced by $10 million for capital expenditures during the last half of the year in accordance with our revised distribution policy to use a portion of the cash flow generated to offset production decline and enhance long-term unitholder returns. The $10 million represents 17% of cash flow for the six-month period. A total of $85 million was paid out in distributions, representing a payout ratio of 83%.

At December 31, 2002, the Trust had $30.1 million available to pay future distributions, capital and other costs, of which $16.8 million was used to pay the January and February 2003 distributions. There is approximately a two-month delay between collecting revenues and the payment of distributions.

Production Revenue

	2002	2001	2000
Production			
Oil (bbl/d)	11,162	8,156	5,784
Gas (mmcf/d)	76.9	67.2	49.3
NGLs (bbl/d)	*1,808*	*1,452*	*1,001*
Total (boe/d – 6:1)	25,782	20,810	14,998
Sales Prices			
Oil per bbl (1)	$34.68	$34.37	$39.99
Gas per mcf (2)	3.95	5.09	4.76
NGL per bbl	*28.30*	*32.57*	*38.19*
Weighted average (6:1)	$ 28.77	$32.19	$33.66
Production Revenue (millions)			
Oil	$141.3	$102.3	$ 84.7
Gas	110.7	125.0	85.8
NGLs	18.7	17.2	14.3
Total	$270.7	$ 244.5	$184.8
(1) The oil price was increased (decreased) per bbl due to hedging	$(2.10)	$ 1.05	$ (2.24)
(2) The gas price was increased (decreased) per mcf due to hedging	$ 0.00	$(0.13)	$ (0.17)

Revenues from the sale of crude oil, natural gas and natural gas liquids increased 11% to $270.7 million in 2002 from $244.6 million in 2001 due to a 24% increase in production. Prices declined 11% on a boe basis.

Crude oil sales rose to $141.3 million in 2002 from $102.3 million in 2001 due to a 37% increase in production from 8,156 bbl/d in 2001 to 11,162 bbl/d in 2002. The average Canadian wellhead price increased marginally from $34.37 per barrel in 2001 to $34.68 per barrel in 2002.

Natural gas sales decreased to $110.7 million in 2002, from $125.0 million in 2001 in spite of the 14% rise in production. The average price decreased 22% from $5.09 per mcf in 2001 to $3.95 per mcf in 2002. Production volumes were 76.9 mmcf/d in 2002, compared to 67.2 mmcf/d in 2001. Gas prices were weak throughout most of the first nine months of 2002, averaging $3.57 per mcf, then rose to $5.15 per mcf in the fourth quarter.

Sales of natural gas liquids increased to $18.7 million in 2002 from $17.2 million in 2001 as production rose to 1,808 bbl/d in 2002 from 1,452 bbl/d in 2001. The average price declined from $32.57 per barrel in 2001 to $28.30 per barrel in 2002.

Crude oil sales accounted for 43% of total production volumes in 2002 (2001 – 39%), while natural gas sales contributed 50% of production in 2002 (2001 – 54%). Natural gas liquid volumes accounted for 7% of total production in 2002 (2001 – 7%). The Trust continues to maintain an excellent balance between oil and gas production.

Royalties	**2002**	**2001**	**2000**
Royalties (millions)	$ 50.4	$ 54.8	$ 39.2
Average royalty rate (%)	19%	22%	21%
$/boe	$ 5.36	$ 7.21	$ 7.13

Royalties, which include Crown, freehold and overrides paid on oil and gas production, decreased to $50.4 million in 2002 from $54.8 million in 2001, net of the Alberta Royalty Credit. Royalties declined to 19% of revenues in 2002 from 22% of revenues in 2001 and 21% in 2000, mainly due to the lower average gas prices.

Expenses	**2002**	**2001**	**2000**
Expenses (millions)			
Lease operating	$ 74.8	$ 48.2	$ 28.7
General & administrative	15.5	14.4	8.8
Management fee	4.7	5.3	4.4
Net interest	8.3	7.8	6.0
Expenses per boe			
Lease operating	$ 7.95	$ 6.35	$ 5.23
General & administrative	1.65	1.90	1.60
Management fee	0.50	0.70	0.80
Net interest	0.88	1.03	1.10

Lease Operating

Oil and gas operating expenses were $74.8 million in 2002, up from $48.2 million in 2001 due to the additional wells on production resulting mainly from acquisition and the increase in costs on a boe basis. Operating costs on a boe basis increased to $7.95 in 2002 from $6.35 in 2001 due to increased production optimization work performed on existing and newly acquired properties, as well as higher repair and maintenance and utility costs. The current year costs also include an under accrual of prior year costs of $5.5 million, or $0.58 per boe, including a $1 million loss on a utility power hedge, primarily relating to the properties acquired from Magin Energy Inc. (“Magin”).

General and Administrative
General and administrative costs increased to $15.5 million in 2002 from $14.4 million in 2001. The 2001 costs include $2.6 million relating to a U.S. offering which was withdrawn mainly due to the events of September 11, 2001. One of our major objectives has been to reduce general and administrative costs on a boe basis. Major progress has been made - costs have been reduced from $1.78 per boe in the first half of 2002 to $1.53 per boe in the second half. We expect this downward trend to continue into 2003.

Upon completion of the internalization transaction described below under the heading “Management Fees”, the Trust’s management will be consolidated in Calgary, which is expected to reduce future general and administrative costs. To ensure an orderly transition of the services currently provided by the manager through its Toronto office, upon completion of the internalization transaction, an affiliate of the manager will enter into an agreement effective January 1, 2003 to provide certain of these services to the Trust until December 31, 2003, for a maximum fee of $2 million.

Management Fees
Management fees decreased to $4.7 million in 2002 from $5.3 million in 2001 in spite of the increase in cash flow from operations, as the fee was reduced to 3.25% from 3.75% effective January 1, 2002. This percentage applies to net operating revenue including the Alberta Royalty Credit.

As announced on March 10, 2003, the Trust has entered into an agreement to internalize its management structure such that NCE Petrofund Management Corp., the manager of the Trust, would become a wholly owned subsidiary of NCEP. Completion of the transaction is subject to unitholder and regulatory approval. If completed, all management, acquisition and disposition fees payable to the manager would be eliminated effective January 1, 2003. The purchase price payable by the Trust will be $23.6 million, subject to adjustment, to be satisfied by the issuance of 1,939,147 exchangeable shares. Each exchangeable share will be exchangeable into one NCE Petrofund unit, subject to adjustment to reflect distributions paid after the date of closing. Each unit or exchangeable share is valued at $12.1703, the weighted average trading price of NCE over the 10 trading days ending March 4, 2003 on the Toronto Stock Exchange. In addition, at closing NCEP will pay $3.4 million in cash to fund the repayment of indebtedness owing by the manager and an aggregate of $2 million to certain senior executives of the manager, such payment to be comprised of $780,000 in cash and 100,244 units, subject to adjustment.

Interest
Interest expense increased to $8.3 million in 2002 from $7.8 million in 2001, due to the increase in the average loan balance outstanding.

Depletion and Depreciation and Provision for Reclamation and Abandonment
Depletion and depreciation is provided on the unit-of-production method based on total estimated proven reserves. Depletion and depreciation expense was $98.8 million in 2002 compared to $68.5 million in 2001 (2000 - $30.6 million). The depletion rate per boe

increased to $10.50 in 2002 from $9.01 in 2001 and $5.57 in 2000. The $1.49 increase in the depletion rate from 2001 to 2002 was due to the increase in the acquisition costs of properties and negative reserve revisions. Unproved properties are included in the depletion and depreciation rate. The provision for reclamation and abandonment per boe in 2002 was $0.62, compared to $0.48 in 2001 (2000 - $0.42).

Reclamation and Abandonment Reserve
At the end of the year, NCEP had $3.0 million set aside in cash to fund future abandonment costs. This cash fund is increased by $0.075 per boe produced on an ongoing basis. The fund is maintained to provide for unusual or exceptionally large reclamation and abandonment costs. Ongoing well abandonment costs are paid from cash flow.

Working Capital
Accounts receivable increased by $29 million, as $22.9 million is due on the sale of properties, and joint and other receivables increased as a result of the purchase of NCE Energy Trust.

Prepaid expenses and deferred charges increased by $5.5 million due to cash calls paid on capital projects, prepaid royalty deposits and deferred costs on the purchase of hedge contracts.

Current liabilities increased by $19 million due to the increase in distributions payable to unitholders.

Liquidity and Capital Resources
The Trust completed a public offering in 2002, raising net proceeds of $56.3 million and generated cash flow from operating activities of $112.6 million. The Trust paid out $85 million in distributions in 2002 including $12.2 million accrued at December 31, 2001.

The credit facility was increased from $165 million to $200 million on February 28, 2002 and from $200 million to $245 million on July 3, 2002. At year-end, there was $212 million outstanding.

NCEP incurred net capital expenditures of $229.3 million during 2002, of which $154.9 million was financed by the issue of units for the Energy Trust acquisition and from the equity offering and $84 million by an increase in the bank loan.

As at December 31, 2002 NCEP had drilling and other commitments of approximately $1 million.

Accounting Changes
As discussed in Note 3d to the financial statements, the Trust and NCEP were consolidated effective with the third quarter of 2000 and the prior periods have been restated.

Quarterly Financial

($millions, except per unit amounts)	Net Oil and Natural Gas Sales*	Net Income	Net income per unit Basic	Net income per unit Diluted

2002				
First quarter	$ 42.7	$ 0.9	$ 0.02	$0.02
Second quarter	53.1	8.5	0.17	0.17
Third quarter	55.8	9.6	0.18	0.18
Fourth quarter	68.6	5.4	0.10	0.10
	$ 220.2	$ 24.4	$ 0.49	$0.49
2001				
First quarter	$ 54.4	$ 26.3	$ 1.19	$1.19
Second quarter	46.9	16.4	0.60	0.60
Third quarter	45.4	7.7	0.20	0.20
Fourth quarter	43.0	3.6	0.09	0.09
	$ 189.7	$ 54.0	$ 1.71	$1.71
2000				
First quarter	$ 26.1	$ 8.8	$ 0.55	$0.55
Second quarter	32.6	12.1	0.65	0.65
Third quarter	39.8	17.5	0.89	0.89
Fourth quarter	47.1	24.5	1.12	1.12
	$ 145.6	$ 62.9	$ 3.31	$3.30

*Net after royalties

Business Risks

The success of the Trust in meeting its objective of stable distributions over the long term depends mainly on management's ability to:

1) Identify and acquire oil and gas properties and/or companies at prices that add value to the Trust.
2) Cost effectively add or extend reserves with internal development and drilling or farm-outs.

3) Manage and control costs.

There are numerous factors beyond management's control that have a major influence on distribution levels including product prices, unforeseen production declines and cost increases from major suppliers. (A much more detailed assessment of risk factors and strategies to offset them appears elsewhere in this report.)

Below is a table that shows sensitivities to pre-hedging cash flow as a result of product price and operational changes. The table is based on actual 2002 prices and production volumes.

Change to annual cash flow

	Change	$ 000s	$/unit
Price per barrel of oil (US$ WTI)*	$ 1.00	$ 5,865	$ 0.117
Price per mcf of natural gas (C$ AECO)*	$ 0.10	2,217	0.044
US / Cdn exchange rate	$ 0.01	2,363	0.047
Interest rate on debt	1.0%	1,710	0.034
Oil production volumes - 100 bbl/d*	0.77%	1,094	0.022
Gas production volumes - 1 mmcf/d*	1.30%	1,139	0.023

* After adjustment for estimated royalties.

Outlook

Looking ahead to 2003, we intend to continue with our acquisition strategy to add value through the purchase of long-life production. It is our expectation that more properties will come available on the market as a result of non-core property divestitures by the large E&P companies, and NCEP will participate in the review and evaluation process of these properties. We will also continue with our drilling, development and optimization programs as a complement to our base strategy. We expect to continue to grow but we are more focused on providing good yields to our unitholders while, at the same time, maintaining unit value.

In the event that the internalization transaction announced on March 10, 2003 is completed, we expect to be able to further reduce general and administrative costs on a boe basis, a trend which has already become evident in the second half of 2002.

Impact of New Canadian Accounting Pronouncements

In November 2002, the Canadian Institute of Chartered Accountants ("CICA") amended the effective date of its accounting guideline on hedging relationships, which was originally issued in November 2001. The guideline establishes certain conditions where hedge accounting may be applied. It is effective for fiscal years beginning on or after July 1, 2003. The guideline will not have a significant impact on the Trust's financial position or results of operations.

In December 2002, the CICA issued a new standard on the accounting for asset retirement obligations. This standard, as with the new U.S. standard (FAS 143) described in Note 16 to the consolidated financial statements, requires recognition of a liability for the future retirement obligations associated with property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The new standard is effective for all fiscal years beginning on or after January 1, 2004 but earlier adoption is encouraged. The Trust expects to adopt this standard effective January 1, 2003. The impact of the effect of this new standard on the consolidated financial statements has not been determined.

Other accounting standards issued by the CICA during the year ended December 31, 2002 are not expected to impact the Trust at this time.

Controls and Procedures

Evaluation of disclosure controls and procedures. The Trust's principal executive officer and its principal financial officer, after evaluating the effectiveness of the Trust disclosure controls and procedures (as defined in U.S. Exchange Act Rules 13a-14(c) and 15d-14(c)) as of a date within 90 days prior to the filing date of this annual report, have concluded that, as of such date, the Trust's disclosure controls and procedures were adequate and effective to ensure that material information relating to the Trust and its subsidiaries would be made known to them by others within those entities.

Changes in internal controls. There were no significant changes in the Trust's internal controls or in other factors that could significantly affect the Trust's internal controls subsequent to the date of their evaluation, nor were there any significant deficiencies or material weaknesses in the Trust's internal controls. As a result, no corrective actions were required or undertaken.

Statement of Corporate Governance

NCE Petrofund's Statement of Corporate Governance is included in the Information Circular for the Annual General Meeting, which is being mailed to unitholders at the same time as this Annual Report.

Forward-looking Statements

Some of the statements contained herein including, without limitation, financial and business prospects and financial outlooks, may be forward-looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and other similar expressions have been used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, changes in general economic and market conditions and other risk factors. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, we cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and we assume no obligation to update or revise them to reflect new events or circumstances.

Forward-looking statements and other information contained herein concerning the oil and gas industries and our general expectations concerning these industries are based on estimates prepared by us using data from publicly available industry sources as well as from reserve report, market research and industry analysis and on assumptions based on data and knowledge of these industries which we believe to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While we are not aware of any misstatements regarding any industry data presented herein, the industries involve risks and uncertainties and are subject to change based on various factors.

EXHIBIT 2

Management's Report

These financial statements are the responsibility of the management of NCE Petrofund, NCE Petrofund Management Corp. ("Management"). They have been prepared in accordance with generally accepted accounting principles using Management's best estimates and judgments, where appropriate.

Management is responsible for the reliability and integrity of the financial statements, notes to the financial statements and other financial information contained in this report. Estimates are sometimes necessary in the preparation of these statements because a precise determination of some assets and liabilities depends on future events. Management has based these estimates on careful judgments and believes they are properly reflected in the accompanying financial statements. Management is also responsible for maintaining a system of internal controls designed to provide reasonable assurance that assets are safeguarded and that accounting systems provide timely, accurate and reliable financial information.

The Board of Directors of NCE Petrofund is responsible for ensuring that Management fulfills its responsibilities for financial reporting and internal controls. The Board meets with Management to ensure that management's responsibilities are fulfilled, to review financial statements and to recommend approval of the financial statements. An independent auditor appointed by Management, Deloitte & Touche LLP, has audited the financial statements of NCE Petrofund in accordance with generally accepted auditing standards and has provided an independent professional opinion.

By: /s/ John F. Driscoll
Title: Chief Executive Officer

By: /s/ John Vooglaid
Title: Chief Financial Officer

Toronto, Canada
March 10, 2003

Auditors' Report

TO THE UNITHOLDERS OF NCE PETROFUND:

We have audited the consolidated balance sheet of NCE Petrofund (an Ontario open-ended investment trust) as at December 31, 2002 and the consolidated statements of operations, unitholders' equity and cash flows for the year then ended. These financial statements are the responsibility of the management of NCE Petrofund Management Corp. Our responsibility is to express an opinion on these financial statements 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 financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

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

The consolidated financial statements of NCE Petrofund as at December 31, 2001, and for each of the years in the two-year period then ended were audited by other auditors who have ceased operations. Those auditors expressed an opinion without reservation on those financial statements in their report dated February 15, 2002.

Calgary, Alberta
March 10, 2003

By: /s/ Deloitte & Touche LLP
Chartered Accountants

Consolidated Balance Sheet
(thousands of dollars)

As at December 31	2002	2001
Assets		
Current assets		
Cash	$ -	$ 1,917
Accounts receivable	41,953	12,965
Due from affiliates	164	-
Prepaid expenses	10,090	4,584
Total current assets	52,207	19,466
Reclamation and abandonment reserve (*Note 7*)	3,001	2,073
Oil and gas royalty and property interests, at cost less accumulated depletion and depreciation of $354,309 (2001 - $255,532) (*Notes 2, 3 and 4*)	835,366	677,776
	$ 890,574	$ 699,315
Liabilities and unitholders' equity		
Current liabilities		
Bank overdraft	$ 1,572	$ -
Accounts payable and accrued liabilities	22,007	21,319
Payable to affiliates (*Note 4)*	2,168	1,056
Current portion of capital lease obligations *(Note 6)*	3,304	5,467
Distributions payable to unitholders	30,065	12,188
Total current liabilities	59,116	40,030
Long-term debt (*Note 5*)	212,253	128,783
Capital lease obligations *(Note 6)*	6,965	16,168
Future income taxes (*Notes 2, 3 and 13*)	116,845	104,000
Accrued reclamation and abandonment costs	15,298	11,632
Total liabilities	410,477	300,613
Unitholders' equity (*Note 8***)**	480,097	398,702
	$ 890,574	$ 699,315

Signed on behalf of NCE Petrofund by NCE Petrofund Management Corp., Manager of the Trust:

By: /s/ John Driscoll, Director

By: /s/Richard Zarzeczny, Director

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

Consolidated Statement of Operations

(thousands of dollars except per unit amounts)

For the years ended December 31	**2002**	**2001**	**2000**
Revenues			
Oil and gas sales	$ 270,669	$ 244,512	$ 184,764
Royalties, net of incentives	(50,427)	(54,746)	(39,155)
	220,242	189,766	145,609
Expenses			
Lease operating	74,774	48,237	28,715
Management fee *(Note 4)*	4,728	5,307	4,383
Interest on long-term debt *(Notes 5 and 6)*	8,291	7,806	6,048
General and administrative (*Note 4*)	15,514	14,436	8,764
Capital taxes	2,137	2,620	1,519
Depletion and depreciation	98,777	68,453	30,560
Provision for reclamation and abandonment	5,856	3,680	2,306
	210,077	150,539	82,295
Net income before provision for income taxes	10,165	39,227	63,314
Provision for (recovery of) income taxes *(Note 13)*			
Current	38	800	265
Future	(14,252)	(15,561)	143
	(14,214)	(14,761)	408
Net income	$ 24,379	$ 53,988	$ 62,906
Net income per Trust unit *(Notes 2 and 14)*			
Basic	$ 0.49	$ 1.71	$ 3.31
Diluted	$ 0.49	$ 1.71	$ 3.30

Consolidated Statement Of Unitholders' Equity

(thousands of dollars)

For the years ended December 31	**2002**	**2001**	**2000**
Balance, beginning of year	$ 398,702	$ 136,812	$ 97,309
Units issued, net of issue costs (*Note 8*)	154,460	318,548	72,614
Net income	24,379	53,988	62,906
Distributions accruing to unitholders	(97,444)	(110,646)	(96,017)
Balance, end of year	$ 480,097	$ 398,702	$ 136,812

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

Consolidated Statement of Cash Flows

(thousands of dollars except per unit amounts)

For the years ended December 31	2002	2001	2000
Cash provided by (used in):			
Operating activities			
Net income	$ 24,379	$ 53,988	$ 62,906
Add items not affecting cash:			
Depletion and depreciation	98,777	68,453	30,560
Provision for reclamation and abandonment	5,856	3,680	2,306
Future income taxes	(14,252)	(15,561)	143
Actual abandonment costs incurred (*Note 7*)	(2,190)	(384)	(402)
Cash flow from operating activities *(Note 14)*	112,570	110,176	95,513
Net change in non-cash operating working capital balances	(30,938)	18,334	1,716
Cash provided by operating activities	81,632	128,510	97,229
Financing activities			
Bank loan	83,470	14,216	89,883
Distributions paid	(85,218)	(126,883)	(76,454)
Capital lease repayments	(11,366)	(2,629)	-
Repayment of bank loan	-	-	(65,000)
Issuance of Trust units (*Note 8*)	55,821	161,409	72,614
Advances to affiliates *(Note 4)*	948	-	-
Cash provided by financing activities	43,655	46,113	21,043
Investing activities			
Reclamation and abandonment reserve (*Note 7*)	(706)	(447)	(322)
Acquisition of property interests	(158,516)	(177,729)	(123,620)
Proceeds on disposition of properties	30,019	3,736	6,496
Cash acquired on acquisition *(Note 3a)*	427	-	-
Cash used in investing activities	(128,776)	(174,440)	(117,446)
Net change in cash	(3,489)	183	826
Cash, beginning of year	1,917	1,734	908
Cash (bank overdraft), end of year	$ (1,572)	$ 1,917	$ 1,734
Cash flow from operating activities per Trust unit *(Note 14)*			
Basic	$ 2.25	$ 3.49	$ 5.02
Diluted	$ 2.25	$ 3.48	$ 5.01
Interest paid during the year	$ 8,016	$ 7,806	$ 6,048
Income taxes paid during the year	$ 1,281	$ 1,065	$ -

The accompanying notes to consolidated financial statements are an integral part of these consolidated financial statements.

Notes to consolidated financial statements

December 31, 2002, 2001 and 2000

(thousands of dollars except per unit amounts, unless otherwise stated)

1. ORGANIZATION

NCE Petrofund (the "Trust") is an open-ended investment trust created under the laws of the Province of Ontario pursuant to a trust indenture, as amended from time to time (the "Trust Indenture"), between NCE Petrofund Corp. ("NCEP") and Computershare Trust Company of Canada (the "Trustee"). Active operations commenced March 3, 1989. The beneficiaries of the Trust are the holders of the trust units ("Unitholders").

NCEP, a wholly owned subsidiary of the Trust, acquires oil and gas properties for its own account and sells a royalty interest (the "Royalty") to the Trust. The Royalty acquired from NCEP effectively transfers substantially all of the economic interest in the oil and gas properties to the Trust. The Trust is entitled to 99% of the production revenue from properties purchased by NCEP, less operating costs, general and administrative expenses, management fees, debt service charges (including principal and interest) and taxes payable by NCEP. The residual 1% interest in the properties retained in NCEP is used to reduce the amount of the management and other fees ultimately paid by the Unitholders (see Note 4).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared by the management of NCE Petrofund Management Corp. (the "Manager") following Canadian generally accepted accounting principles. The preparation of financial statements requires the Manager to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimated. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements.

(a) Basis of consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries, NCEP, 418187 Alberta Ltd. and 418189 Alberta Ltd. (collectively, the "Subsidiaries").

(b) Oil and gas royalty and property interests

Oil and gas royalty and property interests are accounted for using the full cost method of accounting whereby all costs of acquiring oil and gas royalty and property interests and equipment are capitalized. General and administrative costs and interest are not capitalized.

The provision for depletion and depreciation and the provision for site reclamation and abandonment costs are computed using the unit-of-production method based on the estimated gross proven oil and gas reserves. Proceeds on sale or disposition of oil and gas royalty and property interests are credited to oil and gas royalty and property interests, unless this results in a change in the depletion and depreciation rate by 20% or more, in which case a gain or loss is recognized in the consolidated statement of operations. The provision for reclamation and abandonment costs is accumulated as a long-term liability, which is reduced as actual expenditures are made.

The cost of the oil and gas royalty and property interests, net of accumulated depletion and depreciation, accrued reclamation and abandonment costs and future income taxes is limited to an amount equal to the estimated future net revenue, net of production-related general and administrative costs, reclamation and abandonment costs, and income taxes. Future net revenue was calculated using year-end oil and gas prices and costs.

(c) Distributions payable to Unitholders
Distributions payable to Unitholders are equal to amounts received or receivable by the Trust on the cash distribution date. Income earned, but not received, is distributed on the cash distribution date following receipt.

(d) Future income taxes
The Trust 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 the financial statements of the Subsidiaries and their respective tax bases, 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 or liabilities.

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 distributes all of its taxable income to the Unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for future income taxes in the Trust has been made.

(e) Net income and cash flow from operating activities per Trust unit
Basic net income per Trust unit and cash flow from operating activities per Trust unit are computed by dividing net income and cash flow from operating activities by the weighted average number of Trust units outstanding for the period. Diluted per unit amounts reflect the potential dilution that would occur if contracts to issue Trust units were exercised and Trust units were issued. The treasury stock method is used to determine the effect of dilutive instruments.

(f) Hedging activity
The Trust uses derivative instruments to reduce its exposure to commodity price fluctuations. Gains and losses on contracts, all of which constitute effective hedges, are deferred and recognized as a component of the price of the related transaction.

(g) Trust unit incentive plan
A Trust Unit Incentive Plan (the “Unit Incentive Plan”) has been established authorizing the issuance of options to acquire Trust units to directors, senior officers, employees and consultants of NCEP, the Manager, NCE Petrofund Advisory Corp., NCE Management Services Inc. (“NMSI”) and certain other related parties, all of whom are deemed to be employees of the Trust.

Effective for fiscal years beginning on or after January 1, 2002, the Trust adopted the recommendations of the CICA on accounting for stock-based compensation, which apply to new options granted on or after January 1, 2002. The Trust has elected to continue to measure compensation cost based on the intrinsic value of the award at the date of grant and recognize that cost over the vesting period. As the exercise price of the options granted approximates the market price of the Trust units at the grant date, no compensation cost has been provided in the statement of operations.

The exercise price of options granted under the Unit Incentive Plan may be reduced in future periods in accordance with the terms of the Unit Incentive Plan. The amount of the reduction cannot be reasonably determined as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and gas, and the determination of the amount to be withheld from future distributions to fund capital expenditures. Therefore, it is not possible to determine a fair value for the options granted under the Unit Incentive Plan.

As it is not possible to determine the fair value of options granted under the Unit Incentive Plan, compensation cost for pro-forma disclosure purposes has been determined based on the excess of the unit price over the exercise price at the date of the financial statements. For the year ended December 31, 2002, net income would be reduced by $60 for the estimated compensation cost associated with options granted under the plan on or after January 1, 2002, with negligible impact on net income per Trust unit.

3. ACQUISITIONS

(a) NCE Energy Trust

On May 30, 2002, NCE Petrofund acquired NCE Energy Trust for 0.2325 of an NCE Petrofund Trust unit for each NCE Energy Trust unit on a tax-free rollover basis. The value assigned to the NCE Petrofund Trust units of $13.024 per unit issued on the acquisition was based on the average market value of the NCE Petrofund units five days before and after the acquisition was announced.

The acquisition was accounted for using the purchase method. A summary of the net assets acquired is as follows:

Working capital	$	(39,518)
Oil and gas properties		165,254
Future income taxes		(27,097)
	$	98,639

Prior to the acquisition, NCE Petrofund advanced $37.3 million to NCE Energy Trust to pay down the bank debt of NCE Energy Trust.

(b) Magin Energy Inc. ("Magin")

On June 25, 2001, NCEP acquired 93.6% of the outstanding common shares of Magin and on July 3, 2001 acquired the remaining shares. Magin was amalgamated into NCEP on July 3, 2001.

In total, NCEP acquired 38,338,535 Magin common shares for $58.6 million in cash, 8.5 million Trust units with a deemed value of $18.56 per unit and the assumption of $43.7 million of debt including negative working capital, the outstanding bank loan and capital leases. In addition, other transaction costs of $11.8 million were incurred.

The acquisition was accounted for using the purchase method. A summary of the net assets acquired is as follows:

Working capital	$	(4,749)
Oil and gas properties		381,043
Bank loan		(21,569)
Capital leases		(17,359)
Future income taxes		(109,790)
	$	227,576

(c) Pacific Cassiar Limited

Effective December 1, 2000, NCEP acquired the shares of Pacific Cassiar Limited and three private companies (collectively, the "Companies") with interests in the same properties for $32.5 million including costs. NCEP accounted for this acquisition under the purchase method. The purchase price consisted of $323 of working capital and the remaining amount was allocated to oil and gas properties. In addition, future income taxes of $9.6 million based on the difference between the amount allocated to oil and gas properties and the tax basis of the properties were recognized and added to oil and gas properties. This amount is net of a future income tax asset of $5.3 million not previously recognized in NCEP. Current income taxes of $265 were paid on the taxable income of Pacific Cassiar Limited for the month of December in 2000 and $800 was paid for the period from January 1 to January 25, 2001. Effective January 26, 2001, the Companies were amalgamated into NCEP.

(d) Acquisition of Control of NCE Petrofund Corp.

On November 1, 2000, the Trust acquired all of the issued and outstanding common shares of NCEP for the nominal amount of $1. The purchase price reflects the fact that the Trust already received substantially all of the risks and rewards of ownership of NCEP through the Royalty. At the same time, the Unitholders of the Trust approved organizational changes to the Trust and NCEP such that the Unitholders now have effective representation on the board of directors of NCEP and elect a majority of the NCEP executive committee. Prior to this time, although the Trust received substantially all of the risks and rewards of ownership of NCEP through the Royalty, the Trust did not control NCEP. Therefore, NCEP was not a subsidiary of the Trust and its accounts were not consolidated with the accounts of the Trust for financial statement purposes.

The acquisition of NCEP has been accounted for as a continuity of interests to reflect the Trust's continuing interest in the operating activities of NCEP. This is similar to pooling of interest accounting in that the assets and liabilities of the Trust and NCEP are combined and accounted for in the consolidated financial statements at their historic carrying values for all periods presented. Consolidated income includes the income of the Trust and NCEP as if they had been combined since their inception.

4. RELATED-PARTY TRANSACTIONS

(a) Management, advisory and administration agreement

NCEP, the Manager and the Trust entered into an agreement, as amended from time to time, whereby the Manager will provide management, advisory and administrative services to NCEP and the Trust. During 1999 and the first three quarters of 2000, the Manager was paid a management fee equal to 5.0% of net operating income plus Alberta Royalty Credit. Effective October 1, 2000, the fee was reduced to 3.75% and on January 1, 2002 was reduced to 3.25%. In addition, the Manager receives an investment fee of 1.50% (1.75% prior to January 1, 2002) of the purchase cost of all properties purchased by NCEP other than replacement properties, and a disposition fee equal to 1.25% (1.5% prior to January 1, 2002) of the sale price of properties sold. During 2002, the Manager received a management fee from NCEP of $4,728 (2001 – $5,307, 2000 – $4,383). In addition, the Manager received investment fees of $1,268 (2001 – $5,195, 2000 – $1,735), which were capitalized as part of the acquisitions and disposition fees of $116 (2001 – $3, 2000 – $132), which reduced the proceeds of disposition. No management fees have been charged directly to the Trust.

Under the terms of the agreement, the Manager is also entitled to be reimbursed by NCEP for general and administrative expenses. In any year, NCEP shall reimburse the Manager no less than $240 and no more than 5% of gross production revenue for general and administrative expenses. To the extent that general and administrative expenses exceed 5% of gross production revenue, NCEP is entitled to set off and deduct the excess from its liability to pay management fees to the Manager.

(b) Management agreement

The Manager entered into an agreement with NMSI to provide oil and gas investment, consulting, administrative and management services to NCEP. An officer and director of the Manager is the sole beneficial shareholder of NMSI. During 2002 NCEP paid NMSI $11,672 (2001 – $9,345, 2000 – $6,828) for accounting and administrative services, which is included in general and administrative expenses and $838

(2001 – $1.4 million, 2000 – $1.5 million) for project sourcing and evaluation services, which have been capitalized to oil and gas properties, and $300 (2001 – $600, 2000 – $200) for marketing and other related equity issue costs. The amounts for general and administrative expenses paid to NMSI are subject to the same limitations noted for the Manager in (a) above.

5. LONG-TERM DEBT

Under the loan agreements, NCEP has a revolving operating facility of $25 million and a syndicated facility of $220 million. Interest on the operating facility is at prime and interest on the syndicated facility varies with NCEP's debt-to-cash-flow ratio from prime to prime plus 50 basis points or, at the Trust's option, Bankers' Acceptances rates plus stamping fees. As at December 31, 2002, there was $5 million outstanding under the working capital facility and $207 million outstanding under the syndicated facility.

The revolving period on the syndicated facility ends on May 30, 2003, unless extended for a further 364-day period. In the event that the revolving bank line is not extended at the end of the 364-day revolving period, no payments are required to be made to non-extending lenders during the first year of the term period. However, NCEP will be required to maintain certain minimum balances on deposit with the syndicate agent.

The limit of the syndicated facility is subject to adjustment from time to time to reflect changes in NCEP's asset base.

The credit facility is secured by a debenture in the amount of $350 million pursuant to which a Canadian chartered bank (the "Lender"), as principal and as agent for the other lenders, received a first ranking security interest on all of NCEP's assets.

The loan is the legal obligation of NCEP. While principal and interest payments are allowable deductions in the calculation of royalty income, the Unitholders have no direct liability to the bank or to NCEP should Bankers' Acceptances the assets securing the loan generate insufficient cash flow to repay the obligation.

Substantially all of the credit facility is financed with Bankers' Acceptances, resulting in a reduction in the stated bank loan interest rates of approximately 0.70%.

6. CAPITAL LEASE OBLIGATIONS

The future minimum lease payments under the capital leases are as follows:

2003	$	9,871
2004		423
2005		621
Total minimum lease payments		10,915
Less imputed interest at rates ranging from 6.88% to 8.43%		(646)
Obligation under capital leases		10,269
Current portion		(3,304)
Long-term portion	$	6,965

The bargain purchase option of $6 million due in 2002 was refinanced by long-term debt.
The bargain purchase option of $6 million due in 2003 will be refinanced by long-term debt.

7. RECLAMATION AND ABANDONMENT RESERVE

NCEP maintains a cash reserve to finance large and unusual oil and gas property reclamation and abandonment costs by withholding distributions accruing to Unitholders. At December 31, 2002, the cash reserve was $3,001 (2001 – $2,073, 2000 – $1,625). In 2002, NCEP increased the cash reserve by withholding $706 (2001 – $447, 2000 – $322) from distributions accruing to Unitholders. The reserve also includes $222 transferred to NCEP on the acquisition of NCE Energy Trust (Note 3a).

In addition, routine ongoing reclamation and abandonment costs of $2,190 in 2002 (2001 – $384, 2000 – $402) were incurred and deducted from distributions accruing to Unitholders.

8. TRUST UNITS

On July 6, 2001, the Trust units were consolidated on a one-for-three basis. All unit-related numbers including units outstanding, options outstanding and option prices, net income per unit and distributions per unit have been restated for all prior periods to reflect this consolidation.

	Number of units		Amount
Issued			
December 31, 1999	16,130,324	$	248,730
Issued for cash	5,741,667		79,250
Commissions and issue costs	-		(7,268)
Options exercised	27,555		424
Unit purchase plan	13,877		208
December 31, 2000	21,913,423		321,344
Issued for cash	11,183,334		167,350
Issued for Magin acquisition	8,464,399		157,139
Commissions and issue costs	-		(11,781)
Options exercised	341,305		5,620
Unit purchase plan	13,279		220
December 31, 2001	41,915,740		639,892
Issued for cash	4,600,000		59,800
Issued for NCE Energy acquisition	7,573,874		98,639
Commissions and issue costs	-		(4,190)
Options exercised	7,966		85
Unit purchase plan	10,184		126
December 31, 2002	54,107,764	$	794,352

The Trust has a Distribution Reinvestment and Unit Purchase Plan (the “Plan”). Under the terms of the Plan, Unitholders can elect, firstly, to reinvest their cash distributions and obtain either newly issued units of the Trust directly from the Trust or previously issued units of the Trust purchased in the open market and, secondly, to purchase for cash newly issued units directly from the Trust.

For the years ended December 31		2002		2001		2000
Distributions reinvested to acquire previously issued units	$	3,387	$	6,979	$	5,585
Price per unit	$	12.15	$	16.61	$	14.71
Number of units acquired		278,297		420,100		379,674

Distributions reinvested to acquire newly issued units	$	126	$	220	$	208
Price per unit	$	12.36	$	16.59	$	15.00
Number of units acquired		10,184		13,279		13,877

9. UNIT INCENTIVE PLAN

A total of 5,200,000 units may be reserved for issuance under the Unit Incentive Plan, of which 2,598,000 have been reserved for issuance at December 31, 2002. A summary of the status of the Unit Incentive Plan as of December 31, 2002, 2001 and 2000, and changes during the years then ended are presented below:

	2002		2001		2001	
	Units	Weighted Average Exercise Price	Units	Weighted Average Exercise Price	Units	Weighted Average Exercise Price
Options outstanding, beginning of year	1,840,190	$15.92	941,278	$16.71	612,167	$17.70
Issued	1,468,100	10.65	1,477,800	17.65	371,000	15.00
Forfeited	(272,044)	16.66	(237,583)	18.38	(14,334)	17.10
Exercised	(7,966)	10.65	(341,305)	16.47	(27,555)	15.39
Options outstanding before reduction of exercise price	3,028,280	$13.31	1,840,190	$17.29	941,278	$16.71
Reduction of exercise price	-	(0.10)	-	(1.37)	-	-
Options outstanding, end of year	3,028,280	$13.21	1,840,190	$15.92	941,278	$16.71
Options exercisable, end of year	1,593,681	$14.10	745,565	$16.08	693,945	$17.31

The options granted in 2002 and 2001 are exercisable at the original option prices, which were the market prices of the units on the date of the grants, or if so elected by the participant, at reduced prices as described below. The option prices are reduced for each calendar quarter ending after the date of the grant by the positive amount, if any, equal to the amount by which the aggregate distributions made by the Trust in any calendar quarter ending after the date of the grant exceed 2.5% of the oil and gas royalty and property interests on the Trust's consolidated balance sheet at the beginning of the applicable calendar quarter divided by the issued and outstanding units at the beginning of the applicable quarter.

The following table summarizes the options outstanding at December 31, 2002:

Number of Units	**Exercise Price**		**Reduced Exercise Price**		**Expiry Date**
197,850	$	15.00		N/A	May 8, 2005
628,124	$	19.35	$	16.88	January 30, 2006
423,872	$	17.25	$	15.44	April 4, 2006
321,000	$	14.71	$	13.95	July 20, 2006
1,457,434	$	10.65	$	10.57	July 25, 2007

10. DISTRIBUTIONS ACCRUING TO UNITHOLDERS

Under the terms of the Trust Indenture, the Trust makes monthly distributions within a specified period following the end of each month ("Cash Distribution Date"). Distributions are equal to amounts received by the Trust on the Cash Distribution Date less permitted expenses. Distributions to Unitholders coincide with cash receipts of royalty income from NCEP. An overall analysis is as follows:

For the period ended	Cash Distribution Date	2002	2001	2000
November 30	January 31	$ 0.15	$ 0.42	$ 0.27
December 31	February 28	0.15	0.42	0.30
January 31	March 31	0.13	0.42	0.33
February 28	April 30	0.13	0.42	0.33
March 31	May 31	0.14	0.45	0.33
April 30	June 30	0.14	0.45	0.33
May 31	July 31	0.14	0.36	0.33
June 30	August 31	0.14	0.32	0.33
July 31	September 30	0.14	0.25	0.36
August 31	October 31	0.15	0.25	0.36
September 30	November 30	0.15	0.25	0.36
October 31	December 31	0.15	0.23	0.36
Cash distributions per Trust unit		**$ 1.71**	**$ 4.24**	**$ 3.99**

Reconciliation of Distributions Accruing to Unitholders

(thousands of dollars except per unit amounts)

For the years ended December 31		2002		2001		2000
Distributions payable, beginning of year	$	12,188	$	28,425	$	8,862
Distributions accruing during the year						
Cash flow from operating activities		112,570		110,176		95,513
Proceeds on disposition of property interests		946		3,546		826
Reclamation and abandonment reserve		(706)		(447)		(322)
Less capital lease repayment (2)		(5,366)		(2,629)		-
Capital expenditures		(10,000)		-		-
Accrual for future debt repayment		-		-		7,000
Less discretionary debt repayment		-		-		(7,000)
Total distributions accruing during the year		97,444		110,646		96,017
NCE Energy Trust cash flow (1)		5,651		-		-
Total distributable income for the year		103,095		110,646		96,017
Distributions paid		(85,218)		(126,883)		(76,454)
Distributions payable, end of year	$	30,065	$	12,188	$	28,425
Distributions accruing to unitholder per Trust Unit (Note 14)						
Basic	$	2.07	$	3.50	$	5.05
Diluted	$	2.06	$	3.49	$	5.04

(1) Remaining undistributed cash flow of NCE Energy Trust on May 30, 2002 (see Note 3a).

(2) Net of $6 million refinanced by increased bank loan in 2002.

11. FINANCIAL INSTRUMENTS

The Trust's financial instruments consist of cash, accounts receivable, accounts payable and accrued liabilities, amounts due from and payable to affiliates, long-term debt, capital lease obligations and derivative instruments. As at December 31, 2002, the carrying values of the cash and accounts receivable and payable approximated their fair value due to their short-term nature. The carrying values of the long-term debt approximated its fair value due to the floating rate of interest charged under the facilities. The carrying values of the capital lease obligations is not significantly different from their fair values.

The derivative instruments have no carrying value (see Note 12). The derivative instruments at December 31, 2002 had a negative fair value of $1.2 million based on quotes provided by brokers. This fair value represents an approximation of amounts that would be paid to counterparties to settle these instruments at the balance sheet date. The Trust plans to hold all derivative instruments outstanding at December 31, 2002 to maturity.

12. DERIVATIVE FINANCIAL INSTRUMENTS AND PHYSICAL CONTRACTS

The Trust is exposed to risks resulting from fluctuations in commodity prices and interest rates. The Trust enters into various pricing mechanisms to reduce price volatility and establish minimum prices for a portion of its oil and gas production. These include fixed-price contracts and the use of derivative financial instruments.

The outstanding derivative financial instruments, all of which constitute effective hedges, and the related unrealized gains or losses, and physical contracts as at December 31, 2002 are summarized separately below:

Natural Gas	Term	Volume mcf/d	Price $/mcf	Delivery point	Unrealized gain (loss)
Call option (purchased)	July 1, 2001 to October 31, 2003	6,159	$4.91	AECO	$ 2,400
Collar	January 1, 2003 to March 31, 2003	14,212	$4.59 - $7.97	AECO	(46)
Collar	January 1, 2003 to March 31, 2003	4,737	$4.59 - $7.97	AECO	(6)
Collar	January 1, 2003 to March 31, 2003	4,737	$5.17 - $6.75	AECO	(55)
Collar	January 1, 2003 to March 31, 2003	4,737	$5.17 - $7.07	AECO	(13)
Collar	April 1, 2003 to October 31, 2003	4,737	$4.64 - $6.23	AECO	(510)
Collar	April 1, 2003 to October 31, 2003	9,475	$4.64 - $6.23	AECO	(1,051)
Collar	April 1, 2003 to October 31, 2003	4,737	$4.64 - $6.24	AECO	(308)
Total					**$ 411**

Oil	Term	Volume bbl/d	Price $/bbl	Delivery point	Unrealized gain (loss)
Fixed price	January 1, 2003 to January 31, 2003	2,000	$44.49	Edmonton	$ (271)
Fixed price	February 1, 2003 to February 28, 2003	2,000	$44.25	Edmonton	(193)
Collar	January 1, 2003 to June 30, 2003	2,000	$37.06-45.34	Edmonton	(728)
Three-way collar	March 1, 2003 to June 30, 2003	2,000	*(1)	Edmonton	(413)
Total					**$ (1,605)**

*(1) At prices above $45.87 Petrofund receives $45.87.
At prices between $38.65 and $45.87 Petrofund receives actual price.
At prices between $32.34 and $38.65 Petrofund receives $38.65.
At prices below $32.34 Petrofund receives actual price plus $6.31/bbl.

In addition to the financial instruments, the Trust has the following physical gas contract:

Natural Gas	Term	Volume mcf/d	Price $/mcf	Delivery point	Unrealized gain (loss)
Call option (sold)	November 1, 1999 to October 31, 2003	6,159	$3.17	AECO	$ (5,020)
Total					$ (5,020)

The gains or losses on the hedges are recognized on a monthly basis over the terms of the contracts and adjust the prices received.

Derivative financial instruments and physical contracts involve a degree of credit risk, which the Trust controls through the use of financially sound counterparties. Market risk relating to changes in value or settlement cost of the Trust's derivative financial instruments is essentially offset by gains or losses on the underlying physical sales.

13. INCOME TAXES

The future income tax liability (asset) includes the following temporary differences:

As at December 31	2002	2001	2000
Oil and gas properties	$ 119,825	$ 106,961	$ 10,305
Resource allowance	(2,980)	(2,961)	(534)
	$ 116,845	$ 104,000	$ 9,771

The provision for current and future income taxes differs from the result which would be obtained by applying the combined federal and provincial statutory tax rates to income before income taxes. This difference results from the following:

As at December 31	2002	2001	2000
Net income before income tax provision	$10,165	$39,227	$63,314
Income tax provision computed at statutory rates	$ 4,294	$ 16,915	$ 28,251
Effect on income tax of:			
Income attributed to the Trust	(24,435)	(32,665)	(28,251)
Non-deductible Crown charges, net of Alberta Royalty Credit	17,055	19,276	140
Resource allowance	(15,045)	(16,661)	(312)
Capital taxes	831	1,130	678
Income tax rate reductions on opening balances	-	(329)	-
Temporary differences in resource allowance	(19)	(2,427)	(907)
Increase (decrease) in valuation allowance	-	-	(276)
Other	3,105	-	1,085
Provision for (recovery of) income taxes	$ (14,214)	$(14,761)	$408

The petroleum and natural gas properties and facilities owned by the subsidiaries have a tax basis of $212 million ($153.3 million in 2001, $113.4 million in 2000) available for future use as deductions from taxable income. Included in this tax basis are non-capital loss carryforwards of $34.0 million ($33.6 million in 2001, $24.3 million in 2000), which could expire in various years through 2009.

14. NET INCOME AND CASH FLOW FROM OPERATING ACTIVITIES PER TRUST UNIT

Basic per unit calculations are based on the weighted average number of Trust units outstanding. Diluted calculations include additional Trust units for the dilutive impact of options. There were no adjustments to net income or cash flow from operating activities in calculating diluted per Trust unit amounts. A total of 1,676,934 options (2001 – 1,019,002 options; 2000 – 1,851,625 options) are anti-dilutive and therefore have not been included in the dilution calculations.

The weighted average units outstanding are as follows:

	2002	2001	2000
Basic	49,921,523	31,593,378	19,026,926
Diluted	49,967,648	31,635,976	19,049,086

Cash flow from operating activities was calculated by adding depletion and depreciation, provision for reclamation and abandonment, actual abandonment costs incurred and future income taxes to net income and dividing by the weighted average number of Trust units.

15. SUBSEQUENT EVENT

On March 10, 2003, the Trust announced plans to internalize its management structure and eliminate all management, acquisition and disposition fees payable to the Manager effective January 1, 2003. Under the terms of the agreements, the Manager will, prior to closing, acquire NCE Management Services Inc., which employs all of the individuals who provide services to Petrofund on behalf of the Manager. At closing, NCEP will purchase all the issued shares of the Manager from Petro Assets Inc., and the outstanding obligations of the Manager for cash of $3.4 million, and the issue of 1,939,147 exchangeable shares valued at $12.1703 per unit, representing the weighted average trading price of the units on the Toronto Stock Exchange over the 10 trading days ending on March 4, 2003. In addition, NCEP will provide an aggregate of $2 million to certain senior executives of the Manager, such payment to be comprised of $780,000 in cash and 100,244 units, subject to adjustment.

16. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")
(all amounts are stated in Canadian dollars)

The Trust's consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles, as they pertain to the Trust's consolidated financial statements, differ from United States generally accepted accounting principles ("U.S. GAAP") as follows:

(a) The Canadian GAAP ceiling test is comparable to the Securities and Exchange Commission ("SEC") method using constant prices, costs and tax legislation except that the SEC requires the resulting amounts to be discounted at 10%. In addition, the SEC does not require the inclusion of any general and administrative or interest expenses in the calculation.

(b) U.S. GAAP utilizes the concept of comprehensive income, which includes items not included in net income.

(c) Effective January 1, 2001, for U.S. reporting purposes, the Trust adopted Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments (including derivative instruments embedded in other contracts), as defined, be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met. There are no similar standards under Canadian GAAP at this time.

Hedge accounting treatment allows unrealized gains and losses to be deferred in other comprehensive income (for the effective portion of the hedge) until such time as the forecasted transaction occurs and requires that an entity formally document, designate and assess effectiveness of derivative instruments that receive hedge accounting treatment. Upon adoption, the Trust formally documented and designated all hedging relationships and verified that its hedging instruments are effective in offsetting changes in actual prices received by the Trust. Such effectiveness is monitored at least quarterly and any ineffectiveness is reported in other revenues (losses) in the consolidated statement of operations.

On the transition date, January 1, 2001, the Trust recognized a derivative liability of $7,139 related to its cash flow hedges.

A reconciliation of the components of the unrealized gain (loss) on derivatives included in accumulated other comprehensive income related to the Trust's derivative activities is presented below:

	Gross	After-Tax
Cumulative effect of change in accounting principle	$ (7,139)	$ (3,954)
Reclassification of net realized losses into earnings	98	56
Net change in derivative fair value	8,856	5,037
Effect of reduction in income tax rates	-	(107)
Accumulated other comprehensive income related to derivatives at December 31, 2001	1,815	1,032
Reclassification of net realized losses into earnings	8,668	5,007
Net change in derivative fair value	(11,264)	(6,506)
Effect of reduction in income tax rates	-	16
Accumulated other comprehensive income related to derivatives at December 31, 2001	$ (781)	$ 581

Under Canadian GAAP, compensation expense for options granted under the Unit Incentive Plan is measured based on the intrinsic value of the award at the grant date. For U.S. GAAP purposes, the Trust uses the intrinsic value method of accounting for compensation expense related to options granted. For options granted prior to January 1, 2001, the exercise price of the options was equal to the market price of the Trust units on the grant date and no compensation expense was recorded for U.S. GAAP purposes. For options granted in 2001 and subsequent years, the Unit Incentive Plan is a variable compensation plan as the exercise price of the options is subject to downward revisions from time to time. Accordingly, compensation expense is determined as the excess of the market price of the Trust units over the adjusted exercise price of the options at each financial reporting date and is deferred and recognized in income over the vesting period of the options. After the options have vested, compensation expense is recognized in income in the period in which a change in the market price of the Trust units or the exercise price of the options occurs. At December 31, 2001, the exercise price of the options granted under the Unit Incentive Plan exceeded the market price of the Trust units. Therefore, no compensation expense was recorded in 2001.

(e) **Recent Developments in U.S. Accounting Standards**
In June 2001, the U.S. Financial Accounting Standards Board issued Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 requires recognition of a liability for the future retirement obligations associated with property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. FAS 143 is effective for all fiscal years beginning after June 15, 2002. The impact of the effect on the consolidated financial statements at January 1, 2003 has not been determined.

In November 2002, the FASB issued Interpretation No. 45, "Guarantors' Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 elaborates on the disclosures that must be made regarding obligations under certain guarantees issued by the Trust. It also requires that the Trust recognize, at the inception of a guarantee, a liability for the fair value of the obligations undertaken in issuing the guarantee. The initial recognition and initial measurement provisions are to be applied to guarantees issued or modified after December 31, 2002. Adoption of these provisions will not have a material impact on the Trust's financial position or results of operations. The disclosure requirements are effective for annual or interim periods ending after December 15, 2002.

In January 2003, the FASB issued Statement No. 148 "Accounting for Stock-Based Compensation – Transition and Disclosures, an Amendment of FASB Statement No. 123" (FAS 148). FAS 148 amends FAS 123 "Accounting for Stock-Based Compensation", to provide alternative methods of transition for a voluntary change to the fair-value-based method of accounting for stock-based employee compensation. In addition, FAS 148 amends the disclosure requirements of FAS 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. FAS 148 will not have a material impact on the Trust, as the Trust Unit Incentive Plan is a variable compensation plan.

The following standards issued by the FASB do not impact the Trust:
• Statement No. 145 – "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," effective for financial statements issued on or after May 15, 2002;
• Statement No. 146 – "Accounting for Costs Associated with Exit or Disposal Activities," effective for exit or disposal activities initiated after December 31, 2002;
• Statement No. 147 – "Acquisitions of Certain Financial Institutions – an Amendment of FASB Statements No. 72 and 144 and FASB Interpretation No. 9," effective for acquisitions on or after October 1, 2002; and
• Interpretation No. 46 – "Consolidation of Variable Interest Entities," effective for financial statements issued after January 31, 2003.

The application of U.S. GAAP would have the following effects on net income as reported:

	2002	**2001**	**2000**
Net income as reported in consolidated statement of operations	$ 24,379	$ 53,988	$ 62,906
Adjustments (net of tax)			

Unrealized loss on derivatives		(238)		-		-
Compensation expense		(59)		-		-
Depletion and depreciation		17,338		993		1,059
Ceiling test write down		-		(154,937)		-
Deferred income taxes		(1,339)		-		-
Net income (loss), as adjusted		40,081		(99,956)		63,965
Unrealized gain on derivatives, net of income taxes of $1,113 (2001 - $783)		(1,483)		1,032		-
Comprehensive income (loss)	$	38,598	$	(98,924)	$	63,965
Net income (loss) per unit, as adjusted						
Basic	$	0.77	$	(3.16)	$	3.36
Diluted	$	0.77	$	(3.16)	$	3.36
Accumulated other comprehensive income						
Opening balance at January 1	$	1,032	$	-	$	-
Unrealized gain (loss) on derivatives, net of income taxes of $1,113 (2001 - $783)		(1,483)		1,032		-
Closing balance at December 31	$	(451)	$	1,032	$	-

The application of U.S. GAAP would have the following effects on the consolidated balance sheets as reported:

		As reported		**Increase (Decrease)**		**U.S. GAAP**
December 31, 2002						
Oil and gas derivative instruments	$	-	$	(1,194)	$	(1,194)
Oil and gas royalty and property interests, net		835,366		(198,651)		636,715
Future income taxes		116,845		(58,344)		58,501
Unitholders' equity		480,097		(141,501)		338,596
December 31, 2001						
Oil and gas derivative instruments		-		1,815		1,815
Oil and gas royalty and property interests, net		677,776		(223,203)		454,573
Future income taxes		104,000		(65,609)		38,391
Unitholders' equity		398,702		(155,779)		242,923
December 31, 2000						
Oil and gas royalty and property interests, net		281,044		(2,867)		278,177
Unitholders' equity		136,812		(2,867)		133,945

EXHIBIT 3

Independent Auditors' Consent

We consent to the inclusion in this annual report of NCE Petrofund on Form 40-F of our report dated March 10, 2003 on our audit of the consolidated balance sheet of NCE Petrofund as at December 31, 2002 and the consolidated statements of operations, unitholders' equity and cash flows for the year ended December 31, 2002.

(signed) “Deloitte & Touche LLP”

Chartered Accountants
Calgary, Alberta, Canada

March ___, 2003